Australian Energy Market Commission

FINAL RULE DETERMINATION

National Electricity Amendment (Demand Response Mechanism and Ancillary Services Unbundling) Rule 2016

Rule Proponent(s)

COAG Energy Council

24 November 2016

RULE CHANGE

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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

Demand response is a type of demand side participation, which is actions a consumer can take to alter or shift its electricity consumption in response to changing market conditions. In the National Electricity Market (NEM), the supply side of the market provide electricity at a price, and the demand side, consumers, directly or indirectly through a service provider respond to the price or the value of the product or service presented to them based on that price.

There are various ways in which demand can respond or participate in the market. Demand response provides consumers with a suite of options to manage their electricity consumption and, in turn, their expenditure. By actively participating in the market through such options, demand for electricity services is efficiently met through the lowest cost combinations of demand and supply side options. Other demand side participation options provide opportunities for usually larger consumers, to use their load in a way that maximises its value.

Demand side participation options may include direct participation in the wholesale energy market, the ancillary services market, or it may provide system reliability or network support services. The energy market has developed innovative solutions to facilitate consumers' demand response, reflecting the absence of any barriers in the Rules to demand side participation.

The Australian Energy Market Commission (the Commission) has made a final rule that would facilitate more demand side participation in ancillary services markets. Reform must add value for consumers. Unbundling the provision of ancillary services from the sale of energy will provide another demand side participation option for consumers.

In light of the absence of any regulatory barriers in the Rules to the uptake of demand side participation, the Commission has not made a rule to implement the proposed demand response mechanism. The Commission acknowledges that demand response can be of benefit where it is an efficient form of market response to price signals. However, the proposed mechanism is costly and adds little benefit to consumers, because the benefits of demand side participation can, and already are, accessible under current arrangements. While the Commission acknowledges that there may currently be commercial reasons that complicate access to demand response for some consumers, implementing a market wide mechanism in the Rules, at considerable cost to all consumers, is not the appropriate vehicle to address these reasons. Nor would it encourage an efficient level of demand response.

Overview of the final rule

The final rule, which is a more preferable final rule, would provide for a new type of market participant – a market ancillary service provider. This new participant is able to offer appropriately classified ancillary services loads or aggregation of loads into FCAS markets. The market ancillary service provider need not be the retailer. By not requiring the provider to purchase electricity from the wholesale market for a customer, as a retailer currently does, the provision of demand response services by a

market ancillary service provider in FCAS markets becomes independent of, or 'unbundled' from, retailers. Allowing for the 'unbundling' of the supply of ancillary services from the retail supply of electricity will enable an increase in levels of demand side participation in FCAS markets. This 'unbundling' will increase the diversity of suppliers of ancillary service in FCAS markets.[1]

Deeper and more diverse FCAS markets have the potential to provide improved system security services by increasing the competition among suppliers of ancillary service in FCAS markets and so leading to more efficient FCAS prices. More and greater diversity in providers of ancillary services would complement the increased penetration of intermittent and non-synchronous generation that is occurring in the NEM.

The key features of the final rule can be summarised as follows:

- the creation of a new a market participant – a market ancillary service provider
    - any person, including third-party service providers, as well as retailers are able to register as a market ancillary service provider subject to meeting eligibility requirements. Registration as a market ancillary service provider allows a party to offer a customer's load, or an aggregation of loads, directly into FCAS markets without having to be the customer's retailer.
    - in practice, this means that while a customer has a retail supply contract with a retailer, a customer may have a separate contract with a market ancillary service provider (who may be another retailer) to provide ancillary services. In this case, the ancillary service contract sits alongside the existing electricity retail contract.
- a market ancillary service provider is required to meet registration requirements and have appropriate arrangements in place with the retail customers before being able to offer the customers' loads into FCAS markets.
- a market ancillary service provider is also required to have all the appropriate systems in place, and deliver the FCAS service in accordance with AEMO's market ancillary services specifications just as any other market participant currently is required to do.
- in providing FCAS services, a market ancillary service provider is required to submit FCAS offers to the relevant FCAS markets in accordance with the provisions in the National Electricity Rules.

During consultation on the draft determination the Commission became aware of a restriction in the technical specifications AEMO requires its FCAS providers to meet that currently only allows regulation FCAS to be provided by individual loads, not through the aggregation of loads. This means that without amending the technical specification market ancillary service providers may offer individual loads into both regulation and contingency FCAS markets but may only offer aggregated load into the contingency FCAS market. The Commission recommends that AEMO review the

1 FCAS services are used by AEMO to stabilize the frequency of the electricity system around a nominal level.

relevant market specifications from which this restriction arises, to consider whether these technical limitations can be overcome or removed given stakeholders have suggested they can.

The Commission considers there is still benefit in unbundling the provision of FCAS services regardless of the current technical restriction identified above. The unbundling allows the market to develop and will facilitate more providers of FCAS to participate in those markets as the technical restrictions are resolved and technologies evolve.

The rule change request

The Commission has made this draft determination in response to a rule change request from the COAG Energy Council (the Energy Council). The Energy Council consider that the rule change request will address barriers for effective demand side participation in the energy and ancillary services markets, improve the role of the demand side in determining a price for energy in the wholesale spot market and improve the lack of competition in the provision of ancillary services. In addition to the unbundling of the provision of ancillary services from the purchase and sale of electricity in the wholesale spot market, the rule change request also sought to implement a demand response mechanism (DRM) to enable large customers to sell demand response in the spot market.

Demand response mechanism

While the Commission acknowledges that commercial negotiations around demand response contracts are not without difficulty, the Commission was unable to identify any barriers in the Rules that would prevent demand response from taking place in the wholesale market. Nor were any Rules based barriers raised during stakeholder consultation. The demand side can already participate in a number of ways and can include actions such as, peak demand shifting, changing consumption patterns or load control of consumption and consumers generating their own electricity. The DRM included in the rule change request seeks to separate some of these demand side participation actions from the retailing of electricity in order to improve the market's ability to provide demand response using the loads of large customers. Participation in the mechanism was not proposed to extend to small customers at least initially and so was beyond scope of this rule change request.

The market provides a range of innovative services to facilitate consumers' demand response without a standardised market wide mechanism for demand response. The Commission's survey of the market reflects that retailers do offer, or are willing to offer, a range of products and services intended to facilitate customers' demand response and there is evidence of a competitive demand side management market. These demand side management providers offer a broad range of services and products. This range includes demand response services that help consumers identify opportunities for when they can benefit from curtailment of their load (consumption), support to run tenders to help customers with large loads exploit the value of their demand response capabilities or provide wholesale spot prices forecasting or related technologies to allow larger consumers to manage wholesale spot price risk directly.

These services are able to take place independently from the retailing of electricity. It reflects that delivering demand response to retailers through the use of standardised baseline consumption methodologies, a key feature of the proposed DRM, is becoming increasingly obsolete. To implement the DRM is not only unnecessary but, in light of its costs and distortionary impacts, is likely to reduce incentives for consumers to access a wider range of tools to manage wholesale electricity spot price fluctuations. This could now impede the customer driven transformation in relation to demand response that is already underway in the market.

The Commission appreciates that the DRM would provide an additional demand side participation option and that demand response, in and of itself, can be of benefit to market participants. However, such an option is not without significant costs, both related to its implementation - which would effectively need to require mandatory participation by all retailers for the mechanism as designed to work – and to its use of baseline consumption methodologies, in which being able to establish a baseline that accurately reflects consumption absent demand response can be challenging and costly if inaccurate.

The Commission has determined not to make this aspect of the rule change request.

Overview of determination to not implement the DRM

The Commission considers that implementing the DRM would not be in the long term interests of consumers because the benefits of the proposed DRM do not outweigh its implementation costs for the reasons outlined below.

Demand response can and already is happening in the NEM. There are no barriers to the continued proliferation of demand response that is currently underway.

Market developments and innovation by demand side management providers means that large customers now have a greater range of opportunities to take on exposure to wholesale market prices directly or provide demand response services to retailers and/or networks when they consider it is of most value to them.

Importantly, these developments and innovations are evolving in response to consumer demands and preferences. The Commission's survey evidence reflects consumers are seeking more flexible and tailor made products than products calculated relative to standardised baselines, as envisaged by the DRM. They are already choosing to use more sophisticated products and services, including flexible contractual arrangements that cater for specific needs which allow them to manage the wholesale price risk by themselves rather than relying on their retailer.

There are no barriers to large customers entering into commercial arrangements with retailers and network businesses or accessing a relatively competitive demand side management service market to help take advantage of their demand response capabilities. A survey of the market[2] reveals currently, there are at least 21 businesses

2 See Oakley Greenwood, Current status of DR in the NEM – Interviews with electricity retailers and DR specialist service providers, http://www.aemc.gov.au/Rule-Changes/Demand-Response-Mechanism

capable of providing a variety of products and services, with a presence across all major jurisdictions in the NEM. There has been an increase in large customers opting to use their demand response capabilities through these products and the services of DSM service providers to manage the spot price risk themselves. Retailers no longer seem to have an exclusive role in managing spot price risk for large customers. There is a consistent view between retailers and demand side management service providers that this form of demand side participation is likely to increase in the future.

The Commission notes that this range of products and services is likely to increase and extend to smaller customers as the market reforms commenced by the PoC review start to take effect from 1 July 2017. The distribution network pricing arrangements rule[3] should facilitate pricing and product alternatives that will allow customers to value their demand response. For example, some networks have implemented time of use tariffs as part of more cost reflective networks tariffs designed to allow consumers compare the value they place on using the networks with the costs of using it. A customer could utilise a time of use tariff to reduce its demand at relevant times and be rewarded in doing so. The expanding competition in metering services rule[4] will provide the tools through which large customers can access a wider range of services or products that values their demand response.

It is clear from market developments that retail supply and demand response are not bundled, as the proposed demand response mechanism assumed. Demand side management service providers and retailers already compete to provide wholesale price risk management services to large customers. Customers that shop around for better retail supply deals can get better deals if they make their demand response capabilities available to their retailer. If offers are unsatisfactory, customers now have the option to contract the services of a demand side management service provider to make the most of their demand response capability and manage wholesale price risk themselves. Networks are also starting to compete with retailers to contract a customer's demand response capabilities, primarily for the network benefits that they offer.

The Commission has been unable to find evidence of a relevant market failure that would prevent the current demand side participation arrangements in the market from delivering the benefits identified as arising from the implementation of the demand response mechanism in the cost benefit analysis submitted with the rule change.

There is also no evidence that there are insufficient incentives on retailers to offer demand response services. The Commission's survey evidence, and stakeholder feedback, reflects that retailers do make demand response services available and some are proactive about it. It is in retailers' interests to maximise the demand response of their customers, particularly their large customers, because it allows them to better manage the spot price risk that they are fully exposed to. A retailer can offer better retail supply deals when it takes advantage of a customer's demand response.

3 *National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014 No.9.*

4 *National Electricity Amendment (Expanding competition in metering and related services) Rule 2015 No.12.*

However, a customer will only take advantage of demand response related retail product where the value of its demand response exceeds its costs of responding.

The DRM would not result in overall savings to consumers through lower electricity prices

The DRM would not result in lower electricity prices principally because of four factors:

1. Under the DRM, spot prices will not reflect competition from demand response.

In the proposed DRM demand response would be self-scheduled by a new market participant, a demand response aggregator. Only scheduled (or semi scheduled) generation and loads are included in central dispatch,[5] which determines wholesale market prices. Demand response under the proposed DRM is not scheduled and hence its price effects are no different from the demand response occurring currently in the market.

This is a variation from the original DRM specifications proposed by the Commission as part of its PoC recommendations, where it was envisaged that demand response would be scheduled by AEMO through central dispatch rather than by a demand response aggregator outside of it.

Currently, AEMO's pre-dispatch and dispatch processes do not explicitly take into account the intentions of non-scheduled market loads to respond to price signals. That is, AEMO does not take into consideration demand response. Whether it should do so, and whether this would improve the accuracy of demand forecasts, is being considered by the Commission in a separate rule change request.[6]

Without pre-dispatch and dispatch processes taking account of demand response, demand response cannot directly compete with generation as the rule proponent considered it would. Any demand response facilitated by the DRM would compete with generation the same way as demand response currently active in the market already does, that is outside of central dispatch.

2. The DRM requires costly changes to the wholesale market and retailer systems

AEMO has estimated the costs to change the spot market systems to allow the demand response aggregator to participate in the spot market through the DRM in the region of $8 to $14 million.

In addition, retailers will also incur implementation costs to change billing systems to accommodate consumers wishing to use the DRM. These are likely to be extensive (up to $112 million) but the exact size of these costs is influenced by whether participation in the mechanism is voluntary or mandatory.

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5 AEMO operates central dispatch to balance the power system supply and demand. It aggregates information from market participants and aims to obtain the least cost resources to balance supply and demand in the power system, while maintaining its reliability and security.

6 See the Non-scheduled generation and load in central dispatch consolidated rule change request http://www.aemc.gov.au/Rule-Changes/Non-scheduled-generation-in-central-dispatch

If the DRM were implemented on a voluntary basis, that is, retailers could choose to allow their customer to participate or not, the extent of these implementation costs is difficult to know. This is because the incentive to allow customers to participate in the DRM and incur the implementation costs is low. Where participation in the DRM is voluntary all the benefits associated with a customer's demand response accrues to the demand response aggregator, with the retailer being left to continue to manage the risk of price fluctuations in the wholesale market, as it currently does. The retailer, who under the DRM is expected to incur all its implementation costs but receive none of its benefits, will be better off in developing demand response arrangements directly with a customer outside of the DRM because under such arrangements a retailer will be able to manage the risk of wholesale market price fluctuations and receive the benefit of doing so.

If participation in the DRM were made mandatory, retailers will include risk premiums into its pricing, to provide for the fact that it must still manage the risk of price fluctuations in the wholesale market without receiving the benefit of the customer's demand response. This will result in higher prices being paid by consumers for their electricity. Further, with mandatory participation, all retailers have to incur high costs to upgrade their systems. These costs would have to be recovered from either those customers that participate in the DRM or all customers. If it is the former, this cost could discourage participation in the DRM. If it is the latter then the DRM will lead to increased electricity prices without any benefits for some customers.

3. The DRM will not necessarily alleviate network constraints and defer network expenditure

The DRM would only achieve this outcome if peaks in wholesale market prices coincided with network peak demands. This is not necessarily so.

Demand response is usually triggered by a peak in spot market prices. This provides a price signal to decrease consumption over paying the high price in the wholesale market. Network constraints do not necessarily coincide with wholesale market price peaks. In order to address network constraints with demand response, the response would have to take place at specific locations and times within the network that coincide with those constraints and in sufficient magnitude in order for the demand response to have a positive impact.

4. The DRM can have unintended consequences and create distortions in the spot market and other related markets.

Implementing the DRM may have unintended consequences and create distortions in the spot market as well as in other related markets, such as retail, financial (hedging) and demand response services markets.

The costs of these distortions would be borne by consumers in the form of higher electricity prices and in the absence of any net benefits accruing from the implementation of the DRM, is not in their long term interests.

These distortions are summarised as follows:

- the DRM would distort efficient economic outcomes in the spot market because under the DRM less reliable self-scheduled demand response resources would be rewarded equivalently to more reliable, firm scheduled resources in the spot market.[7]

- as retailers that participate in the DRM would continue to be financially responsible for their customers' baseline consumption, an outcome of the DRM may be that customers pay for a retailer's hedging costs through their retail contract even if they provide demand response. Furthermore, if demand response is achieved by shifting the load to another time period, customers would face increased retail costs as their consumption, at times, would increase relative to the baseline. Although customers are expected to receive payments from demand response aggregator for their demand response services, the net outcome for customers is difficult to estimate.[8]
- under the DRM, the demand for financial hedging contracts would remain the same as retailers would continue to remain financially responsible for the baseline consumption of their customers. The availability (supply) of hedging contacts, will depend on the generators being successfully able to generate during high price events. If demand response is successful in displacing generation during high price events, then there will be an imbalance between demand and supply in the hedging market. The retailer would still seek to enter into hedging arrangements as it is exposed to the spot price to the extent of the baseline consumption but the generator would no longer be able to offer a hedging contract; this will lead to an increase in hedging contract prices.
- competition among demand response aggregators under the DRM, combined with the lack of responsibility for inaccurate baselining, may create strong incentives for demand response aggregators to implement the most 'generous' of available baseline methodologies. Demand response aggregator's and customers' incentives are also aligned in potentially 'gaming' the baseline. Whilst such outcome may be mitigated, the cost of monitoring and enforcement will ultimately be passed onto consumers.

Expected benefits of the final rule

The Commission considers that the final rule will, or is likely to, better contribute to the National Electricity Objective (NEO) because it will unbundle the provision of the ancillary services from the provision of electricity by allowing other parties to offer them. This will increase competition among and diversity of suppliers in FCAS markets. Providing for this unbundling in the regulatory framework will also increase demand response opportunities for consumers in FCAS markets. Importantly it achieves this without the associated costs and distortions that are likely to arise from the implementation of the DRM.

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7 Under the proposed demand response mechanism the market operator is not able to dispatch demand response. In fact it may not even be aware of the demand response. This means that the market operator cannot rely on demand response to the same extent as it can on dispatched scheduled generation.

8 The expected wealth transfers of the proposed DRM are further detailed in Annex F.

Differences between the draft and final rule

The final rule is consistent with the draft rule in policy intent and effect. The final rule includes minor changes from the draft rule to change the eligibility criteria relevant to market ancillary service provider registration, removes the need for market ancillary service providers to have to meet prudential requirements (consistent with other providers of ancillary services) and provides for transitional arrangements to accommodate AEMO’s recent participant fees determination.

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1 COAG Energy Council's rule change request

1.1 The rule change request

On 30 March 2015 the COAG Energy Council (Energy Council) submitted a rule change request proposing to:

- introduce a demand response mechanism (DRM) within the National Electricity Market (NEM) that would create a new demand side participation option for large customers through the wholesale spot market. This mechanism would allow customers, or third-parties acting on customers' behalf, to directly participate in the spot market and receive the spot price for changes in their electricity demand; and
- unbundle the provision of ancillary services from the purchase and sale of electricity in the spot market. This aspect of the rule change request is referred to as ancillary services unbundling (ASU proposal) in this determination.

The rule change request was related to recommendations made by the AEMC in 2012 in the Power of choice (PoC) review.

In early 2013 the Energy Council requested AEMO to develop, in consultation with stakeholders, a detailed design of the DRM and ASU proposal as well as a corresponding draft rule.

In December 2013, the Energy Council requested AEMO to defer lodgement of the rule change due to a "change in market circumstances since the initiative was initially proposed"[9] and to undertake a cost-benefit analysis to understand the merits of implementing a DRM considering the evolving market conditions. The cost-benefit analysis was completed by Oakley Greenwood[10] and it concluded that implementing a DRM could still deliver a net benefit going forward. This cost benefit analysis has also been submitted as part of this rule change request.

On the basis of the cost-benefit analysis, the Energy Council considered there is merit in considering a DRM, based on a voluntary and staged approach, rather than mandating that all retailers allow their customers to participate in the DRM.

1.2 Current demand side participation arrangements

The demand side in the NEM can participate and provide value in the market in a variety of ways. Table 1.1 below provides an overview of the existing demand side participation options in the NEM for large customers.

Those demand side participation options relevant to this rule change request are further explained immediately below.

9 Standing Council on Energy and Resources, Meeting Communiqué, See https://scer.govspace.gov.au/files/2013/12/SCER-Communique-DEC-2013-v.2.pdf

10 Oakley Greenwood, Cost-Benefit analysis of a possible Demand Response Mechanism, Oakley Greenwood, 9 December 2014

Table 1.1 Demand side participation options in the NEM

Relevant aspect of the NEM	Spot market	Retailer DR program	Ancillary services market	Reliability services	Network support services
Objective	Become exposed to the spot price directly through the spot market	Participate through a retail contract: a) Accept a degree of spot price exposure; b) Retailer to manage spot price risk while customer's demand response capability is valued through contracts	Provide services to balance supply and demand in short time scales to maintain system frequency to AEMO	Provide system reliability services to AEMO	Provide demand response services that are an alternative to planned network augmentation, constraint management or voltage support.
Mechanism	Become a Market Customer in the spot market either as a scheduled or a non-scheduled load	Agreement with the retailerin the form of: a) Spot price pass-through contract; b) Demand response contract; c) Customised time of use tariff	Become a market customer in the spot market	Participate in the reliability and emergency reserve trader (RERT) program	Actively supported by a range of regulatory incentives schemes and contractual requirements (e.g. Demand Management Incentive Scheme, Network Loading Control Ancillary Services)

The following sections provide further details of some of the above demand side participation options that are relevant to this rule change request.

1.2.1 Participation through the spot market

As described in Table 1.1, current market arrangements allow the demand side to participate directly in the spot market. For example, a large customer can register as a Market Customer in the spot market to buy its energy requirements directly from the spot market. Registration requires the large customer to bear the risks of becoming exposed to the spot price and comply with the NER.[11]

A large customer registered as a Market Customer in the spot market also has the opportunity to voluntarily schedule its load. Scheduling load is the most 'integrated' way for a large customer to participate in the wholesale energy market.[12] This is because all scheduled and semi-scheduled participants are required to submit to AEMO their initial bids for each of the 30 minute trading intervals by 12:30 pm the day

11 For example, this would require the customer to become subject to the spot market prudential requirements, pay ancillary services costs and participation fees

12 In October 2015, at the request of the AEMC, the Brattle Group conducted an international review of demand response mechanisms. Similarly to the NEM, the review found that all three energy-only markets considered have a mechanism in place that allows the demand side to directly participate in wholesale energy markets through submitting bids into a market dispatch process. See p 25, 28 and 39. The report is available on AEMC's website http://www.aemc.gov.au/Rule-Changes/Demand-Response-Mechanism

before the trading day.[13] The bids specify the quantities and prices at which scheduled generators/loads are willing to supply/consume electricity. AEMO uses the information contained in all of the individual bids to create a bid stack representing the known supply and demand intentions of scheduled participants. In the NEM, each of the six regions has its own regional spot price that is determined based on supply and demand in that region. In the NEM, the settlement price is based on the average of the six five-minute dispatch interval prices over the 30-minute trading interval. The price at which the generator or load is dispatched (the dispatch price) is calculated by reference to the bid submitted by the last dispatched market participant (marginal bidder).

Demand participating in this fashion enhances economic efficiency and benefits the market as a whole.[14] However, participating in central dispatch large customers may lose some flexibility over their consumption decisions and may incur come costs to comply with requirements. This often discourages customers from pursuing this demand side participation avenue.[15]

1.2.2 Participation through a retailer's DR program

Retailers offer a number of products and services that allow customers to participate in the energy market under a variety of different options. Customers participating in such programs are generally large customers but are not necessarily registered to participate in the market directly. For example, customers might be willing to accept full or partial exposure to spot market prices through a spot price pass-through contractual arrangement with a retailer. Customers may then undertake measures to manage this exposure. For example, they may engage energy management experts to manage their electricity price exposure through their energy use. Another (weaker) form of DR participation may include negotiating a time of use tariff with the retailer. Under this option customers are incentivised to shift their load from peak (high price) time periods to off-peak (lower price) periods.

Other customers might prefer the retailer to manage the spot price risk on their behalf and pay the retailer a premium for this service. In these instances, some retailers might also offer commercial arrangements – referred to as demand response contracts in Table 1.1 above - that reward customers for their willingness to reduce demand upon receiving a request from the retailer. Customers may be rewarded through lower retail

13 Generally, the sellers' (generators') price is referred to as offers whereas the buyers' (loads') price is referred to as bids. In order to remain consistent with the terminology used in the Rules and language often used in the industry, in this determination the term bid will be used for both.

14 See for example the Brattle Report p iii and iv.

15 This outcome is not specific to the NEM. The Brattle report also reports minimal demand side participation in central dispatch in other energy-only markets such as the ones operating in Texas and Alberta. This is likely to be due to the costs of purchasing real-time telemetering equipment and the reduction in operational flexibility for the customer. See the Brattle Report p iv.

tariff rates, an arbitrage payment between the spot price and the applicable retail tariff rate or an availability payment.[16]

The commercial arrangements referred to above are private arrangements. AEMO has no role in administering the settlement of these contracts or in administrating baseline consumption methodologies[17] that might be used as part of these arrangements.

1.2.3 Participation in the ancillary services market

Ancillary services are essential to the management of power system security by AEMO, facilitate orderly trading in electricity and ensure electricity supplies are of acceptable quality. These services maintain key technical characteristics of the system, including standards for frequency, voltage, network loading and system restart processes. In the context of the spot market the most relevant services provided are frequency control ancillary services (FCAS) used to maintain the frequency of the system under normal conditions and/or to restore operating frequency following a contingency event. Loads and generating units that provide FCAS are paid by AEMO for the type(s) of FCAS that they are enabled to provide during a given dispatch interval. The price of the FCAS is set based on bids and offers submitted FCAS providers. For this reason, the NER refers to FCAS as market ancillary services.[18]

Under the current NER only a party that is registered as a Market Customer may provide FCAS services through the control and operation of its load.

1.3 International review of demand response mechanisms

In 2015 the Commission has commissioned the Brattle Group[19] to review how the demand side participates in six different energy markets. Three of the six markets reviewed are based on an energy-only market design (Singapore, Alberta and Texas), like the NEM, while the remaining markets incorporate a capacity mechanism complementing their market design (PJM, ISO-NE and Ontario).[20] In addition, the

16 For example, see Oakley Greenwood, The Impact of Late Rebidding on the Provision of Demand Response by Large Electricity Users in the NEM, Oakley Greenwood, 25 November 2014, Section 3, p 9.

17 A common problem to demand response arrangements is the measurement of the load reduction provided by the customer. To calculate the load reduction typically a 'counterfactual' is calculated to determine the consumption level in absence of demand reduction. These methodologies are called baseline consumption methodologies. These are an integral part of the DRM proposal. See Annex C for details regarding the baseline consumption methodologies proposed in the rule change request.

18 The service tends to be used over time frames of several seconds or minutes. This necessitates metering at a much more refined scale than the one currently used for settlement purposes in the NEM.

19 In October 2015, at the request of the AEMC, the Brattle Group conducted an international review of demand response mechanisms. The report is available on AEMC's website http://www.aemc.gov.au/Rule-Changes/Demand-Response-Mechanism

20 Some wholesale electricity market designs incorporate a mechanism to pay capacity resources to be available to provide energy. Other market designs, including the NEM, are 'energy only' and do not have explicit capacity mechanisms.

Commission also assessed some of the European energy-only markets to compare their demand response arrangements to the ones proposed in the DRM. Neither the Brattle Report nor the Commission was unable to identify demand response programs in any of the energy-only markets studied that would share important design elements with the proposed DRM.

What is clear from both the Brattle Group review, and the Commission's own research is that there are no DRM –like arrangements in any market that is designed similarly to the NEM (i.e. an energy only market). Stakeholders who make reference to demand response mechanisms operating in other markets are referring to DRM like mechanisms operating in capacity markets which are fundamentally different in design to the NEM.[21]

The Brattle Report also reflects that the energy-only markets reviewed have similar demand side participation options to the ones available in the NEM.[22] Although several energy-only markets refer to demand response arrangements, the term is typically used in relation to what we understand in the NEM to be ancillary services or reserve trading arrangements. For example, Alberta's program is similar to the ancillary services market in the NEM and Texas' program is similar to the Reliability and Emergency Reserve Trader (RERT) program in the NEM. The currently available demand side participation options in the NEM are summarised in Table 1.1.

1.3.1 Demand side participation in international energy markets

Demand side participation options in the Albert and Texan energy markets are similar to the ones in the NEM; customers can voluntarily bid their loads (demand) into the central dispatch system. Similarly to the NEM, the participation rate by loads in the central dispatch has been low in both markets.[23] This is due to similar reasons why demand does not voluntarily participate in the NEM; while demand side bids would reduce reliance on the system operator's demand forecasts, this comes at a cost for loads as they would be subject to market rules, including having to comply with bidding and dispatch instructions.

Other similarities exist between Alberta's energy market and the NEM. For example, in Alberta, just like in the NEM, there is a difference between dispatch prices and the settlement prices and the lack of alignment between dispatch and settlement prices

21 In capacity markets the market operator (or a grid operator) is required to maintain long term balance of supply and demand. This is typically achieved through procurement of contracts. In these markets there is no functional difference between a megawatt of power from a power plant and a megawatt of reduced power from demand response as both may serve to achieve the balance

22 These were discussed in section 1.2 and summarised in Table 1.1.

23 According to the Brattle Report, load reductions attributable to price-responsive load ranged from about 1% of peak load in Texas to more than 2% in Alberta, although the exact amounts are difficult to determine. Brattle Report, page iii.

was identified as one of the key contributors to low demand side participation in 2005 review.[24]

In Singapore a demand response mechanism was recently introduced in the wholesale electricity market. The program is intended to improve overall system efficiency and deliver cost savings to contestable customers. The program requires demand-side bidding, and demand response is dispatched by the market operator. Contestable customers (i.e. customers other than residential and small business) may participate directly, through their retailers or through demand response aggregators.

Participants are required to submit bids indicating their willingness to reduce volume at different price points, with the minimum volume unit being 0.1 MW. Consumers can simultaneously offer their loads into both the wholesale market and as an interruptible load (i.e. into the reserves system), although dispatch can only be into one.

This demand response program is similar to the one proposed in this rule change request. However, the Singapore model is also different from the one proposed in the rule change request in important ways:

- Rather than the system operator implementing a baseline consumption methodology, demand response aggregators are required to bid their baseline demand into central dispatch.[25] This overcomes the need for an administratively-determined baseline;
- It is the system operator's decision rather than that of the participant when and how much demand response is provided, i.e. the demand response is scheduled through central dispatch;
- Participants are required to register all their loads, to bid their demand response into dispatch and to follow dispatch instructions. Participants face penalties if energy consumption does not closely follow their baseline demand (when not dispatched) or their promised demand response (when dispatched);
- Payments for demand response are not guaranteed. Rather than receiving a wholesale price, successful participants receive a share (a third) of their price impact, if there is any. The market clearing engine is run twice to establish the market price with and without demand response. If the demand response results in a reduction of price, participants are entitled to one third of their price impact. This payment is capped at $4,500/MWh, which is the wholesale electricity price cap;

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24 The Five minute settlement rule change request currently under consideration by the AEMC is also assessing the potential benefits from the alignment of settlement and dispatch prices. Further details are available on the AEMC website: **aemc**.gov.au/Rule-Changes/**Five-Minute**-Settlement

25 Participants are allowed to include a ramp rate in its bids. This ramp rate is treated similar to generator ramp rates. Compliance is based on deviations from dispatch signals, which is constrained by the provider's ramp rate bid.

- Retailers are "kept whole" because they are settled on the basis of metered load;[26] and
- The program caters for those who wish to opt out by calculating settlement prices for participants and non-participants. The market clearing engine is run with and without demand response in each trading period to achieve this.

French energy market

In Europe there are different levels of implementation and participation in demand response programs. In France the market design is particularly favourable for demand response. For each market area there is a Balancing Responsible Party (BRP) that must balance generation (supply) and load (demand). The BRP can be a generator, a retailer or an aggregator and is required to estimate the energy requirements and negotiate (usually longer-term) contracts with generators to meet these requirements. Demand estimates and corresponding generation contracts are required to be submitted to the Transmission System Operator (TSO) prior to gate closure. Any changes in demand or generation after the gate closure require an adjustment through trading in the intra-day market.

If there is any "deviation from balance" the TSO will use ancillary services to achieve system balance and this will be paid by BRP whose estimates necessitated the ancillary services. In the context of the French market, when BRPs are responsible for the procurement of generation contracts to meet the demand, and the market design includes a gate closure, it is logical for BRPs to then seek the demand flexibility of loads. In particular, it is within the balancing market context (i.e. after gate closure) that demand response opportunities exist.

However, there are fundamental differences between the French and Australian markets:

- In France the BRP (whether a generator, retailer or aggregator) has responsibility for contracting their area volumes and balancing generation and load. This means retailers and large customers have to forecast their load, in addition to generators forecasting their supply. In Australia while generators have to schedule their supply through central dispatch, there is no equivalent forecast obligation on retailers or large customers. Instead AEMO undertakes the system balancing function without firm demand side commitments; and
- In France there are financial consequences for parties that create system imbalance. If the BRP's area is not in balance the TSO will 'balance out' the system by procuring ancillary services. These services have an availability and dispatch component, are generally more expensive than in Australia, and are charged to the entity causing the imbalance. This creates an incentive for

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26 An additional incentive payment to demand response providers is paid from an uplift charge applied to all participating retailers. Retailers were provided with a "one-time" option to opt-out of the program. Retailers that opted out would not have been able to participate subsequently, and would not be required to pay the uplift. However, retailers that opted out would not pay the regular system price: they would pay a higher system price estimated for the counterfactual scenario where demand response did not participate in the market. In any event, no retailers opted out.

market participants to have accurate forecasts. There are no equivalent requirements or incentives on Australian retailers or large customers as these participants do not have ‘causer pays’ settlement factors and the ancillary costs of the imbalances they cause are ‘socialised’ across the market.

1.3.2 Demand side participation in international ancillary service markets

Demand response is commonly referenced in literature discussing the market arrangements in Alberta and Texas. The term refers to arrangements that are similar to the ancillary service (Alberta) and reserve trader arrangements (Texas) rather than a DRM. The purpose and the design of these programs substantially differ from that of the DRM.

The Brattle Report indicates that in energy-only markets (like the NEM), demand side participation in the ancillary service markets is common. For example, load participation in ancillary service provision in Texas and in Alberta are higher with respect to other markets considered in the review. In general, the principles that underpin the ancillary service arrangements in the energy-only markets studied are similar to the ones in the NEM.

A common feature of the ancillary service markets examined in the Brattle Report is that rather than responding to energy prices, participating loads are paid for their availability in the ancillary service market. Therefore, the load receives some payment and probably will be able to continue to operate as normal, unless it is requested to provide the service. By participating in the ancillary service market, the load does bear the risk of having to curtail when the market operator directs the load in response to an event. Again, this is similar to the arrangement in the NEM where market ancillary services such as regulation and contingency frequency control services are paid for being ‘enabled’ over a period rather than for actually providing the service.

In Alberta, the market operator procures ancillary services either through a day-ahead market or through tenders.

For example, the Load Shed Service for Imports (LSSi) is an under-frequency interruptible load service procured through tenders to support the intertie with British Columbia. The technical and geographic characteristics of the Alberta market are such that a large interconnector with neighbouring British Columbia is a significant source of (relatively cheap) supply. The interconnector is so large that the amount of import capacity that can be used is sometimes limited by the quantity of fast-acting frequency support within the Alberta market that would be available if the interconnector were to trip. This constraint (rather than the physical characteristics of the interconnector itself) limits the quantity of imports, at least in some hours. The LSSi program was specifically designed to allow demand response providers to supply additional frequency support over and above the quantity available from generation. The program has been successful in bringing additional frequency support to the market and permitting a greater quantity of import.

In Texas, under the Load acting as a Resource (LaaR) program, loads are eligible to provide Responsive Reserves. LaaR participants have to meet similar requirements to generators, including installing telemetry equipment and demonstrating their ability to respond to dispatch instructions on the required timeframe. Loads were initially limited to providing 25% of the total Responsive Reserve requirement, but this limit was increased to 50% by 2006.[27] This type of demand response is similar to the RERT arrangements in the NEM which has existed since the inception of the market.

In 2011, the Texas market implemented the Controllable Load Resources (CLR) program. The CLR program has more stringent requirements for participation, enabling loads to provide regulation services as well as reserves. For example, CLRs must be able to both respond automatically to frequency changes in a manner similar to generator governor control, and respond to 2-second signals from the system operator.[28] The programs have achieved substantial demand response penetration in ancillary service markets.

1.4 Rationale for rule change request

The Energy Council considers that current market arrangements in relation to demand response result in:

- barriers to demand side participation;
- demand reductions not being treated in a similar way to supply in the spot market; and
- a lack of competition in the provision of ancillary services.

These are explained immediately below.

1.4.1 Barriers to demand side participation

The Energy Council identifies a series of barriers to demand side participation in the spot market:

- under current demand side participation arrangements large customers have two broad options to choose from if they wish to become exposed to the spot price. Either they become a registered participant, or they arrange a spot price pass-through contract with their retailer. Both options involve costs for the customers to monitor and manage exposure to spot price risk. The Energy Council identifies these costs as being greater than the potential benefits of being exposed to the spot price risk, resulting in customers not choosing either of these options; and
- while retailers offer demand response arrangements to customers as part of their contract offerings, the Energy Council[29] and large customers[30] argue that retailers lack incentives to induce customers to reduce demand because retailing

27 Electric Reliability Council of Texas (ERCOT), “The History of Load Participation in ERCOT,” presented by Mark Patterson, presented at DOE Workshop, Washington, DC, October 25, 2011.

28 ERCOT, “Controllable Load Resource (CLR) Participation in the ERCOT Market: Addendum to Load Participation in the ERCOT Market,” prepared by the Demand-Side Working Group of the ERCOT Wholesale Market Subcommittee

29 Oakley Greenwood, Cost-Benefit analysis of a possible Demand Response Mechanism, Oakley Greenwood, 9 December 2014.

30 Major Energy Users Inc's submission to the Oakley Greenwood Cost-Benefit Analysis consultation paper.

is a volume driven business and retailers receive a profit margin for the spot price risk they manage on behalf of their customers. So, unless demand response delivers a greater profit margin than selling energy, the retailer will not be active in this area; and

- large customers consider that the terms offered on demand response contracts are generally not attractive, and they are rarely called upon when the spot market price is above the price at which the customer has agreed to provide demand response.[31] This limits customers' willingness to agree to demand response especially when investment is required.[32] In addition, it is the retailer calling the demand response rather than the customer providing demand response as an option to the retailer.

1.4.2 Treating demand in a similar way to supply in the spot market

The Energy Council argues that the current operation of the spot market has a bias towards the supply side in setting the spot price. This is because generators' bids determine the spot price, but consumers are not given the option to change their demand in response to the likely costs of supply as they do not experience any time-based spot price signal.[33]

In the Energy Council's view, given the limited opportunities for end use customers to respond to wholesale spot price signals, demand reductions are not valued in the spot market in the same way as supply side resources.

Overall, the Energy Council considers that this limits the ability of the demand side to compete with generators to offer the most efficient option to balance the market and minimise wholesale energy costs for all users through greater market competition and the potential for deferring investment in peak generation.

1.4.3 Lack of competition in the provision of ancillary services

The Energy Council notes that the NER limits the provision of FCAS services to generators, retailers, and those customers registered in the wholesale market with large loads. While aggregation of loads for the purpose of ancillary service provision is possible, most retailers do not have the capacity to effectively and efficiently offer these services to customers.

The Energy Council argues that 'unbundling' the provision of FCAS from the sale of energy would promote more competition in providing these services and allow for a more diverse supply of ancillary services. This is expected to increase the number of potential suppliers of FCAS and offer more options to consumers. As a result, the

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31 COAG Energy Council, Demand Response Mechanism Rule Change Request, COAG Energy Council, 8 April 2015, p 4.

32 COAG Energy Council, Demand Response Mechanism Rule Change Request, COAG Energy Council, 8 April 2015, p 4-5.

33 COAG Energy Council, Demand Response Mechanism Rule Change Request, COAG Energy Council, 8 April 2015, p 5.

supply of these services will be diversified and will help support the reliability and stability of the system.

1.5 Overview of the Energy Council's proposed solution

The solutions proposed by the Energy Council to address the three issues identified above are the implementation of a DRM and the 'unbundling' of FCAS services, each of which is discussed below.[34]

1.5.1 The demand response mechanism design

The key features of the proposed DRM are as follows:

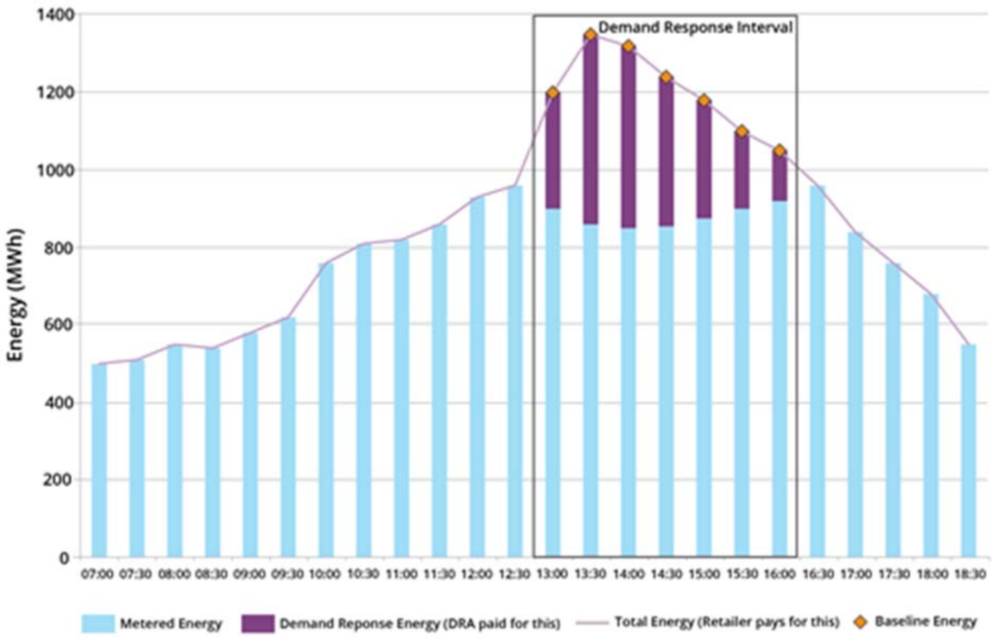
- demand response aggregators would be created as a new class of market participant in the spot market;
- AEMO would implement a baseline calculation methodology (BCM) to calculate the consumption that would have occurred in the absence of demand response;
- the demand response aggregator would initiate (self-schedule) a demand response event and would notify AEMO of the intended commencement and the likely end of the demand response event;
- the demand response is taken to be the difference between baseline and actual metered consumption during the demand response event;
- the demand response aggregator would be paid the spot price for demand response that occurred during the demand response event and would be liable for the spot price if the metered energy exceeds the baseline during a demand response event;
- the retailer would be settled and charged for the baseline energy consumption during a demand response event; and
- demand response aggregators would have commercial arrangements with customers to share the payments they receive for the customers' demand response services.

Figure 1.1 further illustrates how metered energy, demand response energy and baseline energy are calculated during a demand response event. Annex C provides further details of the proposed DRM design. In particular, it details how the self-scheduling arrangement is proposed to work and the voluntary nature of the proposed DRM.

Annex F provides a description of the wealth transfer (or cash-flows) between customers, retailers, demand response aggregators and generators under the DRM proposal.

34 Annex C and D set out a more detailed designed description of the DRM and the ASU proposal. AEMO's detailed design specification is available on AEMC's website. See http://www.aemc.gov.au/Rule-Changes/Demand-Response-Mechanism

Figure 1.1 Illustration of a demand response event



Source: AEMO's demand response mechanism and ancillary services unbundling – detailed design documents 15 November 2013

1.5.2 Ancillary services unbundling

The Energy Council also proposed the ancillary services unbundling (ASU) in its rule change request. Under the proposed rule, the new class of market participant, the demand response aggregator, would be able to provide ancillary services to the market in addition to also participating in the DRM. This is accomplished without requiring the demand response aggregator to be a Market Customer in the spot market, thereby effectively unbundling the provision of these services from the purchase of energy in the spot market.

The demand response aggregator would be able to register a load or aggregation of loads as ancillary services load[35] and provide FCAS independently of whether the demand response aggregator is the Market Customer, e.g., the retailer, who is financially responsible for those loads. The demand response aggregator would be required to meet existing ancillary services classification procedures, as well as technical requirements for FCAS services set out in AEMO's Market Ancillary Services Specification (MASS).

Unlike the DRM, where it is proposed that only large customers could participate, the Energy Council proposes no minimum annual consumption requirements for individual loads eligible to providing FCAS services through the demand response aggregator, effectively extending the ASU proposal to small customers. However, the

35 Ancillary services load is a classification category that appears in the NER for market loads. Currently, only Market Customers can classify a market load as ancillary services load as a pre-condition for that market load to participate in the FCAS markets.

Energy Council proposes some restraints on loads providing FCAS through a demand response aggregator. These include that the load is not a scheduled load in the NEM, and that is not classified as providing ancillary services to the NEM by another participant.

Annex D provides a more detailed description of the ancillary services unbundling proposal.

1.6 Key changes since the publication of the Power of Choice review

This rule change request is part of a broader package of reforms to support greater demand side participation in the NEM which was recommended in the Power of Choice review. In addition to this DRM rule change request the AEMC also made a number of other recommendations to facilitate more efficient demand side participation in the NEM, including in the areas of information, education, technology and flexible pricing options. Four of the rule change requests resulting from the review are relevant to the DRM rule change request. These are summarised below:

- **Distribution network pricing arrangements:**[36] On 27 November 2014 the AEMC made a final rule determination that requires distribution network service providers to develop prices that better reflect the costs of providing services to individual consumers. The rule, which effectively commences on 1 January 2017 assists demand side participation in the NEM, and builds on the existing incentive-based network regulation framework. Network businesses will have to consider how to differentiate network prices applicable to individual customers and, at the same time, recover the total amount of allowed revenue under the price control. The structure of network prices will be consulted on, developed and approved as part of a Tariff Structure Statement (TSS). Overall, these changes should aid consumers to make more informed choices about how they use electricity and assist them to participate more actively in the energy market;
- **Improving demand side participation information provided to AEMO by registered participants:**[37] On 26 March 2015, the AEMC made a final rule determination providing a process by which AEMO may obtain information on demand side participation from registered participants in the NEM. The final rule, which commenced on 26 March 2015, requires registered participants to provide AEMO information on demand side participation, in accordance with the guidelines that were developed by AEMO in consultation with stakeholders. AEMO must take into account that information when developing or using load forecasts. The rule may impact on the quality of AEMO's load forecasts, from short term forecasts such as 5 minute pre-dispatch, to long term forecasts such as the ten year forecasts in the National Electricity Forecasting Report;

36 See, http://www.aemc.gov.au/Rule-Changes/Distribution-Network-Pricing-Arrangements

37 See, http://www.aemc.gov.au/Rule-Changes/Improving-Demand-Side-Participation-information-pr

- **Demand management incentive scheme:**[38] On 20 August, 2015, the AEMC made a final rule determination to amend the rules relevant to the demand management incentive scheme (DMIS) and demand management incentive allowance (DMIA) to provide greater clarity to the AER and stakeholders in respect of how demand management incentive mechanisms should be developed and applied. The DMIS and DMIA provide additional tools 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, where it is efficient to do so. The final rule will commence on 1 December 2016;
- **Expanding competition in metering and related services:**[39] On 26 November 2015, the AEMC made a final rule determination that is aimed at facilitating a market-led approach to the deployment of advanced meters where consumers drive the uptake of technology through their choice of products and services. This framework is expected to promote innovation and lead to investment in advanced meters that deliver services that are valued by consumers. While consumers with an advanced meter will not be required to switch away from their current retail tariff, it will create greater opportunities for consumers to better understand and take control of how they use electricity and the costs associated with their usage decisions. Further, advanced meters may provide retailers and DNSPs the opportunity to access services that support the efficient operation of the electricity system, allowing them to provide lower cost and higher quality services to consumers. The new framework will commence on 1 December 2017.

1.7 The rule making process to date

On 5 November 2015, the AEMC published a consultation paper, setting out the rule change request, the Commission's proposed assessment framework and consultation questions for stakeholders. The Commission received 24 submissions from stakeholders including retailers, consumer groups, network service providers (NSPs), energy service providers, industry peak bodies, and the AEMO.[40] A summary of the issues raised in submissions and the Commission’s response to each issue is contained in Annex A.1.

On the 18 February 2016 the Commission published a notice under the NEL to provide notice that under s107 the time for making the draft determination for this rule change request had been extended to 9 June 2016. Further notices were published on the 2 June 2016 and 21 July 2016 that under s107 the time for making the draft determination was further extended to 28 July 2016 and 1 September 2016 respectively.

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38 See http://www.aemc.gov.au/Rule-Changes/Demand-Management-Embedded-Generation-Connection-I

39 See, http://www.aemc.gov.au/Rule-Changes/Expanding-competition-in-metering-and-related-serv

40 See http://www.aemc.gov.au/Rule-Changes/Demand-Response-Mechanism

On 1 September 2016, the AEMC published a draft determination, setting out the Commission's assessment of the rule change request and a draft rule relating to the ancillary services unbundling component of the rule change request. The Commission received 16 submissions from stakeholders including retailers, network service providers (NSPs), energy service providers, industry peak bodies, the South Australia Department of State Development (SA DSD), and AEMO.[41] A summary of the issues raised in the submissions and the Commission's response to each issue is contained in Annex A.2.

41 See http://www.aemc.gov.au/Rule-Changes/Demand-Response-Mechanism

2 Final Rule determination

The Commission has determined to make a final rule, which is a more preferable rule (final rule). The final rule contains many of the proposed changes to the NER, as they related to the ASU proposal, set out in the rule change request. The final rule does not implement the proposed DRM.

The final rule will create a new market participant, a market ancillary service provider to sell frequency control ancillary services (FCAS) using customers' loads or aggregation of customers' loads. The market ancillary service provider will be able to offer appropriately classified load (ancillary service load) into FCAS markets and be scheduled through the central dispatch process without having to be that customer's retailer to offer such services. This effectively 'unbundles' the provision of ancillary services in FCAS markets from the provision of energy in energy markets. This should enable a greater diversity of suppliers and lead to more competitive FCAS markets.

This chapter outlines:

- the Commission's rule making test for changes to the NER (section 2.1);
- the Commission's rationale and assessment framework (section 2.2);
- the Commission's consideration of the proposed rule against the national electricity objective (section 2.3); and
- how this determination is relevant to the Commission's strategic priorities (section 2.4).

Further information on the legal requirements for making this final rule determination is set out in Annex B.

2.1 Rule making test

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). This is the decision making framework that the Commission must apply.

The NEO as set out in section 7 of the NEL is as follows:

> "The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system;"

In this case, the Commission considers that the relevant aspects of the NEO are the promotion of efficient investment in, and operation and use of electricity services for the long term interests of consumers with respect to price, reliability and security of supply of electricity."[42]

2.2 Assessment framework

In assessing the proposed rule against the NEO, the Commission considered the following:

1. the significance of relevant barriers to demand side participation identified in the rule change request;
2. the benefits of the DRM and ASU proposals relative to existing demand side participation options, including, where relevant, the consideration of:
   (a) spot market benefits such as:
      (i) more efficient dispatch outcomes (productive efficiency); and
      (ii) more efficient long term price signals (dynamic efficiency);
   (b) network benefits;
   (c) spot market implementation and operating costs;
   (d) retail market implementation costs;
   (e) FCAS market benefits.
3. whether the proposal may create distortions within the spot market and in related markets that might result in costs that would be borne by consumers, including, where relevant:
   (a) distortions in the spot market;
   (b) distortions in the retail market;
   (c) distortions in the financial market;
   (d) distortions to competition and innovation in demand response services;
   (e) distortions emerging from gaming opportunities;
   (f) distortions in FCAS markets.

2.2.1 Significance of the identified barriers to demand side participation

Demand Response Mechanism

To determine whether implementing the DRM meets the NEO, the Commission considered whether the identified barriers to demand side participation constitute a market failure that warrants the proposed changes to the NER.

The consideration of the nature of the barriers to demand side participation is relevant to this rule change request. If customers are able and willing to respond to spot prices

42 Under section 88(2), for the purposes of section 88(1) the AEMC may give such weight to any aspect of the NEO as it considers appropriate in all the circumstances, having regard to any relevant MCE Statement of Policy Principles.

but they face challenges in being exposed to the spot price, this may prevent efficient consumption decisions from taking place. For this reason it is important that consumers are not prevented from capturing the value of their demand response services or delivering demand response services to retailers and/or network businesses. Consequently, this would prevent retailers from considering efficient solutions as part of their risk management strategies and network businesses from considering efficient alternatives to network capacity augmentations. Overall, this would prevent the efficient operation and use of electricity in the NEM. If barriers to demand side participation persisted, electricity prices would become higher than otherwise efficient.

Ancillary Services Unbundling

Barriers to demand side participation in FCAS markets could prevent customers that have the ability and the willingness to provide FCAS services from participating in them. This would restrict a potential source of competition in the FCAS markets and prevent the efficient operation and use of electricity in the market. Such barriers can lead to prices for FCAS services being higher than otherwise efficient.

2.2.2 Benefits relative to existing demand side participation options

Demand Response Mechanism

A distinctive feature of the proposed DRM is that it would allow a demand response aggregator to self-schedule demand response in the spot market. Assessing whether the proposed rule leads to more efficient dispatch outcomes is a key to determining whether the proposed DRM is likely to result in benefits that meet the NEO. Assessing the merits of the proposed DRM includes evaluating the DRM's ability to:

- assist in determining the lowest cost of dispatched generation and ancillary services to balance supply and demand (productive efficiency); and
- assist in determining a price signal that leads to efficient investment decisions, including, for example, investments in generation, demand response capability and storage capacity (dynamic efficiency).

These benefits and other benefits, for example potentially alleviating network constraints, can then be compared with the DRM's implementation and operating costs to determine whether implementing the DRM furthers the NEO.

Ancillary Services Unbundling

Assessing the benefits of unbundling ancillary services includes a consideration of how unbundling may lead to increased competition in the FCAS markets and so may lead to more diverse supply and more competitive prices of FCAS.

2.2.3 Potential distortions in related markets

Demand Response Mechanism

If implemented the DRM would require significant changes to the spot market and related settlement systems. These changes have the potential to result in market distortions that may result in costs that would be borne by consumers. For example, market distortions may arise in the spot market itself, but may also emerge in related markets such as the retail and financial markets or in markets where large customers may sell or obtain demand response services. Therefore, the consideration of the potential market distortions is required to understand whether the implementation of the DRM will be in the long term interests of consumers.

2.3 Summary of reasons

The final rule made by the Commission (which is a more preferable rule) is attached to and published with this final rule determination.

The final rule does not provide for the implementation of a demand response mechanism, but does include the rules to facilitate the unbundling of the provision of ancillary services. As described in more detail in Chapter 6, the final rule creates a new class of market participant, a market ancillary services provider. This new participant is able to register to provide appropriately classified ancillary services loads or aggregation of loads and offer these into the FCAS market. The market ancillary service provider need not be the retailer.

The key features of the final rule can be summarised as follows:

- the creation of a new market participant – a market ancillary service provider
  - any person, including third-party service providers, as well as retailers are able to register as a market ancillary service provider subject to meeting eligibility requirements. Registration as a market ancillary service provider allows a party to offer a customer's load, or an aggregation of loads, directly into FCAS markets without having to be the customer's retailer.
  - in practice, this means that while a customer has a retail supply contract with a retailer, a customer may have a separate contract with a market ancillary service provider (who may be another retailer) to provide their load as ancillary services. In this case, the ancillary service contract sits alongside of the existing electricity retail contract.
- a market ancillary service provider is required to meet registration requirements and have appropriate arrangements in place with the retail customers before being able to offer the customers' loads to the FCAS markets.
- a market ancillary service provider is also required to have all the appropriate systems in place, and deliver the FCAS service in accordance with AEMO's market ancillary services specifications just as any other market participant currently is required to do.
- in providing FCAS services, a market ancillary service provider is required to submit FCAS offers to the relevant FCAS markets in accordance with the provisions in the National Electricity Rules.

Having regard to the issues raised in the rule change request and submissions, the Commission is satisfied that the final rule will, or is likely to, contribute to the achievement of the NEO for the following reasons:

- it removes barriers to demand side participation in FCAS markets. Under current market arrangements only retailers (the Market Customer) can offer their customers' load in the FCAS market. Third-party service providers wanting to offer a customer's load into FCAS markets can either register as a Market Customer and become the customer's retailer (with all the costs that this entails) or come to an arrangement with a customer's retailer to enable the customer's load to participate in the FCAS markets. Under these types of arrangements the retailer is responsible for offering the ancillary service into the FCAS markets and ensuring the service is provided through central dispatch, even though the third party service provider is the one offering the service to the customer. The Commission considers that the above options constitute a barrier to entry to third-party service providers, and could be particularly restrictive of business models that aim to provide FCAS services through an aggregation of customers' loads. This barrier may restrict the range of demand side participation products and services available to consumers.

- the creation of the market ancillary service provider unbundles the provision of ancillary services in FCAS markets from the retailer's supply of electricity. This provides a demand side participation opportunity for retail customers to be enabled in the FCAS markets through a third-party service provider. This should increase the diversity of suppliers in FCAS markets. More diverse FCAS markets can increase competition among ancillary service providers, which is likely to lead to lower FCAS prices.
- AEMO's implementation costs to introduce the market ancillary service provider are not significant. Retailers are also unlikely to incur any implementation costs associated with the introduction of the market ancillary service provider framework because the market arrangements in place under which a retailer can offer a customer's load into FCAS markets remain unchanged.

During consultation on the draft determination the Commission became aware of a restriction in the technical specifications AEMO requires its FCAS providers to meet that currently only allows regulation FCAS to be provided by individual loads, not through the aggregation of loads. The restriction relates to the technology enabling the provision of these services. This means that without amending the technical specifications market ancillary service providers may offer individual loads into both regulation and contingency FCAS markets but may offer aggregated load into the contingency FCAS market only. These limitations currently also exist for Market Customers. The Commission understands from stakeholders that the outcome AEMO currently seeks to achieve through this restriction can also be achieved through other forms of technology.

The Commission recommends that AEMO review these specifications as soon as possible in order to consider whether any technical restrictions preventing market ancillary service providers from providing raise and lower regulation FCAS using aggregation of loads can be removed. [43] The Commission understands that AEMO is aware of these limitations imposed by the market ancillary service specification and the review of these technical requirements is part of their upcoming work program.

The Commission considers that there is still benefit in the unbundling to:

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43 This issue is further discussed in Section 6.3.

- allow market ancillary service providers to provide contingency FCAS and regulation FCAS using an individual load, and aggregated load for contingency FCAS; and
- providing for a regulatory framework that will enable, and potentially encourage, market ancillary service providers to provide raise and lower regulation FCAS using an aggregation of loads when technologically appropriate solutions are available.

Under s. 91A of the NEL, the AEMC may make a rule that is different (including materially different) from a proposed rule if it is satisfied that, having regard to the issues raised by the rule change request, the more preferable rule will, or is likely to, better meet the NEO than the proposed rule.

The Commission considers that the final rule, which is a more preferable rule, will, or is likely to, better contribute to the achievement of the NEO than the proposed rules because it implements the ASU proposal without the associated costs and distortions that are likely to arise from the implementation of the DRM, and facilitate greater competition in FCAS markets.

Demand Response Mechanism

The Commission considers that implementing the DRM would not be in the long term interest of consumers because the benefits of the proposed DRM do not outweigh its implementation costs for the reasons set out below. Further discussion is set out in Chapters 3 -5.

Demand response can and already is happening in the NEM. There are no barriers in the Rules to the uptake of demand response

Whilst there may be commercial reasons complicating the wider uptake of demand response arrangements, the Commission was unable to identify any barriers in the Rules that would prevent such arrangements. . Nor were any Rules based barriers raised during stakeholder consultation.

There are no barriers in the Rules to large customers entering into commercial arrangements with retailers and network businesses or accessing a relatively competitive demand side management service market to help take advantage of their demand response capabilities. A survey of the market completed for the Commission[44] reveals:

- currently, there are at least 21 businesses capable of providing a variety of products and services, with presences across all major jurisdictions in the NEM; and.
- retailers have at least 235MW of demand response capacity under contract, of which 200W is capacity that is directly exposed to the spot price. Demand side

44 See Oakley Greenwood: Current status of DR in the NEM: Interviews with electricity retailers and DR specialist service providers, http://www.aemc.gov.au/getattachment/ea3b6214-a288-460d-90a6-07985a9ea0cf/Oakley-Greenwood-Survey-Report.aspx

management providers are managing at least 310MW of demand response capacity. Other estimates suggest 2000MW of demand is currently available to respond to wholesale market prices.

The survey completed for the Commission also indicates that there has been an increase in large customers opting to use their demand response capabilities and the services of DSM service providers to manage the spot price risk themselves. Retailers no longer seem to have an exclusive role in managing spot price risk for large customers. There is a consistent view between retailers and demand side management service providers that this form of demand side participation is likely to increase in the future. There are a number of products and services that demand side management service providers offer that explain this trend, including:

- services that enable customers to identify operation and/or process opportunities to shift and/or curtail load, when they will benefit from doing so;
- products to forecast spot prices, automate demand response operations and/or hedging support services; and
- advice and/or brokering competitive deals on spot price pass-through contracts with retailers that enable customers to choose their preferred level of spot price exposure.

The Commission notes that this range of products and services is likely to increase and extend to smaller customers as the market reforms commenced by the PoC review start to take effect from 1 July 2017. The distribution network pricing arrangements rule[45] should facilitate pricing and product alternatives that will allow customers to value their demand response. For example, a customer could utilise a time of use tariff to reduce its demand at relevant times and be rewarded in doing so. The expanding competition in metering services rule[46] will provide the tools through which customers can access a wider range of services or products that values their demand response.

Retail supply and demand response services are not bundled. Customers are free to choose from a range of retail arrangements, including full- or partial spot price pass through to a fully hedged retail contract. Once customers select their price exposure in line with their risk preference, customers are free to respond to the price signals they choose. When customers opt into a spot price exposure, they are free to respond to this price signal and when they choose a retail tariff rate they are able to take advantage of demand response in line with the incentives the retail tariff creates. A partial spot price pass-through contract allows customers to further tailor arrangements to suit their needs. Demand side management service providers and retailers compete to provide wholesale price risk management services to large customers. Customers that shop around for better retail supply deals may get better deals if they make their demand response capabilities available to their retailer. If offers are unsatisfactory, customers have the option to contract with a demand side management service provider to make the most of their demand response capability and manage wholesale price risk using the expertise of these service providers. Networks are also starting to compete with

45 *National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014 No.9.*

46 *National Electricity Amendment (Expanding competition in metering and related services) Rule 2015 No.12.*

retailers to contract a customer's demand response capabilities, primarily for the network benefits that they offer.

The Commission has been unable to find evidence of any barrier in the Rules that would prevent the current demand side participation arrangements in the market from delivering the benefits identified in the cost benefit analysis submitted with the rule change.

The Commission has also been unable to find evidence of insufficient incentives for retailers to offer demand response services. The Commission's survey evidence reflects that retailers do make demand response services available and some are proactive about it. It is in retailers' interests to maximise the demand response of their customers, particularly their large customers, because it allows them to better manage the spot price risk that they are fully exposed to. A retailer may offer better retail supply deals when it can take advantage of a customer's demand response. Similarly, a customer may take advantage of demand response related retail product where the value of its demand response exceeds its costs of responding.

The DRM would not result in overall savings to consumers through lower electricity prices

The Commission considers the DRM would not result in lower electricity prices principally because of four factors:

1. Under the DRM, spot prices will not reflect competition from demand response.

In the proposed DRM demand response would be self-scheduled by a new market participant, a demand response aggregator. Only scheduled (or semi scheduled) generation and loads are included in central dispatch,[47] which determines wholesale market prices. Demand response under the proposed DRM is not scheduled and hence its price effects are no different from the demand response occurring currently in the market.

This is a variation from the original DRM specifications proposed by the Commission as part of its PoC recommendations, where it was envisaged that demand response would be scheduled by AEMO through central dispatch rather than by a demand response aggregator outside of it.

Currently, AEMO's pre-dispatch and dispatch processes do not explicitly take into account the intentions of non-scheduled loads' response to price signals; that is, it does not take into account demand response. Whether it should do so, and whether this will improve the accuracy of demand forecasts, is being considered by the Commission in a separate rule change request.[48]

Without pre-dispatch and dispatch processes taking account of demand response, demand response cannot compete directly with generation as the rule proponent considered it would. Any demand response facilitated by the DRM would compete

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47 AEMO operates central dispatch to balance the power system supply and demand. It aggregates information from market participants and aims to obtain the least cost resources to balance supply and demand in the power system, while maintaining its reliability and security.

48 Non-scheduled generation and load in central dispatch consolidated rule change request, see http://www.aemc.gov.au/Rule-Changes/Non-scheduled-generation-in-central-dispatch

with generation the same way as demand response currently active in the market already does, that is outside of central dispatch.

2. The DRM requires costly changes to the wholesale market and retailer systems

AEMO has estimated the costs to change the spot market systems to allow the demand response aggregator to participate in the spot market through the DRM in the region of $8 to $14 million.

In addition, retailers will also incur implementation costs to change billing systems to accommodate consumers wishing to use the DRM. These are likely to be extensive (up to $112 million) but the exact size of these costs is influenced by whether participation in the mechanism is voluntary or mandatory.

If the DRM were implemented on a voluntary basis, that is, retailers could choose to allow their customers to participate or not, the extent of these implementation costs is difficult to know. This is because the incentive to allow customers to participate in the DRM and incur the implementation costs is low. Where participation in the DRM is voluntary all the benefits associated with a customer's demand response accrues to the demand response aggregator, with the retailer being left to continue to manage the risk of price fluctuations in the wholesale market, as it currently does. The retailer, who under the DRM is expected to incur all its implementation costs but receive none of its benefits, will be better off in developing demand response arrangements directly with a customer outside of the DRM. This is because under such arrangements a retailer will be able to manage the risk of wholesale market price fluctuations and receive the benefit of doing so.

If participation in the DRM were made mandatory, retailers will include risk premiums into their pricing, to provide for the fact that they must still manage the risk of price fluctuations in the wholesale market without receiving the benefit of the customers' demand response. This will result in higher prices being paid by all consumers for their electricity. Further, with mandatory participation, all retailers have to incur high costs to upgrade their systems. These costs would have to be recovered from either only those customers that participate in the DRM or all customers. If it is the former, this cost could discourage participation in the DRM. If it is the latter, then the DRM will lead to increased electricity prices without any benefits for some customers.

3. The DRM will not necessarily alleviate network constraints and defer network expenditure

The DRM would only achieve this outcome if peaks in wholesale market prices coincided with network peak demands. This is not necessarily so.

Demand response is usually triggered by a peak in spot market prices. This provides a price signal to decrease consumption over paying the high price in the wholesale market. Network constraints do not necessarily coincide with wholesale market price peaks. In order to address network constraints with demand response, the response would have to take place at specific locations and times within the network that coincide with those constraints and in sufficient magnitude in order for the demand response to have a positive impact.

4. The DRM can have unintended consequences in the spot market and other related markets.

The costs of these distortions would be borne by consumers in the form of higher electricity prices and in the absence of any net benefits accruing from the implementation of the DRM, is not in their long term interests.

These distortions are summarised as follows:

- the DRM would distort efficient economic outcomes in the spot market because under the DRM less reliable self-scheduled demand response resources[49] would be rewarded equivalently to more reliable scheduled resources in the spot market.[50]
- as retailers would continue to be financially responsible for their customers' baseline consumption, an outcome of the DRM may be that customers pay for a retailer's hedging costs through their retail contract even if they provide demand response. Furthermore, if demand response is achieved by shifting the load to another time period, customers would face increased retail costs as their consumption, at times, would increase relative to the baseline. Although customers are expected to receive payments from demand response aggregator for their demand response services, the net outcome for customers is difficult to estimate.[51]
- under the DRM, the demand for financial hedging contracts would remain about the same as retailers would continue to remain financially responsible for the baseline consumption of their customers. The availability (supply) of hedging contacts will depend on the generators being successfully able to generate during high price events. If demand response is successful in displacing generation during high price events, than there will be an imbalance between demand and supply in the hedging market. The retailer would still seek to enter into hedging arrangements as it is exposed to the spot price to the extent of the baseline consumption but the generator would no longer be able to offer a hedging contract; this will lead to an increase in hedging contract prices.
- competition among demand response aggregators under the DRM, combined with the lack of responsibility for inaccurate baselining, may create strong incentives for demand response aggregators to implement the most 'generous' of available baseline methodologies. Demand response aggregator's and customers' incentives are also aligned in potentially 'gaming' the baseline. Whilst such outcome may be mitigated, the cost of monitoring and enforcement will ultimately be passed onto consumers.

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49 Under the proposed demand response mechanism the market operator is not able to dispatch demand response. In fact it may not even be aware of the demand response. This means that the market operator cannot rely on demand response to the same extent as it can on dispatched scheduled generation

50 Although demand response aggregators are required to notify AEMO of any demand response that they have self-scheduled, this notification is not required to be submitted by the demand response aggregator until the end of the trading interval which may up to 30 minutes after the demand response too place.

51 The expected wealth transfers of the proposed DRM are further detailed in Annex F.

2.4 Strategic priority

This rule change request is relevant to the AEMC's strategic priority on providing market and network arrangements that encourage efficient and appropriate investment over time. This strategic priority recognises that new products and services have the potential to benefit small customers, particularly where the products and services offered reflect small customer preferences.

Consistent with the reasons set out in the previous section the final rule will reduce barriers to demand side participation in the FCAS markets. This should deliver increased competition and support a more competitive FCAS market through increased demand side participation resulting in more efficient FCAS prices.

3 DRM and barriers to demand side participation

Summary

Current market developments enable demand side participation arrangements to deliver demand response in the NEM. The Commission did not identify any barriers to demand side participation in the Rules. Large customers, as well as retailers and networks, can access a competitive demand side management services market to unlock the economic benefits of their demand response or to offer a range of different products and services, respectively.

A survey of market activity completed by Oakley Greenwood on behalf of the Commission reflects that demand side management service providers have reduced barriers for large customers to become exposed to the spot price. The market is moving from large customers choosing retailers to manage exposure to spot prices on their behalf, to a situation where large customers are partnering with demand side management service providers to manage this risk. They are facilitating large customers' exposure to the spot price, and are enabling them to provide demand response services to retailers and/or network businesses. This type of demand side participation is expected to increase in the future in the NEM.

Retail supply and demand response services are not bundled. Customers are able to select from a range of retail tariffs that includes varying degrees of price signals. Alternatively, customers can accept partial or full spot price exposure. These options allow customers to find arrangements that suit their risk attitudes and allow them to exploit the economic value of their demand response capabilities. Retailers have efficient market incentives to choose that portfolio of instruments, including demand response from their customers that best allows them to provide competitive retail offers to their customers, while managing their wholesale market exposure. Retailers will utilise demand response as part of managing their wholesale market exposure when it is efficient to do so. Similarly, customers have a range of options that allows them to select an arrangement that is in line with their risk preferences and demand response capabilities.

This chapter sets out the Commission's analysis of the barriers in the Rules to demand side participation that has been identified either by the rule proponent or by stakeholders in their submissions to the 5 November 2015 consultation paper and the 1 September 2016 draft determination. It also presents the Commission's analysis of

- current market activity in relation to demand side participation;
- demand side participation options through a retailer's demand response program; and

- the findings from a survey of current demand response activity and products and service offerings that Oakley Greenwood completed on behalf of the Commission.[52]

In order to better understand the nature of such barriers to demand side participation the Commission sought both quantitative and qualitative evidence regarding the amount of demand response capacity that is currently available in the NEM through several different contracting forms offered by electricity retailers to customers that consume 100MWh per year or more.[53] Oakley Greenwood was retained for this purpose. More specifically, the Commission sought quantitative information on:

- the magnitude of demand response capacity that is currently subject to contract with an energy retailer and demand side management (DSM) service providers; and
- the number of businesses that provide DSM services to large customers and/or retailers, and a description of the products and services they offer. Oakley Greenwood's survey evidence complemented the Commission's own investigations of relevant market activity, which are reported throughout section 3.3.

Currently very little information is publicly available on demand response activity in the NEM. The recent rule made in relation to the demand side participation information rule change request[54] will make more information available to AEMO and to other market participants. However, a significant part of demand side participation does not take place directly through registered market participants but rather through third parties such as DSM service providers. The Commission conducted a survey not only to understand the quantity but also the diversity of service offerings. While it is difficult to know the exact volume of demand response, the report contains an indication of the nature and level of market activity.

3.1 Rule proponent's view

As set out in Chapter 1, the Energy Council identified a number of barriers to the take up of existing demand side participation options. For example, although large customers may buy electricity directly from the spot market, to do so customers must either register with AEMO as a Market Customer or seek a spot price pass-through contract with a retailer. Under both of these options the customer will incur costs to monitor spot prices and manage spot price risks. The Energy Council is of the view that these costs offset the benefits that large customers would derive from purchasing

52 See Oakley Greenwood: Current status of DR in the NEM: Interviews with electricity retailers and DR specialist service providers, http://www.aemc.gov.au/Rule-Changes/Non-scheduled-generation-in-central-dispatch

53 This is generally the threshold at which a customer is considered to be a large. See clause 7(2) National Energy Retail Regulations

54 See Improving demand side participation information provided to AEMO by registered participants final determination http://www.aemc.gov.au/Rule-Changes/Improving-Demand-Side-Participation-information-pr

their electricity needs at the spot price, and so these costs act as barriers to effective demand side participation.

The Energy Council also considers that under current demand side participation arrangements retailers lack incentives to engage in demand response activities with their large customers. The Energy Council considers that this is because retailing electricity is a volume driven business. Further the Energy Council also argues that retailers have an incentive to limit demand response because they already manage risk on behalf of their customers for which they get a profit margin in the retail market. So, unless demand response delivers a greater profit margin than selling energy, the retailer will not be active in this area.

The last barrier identified by the Energy Council notes that some large users have reported that the terms offered in demand response contracts are generally not attractive, and demand response contracts are rarely called upon. This limits the willingness of customers to agree to demand response contracts, especially when an investment in technology or systems is required. In addition, with contracts of this kind it is the retailer calling the demand response rather than the customer providing demand response as an option to the retailer.

3.2 Stakeholder views

A number of stakeholders made submissions to the draft determination and consultation paper. The Energy Efficiency Council (EEC),[55] Major Energy User Inc (MEU),[56] Alternative Technology Association (ATA),[57] Embertec,[58] and EnerNOC[59] all consider that there are barriers to effective demand side participation because large customer can only sell their wholesale demand response capability through their retailer. As noted by the EEC:[60]

> "*mandatorily bundling demand-response and retail services has led to sub-optimal provision of demand response services, as:*
>
> - *This reduces competition for demand-response services; and*
> - *Some retailers have conflicting incentives in providing demand-response services.*"

In relation to the same issue, the MEU notes that except for the decision by a consumer to take spot market risk and provide demand response when high prices occur, it is the supply side (the retailer) that initiates the request for demand response. This places negotiating power with the supply side entity rather than being equal negotiating

55 EEC, Submission to consultation paper, p. 4.

56 MEU, Submission to consultation paper, p.12

57 ATA, Submission to consultation paper, pp. 6-7, and Submission to the draft determination, p.2-3

58 Embertec, Submission to the draft determination, p.2

59 EnerNOC, Submission to consultation Paper, p.8 and Submissions to the draft determination, p. 1

60 EEC, Submission to consultation Paper, p.4

powers between parties.[61] EnerNOC[62] disagrees with the Commission's view that consumers have sufficient options in monetising their demand response flexibility.

Similarly, this group of stakeholders also consider that consumers do not choose retailers on the basis of their demand response offerings. They shop around for the best electricity deal which is of much greater value to them. Further, as it is only retailers that can provide consumers with the ability to respond to spot prices, consumers do not have the opportunity to shop around for a better deal for their demand response. As a result there is little competitive pressure on retailers to deal with demand response and provide good value for a customer's demand response capabilities. This has led to low demand response across the market. ATA[63] also notes that a retail business model is predicated on managing the risk inherent in volatile pricing and hence "it will never be worthwhile for retailers to give this up at any material scale." Furthermore, ATA notes that retailer ownership of generators – that compete directly with demand side participation – adds to their interest in not encouraging large-scale demand response.

EnerNOC[64] in its submission to the draft determination notes that becoming a Market Customer is administratively costly and impractical for customers other than for very large loads and with dedicated staff. EnerNOC considers that this is only feasible in industries such as aluminium, steel, cement, paper, oil and gas, and water.

Furthermore, EnerNOC[65] considers that customers may take spot price exposure through a retailer. While this seems to be the most common way for loads to participate in demand response, EnerNOC consider that this option is impractical for smaller consumers for the same reasons as above, i.e. small customers still have to manage risks and possibly prudential requirements.

South Australia Department of State Development (SA DSD)[66] and EnerNOC[67] consider that retailers' objectives are not always aligned with maximising demand response at times of high market prices and volatility and unless there is a benefit to the retailer from reducing demand at a given time, a retailer will not activate customer's curtailment even if it would benefit the customer. EnerNOC[68] considers that retail competition is not sufficiently near perfect to ensure that major retailers – especially vertically-integrated ones – offer meaningful rewards for customer flexibility.

Retailers such as AGL,[69] PG Energy,[70] Energy Australia[71]and ERM Power[72] do not support the proposed rule change. They share similar views that there is no evidence

61 MEU, Submission to consultation paper, pp. 5-9

62 EnerNOC, Submission to draft determination, p.1.

63 ATA, Submission to draft determination, p.2

64 EnerNOC submissions, Submissions to draft determination, p. 6.

65 EnerNOC submissions, Submissions to draft determination, p. 6.

66 SA DSD, Submission to draft determination, p.2

67 EnerNOC, Submission to draft determination, p.10

68 EnerNOC, Submission to draft determination, p.10

69 AGL, Submission to consultation Paper, p 1

to suggest that the market is not providing opportunities for demand response. They consider too little demand response is due to oversupply of generation capacity and that demand response is not necessarily the most efficient means of managing wholesale pricing risk or optimizing onsite energy consumption. Energy Australia[73] also considers that wholesale market conditions, and in particular the frequency of extreme price events, are important factors in driving the amount of demand response that is occurring in the market. Snowy Hydro[74] considers that the "DRM was a complex solution looking for a problem that simply does not exist." Snowy Hydro[75] considers that the implementation of the DRM would benefit a small group of large consumers at the expense of a much broader group of consumers.

Retailers also consider that they are differentiating themselves through service offerings outside the traditional core-business of providing energy, and so existing competition will deliver to customers the ability to extract the value of their demand response capabilities. These stakeholders note that this is evidenced by a wide variety of bespoke demand response related contracts. For example, ERM offers its customers customized time of use tariffs, capacity availability payments and spot sharing arrangements.[76]

While Energy Australia[77] notes that barriers for customers to switch their retailers are very low, GDF Suez further notes[78] that the barriers for new businesses to enter into retailing are also low. Many new retailers have emerged over time, some successfully starting with just a few customers. In such an environment, a retailer's willingness to provide all possible benefits to customers, especially large customers, is acute. GDF Suez and Snowy Hydro note that supply to large customers is hotly contested as evidenced by the very low retail margins in this market segment. There are therefore strong commercial incentives to negotiate with consumers of all sizes to derive mutually beneficial products.[79]

Other stakeholders, including AGL,[80] Origin,[81] Red Energy, Lumo Energy[82] and Stanwell,[83] note that the Commission have already put in place new rules which will assist increased levels of demand side participation, for example:

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70 PG Energy, Submission to consultation paper, p.1 and 2

71 EnergyAustralia, Submission to consultation paper, p.2 and Submission to draft determination, pp.1-2

72 ERM Power, Submission to consultation paper, p 1

73 EnergyAustralia, Submission to draft determination, pp.1-2

74 Snowy Hydro, Submission to draft determination, p.3

75 Snowy Hydro, Submission to draft determination, p.3

76 ERM Power, Submission to consultation Paper, p 4.

77 EnergyAustralia, Submission to draft determination, pp.1-2

78 GDF Suez, Submission to consultation Paper, p.3

79 GDF Suez, Submission to consultation Paper, p.3; Snowy Hydro, Submission to consultation paper, p.5

80 AGL, Submissions to consultation paper, p.4;

81 Origin, Submission to consultation paper, p. 3;

- the distribution network pricing arrangements rule,[84] which requires distribution businesses to design cost-reflective pricing that will, from 2017 when it becomes effective, provide the opportunity for customers to adjust their consumption with reference to the costs of using the network at different times provided that retail tariffs will efficiently reflect these cost;
- the expanding competition in metering and related services rule,[85] which will enable more large customer driven demand response; and
- the demand management incentive scheme rule,[86] which will incentivise networks to consider efficient non-network alternatives to traditional network augmentation as part of their revenue proposals, including potential demand management initiatives, which can facilitate demand side participation.

EnerNOC[87] considers that the Oakley Greenwood survey report depicts a market in which only the largest, most sophisticated industrial consumers are able to bring their demand response flexibility to market, with other consumers remaining disengaged and inelastic. The Oakley Greenwood survey report confirms EnerNOC's view that most demand response consists of spot price exposure arrangements and there is very little "dispatchable" demand response happening in the market. Not all spot exposed loads are able to or willing to respond to high spot prices with any regularity or certainty.

SA DSD[88] considers that the Oakley Greenwood survey report is flawed to the extent that it does not consider the views of electricity consumers.

3.3 Commission's analysis

Before, during and after the consultation period, the Commission engaged with key stakeholders to understand the significance of any barriers to demand side participation which may prevent large customers from extracting value from their demand response capabilities under current market arrangements. As noted above, the Commission also requested Oakley Greenwood to carry out a market survey to understand the amount of demand response that retailers and demand side management service providers currently manage and the types of products and services that they offer.[89]

82 Red and Lumo Energy, Submission to consultation paper, p. 1;

83 Stanwell, Submission to consultation paper, p. 9;

84 http://www.aemc.gov.au/Rule-Changes/Distribution-Network-Pricing-Arrangements

85 http://www.aemc.gov.au/Rule-Changes/Expanding-competition-in-metering-and-related-serv

86 http://www.aemc.gov.au/Rule-Changes/Demand-Management-Embedded-Generation-Connection-I

87 EnerNOC, Submission to draft determination, p.1.

88 SA DSD, Submission to draft determination, p.1

89 See Oakley Greenwood: Current status of DR in the NEM: Interviews with electricity retailers and DR specialist service providers, http://www.aemc.gov.au/Rule-Changes/Non-scheduled-generation-in-central-dispatch

While the Commission acknowledges that negotiating demand response arrangements between retailers, customers and DSM service providers are at times challenging, the Commission did not find any barriers in the Rules that would prevent such arrangements from being put in place. The Commission found that current market arrangements enable demand side participation in the NEM. Large customers, retailers and networks businesses can access a competitive demand side management services market to find services that helps them take advantage of demand response opportunities.

Consistent with Oakley Greenwood's survey findings, the Commission has found that DSM service providers:

- have reduced commercial barriers for large customers seeking exposure to the spot price. The market is moving from large customers choosing retailers to manage exposure to spot prices on their behalf to a situation where large customers are partnering with DSM service providers to manage this risk. Survey findings reveal that DSM service providers are predicting that this type of risk management will increase in the future in the NEM (see section 3.3.1 for more detail); and
- are supporting large customers to exploit the economic benefit that can be derived from their demand response capabilities. They are facilitating large customers seeking exposure to the spot price, and enabling them to provide demand response services to retailers and/or network businesses (see section 3.3.1 for more detail).

In addition, the Commission has not found evidence of a relevant market failure or barrier in the Rules that would prevent retailers, network businesses or demand side service providers from engaging in demand response activities with large customers. Retailers have a number of instruments (including demand response) at their disposal to manage spot price exposure. Retailers have efficient market incentives to choose that portfolio of instruments that would best allow them to provide competitive retail offers to their customers. Consistent with the Commission's review of market activity, the survey indicates that a range of different products and services exist in the market that allow large customers to take advantage of their demand response services. This is explored in further detail in section 3.3.2 below.

Further, the Commission notes that under current market arrangements, spot price risk management is not 'bundled' with retail supply. Large customers have a several options, ranging from full or partial spot price pass-through contract with a retailer or a fully hedged retail contract. Under full or partial spot price pass-through contracts customers may manage the risk themselves or use the services of a DSM service provider to manage the spot price risk on their behalf. Therefore, DSM service providers and retailers already compete to provide spot price risk management services to the customer. Such competition may include the utilization of the customer's demand response capabilities.

As the survey findings show, this is already happening under current market arrangements without a market wide mechanism such as the DRM. It is the customer's preference for a fully hedged retail contract that creates the retail tariff as a price signal relative to which demand response services are less attractive. When a customer selects a specific retail tariff rate, for example with peak and off-peak prices, the customer is also able to carry out demand response and shift its consumption to a lower (off-peak) period. Customers can select from a range of different arrangements and once they opt into an arrangement that is in line with their risk attitude, they are able to change their demand profile or carry out demand response relative to the prices or tariffs they prefer to face. Nothing prevents a customer, either under the Rules or within the marketplace, from carrying out demand response, within or outside of a retail contract.

When customers opt in to a retail contract that includes fixed tariffs, retailers already had to have hedging strategies in place in order to offer such contracts. In such situations there is little or no benefit from the customer's demand response capabilities to the retailer as the customer's preference for fixed tariffs already necessitated the implementation of a hedging strategy and the customer's retail tariff rate already reflects this hedging cost.

3.3.1 The demand side management services market

As reflected in the Oakley Greenwood survey's findings there are a range of businesses that provide specialized demand side management (DSM) products and services to large customers, retailers and network businesses to facilitate demand response activities. DSM service providers play a similar role to that envisaged for demand response aggregators under the proposed DRM.

The development of this DSM service market has not required an intervention through changes to the Rules. To the contrary, barriers to entry to provide DSM services seem to be relatively low. For example, Oakley Greenwood's web-based search exercise has found 21 businesses that provide a diverse range of DSM related products and services.

DSM service providers are active across all major jurisdictions in the NEM providing competition and choice to large customers, retailers and network businesses.[90] From the five DSM service providers participating in the survey the level of demand response being managed is 308MW: 200MW engaging directly with the customer, 99MW providing assistance to the customer on behalf of a retailer, and 9MW on behalf of a distribution network business.[91]

Table 3.1 below provides a description of some of the products and services that DSM service providers currently offer to the market:

90 See Oakley Greenwood's survey report, Current status of DR in the NEM: Interviews with electricity retailers and DR specialist service providers, table 5 at p 16.

91 See Oakley Greenwood's survey report, Current status of DR in the NEM: Interviews with electricity retailers and DR specialist service providers, table 1 at p 9.

Table 3.1 Description of DSM service providers' products and services offerings

Identify opportunities for curtailment	Involves the provision of advice to end customers regarding the identification of potential unit operations and/or processes able to participate in a demand response activity, including load shedding and load shifting. Advice may include the broad identification of potential opportunities through to detailed action plans for implementation.
Support to tender large loads	Includes the provision of advice and/or brokering opportunities to leverage the demand response capabilities as part of a retail energy contract negotiation, or as part of a call for significant demand response load.
Spot price forecasting technologies	Provides end customers with the information necessary to actively participate in the energy market. This can include services ranging from the provision of spot price information and forecasts of potential spot price spikes to allow the end customer to take action and avoid significant price penalties for operating during these spikes, or through the automation of demand response operations and/or processes.
Hedging support	Involves the provision of complex contract negotiation advice to enable the end customers to limit their exposure to the spot price through the use of financial energy derivatives.
Enable / support participation in DR programs	Provides end customers with advice and support in the identification and participation of DR programs managed by other parties such as retailers and/or network business. It includes identification of opportunities, evaluation of price points that justify involvement, negotiation with program managers and ongoing assistance to maximise involvement.

Source: Oakley Greenwood's survey report.[92]

It is clear that DSM service providers are contributing to active participation by large customers in the wholesale market. They often overcome the need for large customers to become a Market Customer in the spot market by helping such customers negotiate a full or partial spot price pass-through contract with a retailer. DSM service providers have enabled this by:[93]

- working closely with customers to identify operations and/or processes that can either be shifted or curtailed in response to spot price spikes;
- providing spot price forecasting services, automation of demand response operation technologies and/or hedging support services to effectively manage exposure to the spot price; and

92 See section 4 of Oakley Greenwood's survey report, Current status of DR in the NEM: Interviews with electricity retailers and DR specialist service providers.

93 This is also consistent with the views from retailers and Oakley Greenwood's observations. See Oakley Greenwood's survey report, Current status of DR in the NEM: Interviews with electricity retailers and DR specialist service providers, p 19 and 20.

- providing advice and/or brokering competitive deals on retail spot price pass-through contracts for large customers' loads.

Box 3.1 below provides an example of how a DSM service provider supports large customers wanting to become exposed to the spot price:

Box 3.1 Altus Energy business offering

Altus Energy offers DSM advisory services to allow customers to benefit from purchasing energy in the spot market, either through helping their customers to become a Market Customer in the NEM or through procuring (via competitive tendering) a spot price pass-through contract with the lowest administration fee with a retailer.

While customers with large loads can quite easily negotiate a spot price pass-through contract with large established retailers, customers with smaller loads may also be successful with smaller retailers who specialize in this product.

Altus Energy also provides risk management strategies to break the 'traditional nexus' which is described as 'the trade-off between reliability of energy supply and the cost of energy.'

Altus Energy's main region of activity is South Australia, and their portfolio includes customers active in the mining, construction materials and heavy manufacturing sectors.

Consistent with the Commission's findings, the Oakley Greenwood survey reflects that large customers can take-up a variety of demand side participation options, most of which involve a level of spot price exposure, the strongest form of demand response. The Oakley Greenwood survey indicates that large customers are moving away from arrangements where retailers manage the spot price risk on their behalf and that this trend is likely to increase in the future. This is a consistent view between retailers and DSM service providers.

When customers have already chosen to accept full spot price exposure, demand side service providers that require them to have retail contracts becomes less attractive to them. This seems to be consistent with Oakley Greenwood's findings that 'aggregators' that rely on customers' retail arrangements have seen their market decline over time as more sophisticated customers move to a spot price arrangement.

While direct spot price exposure may not be attractive to smaller customers, there are no Rules based barriers that would prevent DSM service providers from providing an 'aggregate' level service to multiple small customers. For example, there is nothing to prevent DSM service providers from treating multiple customers as a portfolio and offering this aggregate group of customers some form of hedging arrangement that may also provide an opportunity for small customers to exploit the economic value of their demand response capabilities.

Box 3.2 below provides an example of a service provider that provides partial or full spot price exposure to its customers rather than fixed tariff contracts.

Box 3.2 PG Energy - Managed Wholesale Electricity Pool Purchasing[94]

PG Energy's Managed Wholesale Electricity Pool Purchasing product offers customers an opportunity to access the generally lower spot market prices. It is suited to large energy users with backup generators onsite or some ability to curtail electricity consumption occasionally, usually for short durations of time. PG Energy offers an end to end solution for customers to manage their electricity loads in response to high spot market prices. This includes:

- a notification system that informs customers of spot market price events; and
- a communication and control device installed on site that manages each site's electricity load and signals the right time to shed load or transfer to generator.

PG Energy also offers partial exposure to spot prices by offering its customers to fix the price on a portion of their load using wholesale energy blocks or capped electricity contracts.

Surveyed DSM service providers also indicated that most customers choosing spot price exposure have facilities with demands greater than approximately 5 MW, although smaller facilities do participate. They envisaged that easier access to automation and software to assist electricity consumption decision-making within relatively short timeframes could increase the ability and the willingness of smaller facilities to participate in this way.

Box 3.3 below provides an example of a customer taking advantage of its local generation capabilities and automation technology in order to carry out demand response.

Box 3.3 PG Energy - Cold Store in Brisbane[95]

One of PG Energy's customers operates a cold store in Brisbane and has an electricity consumption requirement of 500-600KW. The customer also has a 1,200KW back up diesel generator on site. On 5 March 2015, Queensland experienced a high demand for power and consequently the spot price was high for an extended period. PG Energy remotely dispatched the diesel generator from its Melbourne office and this allowed the cold store to avoid high spot prices. The cold store never lost power and operated as normal and when the high priced event passed, it returned to mains power.

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94 For further details please visit http://pgenergy.com.au/products-business-electricity-suppliers/

95 Based on publicly available information available on http://www.demandresponse.com.au/articles/2016/02/case-study-cold-store-in-brisbane-earns-revenue-from-demand-response-in-2015/ last accessed on 20 August 2016.

The Commission also notes that increasing large customer demand side participation through direct spot price exposure encourages active demand side participation in the wholesale energy market. This in turn creates a more functional price responsive demand in comparison to the demand side participation arising through the DRM. This is because large customers directly consider the cost of electricity in their consumption decisions when they are exposed to the spot price rather than relying on a demand response aggregator's signal to reduce consumption when spot prices are high.

Further, increased demand side participation through greater exposure to spot prices is also capable of improving the efficiency of large customers' consumption decisions at a lower cost to all consumers in comparison to the proposed DRM. This is because the financial payments a large customer would need to make to a demand response aggregator under the proposed DRM are avoided when the large customer is directly exposed to the spot price.[96]

The Commission also found through its own review of market activity that DSM service providers are already supporting large customers to diversify the use of their demand response capability to improve the economic benefit that can be derived from it. These businesses are not only enabling large customers to source their energy requirements directly at spot market prices, but also enabling them to provide demand response services to retailers and/or network businesses when opportunities emerge. This is consistent with Oakley Greenwood's survey findings.[97]

Box 3.4 below outlines an example of a DSM service provider that provides services that allow large customers to participate in retailers' and/or networks' DR programs:

96 Annex F presents a simple stylized economic example that further illustrates this argument

97 See Oakley Greenwood's survey report, Current status of DR in the NEM: Interviews with electricity retailers and DR specialist service providers, section 3.4.

Box 3.4 GreenSync business offering

GreenSync is a technology company that develops software products and services for managing transmission and distribution networks, microgrids, energy storage and large discretionary electrical loads. GreenSync's products allow utilities and large customers to better forecast and predict their energy loads, and to optimally schedule when equipment should be used.

Their software platform operates 24×7 in real time, integrating weather and climatic data, production schedules, along with information from networks and markets around the country to predict forthcoming high load situations, and to identify ways to minimise energy costs for customers. This optimisation technology can be used to manage peaks in large transmission utilities, or to schedule subsystems across a regional microgrid by combining solar, gas, battery storage, and load curtailment into a single solution. For large customers, this in general means that business rules and constraints can be adhered to, whilst maximising any benefits from energy and load reductions.

This product allows for a customer's equipment automation so that it can be scheduled and optimised based on time of year, local climate and electricity prices. This allows customers to participate in retailer-initiated or network-initiated DR programs, where participation generally involves moving non-critical loads to off-peak times.

GreenSync have published a case study on their website.[98] Orora, a large manufacturing facility in Sydney, was fitted with their PeakResponse™ product, allowing it to participate in a network-initiated DR program. By switching off for three hours on a hot summer afternoon, the customer attracted a $35,000 payment from the local distribution utility.

The Commission also found that there is a consistent view among stakeholders that to date the value of demand response resides in the area of network management rather than providing demand response services to retailers. Box 3.5 below provides an example of how the market is currently targeting this value:

98 http://www.greensync.com.au/solutions-for-business-peakresponse/

Box 3.5 United Energy and New Energy (AGL's new business division) Demand response trial[99]

AGL and United Energy have performed a demand response trial with 68 residential customers in Carrum Downs with local network provider United Energy. This particular area was chosen as it may require United Energy to invest in upgrading its infrastructure in the coming years.

All customer homes have cloud-interfaced air conditioning units installed and connected to virtual power plant software. As well, six of the homes have batteries installed, which integrate with existing solar PV systems.

The trial involves customers' air conditioners being sent commands to slightly increase the temperature setpoint to reduce demand from the distribution network. Customers are able to opt-out of particular hot weather events before or during each event. The intention of the trial is to explore how peak demand can be reshaped through customer's demand response.

In line with comments from other stakeholders, one DSM service provider active in Victoria noted that under current market conditions prices for energy financial cap products were relatively low across many jurisdictions in the NEM. This meant that demand response services to retailers are not sufficiently competitive at the moment. Consistent with this comment, this same DSM service provider noted that currently "they make most of their money" from exploiting their customers' demand response capabilities through providing services to networks rather than to retailers.

Another DSM service provider active in South Australia also indicated that this situation is reversing in South Australia and Queensland given increased spot price volatility recently experienced in these jurisdictions. This is seems to be consistent with Oakley Greenwood's survey findings that show that approximately two thirds of demand response capability that surveyed DSM service providers arrange is split between these two jurisdictions.[100]

Some DSM service providers help clients to assess if and if so what form of demand response is of financial value for them and administer the financial transaction without necessarily being actively involved in demand response. Box 3.6 contains an example of such service offering.

99 See https://www.agl.com.au/about-agl/media-centre/article-list/2016/march/agl-trials-impacts-of-emerging-technologies-on-the-grid-and-energy-bills

100 See Oakley Greenwood's survey report, Current status of DR in the NEM: Interviews with electricity retailers and DR specialist service providers, table 4 at p 11.

Box 3.6 Schneider Electric business offering[101]

Schneider Electric offers a range of services for their clients in order to help them exploit their demand response capabilities. Services provided by Schneider Electric include:

- identifying demand response opportunities and to assessing whether these could be finally beneficial;
- coordinating and negotiating the optimal demand response solutions; and
- managing the transaction and ensuring the right compensation for the demand response.

Overall, the above findings indicate that under current market arrangements DSM service providers are already enabling the market to deliver competitive demand side participation outcomes by allocating scarce demand response resources where they are most valued.

3.3.2 Demand side participation through a retailer's demand response program

The nature of demand response opportunities available through a retailer's demand response program depends on the large customer's retail supply choice through:

- **requesting the retailer to manage the spot price exposure on their behalf:** This generally results in the large customer paying a fixed price for their energy requirements that incorporates a premium to the retailer for the spot price risk management service provided as part of that price; or
- **requesting a spot price pass-through contract:** This generally involves the retailer passing on degree of spot price exposure to the large customer who is now responsible for managing that share of the risk.

Oakley Greenwood's survey responses indicated that retailers have under contract at least 235 MW of demand response capacity, of which 200 MW is directly exposed to the spot price.[102] Therefore there does not appear to be any evidence that large customers have barriers to exploit their demand response capabilities through either of these options. This is discussed further below.

101 Based on publicly available information available on http://www2.schneider-electric.com/sites/corporate/en/products-services/professional-services/ems/how-do-i-buy/ems-demand-response.page last accessed on20 August 2016

102 See Oakley Greenwood's survey report, Current status of DR in the NEM: Interviews with electricity retailers and DR specialist service providers, p 3.

Customer requests the retailer to manage the spot price exposure

When a large customer has a preference for the retailer to manage the spot price exposure on its behalf, an opportunity is created for the customers to be rewarded for its demand response. When the spot price is high a large customer's demand response reduces the retailer's costs of buying electricity at high spot prices but having to sell that electricity at a lower retail price (as part of a retail tariff) to the customer. Demand response is beneficial for both the retailer and the customer as long as the spot price is above the revenue that the retailer may expect from the customer and the retailer compensates the customer for the cost of reducing demand. Oakley Greenwood's survey responses indicate that retailers have contracted at least 135 MW of demand response capacity with their customers based on this type of demand response.[103]

Survey evidence reflects that retailers and their customers have developed a range of standardized and bespoke commercial arrangements to engage in these transactions.[104] The basic elements that define these arrangements can be varied to meet how and when demand response can be provided by the customers. For example, given that the large customer is not exposed to the spot price, under all these arrangements it is necessarily the retailer that sends a request to the customer to demand respond.[105] However, the survey findings show that a period to initiate demand response can vary depending on the customer's requirements, for example between 60 down to 5 minutes. Alternatively, the Commission's own review of market activity and the survey also found instances where the large customer's response to a request has been pre-arranged in advance with the retailer, or alternatively the customer responds to the request on a more 'opportunistic' basis.[106]

The arrangements under these demand response contracts can also vary. For example, compensation can be made through: an availability payment, a discount of the retail energy price or through direct compensation at the time of demand response dispatch.[107] One retailer shared two case studies with the Commission which are outlined in Table 3.2 below.

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103 See Oakley Greenwood's survey report, Current status of DR in the NEM: Interviews with electricity retailers and DR specialist service providers, p 3.

104 See Oakley Greenwood's survey report, Current status of DR in the NEM: Interviews with electricity retailers and DR specialist service providers, section 2.4.

105 See Oakley Greenwood's survey report, Current status of DR in the NEM: Interviews with electricity retailers and DR specialist service providers, section 2.3.

106 See Oakley Greenwood's survey report, Current status of DR in the NEM: Interviews with electricity retailers and DR specialist service providers, section 2.4.

107 See Oakley Greenwood's survey report, Current status of DR in the NEM: Interviews with electricity retailers and DR specialist service providers, section 2.4.

Table 3.2 Case study: Demand response compensation arrangements (customer not exposed to the spot price)

Firm demand response case	Non-firm demand response case
The customer's demand response arrangement was firm: • The customer committed to provide 15 MW of curtailment on request for the retailer, with a 30 minute period. • The customer was paid a quarterly availability payment irrespective of performance. • Quarterly dispatch payments were made if the customer met a curtailment call or if there was no call. • If the customer did not meet a curtailment call then the customer attracted a negative performance payment for every MW short of the target and this was subtracted from the quarterly availability payment • There were limits on the number of calls that could be made and their duration per annum.	The customer's demand response arrangement was not firm, and the customer choses whether to respond to a call from the retailer: • On request from the retailer (60 minutes advance notice), the customer can choose whether to participate. If it participates, the target reduction represents 4% of average load. • The customer is paid a percentage of the spot price multiplied by the amount of load reduction as compared to their baseline. This baseline is a function of historic consumption patterns on similar days and is monitored and updated on an ongoing basis. • A guaranteed 'floor' payment is specified to protect the customer against very poor pay-outs in the event that anticipated pool prices do not eventuate.

Customer requests a spot price pass-through contract with the retailer

Current market arrangements allow customers to request a partial or full spot price pass-through contract with their retailers. This enables the transfer of spot price risk from retailers to large customers without the customer having to become a Market Customer. The survey findings show that at least 200 MW of the 235 MW demand response capacity reported by retailers are actually exposed to the spot price. These customers can then contract the services of a DSM service provider to use their demand response capabilities to manage this risk. Therefore, when large customers manage the spot price exposure on their behalf l they are not dependent on their retailer's efficient economic incentives to engage in demand response activities with their customers.

The Commission's findings indicate that the market for retailers' spot price pass-through contracts has also evolved to meet diverse customer preferences. For example, retailers such as PG Energy and Simply Energy already offer a range of spot price pass-through contracts where the customer can chose their degree of spot price exposure.[108]

Findings also show that DSM service providers are already offering brokering services and can organize competitive tenders to enable large customers to access competitive pricing offers for spot price pass-through contracts. As revealed in the Oakley

108 See for example, http://pgenergy.com.au/products-business-electricity-suppliers/

Greenwood's web-search results there are a significant number of DSM service providers that can provide these services.[109] All retailers surveyed with such customer arrangements in place notify their customers of the occurrence of high spot price events.[110]

Overall, the market for spot price pass-through contracts is consistent with competitive outcomes for large customers looking to become exposed to the spot price.

In its submission to the draft determination, SA DSD cites an example[111] of SA Water as a stakeholder that had difficulty sourcing a retail contract that would have appropriately rewarded SA Water for its demand response capabilities. SA DSD notes that under current market arrangements SA Water is unable to receive benefits from its retailer for demand response. Having investigated this issue further, the Commission understands[112] that since 2012 SA Water has been on a full spot price pass-through contract with its retailer. SA Water has a peak load of around 100 MW of which about 10-15MW can be curtailed with varying response time. While small pumps can be switched off more easily, larger pumps can be slowed almost immediately. SA Water also has some 'run-of-pipe' and gas generation capacity (10MW) and is now considering the benefits of storage. Being fully exposed to the spot price sharpened SA Water's incentives for improving curtailment and seeking further options to shift load. SA Water also invested in predicting high price periods and is now considering further improvements to cut costs. In the initial three years of the arrangement SA Water paid around $40/MWh while last year this figure was a bit higher, around $50/MWh. These represent considerable costs savings relative to retail contract rates.

SA Water is a textbook example of the type of arrangement where customers negotiate a spot-price pass through contract with their retailer and thus essentially 'unbundle' their demand response capabilities from their retail contract. SA Water considers that the spot price pass-through contract gives them more options and flexibility in using their own loads and generation assets than a retail contract with a tariff rate would. In addition, the full spot price exposure rewards SA Water fully for its demand response.

The Commission notes that under the proposed DRM, SA Water would be required to pay its retail tariff rate in line with its baseline consumption to its retailer. The DRM would dampen SA Water's price incentives and its payments would depend on the deal it would be able to negotiate with the demand response aggregator, the primary recipient of any demand response payment under the DRM. Instead, SA Water, under its current full spot price pass-through contract is able to make decisions (potentially with the support of specialist demand side management service providers) and be entitled to 100% of the cost savings. While the benefits of full spot price pass-through contracts depend on the demand response capabilities and the risk attitude of the

109 See Oakley Greenwood's survey report, Current status of DR in the NEM: Interviews with electricity retailers and DR specialist service providers, section 2.3.

110 See Oakley Greenwood's survey report, Current status of DR in the NEM: Interviews with electricity retailers and DR specialist service providers, table 4 at p 11.

111 SA DSD, Submission to Draft determination, p.1-2.

112 Stakeholder meeting on 28 October, 2016, Adelaide.

business and so may not be suited to all business, the Commission notes that this type of arrangement creates clear incentives for businesses to consider demand response.

3.3.3 Commercial challenges of engaging in demand response

The Commission acknowledges that negotiating a demand response arrangement may be commercially challenging and may require the skills and expertise of specialist service providers.

Engaging in demand response activities with customers can be costly for retailers. It requires investing time and effort to understand a customer's load profile, identifying conditions under which loads might be turned-off, and engaging with key operational staff to find out whether the rewards from engaging in demand response activities are greater than the operational risks. The Commission recognizes that this can be problematic for the overall level of demand response uptake by retailers if:

- these activities do not necessarily fall within the core expertise of the retailer or the customer; and
- as the Energy Council seems to suggest,[113] incentives to invest in developing demand response capability are reduced if the investment does not deliver a sufficient level of revenue certainty.

However, as already noted in the previous section, should retailers or their customers consider monitoring spot prices or managing price risk too costly, they can access a competitive DSM service market to maximize the benefit from a large customer's demand response capability. For example, the survey findings show that DSM service providers already work with large customers on retailers' behalf to exploit demand response opportunities.[114] DSM service providers also enable large customers to exploit their demand response capabilities through services to networks and/or direct exposure to the spot prices. These activities further increase the potential reward for a large customer investing in developing its demand response capability.

In addition, the Commission notes that existing demand response arrangements can also be used to facilitate investment. For example, arrangements based on availability payments to large customers can provide sufficient revenue certainty to stimulate an investment decision to come forward.[115] As noted in table 3.2 above, even in arrangements without availability payments, contract terms can be specified to guarantee a minimum pay-out to the customer which would also facilitate positive investment decisions. While these negotiations may be challenging commercially, the Rules do not prevent these from taking place.

113 The Energy Council notes: "some large users have reported that the terms offered in demand response contracts are generally not attractive, and demand response contracts are rarely called upon. This limits the willingness of customers to agree to demand response contracts, especially when an investment in technology or systems is required". Pp 4-5.

114 See Oakley Greenwood's survey report, Current status of DR in the NEM: Interviews with electricity retailers and DR specialist service providers, sections 3.4. and 3.5.

115 This is similar to how financial cap products available in the energy derivative market work to facilitate investment in peaking generation.

3.3.4 Mandatory bundling of retailer supply and demand response

Stakeholder submissions also identified the mandatory bundling of demand response services with retail supply as being a barrier to effective demand side participation. These concerns are summarized in EEC's submission:[116]

> "*Mandatorily bundling demand-response and retail services has led to sub-optimal provision of demand response services, as:*
>
> - *This reduces competition for demand-response services; and*
> - *Some retailers have conflicting interests in providing demand-response services*"

The Commission notes that there is no 'mandatory bundling' between retail supply and demand response services as the EEC suggests. The 'bundling' is an outcome of a large consumer's commercial decision to engage a retailer through a retail contract as a means to manage spot price exposure on its behalf. Given that the retailer is requested to both supply the customer and bear the risk of spot price exposure on the customer's behalf, it follows that a customer's demand response services can only be valuable to that retailer. These arrangements already allow DSM service providers to compete with retailers for the provision of spot price risk management services to large customers. As the survey findings show, this is already happening under current demand side participation arrangements.

The large customer is free to negotiate a contract with a retailer that allows full or partial exposure to the spot price and such arrangement effectively 'unbundles' the retail supply of electricity and opportunities for demand response. A range of these arrangements were discussed in section 3.3.3.

Furthermore, if a customer chooses to face a flat rate by opting-into a retail contract, the Rules do not prevent the customer from pursuing demand response or load shifting in relation to its chosen tariff rate. Given the incentives created by the chosen tariff rate, the customer may choose, for example, to shift consumption between peak and off-peak periods.

3.3.5 Retailers' incentives to pursue demand response

Given that retailers already compete in the market place to manage spot price exposure on their customers' behalf, they have an efficient incentive to manage this risk cost effectively to develop competitive pricing offers for their customers. Retailers have a number of instruments at their disposal to manage this risk, and engaging in demand response activities is just one of them. Whether the retailer relies on demand response depends on how competitive it is relative to the other instruments available such as buying energy derivative financial products and/or generation assets. The Rules do not prevent retailers from pursuing any of these options. When compared with alternatives, demand response may not be the first choice for retailers to pursue. If retailers consider that the ownership of generation assets or the purchase of financial instruments is most efficient way of being able to effectively compete in the retail

116 EEC, Submission to Consultation Paper, p.4

market, competitive retail markets will lead to customers benefitting from these options. The Rules do not prevent retailers pursuing the option of demand response.

In addition, the Commission notes that competitive tenders for a large customer's retail supply are commonly organized through brokering services to support the large customer accessing competitively priced retail products. The Commission is not aware of any barrier that would prevent a large customer with demand response capabilities from offering demand response services as part of a tendering process to reduce the premium that retailers require for managing the spot price exposure.[117] The extent to which the customer would be able to reduce the overall premium would depend on the amount and characteristics of the demand response capacity being offered. For example, the customer's opportunity cost, the firmness or commitment of the capacity and the notice period required to deliver demand response.

Some stakeholders commented[118] that retailers that own generating assets (gentailers) may lack incentives to act upon demand response as their interest is conflicted. In the NEM, generation and consumption is independent in a sense that a retailer that owns generating assets does not directly transact with its own customers. Contrary to net pool markets where generators only sell energy they have not already sold through bilateral contracts (for example to retailers), the NEM is a gross pool market where generators are required to sell and retailers are required to buy all of their energy through the wholesale spot market. In a gross pool market a retailer's interest is hence independent from the interest of its generators' interest. Whether a high or a low price is more favourable for a gentailer, and how this may impact on its overall participation in the market, is a complex issue and depends, among many factors, on its position in the energy, retail and related hedging markets.

117 PG Energy in its submission to the consultation paper also raises a similar point. See p. 2.

118 ATA, Submission to draft determination, p.3 and EnerNOC, Submission to Draft determination, p. 4.

4 Costs and benefits of implementing the DRM

Box 4.1 Summary

There is no net benefit from implementing the DRM over and above the benefits already being delivered through existing demand side participation arrangements in the market. This is because implementing the DRM to allow demand response aggregators to self-schedule demand response in the spot market:

- will not result in demand being met at a lower cost and/or demand response competing directly with peaking generation plants to meet demand. The impact of demand response under the DRM on the spot market is no different to demand response outside of the DRM. Without AEMO being able to schedule demand response through central dispatch, all demand response has the potential to unbalance dispatched supply in meeting demand and so create a need for FCAS to rebalance supply and demand, which therefore increases costs. The DRM will not derive the spot market benefits necessary to result in lower electricity prices;
- is not needed to deliver the network benefits attributed to the DRM in the cost benefit analysis submitted with the rule change request. These benefits, and any other network benefits that result from spill-over effects, can be similarly delivered through existing demand side participation arrangements; and
- would incur significant implementation costs. AEMO's costs of implementation have been estimated to be in the range of $8 - $14 million. Retailer implementation costs could also be significant, being estimated to be up to $112million, in the event participation in the DRM was mandatory. The level of implementation costs for voluntary participation in the DRM would be less but still carries a risk that the cost associated with its implementation are borne by all consumers not just those involved in the DRM.

The various costs and benefits that can be directly attributed to implementing the DRM are explored in this chapter. It also outlines the Commission's assessment of whether the proposed DRM delivers any additional benefits over the costs associated with its implementation, relative to existing demand side participation options that are currently available to large customers. Demand side participation options for small customers were not considered as the proposed DRM was limited to large customer involvement only, at least initially.

Sections 4.1 and 4.2 set out the rule proponent's view and stakeholders' views respectively. Section 4.3 presents the Commission's analysis.

4.1 Rule proponent's view

The Energy Council identifies a number of benefits associated with the implementation of the DRM. These include:

(a) the proposed DRM would allow demand to be met at a lower cost and introduce greater competition into the spot market. This would result in lower prices and a more reliable supply to consumers. Large customers would also be rewarded for their efforts to reduce demand at times when the market values it more, and have more options to manage their electricity costs resulting in a more efficient use of energy resources;

(b) demand reductions offered in this way under the DRM would compete with peaking generation plants to meet demand. Having demand response compete with peaking generation would result in a lower cost and a more efficient option to balance supply and demand for electricity. It will also reduce the ability for participants to exercise market power, resulting in lower prices for electricity and a more reliable supply for consumers;

(c) allowing demand response under the DRM to be unscheduled in the spot market would maintain the flexibility of customers to decide when to offer demand response. This would also ensure that demand reductions are treated in a manner consistent with non-scheduled generation,[119] which is similarly flexible and not required to bid into central dispatch (assuming its capacity is under 30 MW);

(d) under current market conditions of excess generation capacity it would be difficult for the DRM to defer investment in generation. However, this would not be the case in the future if the market moved towards tighter supply conditions. Under these circumstances it is suggested that the DRM could provide a more cost-effective option to balance demand and supply;

(e) customers may be more willing to participate in network demand response programs which would result in putting downward pressure on network charges.

The benefits detailed in (a)-(d) above will be collectively referred to in this chapter as 'spot market benefits'. The benefit detailed in (e) is referred to in this chapter as 'network benefits'.

The Energy Council also identifies a number of costs associated with the implementation of the DRM. These fall mainly into two types: costs incurred by retailers and those incurred by AEMO. Cost impacts on generators, and networks are considered by the Energy Council to be minimal. The cost of entry of demand response aggregators is noted as being necessary and recoverable through the commercial arrangements these aggregators will negotiate with their customers.

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119 A generator will normally be classified as non-scheduled if: a) its primary purpose is for local use and the aggregate sent out generation rarely, if ever, exceeds 30MW; or b) its physical and technical attributes make it impracticable for it to participate in central dispatch. Non-scheduled generators do not participate in the central dispatch process, but AEMO can specify additional conditions with which they must comply, usually for power system security reasons.

Retailers would be required to implement systems to support the settlement of the DRM for their customers by billing based on standardised baseline consumption. Given that a mandatory participation in the DRM could impose significant costs on retailers to develop supporting systems, the Energy Council supports voluntary participation in the DRM to minimise costs for those retailers who do not wish to offer DRM services to large customers. Once a retailer opted into the DRM it would be required to allow any of its customers to participate in its DRM program. Despite it being left to retailers to choose whether their customers can participate in the DRM, the Energy Council believes that competitive pressures will ensure that at least some retailers will enable the DRM for their customers.

In addition to voluntary participation, a staged implementation approach is proposed whereby implementation of the DRM would not require retailers to have all systems in place for the commencement of the DRM. For example, retailers may use a manual workaround to bill DRM participating customers in the early stages of the DRM implementation. It is suggested that this approach would allow minimizing costs for the development of systems to support the DRM.

AEMO is expected to incur costs in setting up the DRM, the DRM’s methodologies and processes as well as amending its systems for settlement to account for the operation of the DRM. AEMO would also have ongoing operational costs in administering the DRM (e.g. accrediting baselines, registering participants, changing customers’ settlement arrangements).

4.2 Stakeholder views

Spot market benefits

In its submission to the consultation paper, the Energy Efficiency Council (EEC) argued that the DRM would significantly improve the understanding of demand-side behaviour in a low-cost way, presumably because demand response under a DRM can have the effect of competing with generation, but this argument was not explained in the submission nor substantiated with analysis. The EEC did not undertake modelling on the significance of this improvement for spot market dispatch prices. The EEC is also of the view that the DRM would generate useful information for managing transmission constraints.[120] Similar views are also shared by EnerNOC.[121]

In this context MEU agrees more demand side information about potential load reductions should be made available in the market. They note that requiring large customers to have to comply with existing scheduling arrangements would be excessively expensive. They suggest that better demand related information should be made available to AEMO by retailers, networks and aggregators who have already accessed existing demand response available in the market.[122]

Ergon and GDF Suez argue that the DRM self-scheduling arrangements do not result in a bid system. Therefore, it is not expected that the DRM would generate any new

120 EEC, Submission to Consultation Paper, p.4

121 EnerNOC, Submission to Consultation Paper, p. 9

122 MEU, Submission to Consultation Paper, pp.-5-9

pre-dispatch information. To the contrary, information generated would be post event only, and market participants could only use historical performance and capability as a guide to understand expected responses.[123] Similarly, AEMO notes that the detailed design was created as a response mechanism, i.e. demand response aggregators respond to the spot price rather than set it.[124]

In his submission Dr Chapman from University of Sydney noted that the conception of the DRM and the detailed design drafted by AEMO contains some features that may limit its ability to contribute effectively to the achievement of the NEO over the long term. Dr Chapman considers the underlying issue addressed by the proposed DRM relates to the limited ability of the demand side to influence wholesale prices, and the proposal does not directly address sources of price volatility, and it does not give retailers incentive to share the information they are most likely to have with AEMO to aid the price determination process. [125]

Stakeholders who support the DRM all agree that a mechanism that required demand response to be scheduled in central dispatch would be superior to the one proposed in the rule change request. For example, EnerNOC[126] reiterates its support for a design of a DRM where demand response would be dispatched by the market operator as part of the same merit order as generation resources and the same compliance mechanisms would apply to the demand response aggregator as apply to other scheduled resources if they were unable to deliver the volume of demand response dispatched.

ATA[127] acknowledges that lack of scheduling is a deficiency in the proposed mechanism and that scheduling would be more effective in driving efficient pricing in the spot market. However, ATA highlights that under current registration requirements generating units with a nameplate rating of less than 30MW may not necessarily participate in the central dispatch and hence self-scheduled demand response that is less than 30MW would be consistent with existing regulatory requirements regarding non-scheduled generation.

EnerNOC agrees with the Commission in that the demand side under the proposed DRM would not be able to “set the price” in any dispatch interval but notes that it could have an impact on the price, especially with increased demand-side participation. As an increasing number of consumers would participate and react to high spot prices, the aggregate demand curve used to determine the spot price would shift. EnerNOC acknowledges that this is already happening today and expects that would happen with greater frequency, and at greater volumes, under the DRM.[128]

In its submission to the draft determination, SA DSD considers that in the event that renewable generation is not providing sufficient supply, a demand response

123 Ergon Energy, Submission to Consultation Paper, p. 5; GDF Suez, Submission to Consultation Paper, p. 9.

124 AEMO, Submission to Consultation Paper, p. 3.

125 Dr Chapman, Submission to Consultation Paper, p.2

126 EnerNOC, Submission to Draft determination, p.2.

127 ATA, Submission to Draft determination, p.2

128 EnerNOC, Submission to Draft determination, p.11

mechanism will facilitate the reduction in market demand in order to facilitate a balance in the market.[129]

Network benefits

EEC, ATA and EnerNOC share similar views that the DRM would enable demand response aggregators to develop portfolios of demand side participation that could be used to reduce further investment in electricity transmission and distribution networks.[130]

Ergon also supports the view that the DRM is capable of providing network management opportunities, particularly in mitigating the impacts of significant and growing penetration rates of solar PV systems and in managing network costs.[131]

To the contrary, Stanwell notes that given the incentives already in place for networks to procure, and customers to provide, network support services through demand management, a wholesale DRM is unlikely to create network benefits.[132] The Energy Networks Association (ENA) argues that the cost benefit analysis is only marginally positive and there are already mechanisms which could realise some of the network benefits quantified. They also noted that new initiatives would need to take into account any relevant existing AEMO work programs in order to avoid unnecessary implementation costs and duplication. For example, in their submission to the draft determination, ENA[133] notes that a number of agreements are in place with customers to control appliances with discretionary loads, or to engage in demand response at certain times in exchange for payment or lower price tariffs. Such programs are widespread and can be used to manage demand in parts of the network. In many cases these demand management programs have avoided the costs associated with augmenting the network. Network service providers note that the Demand Management Incentive Scheme and Demand Management Incentive Allowance already encourage network service providers to implement demand management solutions in lieu of network augmentation. Detailed design should minimise the risk of demand response providers being paid twice for the same service.[134]

EnerNOC[135] in its submission to the draft determination notes that any references to the DRM's impact or purported benefit for transmission or distribution purposes are entirely misplaced. EnerNOC[136] agrees with the Commission's assessment of the

129 SA DSD, Submission to Draft determination, p.1

130 EEC, Submission to Consultation Paper, p. 5; ATA., Submission to Consultation Paper, p. 11; EnerNOC, Submission to Consultation Paper, p. 10.

131 Ergon Energy, Submission to Consultation Paper, p. 2.

132 Stanwell, Submission to Consultation Paper, p. 9.

133 ENA, Submission to Consultation Paper, p. 3.

134 ENA, Submission to Consultation Paper, p. 3.

135 EnerNOC, Submission to draft determination, p. 14.

136 EnerNOC, Submission to draft determination, p. 14.

proposed DRM lacking network related benefits. However, EnerNOC believes that this should not be used as a justification for not proceeding with its implementation.

Costs of implementation

ATA, MEU and EnerNOC share a similar view that the biggest risk is that under a 'voluntary' model, retailers will restrict participation in the DRM, limiting the mechanism's ability to best achieving consumer choice.[137] Further, ATA notes that the cost benefit analysis found a net benefit for all consumers. Given this, allowing any retailer to restrict any consumer from participating in the DRM, represents an unambiguous failure to prioritise the long term interests of all consumers.[138] Each suggests that there must be a date after which time it becomes mandatory for retailers to allow their customers to access the DRM.

PG Energy, Origin, AGL and GDF Suez all share similar views in that the voluntary model as proposed is highly unlikely to have net benefits over the current arrangements, because the DRM adds complexity and costs in an attempt to 'facilitate' something that can and does already occur.[139]

The EEC noted that the most significant benefit of the DRM is that it will provide another demand side participation option for large customers and the costs of removing relevant barriers to demand side participation through a DRM are minimal.[140] They consider that the costs identified in the cost benefit analysis are 'inflated'.

In its submission to the draft determination, EnerNOC[141] expressed its concern that the cost estimates in the cost-benefit analysis submitted with the rule change request were based almost entirely on unverifiable assertions made by market participants who have filed submissions against the DRM. EnerNOC finds the estimates 'absurd' and notes that all changes to the market have implementation costs.

4.3 Commission's analysis

Chapter 1 provides a brief description of the key design elements of the proposed DRM in section 1.4.1. A more detailed description the DRM's proposed design is provided in Annex C.

4.3.1 Spot market benefits

The Commission notes that a well-functioning spot market needs information from both the supply and demand side to determine an efficient dispatch outcome. This

137 ATA, Submission to Consultation Paper, p.4; MEU, Submission to Consultation Paper, p.4; EnerNOC, Submission to Consultation Paper, p. 9

138 ATA, Submission to Consultation Paper, p. 1.

139 PG Energy, Submission to Consultation Paper, p. 4; Origin, Submission to Consultation Paper, p. 3: AGL, Submission to Consultation Paper, p. 7; GDF Suez, Submission to Consultation Paper, p. 3.

140 EEC, Submission to Consultation Paper p.4

141 EnerNOC, Submissions, to Draft determination, p. 12

requires a mechanism to incorporate such information in the price determination process to ensure that the spot price reflects supply and demand conditions.

Under the current market design AEMO uses offers and bids submitted by scheduled generators and loads respectively, to construct the supply curve that represents the available generation and their costs. Under the NER a load may voluntarily elect to become scheduled in the spot market and submit bids to AEMO. Bids from loads are treated as negative generation in the dispatch algorithm, and as such are considered within the supply bid stack together with generation's bids. However, load participation in the spot market in this fashion is not common in the NEM. Rather loads demonstrate an overwhelming preference to not to become part of AEMO's spot market scheduling process.[142]

Demand is calculated based on AEMO's 5-minute dispatch demand forecast. For each 5 minute dispatch interval when the network is unconstrained the price is determined based on the bid of the highest priced generator that is required to be dispatched in order to meet forecast demand. Every half an hour six dispatch interval prices are averaged to determine the trading interval prices. It is the trading price that is used to settle payments between retailers, generators. Under the DRM it is the trading price that is proposed to be used as the basis for payments to demand response aggregators.

It is also important to note how AEMO deals with variations to its demand forecast during any given dispatch interval. After dispatch demand may vary relative to AEMO's 5-minute dispatch demand forecast. In this case AEMO may update the dispatch instructions for some or all of its generators and/or may use ancillary services to balance supply and demand.

The proposed DRM seeks to provide payments to demand response aggregators in line with the spot prices when demand response aggregators self-schedule demand response. The Energy Council expects that this would enable demand reductions to compete with generation, and offer a lower cost and more efficient option to balance the spot market. However, in order for demand side to compete on equal footing with generation, the choice between dispatching generation or demand response and their respective costs has to be made available to AEMO at the time of dispatch. This would allow AEMO to dispatch demand response when it is more competitive than generation, or otherwise.

Under the proposed DRM, demand response aggregators can notify AEMO of their intended demand response in advance but they are also allowed to change or cancel the notification at any time up to the end of an affected trading interval. That is, given that a trading interval consists of six dispatch intervals, the notification submitted by demand response aggregators may be several dispatch intervals after the interval

142 The Brattle report also found minimal participation in other energy-only markets that had similar demand side participation arrangements in market dispatch processes. The report argues that this might be explained by the costs to purchase real-time telemetering equipment and the loss of customer flexibility when the system operator controls consumption (see page iv of the Brattle report). The lack of appetite from large users to become a scheduled load in the NEM is also expressed in MEU's submission to the November 2015 consultation paper on this rule change request. See p 5.

during which the demand response occurred. Also, AEMO would only publish aggregated summary information to the market concerning demand response notifications after the event.

Therefore, under these arrangements AEMO would still be required to forecast the demand response delivered through the DRM. Accordingly, from the point of view of market dispatch, demand response under the DRM is equivalent to any other demand response that is currently carried out by a customer, a DSM service provider, a retailer or a network business outside of the DRM.

If the notification of the demand response was provided to AEMO by the demand response aggregators prior to relevant dispatch interval, and the notification was in a format that would enable AEMO to consider such information in the 5-minute dispatch demand forecast than the DRM would have a potential to improve dispatch outcomes relative to current market arrangements.

However, the rule change request did not contain any proposed modifications to AEMO's 5-minute dispatch demand forecasting process and made the requirements to notify AEMO 'flexible' for demand response aggregators. In the proposed design, demand response aggregators can submit or change their demand response notification any time before the end of the relevant trading interval. This means that the there is no difference in terms of spot market outcomes between the DRM and demand response under current market arrangements.

AEMO is not able to consider the information provided by demand response aggregators in a way that would improve dispatch outcomes. The Commission is of the view that that, contrary to the Energy Council' expectations:

(a) the proposed DRM would not result in demand to be met at a lower cost and demand response would not compete with peaking generation plants to meet demand. As noted above, in order to deliver spot market benefits, the choice between generation and demand response and their respective costs has to be made available at the time of dispatch. Under the proposed DRM this would not be the case. Given that demand response intentions are neither necessarily available prior to dispatch nor are proposed to be incorporated into the dispatch decisions, the choice between generations and demand response is not available at the point when this could deliver economic benefits. In absence of this information and without firm commitment of the demand response, AEMO will dispatch generation to meet demand forecast. Any demand response that takes place during the dispatch period (whether the demand response is within the DRM or not) will likely to lead to an increase in the use of ancillary services to balance supply and demand. The costs and inefficiencies of these are borne by all customers;

(b) demand response does not simply displace the highest cost generator that was dispatched. Instead, within a 5 minute period, all generators with capabilities to adjust their dispatch will reduce their outputs to accommodate the demand reduction that took place during dispatch. Given that during high price events the highest cost dispatched generator is most likely to be a fast-start generating unit with inflexible generation profile,[143] it is likely that the highest cost generator's output is not reduced while lower cost generators' are reduced to account for demand response. This is an inefficient outcome, the cost of which is borne by all customers;[144]

(c) the DRM would not necessarily result in AEMO dispatching the least cost scheduled energy resources and FCAS services to balance supply and demand. The impact on dispatch outcomes from having demand response aggregators self-scheduling demand response in the spot market would be the same as any other demand response scheduled outside the spot market. Therefore, there is no specific spot market benefit resulting from the DRM's self-scheduling arrangements.

Impact on ancillary service requirements

It is also important to note how AEMO deals with variations in demand during a dispatch interval. After dispatch, demand may vary relative to AEMO's 5-minute dispatch demand forecast. This may be, for example, due to demand response or a non-scheduled generator starting up. In either case, the variation in demand relative to dispatch forecast will manifest in frequency variation across the network. In order to manage the variation AEMO may use frequency control ancillary services (FCAS) to balance supply and demand. FCAS is used by AEMO to maintain the frequency of the power system within the operating standards. The frequency of the power system reflects the balance between power system demand and adequacy of generation. Regulation FCAS[145] is used to correct minor deviations in demand or generation whereas contingency FCAS is used in response to major contingency events such as the loss of a generating unit or a loss of load.

Any demand response (whether as part of the DRM or not), in fact any change in generation or consumption (whether in response to the spot price or not) that was not predicted accurately or that is not known prior to dispatch by AEMO, may require the use of FCAS. The most relevant of the ancillary services for demand response is the regulation lower frequency control ancillary service. Currently, the costs of regulation lower services are recovered from all customers, not just those that carried out demand response or whose market activities necessitated the frequency control.[146] Although

143 A fast-start generating unit is a unit that can synchronise and reach its minimum loading within 30 minutes, and can synchronise, reach minimum loading, and shut down in less than 60 minutes. A fast-start generating unit must submit a dispatch inflexibility profile in order to be dispatched as a fast-start unit. The format of the dispatch inflexibility profile is defined in section 3.8.19(e) of the Rules, and consists of a number of parameters including time to reach minimum loading and time required at minimum loading.

144 This is, however, not a problem unique to the DRM but a consequence of demand response and the nature of the market design of the NEM.

145 Regulation raise requires participants to add MW to the system in order to raise the frequency to the required range; regulation lower requires participants to take MW out of the system in order to lower the frequency to the required range.

146 In the NEM, the regulation FCAS requirement is determined dynamically in each five minute dispatch interval, based upon the accumulated deviation of the frequency on the electrical system

the Rules describe how the cost of frequency control ancillary services may be recovered from the responsible market participants, AEMO currently does not calculate 'causer pays factors' for customers (loads). Instead, all FCAS costs caused by load deviations are shared ('socialised') across all customers in the NEM.[147] This is because current causer pay calculations rely on SCADA measurements,[148] a requirement that is not typically available for individual loads.

Under the proposed DRM, demand response aggregators, would not be required to provide SCADA measurements and would not be required to contribute to 'causer pays' FCAS fees. Accordingly, under the proposed DRM demand response aggregators would not bear all costs associated with their actions.

In fact, the question of direct cost recovery through fees from demand aggregators has been raised by AEMO. AEMO[149] notes that if participating demand response aggregators are required to bear the costs of their actions, this in itself could act as a disincentive for participation in the DRM.

In conclusion, the Commission note that there are no net benefits from implementing the DRM over and above the benefits already being delivered through existing demand side participation arrangements in the market. This is because implementing the DRM will not result in demand being met at a lower cost and/or demand response competing with peaking generation plants to meet demand. The impact of demand response under the DRM on the spot market is no different to demand response outside of the DRM. Without AEMO being able to include demand response into the dispatch system, all demand response has the potential to increase FCAS requirements and therefore increase costs. Whilst under certain circumstances demand response may lead to lower dispatch prices that may ultimately manifest in lower retail tariff rates, the proposed DRM also will lead to increased FCAS requirements the cost of which would be borne ultimately by all customers. The net effect of the various changes is difficult to assess.

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over time. Thus, the regulation requirement is adjusted each five minutes, responding directly as required to system variability and uncertainty and other factors that influence frequency.

147 Currently only scheduled and semi-scheduled generating units and some of the non-scheduled generating units have their causer pays factors calculated. All other participants, including some non-scheduled generating units and all loads (Market Customers) in the NEM do not have causer pay factors and hence their fees are not calculated in accordance with their impact on the requirements for regulation frequency control ancillary services.

148 SCADA is a supervisory control and data acquisition software/system that typically relies on real-time or near real-time data. Although the SCADA system and the metering/telemetry equipment that provides the data can be separate, in the NEM "SCADA measurement" typically refers to a 4 second power meter.

149 AEMO, Submission to consultation paper, p. 6.

4.3.2 Network benefits

Deferring network expenditure

The cost-benefit analysis included with the rule change request estimated that the majority of the benefits from implementing the DRM – estimated in the range of $117.8 to $178.4 million in net present value terms over an 18 year period – would be due to the deferral of distribution and transmission system augmentations.

However, the range of the estimated benefits indicates that the results of the cost-benefit analyses are very sensitive and depend, to a great degree, on assumptions made. For example, assumptions are required to be made about long term demand forecasts, electricity usage patterns, changes in generation capacity and fuel, and the likely coincidence of network peak demand and high spot prices.

Network peak demand depends on peak demand occurring at particular times and locations in the network. However, spot market peak demand occurs when energy demand across the entire network achieves its peak. Therefore the ability for the DRM to defer network capacity augmentations depend on whether or not the DRM reduces spot market peak demand at times that happen to coincide with network peak demand at a particular location. Therefore, in absence of the DRM being able to address location-specific network peak demand, the identified network benefits cannot be attributed to the implementation of the DRM.

This is an important point because according to the cost-benefit analysis submitted with the rule change request, demand response is not justified based on wholesale market benefits alone. According to the cost-benefit analysis, without network related benefits the demand response program that was subject to the analysis is not justified because the costs outweigh the benefits.

While the cost-benefit analysis that was submitted with the rule change request considered that the network benefits of the proposed DRM are very high relative to wholesale market benefits, it did question the appropriateness of using a wholesale market mechanism to drive network benefits.[150]

EnerNOC[151] also agrees and states that any references to the DRM's impact or purported benefit for transmission or distribution purposes are entirely misplaced. "Wholesale demand response" and "network demand response" are two different and discrete services that serve entirely different purposes at different times.

As noted in section 3.3, the Commission has not found evidence of a significant market failure that the DRM would address and that currently prevents existing demand side participation arrangements from delivering competitive efficient levels of demand response in the NEM. Therefore, the Commission has no reason to believe that demand

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150 Oakley Greenwood: Cost-benefit analysis of a possible Demand Response Mechanism, p. 16.: "Some stakeholders noted that the results of this analysis and those in the initial Power of Choice modelling both indicated that the majority of the benefits accrued to networks. They questioned whether it made sense to use a wholesale market mechanism to drive network benefits. This question has merit."

151 EnerNOC, Submission to draft determination, p. 14.

response delivered through existing demand side participation arrangements, at times when spot market peak price coincides with network peak demand at a particular location, could not deliver a similar benefit identified in cost benefit analysis. As a result, the estimated network benefits based on the deferral of network capacity augmentations can be similarly delivered without implementing the DRM through existing demand side participation arrangements.

Overall, the Commission does not consider that the implementation of the DRM would deliver network benefits over and above those capable of being delivered through existing demand side participation arrangements.

Managing network constraints

As noted in section 4.3.1, AEMO uses offers and bids submitted by scheduled generators and loads respectively, to construct a supply curve and determine the most cost-efficient set of scheduled resources to be dispatched to meet forecasted demand. However, the dispatch of scheduled resources in the NEM does not occur in a vacuum. Constraints over the transmission network also influence whether a scheduled generator or load is fully, partially or not dispatched at all to meet demand at a particular time and location. This is because AEMO uses the ability of scheduled generation and load to follow dispatch instructions to develop a dispatch schedule that adheres to the constraints over the network. Failing to factor in network constraints into the dispatch process would put the power system at risk of operating in an unsecure state.

Given that under the DRM arrangements demand response aggregators would not be required to follow dispatch instructions, there is no firm commitment from demand response aggregators that a demand response would happen with certainty at a specific time and location. Therefore, AEMO cannot rely on demand response delivered through the DRM to happen in a way that would alleviate or at least not exacerbate a network constraint.

For similar reasons to that outlined above, the DRM would neither provide AEMO with improved information to determine where a constraint is likely or not to occur to facilitate the dispatch of scheduled generation and load accounting for constraints over the network. To the contrary, demand response delivered through the DRM could either alleviate or exacerbate a network's constraint, at a particular time and location, as peak spot price events may or may not coincide with a network constraint at a particular location. Therefore demand response delivered thought the DRM is unlikely to improve the management of network constraints.[152]

Spill-over effects

The Energy Council argues that if the DRM encouraged large customers to develop greater demand response capability that same capability could have a spill-over effect enabling the customer to participate in network demand programs. While this is true, it

152 This would also be the case for any demand response that is scheduled outside the spot market.

is also true that the spill-over effect could work the other way around; any networks related demand response may have a spill-over effect for the wholesale market.

As shown in section 3.3 network businesses can resort to a competitive DSM service market to exploit demand response opportunities if required. The survey findings also show that some DSM service providers already help customers participate in a distributor's network demand response programs.[153]

The Commission also notes that more appropriate incentive mechanisms to deliver network benefits have already been developed and implemented through the existing regulatory framework applicable to network businesses. The Demand Management Incentive Scheme rule made on 20 August 2015[154] provides distribution businesses with an incentive to undertake efficient expenditure on non-network solutions as opposed to capacity augmentations. These alternative solutions might include demand side management solutions.

4.3.3 Spot market implementation and operating costs

AEMO would incur costs to implement the DRM, such as developing baseline methodologies as well as changing the spot market systems to implement and administering the DRM. System changes would be necessary to accommodate new settlement functions.

The cost-benefit analysis submitted with this rule change notes that AEMO estimated these costs to lie in the range of $8 million to $14 million in net present value terms over a ten year period for the cost.[155]

As noted by AEMO in its submission to the consultation paper,[156] how these costs are recovered is likely to have different impacts. If costs are recovered on a user pays basis, where participating demand response aggregators bear the cost, this could act as a disincentive for participation in the DRM. Under a voluntary implementation approach to the DRM, this might lead to AEMO being unable to recover its costs if retailers do not offer access to the DRM to their customers. Alternatively, if AEMO recovered its cost through 'market participant fees' then it is likely that those costs would be smeared across all consumers, even those that do not participate in the DRM.

4.3.4 Retail market implementation costs

Retailers would also incur implementation costs over time to accommodate customers that opt-in to the DRM. The high-level cost drivers relate to costs in relation to retailers having to adjust existing or developing new computer systems and processes and/or manual business processes. The cost benefit analysis, accompanying the rule change request noted the survey the Energy Supply Association of Australia's (ESAA)

153 See Current status of DR in the NEM: Interviews with electricity retailers and DR specialist service providers, Oakley Greenwood, p. 11.

154 See http://www.aemc.gov.au/Rule-Changes/Demand-Management-Embedded-Generation-Connection-I

155 See Cost-benefit analysis of a possible Demand Response Mechanism, Oakley Greenwood, p. 60.

156 AEMO, Submission to Consultation Paper, p. 4.

conducted with retailers to understand the costs impacts from implementing the DRM in relation to: (1) registration; (2) metering and data management; (3) settlement and prudential requirements; (4) reporting; and (5) retail customer billing.[157]

This survey reported these costs in the order of $112 million. Independent expert advice obtained for the costs benefit analysis confirmed that such estimates are expected to be in the order of +/- 50% accuracy.[158] In any case, the extent to which retail implementation costs would be incurred depends on the number of retailers that actually enable their customers to participate in the DRM. While participation for retailers in the DRM is voluntary, the proposed rule would require a retailer to offer DRM to all of its customers once it has 'voluntarily' made it available to at least one.

If a retailer can offer a demand response option to consumers both consumers and retailers may be better off arranging this directly with each other rather than through the proposed DRM. This is because under a direct arrangement the retailer can capture value from the spot market for load reduction rather than it flowing to the demand response aggregator. Also, the customer benefits through a decrease in the payment to retailer. Under direct demand response with retailers, customers do not have to pay the retail costs of their baseline consumption to the retailers. Retailers can further avoid the costs of participating in the DRM and having to incur implementation costs of interfacing with AEMO's DRM settlement processes.

The Commission thus notes that the incentives for retailers to offer the DRM on a voluntary basis are very low or non-existent. A retailer will always be better off if it does not offer to support the DRM to its customers because such strategy restricts demand response aggregators from entering the market to compete for their customer's demand response. Further, it is unlikely that any retailer would decide to deviate from this strategy given that enabling the DRM to their customer's only results in the retailer incurring the costs of becoming settled on the DRM's baseline energy consumption and the respective implementation costs for no additional benefit.[159] For this reason, the Commission is of the view that the costs of implementing the DRM would be better assessed under the assumption of a mandatory implementation scheme.

Given the information that has been provided in the cost benefit analysis it is difficult to ascertain the implementation costs of a mandatory implementation scheme. However, the Commission notes that regardless of the extent of the implementation

157 See Cost-benefit analysis of a possible Demand Response Mechanism, Oakley Greenwood, p. 60.

158 See Cost-benefit analysis of a possible Demand Response Mechanism, Oakley Greenwood, p. 61 and 62.

159 Under the DRM, a customer will engage with a retailer not only to agree a retail supply, but also to agree terms so that the retailer manages the spot risk on the customer's behalf for a premium. Under this arrangement, the retailer is the direct beneficiary of a customer's demand response. Therefore, while the retailer is the party to which the customer would naturally sell its demand response, the DRM requires that the customer's demand response is sold to the spot market instead. The retailer is stripped from a tool to manage the spot price exposure that has been asked to manage on behalf of its customers in the first place. It is unlikely that a retailer would ever consider offering access to the DRM to its customers under these unfavorable conditions. See Annex F and section 5.3.2 for more detail on the impact of these arrangements.

cost arising from retailers having to change their billing systems, such costs would be additional to AEMO's implementation and operational costs, and are likely to be considerable.

The rule change request did not provide specific details on how retailers should recover these costs. Under a mandatory implementation scheme, retailers could decide to recover these costs directly from the DRM participating customers which would act as disincentive to participate in the scheme. Alternatively, and potentially more likely, these costs could be smeared across a retailer's customer base leading to increase retail prices to all consumers.

4.3.5 Does the DRM provide a net benefit over the benefits currently being provided by existing demand side participation arrangements?

The Commission has found that implementing the DRM would not result in a net benefit over and above those already being delivered through existing demand side participation options. This is because implementing the DRM to allow demand response aggregators to self-schedule demand response in the spot market results in:

- **An absence of spot market benefits:** Contrary to the Energy Council's expectation, the proposed DRM would not result in demand being met at a lower cost and/or demand response competing with peaking generation plants to meet demand. Rather, the impact on spot market dispatch outcomes from allowing demand response aggregators to participate in the spot market and self-schedule demand response would be the same as any other demand response that is scheduled outside the spot market through existing demand side participation arrangements via: a retailer, a network, DSM service provider or a large customer. As noted in section 4.3.1, this 'unscheduled' demand response results in additional costs to the market because of the increased FCAS needed to balance supply and demand in light of it. The demand response under the proposed DRM would be no different to existing demand response occurring in the market and would be responsible for the same increased frequency control ancillary service costs. While demand response may, under certain circumstances, lead to a decrease in dispatch prices, how this would compare to the increase in FCAS costs over time is difficult to assess.
- **An absence of network benefits:** the DRM is not needed to deliver the network benefits attributed to the DRM in cost benefit analysis accompanying the rule change request. These benefits, and any other network benefits that result from spill-over effects, can be similarly delivered through existing demand side participation arrangements. Neither will demand response delivered through the DRM facilitate the management of constraints over the network.
- **Spot market implementation and operational costs:** AEMO's costs of changing the spot market systems to implement and administer the DRM have been estimated to be in the region of \$8 million to \$14 million in net present value terms. These costs are avoided in their entirety if the DRM were not implemented; and
- **Retail market implementation costs:** A further cost in relation to changes to retailers' systems and business processes to support the DRM settlement would

also be incurred. Given the lack of incentives of behalf of retailers to offer access to the DRM to their customers under the proposed voluntary participation approach, the implementation of the DRM would need to consider the costs of a mandatory implementation scheme. The cost benefit analysis provides survey evidence which suggests that retailer costs of implementation could be as high as $112million. These costs would be avoided in their entirety if the DRM were not implemented.

5 Potential distortions in the spot and related markets

Summary

Implementing the DRM could cause a number of distortions not only in the spot market, but also in other related markets. These are described below. The costs of these distortions would be borne by consumers in the form of higher electricity prices and, in the absence of any net benefits accruing from the implementation of the DRM, is not in their long term interests.

While any form of demand response has the potential, under certain circumstances, to reduce dispatch prices, non-scheduled demand response in the NEM also leads to increased costs. The DRM would distort efficient economic outcomes in the spot market because under the DRM less reliable self-scheduled demand response resources would be rewarded equivalently to more reliable scheduled resources in the spot market.[160]

The DRM would also distort market outcomes. Rather than being rewarded in line with their electricity cost savings, consumers under the DRM would be rewarded by receiving payments for 'non consumption'. Currently customers' liability is calculated in relation to their metered energy consumption and prices (whether retailer or wholesale prices) serve as signals for consumers to make consumption decisions. Under the DRM the price signals and consumers incentives in relation to these are more difficult to assess.

As retailers would continue to be financially responsible for their customers' baseline consumption, an outcome of the DRM may be that customers pay for hedging costs through their retail contract even if they provide demand response. Although customers are expected to receive payments from demand response aggregators for their demand response services, the net outcome for customers is difficult to estimate.

Under the DRM, retailers' demand for hedging contracts would remain aligned with that required to hedge baseline levels of consumption as retailers would continue to remain financially responsible for the baseline consumption of their customers. On the other hand, the impact on the availability (supply) of hedging contacts is more difficult to estimate as the outcome of the proposed DRM on dispatched generation is more difficult to estimate. In any case, if the proposed DRM was successful in displacing generation then it would unbalance demand and supply in the hedging market leading to an increase in hedging contract prices.

Competition among demand response aggregators and the lack of responsibility for inaccurate baselining would create strong incentives for demand response

160 Under the proposed demand response mechanism the market operator is not able to dispatch demand response. In fact it may not even be aware of the demand response. This means that the market operator cannot rely on demand response to the same extent as it can on dispatched scheduled generation

aggregators and customers to choose the most 'generous' one from the available baseline methodologies. While such 'gaming' may be mitigated through increased monitoring and repeated verification of baseline methodologies, the cost of such administration will be ultimately passed onto consumers. While the provisions proposed in the DRM would prohibit a demand response aggregator from declaring a demand response interval, for example, when the customer deliberately inflated its baseline or when the customer did not take any deliberate action, the monitoring of such activities is costly.

This chapter explores the potential to create market distortions from implementing the DRM not only in the spot market itself but in other related markets such as the retail and financial markets or in markets where large customers may sell or obtain demand response services. These distortions might result in costs that would be recovered from consumers.

Section 5.1 and 5.2 set out the rule proponent's and stakeholders' views respectively. Section 5.3 presents the Commission's analysis.

5.1 Rule proponent's views

The Energy Council considers that separating demand response from the sale of energy[161] will give large customers more choice as to if and when to provide demand response by stimulating competition for demand response services in the large customer market.[162] The Energy Council notes that demand response aggregators indicated that based on this separation, demand response aggregators could offer their own financial hedging products to the market to manage financial risks of spot price volatility.[163]

The Energy Council also considers that having demand response through the DRM being self-scheduled through the demand response aggregator would ensure that load reductions are treated in a manner consistent with generation, as there is no requirement to schedule generation with capacity under 30 MW.[164] Overall, the Energy Council expects that these arrangements could improve the reliability and security of supply of the power system.[165]

The Energy Council also notes that retailers claim the DRM will impact on their hedging costs, but argues that this is only likely to occur in the short term. After a period of time, retailers' ability to forecast demand response should improve.[166]

With respect to risks of gaming the baseline consumption calculation, the Energy Council argues that the baseline methodologies developed for the DRM were recommended by DNV KEMA following an assessment of existing methodologies

161 Some stakeholders refer to this as 'unbundling' demand response from the sale of energy.

162 COAG Energy Council rule change request, p. 17 and 18.

163 COAG Energy Council rule change request, p. 18.

164 COAG Energy Council rule change request, p. 6.

165 COAG Energy Council rule change request, p. 17.

166 COAG Energy Council rule change request, p. 18.

used in the United States. The Energy Council notes that these methodologies are considered robust by most stakeholders. In any case, the Energy Council also requests the Commission to consider the risks of gaming the baseline, and any appropriate measures to minimise this risk.[167]

The Energy Council also argues that the cost-benefit analysis suggested a significant volume of demand response would be untapped through the DRM. This is because the DRM would enable a less risky mechanism for large customers to participate in the spot market, provide more competitive offers to demand response providers and demand response aggregators would proactively call for more regular dispatch of demand response.[168] It also considered that the DRM would encourage innovation on a range of energy services for consumers, including energy advice and demand response services.

5.2 Stakeholder views

Stakeholders commented on various distortions that can arise from the implementation of the DRM as they relate to the spot market, retail markets, financial markets, competition and innovation in demand response services and gaming opportunities under the DRM.

Spot market

The EEC notes that the operation of the DRM would result in a technological neutral approach because it would reduce the relative bias of the NEM towards generation resources.[169] Similarly, EnerNOC argued that technological neutrality would be maintained because the DRM would allow demand reductions to access the spot market in much the same way as generation given that demand response is technically able to offer the same services as generation.[170]

Further, EnerNOC also notes that over a longer time scale, such arrangements can contribute to security of supply in exactly the same way as building a new peaking generator, so economic efficiency requires that both resources be regarded and rewarded equivalently.[171] To the contrary, Snowy Hydro argues that the DRM arrangements would distort and dampen high spot price signals which would hurt customers' long term interests.[172] Similarly, Origin believes that the DRM would result in distortion of price signals caused by the non-firm demand response resulting in a reduction in the stock of peaking generation below the levels needed to maintain system reliability, given that demand response is unlikely to have the flexibility or firmness of peaking plant.[173] Snowy Hydro[174] also notes that the proposed DRM

167 COAG Energy Council rule change request, p. 9.

168 COAG Energy Council rule change request, p. 16.

169 EEC, Submission to consultation paper, p. 10

170 EnerNOC, Submission to consultation paper, p.3.

171 EnerNOC, Submission to consultation paper, p. 10.

172 Snowy Hydro, Submission to consultation paper, p. 2.

173 Origin, Submission to consultation paper, p. 3.

174 Snowy Hydro, Submission to draft determination, p.3

distorts the current market design where both the supply and demand side have clear pricing signals and incentives to either produce or to consume energy.

Retail markets

The EEC noted that 'mandatorily bundling' demand response and retail services has led to sub-optimal provision of demand response services because this reduces competition for demand response services, and some retailers have conflicting incentives in providing demand response services.[175] Similarly, EnerNOC relies on the AEMC's rationale at the time of the PoC recommendations for the DRM[176] to suggest that customers are underserved because they can only sell their wholesale demand response capability through their retailer.[177]

However, AGL notes that high quality service delivery by retailers becomes far more difficult where a demand response aggregator is making potentially high impact decisions regarding the customer's load without the retailer having any involvement in, or visibility of, the arrangement.[178] PG Energy notes that AEMO should not be expanding into the settlement of (private) financial products and this should be left to the competitive market.[179] PG Energy also considers retailers have access to all the necessary information required to offer and settle demand response contracts, and are in a prime position to negotiate baselines with customers and to measure actual demand for settlement purposes.[180] ERM Power also notes that the DRM could create distortions because a retailer has a real market position and would seek to reduce their actual exposure. By contrast a demand response aggregator has no market position and could seek to maximise the 'observed' demand reduction.[181]

EnerNOC considers that the decision to accept spot exposure is not one a consumer can take lightly as the financial risks can be large relative to the size of the business. Outside of the 'very large' industrial segment, most consumers cannot afford to, or do not have the 'bandwidth' to administer, or do not have the risk appetite to participate in the electricity market via any mechanism other than a fully hedged retail contract. EnerNOC considers that this highlights the importance of the proposed DRM; it unlocks the value of demand response for consumers of all sizes, despite the consumer's preference for a fully hedged retail contract, whilst their retailer remains unaffected by the consumer's participation in the DRM.

175 EEC, Submission to consultation paper, p. 4.

176 'Providing a way of participating in the wholesale market that is separate to a consumer's electricity contract recognises that consumers and retailers may have different energy needs'

177 EnerNOC, Submission to consultation paper, p. 1.

178 AGL, Submission to consultation paper, p. 3.

179 PG Energy, Submission to consultation paper, p. 3.

180 PG Energy, Submissions to consultation paper, p. 2.

181 ERM Power, Submissions to consultation paper, p. 8.

Financial markets

Snowy Hydro notes that the net effect of the proposed DRM arrangements is to increase hedging risks for both generators and retailers, causing distortions in the financial markets that market participant use to hedge the spot price risk.[182] Similarly, AGL also argues that there are inefficient costs involved in a retailer having to maintain ongoing physical and financial hedge cover for baseline consumption that may not actually occur under the DRM.[183]

Gaming

The EEC notes that demand-side management programs need to be based on an assessment of avoided consumption, which requires a baseline consumption methodology.[184] ATA considers that the proposed DRM design would be very effective at preventing the exercise of gaming opportunities around the baseline. ATA notes that baseline consumption is calculated on the basis of energy consumed on site over a matter of weeks. Given the intermittent nature of high price events and difficulty projecting them more than hours in advance, inflating a baseline would require energy users to increase consumption over weeks on the off-chance of the occasional windfall.[185]

EnerNOC also notes that the DRM consumption baseline methodology was prepared by the world's most experienced consultants on demand response baseline.[186] They believe that a prohibition against signalling false or misleading demand response events would sufficiently address any gaming concerns.[187] To the contrary, ERM Power notes that the proposed baseline methodology will encourage gaming, as a demand response aggregator is motivated to maximise the baseline and correspondingly maximise the 'observed' demand reduction.[188] Similarly, Snowy Hydro note that there are serious gaming risks because once a baseline is known in advance of the next dispatch period the demand response aggregator has a free option to exploit this knowledge for commercial gain.[189] EnerNOC considers that in order to inflate the baseline, a consumer would have to over-consume electricity (and pay their retailer the associated costs) for a period of days or weeks, in anticipation of a high spot price (and associated potential windfall opportunity) that may or may not eventuate many days later. Consumers simply are not going to engage in this sort of behaviour – consumers' focus is on making widgets (or whatever their primary business purpose

182 Snowy Hydro, Submission to Consultation Paper, p. 2

183 AGL, Submission to Consultation Paper, p. 2.

184 EEC, Submission to Consultation Paper, p. 6.

185 ATA, Submission to Consultation Paper, p. 11.

186 EnerNOC, Submission to Consultation Paper, p. 11.

187 EnerNOC, Submission to Consultation Paper, p. 10.

188 ERM Power, Submission to Consultation Paper, p. 8.

189 Snowy Hydro, Submission to Consultation Paper, p. 6.

is), not strategically over-consuming electricity in order to game the DRM.[190] Also, EnerNOC points out that the 'good faith' provisions that were proposed in the rule change request would prohibit a demand response aggregator from declaring a demand response interval where a customer has deliberately inflated its baseline, where the customer is not taking any deliberate action, or where customer is shifting load between NMIs. Compliance with these provisions were proposed to be enforced by the Australian Energy Regulator's (AER) as part of its usual complained activities EnerNOC asserts that demand response aggregators are not going to engage in baseline gaming, as the costs far outweigh the potential benefits, it is difficult to do, the 'good faith' provisions clearly prohibit it, and the risk of reputational damage is simply too great.[191]

Innovation in demand response services

Energy Australia[192] (EA) also notes that standardization of a baseline consumption methodology can assist comparison between product offerings but does limit flexibility and innovation. Similarly, Dr Chapman from the Centre of Future Energy Networks notes that the baselining and accreditation of new loads participating in the DRM will act as a costly barrier to entry to the DRM.[193]

5.3 Commission's analysis

The Commission considers implementing the DRM alongside existing demand side participation arrangements could cause a number of market distortions, the costs of which would be borne by consumers. The distortions arising from the implementation of the DRM include distortions of:

(a) efficient economic outcomes in the spot market;

(b) under the DRM less reliable self-scheduled demand response resources would be rewarded equivalently to more reliable scheduled resources in the spot market. This is discussed in further detail in section 5.3.1;

(c) the efficiency of retailers' economic decisions on how to best manage the spot price risk on behalf of their customers resulting in higher costs to retailers to manage this risk and ultimately higher retail prices to consumers. This would

190 EnerNOC, Submission to draft determination, p. 17

191 EnerNOC also notes that it is only aware of only two instances of baseline gaming that occurred in the last 15 years and these were also noted in the Brattle Report. EnerNOC considers that both instances involve a type of gaming that is not possible under the proposed DRM design. For instance, the baseball stadium example involved a "baseline adjustment period" that occurred after the notification was received from the grid operator that a demand response opportunity was forthcoming. EnerNOC considers that the baseline calculation methodology was poor and no comparable opportunity would exist under the proposed DRM. For further details see EnerNOC's submission to the draft determination, p.17

192 EA, Submission to consultation paper, p. 2

193 Dr Chapman, Centre for future energy networks, Submission to consultation paper, p. 2.

result from the DRM's specific approach to 'unbundling' retail supply from demand response service. This is discussed in further detail in section 5.3.2;

(d) the financial services market where energy financial derivatives are traded in order to manage spot price exposure. This is because the DRM would unbalance the supply and demand of hedging contract in a way that would risk increasing the spot market cost of electricity supply to consumers. This would tend to increase the price that retailers can lock-in through hedging through the financial market for their customers. This is discussed in further detail in section 5.3.3;

(e) the market where large customers sell their demand response services because under the DRM competition between demand response aggregators would not work in the long term interests of consumers. This would increase the cost of delivering demand response under the DRM which would be recovered from consumers. This is discussed in further detail in section 5.3.4; and

(f) the market where large customers sell their demand response services because demand response aggregators and DRM participating customers have a strong aligned incentive to game when opportunities emerge. This would increase the cost of delivering demand response under the DRM which would be recovered from consumers. This is discussed in further detail in section 5.3.5.

5.3.1 Spot market distortions

The spot market is designed to enable it to deliver as closely as possible the efficient outcomes that would be expected from an ideal competitive electricity market. An ideal competitive electricity market delivers three key economic efficient outcomes:

- allocative efficiency: all consumers that have a preference and a willingness to pay for electricity are able to consume electricity as long their willingness to pay is greater than the costs of producing electricity;
- productive efficiency: electricity is produced at the lowest possible cost; and
- dynamic efficiency: investment decisions are made that deliver allocative and productive efficiency as consumer preferences and technology production possibilities change over time.

Implementing the DRM changes how the spot market is expected to deliver these economically efficient outcomes. Under the DRM, demand response aggregators would be entitled to payments for demand response (a financial contract without physical delivery of electricity) in the spot market on the same basis as generators trade electricity (a commodity with physical delivery of electricity). This implies that demand response aggregators would get paid the same price, the marginal cost of generation, for demand response as generators get when they deliver physical electricity. Rewarding demand response in a similar way to generation does not lead to economically efficient outcomes unless:

- the consumer already purchased the energy and it is now re-selling energy (e.g. this may be the case of stored energy); and
- the demand response delivered by the demand response aggregator was a perfect substitute to the electricity delivered by generators. This is not the case as

demand response cannot be relied upon the same way as can be dispatched generation.

In relation to the first point, paying the marginal price for demand response would be appropriate if the customer had already bought the electricity and was now re-selling it to the market. This is, however, not the case. The customer in the DRM did not pre-purchase electricity or has not taken 'ownership' of this electricity. Even if the retail contract entitles the customer to the electricity, the retailer has not previously made arrangements on behalf of the customer to pre-purchase electricity.[194]

In relation to the second point, demand response delivered by demand response aggregators differs significantly in its operational characteristics from the electricity delivered by generators. They cannot therefore be treated as perfect substitutes for one another. For example, the operating characteristics of scheduled generators allow AEMO to issue these generators dispatch instructions which are based on system-wide demand, supply and network conditions. Demand response provided by demand response aggregators is not scheduled; rather than following dispatch instructions, these resources 'respond' after dispatch instructions have been made. While AEMO can rely on generators that follow dispatch instructions to manage system security, it cannot rely on demand response aggregators to the same degree to balance demand and supply.

Implementing a DRM in the spot market dismisses the key differences in the characteristics between demand response and scheduled generation and load but requires the market to value both equivalently. The DRM would then drive a spot market design that will, over time, distort the economically efficient outcomes expected from a competitive spot market.

Distortions can occur because the DRM may lead to inefficiently low spot prices resulting in more efficient and reliable scheduled generators being unable to recover their fixed capital costs. All other things remaining equal, over the longer term there is a risk that the DRM would displace efficient scheduled peaking generation resources. This would lead to inefficiently low peak time prices determined by the less reliable[195] demand response delivered through the DRM. The market would not encourage entry of more efficient new scheduled energy resources and the energy resource mix would become dominated with less reliable demand response.

Furthermore, when customers accept spot price exposure, for example in the form of spot price pass-through contracts, the value of their demand response is equivalent to the 'avoided cost of consumption'. It is this cost savings (i.e. the avoided cost of the spot price) that is the economically efficient 'payment' for non-consumed, non-generated electricity. Avoiding network and other (environmental) charges further

194 In relation to other international energy-only markets, the Brattle Report contains similar conclusions. See also the Brattle Report, page iv. The summary of the international review of demand response mechanisms by the Brattle Group can be found in Annex E.

195 Under the proposed demand response mechanism the market operator is not able to dispatch demand response. In fact it may not even be aware of the demand response. This means that the market operator cannot rely on demand response to the same extent as it can on dispatched scheduled generation

improves the case for demand response. Under the proposed DRM, however, consumers' incentives would erode the economically efficient payments. For example, despite carrying out demand response, consumers would still be liable for the retail energy cost of their baseline consumption, including hedging and other retail fees. However, consumers would not be liable to pay the network and other (environmental) charges in relation to their baseline consumption.[196] Also, their demand response payments would be required to be shared with demand response aggregators. The outcome of this is that customers will face an effective price signal that is much lower than the efficient spot market price but is likely to be higher than their retail price.

5.3.2 Retail market distortions

The Commission notes that the 'unbundling' of retail supply and demand response proposed under the DRM is likely to result in higher electricity prices to consumers. As retailers would continue to be financially responsible for their customers' baseline consumption, an outcome of implementing the DRM may be that customers pay for hedging costs through their retail contract even if they provide demand response. This is because the benefits of the demand response do not accrue to the retailer but rather they accrue to the demand response aggregator. The retailer is left with having to hedge the baseline energy consumption for the customer and recover the cost of doing so from the customer. The customer would continue to be billed based on its baseline consumption and the bill would include the retailer's hedging costs. Although customers are expected to receive payments from demand response aggregators for their demand response, the net outcome for customers is difficult to estimate.[197] Annex E further details the wealth transfers as a result of the DRM.

It is important to note that it is the retailer, through the large customer's choice of a retail contract, that has been chosen to manage the spot price risk on the customer's behalf and so it is the retailer who remains exposed to the spot price. Therefore, it is the retailer and not the demand response aggregator that should benefit from the customer's demand response and decide whether to engage in demand response with their customers to manage its own exposure to the spot price. Retailers compete in the market place to manage spot price exposure on their customers' behalf and, as a consequence, have an efficient incentive to manage this risk cost-effectively to develop competitive pricing offers to their customers.

Retailers have a number of instruments at their disposal to manage this risk, and engaging in demand response activities is just one of them. Whether the retailer relies on demand response depends on how competitive demand response is with respect to the other instruments available to the retailer such as buying energy derivative financial products and/or generation assets.

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196 This is because energy consumption did not actually take place so consumers would not be liable to pay the network and other charges on their retail bill in relation to their baseline consumption.

197 Market distortions in financial markets in relation to products that retailers use to hedge their spot price exposure are presented in section 5.3.4.

The proposed DRM also departs from fundamental tenants of the NEM, namely that generation receives payments for generating electricity and customers pay for electricity used. Rather than being rewarded only with the costs saved in not using electricity, customers under the DRM would be rewarded not only with these cost savings but also by being paid for not consuming. Currently customers' liability for their consumptions is calculated in relation to their metered energy consumption and prices (whether retailer or wholesale prices) serve as signals for consumers to make efficient consumption decisions. Customers' consumption decisions under the DRM would be driven, at least in part, by the 'wedge' they are able to create between the baseline consumption calculated at the retail tariff rate and their metered consumption calculated at wholesale prices.

This potential distortionary effect will be increasingly important with, for example, the proliferation of storage technology. While wholesale (or retail) market price signals could create efficient economic incentives for consumers with storage technology to take advantage of price arbitrage, under the DRM the incentives for consumers and demand response aggregators will be more difficult to assess. Without a DRM the economic value of storage is assessed in relation to its ability to exploit price arbitrage opportunities. Value may be created for customers from charging the storage unit (using electricity from the grid) under low prices conditions and using the storage (in place of using electricity from the grid) under high price condition. While price arbitrage opportunities may exist with retail contracts (e.g. peak and off-peak pricing) the price arbitrage opportunities are greater when facing wholesale prices. Under the DRM the value that may be created for customers from storage is somewhat different., Once retail arrangements are in place with a demand response aggregator the value of a storage unit is not simply in relation to its ability to exploit (retail) price arbitrage opportunities. A storage unit that may, for example, increase consumption prior to a demand response event may also create value through its ability to inflate the baseline.

5.3.3 Financial market distortions

As noted above, it is the retailer that remains exposed to the spot price when a customer chooses a retail contract and so requires the retailer to manage spot market exposure on its behalf.

The DRM has the potential to create distortions in the financial markets used by generators and retailers to hedge their exposure to spot market risks. This is because the DRM has the potential to unbalance payments under hedging contracts between generators and retailers.

Under the DRM, retailers' demand for hedging contracts would remain aligned with that required to hedge baseline consumption levels as retailers would continue to remain financially responsible for the baseline consumption of their customers. On the other hand, the impact on the availability (supply) of hedging contacts is more difficult to estimate as the outcome of the DRM on dispatched generation is more difficult to assess. In any case, if the proposed DRM was successful in displacing generation then it would unbalance demand and supply in the hedging market, leading to an increase in hedging contract prices.

5.3.4 Distortions in competition and innovation in demand response services

Under the DRM, competition would provide efficient incentives to demand response aggregators to maximize the opportunities to buy demand response energy from customers whenever the spot price is greater than the opportunity costs to the customer of not consuming the demand response energy.

However, demand response aggregators would not bear the cost of inaccurate baselining of a customer's consumption. In fact they would benefit from baselines that overestimate the demand response. Demand response aggregators that can find more advantageous baseline consumption methods for their consumers will be in a more competitive position. Therefore, competition among demand response aggregators may aggravate the outcome. Demand response aggregators would have a strong incentive to propose to the customer the most 'generous' baseline consumption methodology from AEMO's administered set of methodologies. While demand response aggregators receive payments for any 'inflated' baseline, it is ultimately the customer that would have to pay for this. Retailers participating in the DRM would be required to accept the baseline methodology that was selected by their customers. If this baseline was inaccurate or 'inflated' than retailers would have no choice but to bill customers accordingly. This would ultimately result in higher costs to retailers that would be recovered from their consumers. While such an outcome may be mitigated through increased monitoring and repeated verification of baseline methodologies, the cost of this oversight will ultimately be passed onto consumers.

Customers' energy consumption is unique and it is highly driven by their business operation, incentives and flexibilities in their energy consumption. It is unlikely that a single or a handful of baseline methodologies would be the best fit for all participating consumers. While the proposed DRM includes provisions of extending the set of baseline methodologies that are administered by AEMO, the administration and verification of such new methodologies would create additional cost burden. Under current market arrangements, when baseline methodologies are used between demand response aggregators and the customers, the cost of the administration are borne by contracting parties, not all customers.

5.3.5 Distortions relating to gaming opportunities

Measurement of the size of demand response requires comparison of metered load against baseline energy consumption. As noted in the Brattle Report (discussed in section 1.3), the use of baseline methodologies is relatively common in capacity markets where an administrative process sets out the methodology to be used to calculate the baseline. As with the DRM, this often relies on the use of historical data to determine what a facility's energy use would have been during a period where demand response was provided. Similarly to the proposed DRM, administrative baselines are often designed to be easily calculated using a transparent and simple mathematical algorithm.

By understanding the administrative algorithm for determining the baseline, loads may be able to raise their baseline energy use and thereby receive additional payments to demand respond. This creates a gaming risk. The Brattle Report outlines a couple of specific examples of how these risks have materialized in other jurisdictions.[198]

The Commission notes that similar gaming opportunities emerge under the proposed baseline methodologies proposed for the DRM, and that the incentives to exploit these opportunities are strong under the DRM. This is because demand response aggregators and their customers have an aligned incentive to game the DRM's administrative baseline because neither of them would suffer the short term negative consequences of their actions. By contrast, the Commission notes that there seems to be fewer gaming opportunities under current market arrangements because the retailer or demand side management service provider negotiates a baseline with its customers and can terminate a demand response contract if gaming is detected. These features are not part of the proposed DRM model.

One of the ways, for example, demand response aggregators may game the payments under the proposed DRM is to continuously monitor the consumption of their consumers and also concurrently calculate the baseline consumption. In any 30 minute period when the actual consumption is below the baseline consumption the demand response aggregator may notify AEMO that demand response occurred. This is regardless of whether the customer actually carried out any demand response.

It is important to note that demand response aggregators (and potentially customers) benefit from high prices under the proposed DRM and these participants' interests are not aligned with reducing dispatch prices.

With increasingly complex rules, compliance requirements and monitoring arrangements, gaming opportunities may be reduced. The cost of such monitoring must then be considered. If AEMO were required to monitor compliance, AEMO's costs would need to be allocated between different market participants. It may be the case that all market participants (including retailers, generators and demand response aggregators) could incur these costs.

Alternatively, monitoring could be undertaken by certain market participants, for example demand response aggregators. Either way, ultimately it is customers that would have to pay for these either through their retail contracts or as reduced payments by response aggregators.

Also, while there are provisions proposed in the DRM that aim to prevent a demand response aggregator from declaring a demand response interval when the customer deliberately inflated its baseline, when the customer did not take any deliberate action, or when the consumption was shifted to another NMI, the monitoring of such activities is costly. If the DRM were implemented, the Australian Energy Regulator (AER) would need to enforce compliance of demand response activities with such provisions. While any imposed penalties for non-compliance would be imposed on demand response aggregators, the increase in general monitoring and compliance activities by the AER increase the implementation costs associated with the DRM. Such monitoring activities

198 Alternatively, it could be borne by only some of the market participants, for example demand response aggregators. Either way, ultimately it is customers that would have to pay for these either through their retail contracts or as reduced payments by response aggregators.

by the AER are not required under current market arrangements as demand response aggregators would include any necessary provisions in the contractual arrangements with their customers or their retailers.

6 Unbundling the provision of ancillary services

Summary

The options available under current market arrangements for third party service providers seeking to provide frequency control ancillary services (FCAS) services through customers' loads or the aggregation of customers' loads may constitute a barrier to entry to third-party service providers.

To address this barrier the Commission has made a final rule that would provide for a new type of market participant – a market ancillary service provider - to offer a customer's demand response, or aggregation of customers' demand responses, into FCAS markets.[199]

A market ancillary service provider will not need to be a customer's retailer to offer such services to the wholesale market. By not requiring the provider to purchase electricity from the wholesale market for a customer, as a retailer currently does, the provision of FCAS by the market ancillary service provider becomes independent of, or 'unbundled' from, retailers.

Allowing for the 'unbundling' of the supply of ancillary services from the retail supply of electricity has the potential to increase the levels and diversity of demand side participation in FCAS markets.

Deeper and more diverse FCAS markets have the potential to lead to increased security of the national electricity system and increased levels of competition among suppliers of ancillary service, leading to more efficient FCAS prices. More and greater diversity of ancillary services would complement the increased penetration of intermittent and non-synchronous generation that is occurring in the NEM.

The Energy Council has identified that current arrangements under the NER result in a barrier to demand side participation in the FCAS markets that could be addressed by unbundling the provision of ancillary services from the sale and supply of electricity in the spot market. While the Commission has decided to not make a rule to implement the DRM for the reasons outlined in the earlier chapters, it considers that it is appropriate to separately consider whether the proposal to unbundle ancillary services, through the creation of a new class of market participant in the spot market (referred to as the ASU proposal), meets the NEO.

Section 6.1 analyses whether current arrangements under the NER result in barriers to demand side participation in FCAS markets that could be addressed by the ASU proposal. Section 6.2 considers the relevant costs and benefits associated with the ASU proposal. A detailed description on the Energy Council's proposal can be found in

199 The final rule does not permit the market ancillary service provider to use the aggregation of generating units for offer into FCAS markets, as the Commission considers that as being out of scope of the current rule change.

Annex D. Section 6.3 discusses the Commission's final rule to implement the ASU proposal. Section 6.4 discusses customer protection issues related to the final rule.

6.1 NER arrangements and barriers to demand side participation in FCAS markets

6.1.1 Rule proponent's view

The Energy Council notes that under the current market rules the capability to provide FCAS to AEMO is currently bundled with the requirement to become a market participant (market customer or market generator) in the spot market. Additionally, the Energy Council also argues that while it is possible to aggregate loads to provide ancillary services, currently this can only be done by these same market participants. As a consequence, the provision of ancillary services using loads or an aggregation of loads is currently limited to those customers registered in the spot market with large loads that can respond quickly, such as aluminium smelters and pumped hydro.[200]

The Energy Council also argues that these arrangements limit competition and diversity of supply for these services to those market participants that either purchase or sell in the spot market and that the ancillary service market is missing out on opportunities that may be achieved through, for example, the aggregation of multiple loads (including small loads). As a result, the rule change aims to address a lack of competition in the provision of ancillary services.

6.1.2 Stakeholder views

The EEC, MEU and Ergon[201] consider that current arrangements where only market participants that purchase or sell electricity in the spot market can participate in FCAS markets are a barrier to entry that restricts demand side participation in the FCAS markets. Similarly, the SA DSD[202] noted that unbundling would provide the market with increased and more diverse FCAS suppliers.

ATA[203] and EnerNOC also support unbundling of ancillary services. EnerNOC notes that the FCAS market would certainly be a market where demand aggregators would seek to participate in. EnerNOC puts forward in its submission that their participation in the New Zealand's FCAS market provides an example of the potential contribution of 'industrials' to the NEM's FCAS requirements.[204]

Generally, retailers and the Australian Energy Council[205] are supportive of ancillary service unbundling. Origin also supports competition in the provision of frequency

200 COAG Energy Council, Demand Response Mechanism Rule Change Request, COAG Energy Council, 8 April 2015, p 5.

201 EEC, Submission to consultation paper, p 7; MEU, Submission to consultation Paper, p. 18; Ergon, Submission to consultation paper, p. 7.

202 SA DSD, Submission to consultation paper, p. 1.

203 ATA, Submission to consultation paper, p. 15

204 EnerNOC, Submission to consultation paper, p 5 and 6.

205 Australian Energy Council, Submission to draft determination, p.1.

control. However, they note that any load offered should meet the existing technical requirements for providing ancillary services.[206] ERM Power notes that demand side participation in the FCAS markets is currently limited to those participants who can meet the technical requirements of the market ancillary service specifications (MASS) and receive active five minute dispatch instructions from AEMO.[207] AGL also support a mechanism to open up the FCAS market that is competitive and technological neutral.[208]

AEMO considers that the ASU proposal may enable a broader number and new types of FCAS providers into the market, potentially expanding competition. This could potentially provide improvements in system security and reliability through increased levels of FCAS being offered into the market.[209] The SA DSD also shares similar views.[210]

Stanwell notes that current rules already allow for market loads to be classified as ancillary services loads. They consider that it is likely that there has been minimal uptake of this option because the obligations associated with registration significantly outweigh the potential commercial benefit for most consumers.[211]

GDF Suez does not agree that the current market arrangements represent an unreasonable barrier to entry that restricts demand side participation in the FCAS markets. Loads that provide FCAS are already able to either register directly with AEMO, or enter into a commercial arrangement with an existing market customer. They note that the more substantial "entry" hurdle is whether loads are able to comply with AEMO's market ancillary service specification.[212]

Similarly, Snowy[213] also argues that the market rules are not a relevant barrier to demand side participation in the FCAS markets. The potential and much more significant barrier to demand side participation is the low FCAS prices.[214] Snowy[215] considers that the ancillary service unbundling may appear in theory to be beneficial but Snowy is concerned that the economic benefits are unlikely to exceed the costs of the rule change.

Energy Australia[216] further notes that the evolution of the NEM – through the diversification of energy sources and the decentralisation of generation – and recent events in South Australia confirm the need for a reassessment of the incentives for

206 Origin, Submission to consultation paper, p.4.

207 ERM Power, Submission to consultation paper, p. 12.

208 AGL, Submission to consultation paper, p. 3

209 AEMO, Submission to consultation paper, p. 5 and 6.

210 SA DSD, Submission to consultation paper p. 2.

211 Stanwell, Submission to consultation paper, p. 4.

212 GDF Suez, Submission to consultation paper, p. 12.

213 Snowy Hydro, Submission to consultation paper, p. 7. and Snowy Hydro, Submission to draft determination, p.1

214 Snowy Hydro, Submission to consultation paper, p. 7.

215 Snowy Hydro, Submission to draft determination, p.2

216 Energy Australia, Submission to draft determination, p. 2

market participants to provide the complete range of support services. This might be through the creation of an inertia market, alignment of settlement and dispatch, or more fundamental changes to wholesale market design. Energy Australia notes that the proposed rule change might be redundant in this context.

6.1.3 Commission's analysis

Under the NER, only customers that register to participate in the spot market as a Market Customer have the ability to offer their spot market loads in FCAS market. However, most customers in the NEM do not register as a Market Customer in the spot market, and buy their energy requirements from a retailer to avoid all the obligations that come with such registration and to manage to spot price risk. Despite this, these retail customers might have the ability and the willingness to participate in the FCAS markets.

Currently, the NER does not prevent retailers (the Market Customer) from making appropriate arrangements to offer their customers' load in the FCAS market. However, under the NER, a third-party service provider wanting to enable these customers to participate in the FCAS markets has two options:

- either it registers as a Market Customer and becomes the customer's retailer. This results in the third party service provider having to meet all existing obligations that the NER contemplates for Market Customers; or
- it agrees commercial arrangements with a customer's retailer (i.e., the Market Customer) to enable the customer's load to participate in the FCAS markets. This results in the third-party service provider incurring a transaction cost to enable retail customers to participate in the FCAS markets.

The Commission considers that both options identified above may constitute a barrier to entry to third-party service providers, and could be particularly restrictive for business models aiming to provide FCAS services through retail customers' loads or an aggregation of retail customers' loads without needing to be a Market Customer. This barrier to demand side participation prevents retail customers that might have the ability and the willingness to provide FCAS services from being given the opportunity to do so.

6.2 Costs and benefits from facilitating demand side participation in FCAS markets

6.2.1 Rule proponent's view

The Energy Council considers that the ASU proposal will promote more competition in the provision of ancillary services and allow for a more diverse supply. A demand response aggregator would be able to provide specialist support for customers to provide FCAS including aggregating their response into the FCAS markets. The Energy Council expects that this would result in an increased number of suppliers and offer more demand side participation options for consumers.

6.2.2 Stakeholder views

EEC considers that facilitating entry through greater demand side participation in the FCAS markets, either from individual or aggregated loads can result in lower cost and higher quality provision of FCAS services.[217] MEU advises that a number of its members have generation embedded in their operations and could therefore provide FCAS lower services in addition to FCAS raise services.[218]

The Government of South Australia and EnerNOC consider that greater demand side participation in FCAS markets will become more important to promote system reliability and reduce overall costs as the penetration of intermittent renewables increases and grid inertia decreases.[219]

ERM considered that the proposal might result in a slight reduction in the costs of FCAS raise contingency services. However, they note that these are fully funded by generators, so reductions in the costs of supply may not flow to consumers.[220]

Origin considers that the AEMC should examine whether demand response can be used as frequency control that is as timely and as high quality as current offerings and whether it can be provided at a relatively comparable cost, particularly given the required metering infrastructure.[221]

Stanwell notes that where energy and ancillary services are both offered these might be offered by different participants under the proposal. It appears likely that AEMO would need to adjust their systems to be able to co-optimise the offers received to ensure the lowest cost to consumers while ensuring that the response in not double-counted.[222]

GDF Suez believes that unbundling the provision of ancillary services, which relies on complex interactions between the demand response aggregator and the end customer, would not result in any positive impact on FCAS liquidity or cost.[223]

Issues relating to the market ancillary service specifications (MASS)

AEMO[224] notes that the market ancillary service provider would be ineligible to offer regulation ancillary services under the current MASS, and only be eligible for contingency ancillary services. The MASS (under section 1.3) does not accommodate aggregated dispatch for the purposes of regulating raise service or regulating lower service. As such, a market ancillary service provider (or indeed Market Customers and

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217 EEC, Submission to consultation paper, p. 7.

218 MEU, Submission to consultation paper, p. 10.

219 SA DSD, Submission to consultation paper, p. 2.; and EnerNOC, Submission to consultation paper, p. 6

220 ERM Power, Submission to consultation paper, p. 13.

221 Origin, Submission to consultation paper,p. 4.

222 Stanwell, Submission to consultation paper, p. 4.

223 GDF Suez, Submission to consultation paper, p. 12.

224 AEMO, Submission to draft determination, p.2

Small Generation Aggregators) is currently ineligible to offer regulation FCAS services using an aggregation or loads (or generating units).

Other retailers also raised concerns that barriers will remain despite the rule change as the MASS contains requirements that seem too onerous or have been surpassed by new technology. For example, the MASS requires that the load is connected with the Automatic Generation Control (AGC) system. AGL notes[225] that there are solutions that could achieve the same frequency control outcome in a verifiable way. Accommodating new technology is considered to be very important to the success of a new rule. In its submission, AGL[226] provides an example of an ARENA-backed 'virtual power plant' project where the intention was to test a number of different applications, including participation in FCAS markets. Conformance to the AGC has emerged as a potential barrier to this particular application.

In their submission to the draft determination Energy Australia[227] considers that the key obstacles to FCAS market participation are technical requirements. The proposed rule does not address these issues so Energy Australia expects that the expansion in FCAS attributable to the proposal will be small and therefore, any incremental benefits may not outweigh implementation costs.

Similarly, Stanwell[228] remains concerned that the practical benefits of the rule change are unlikely to exceed the costs of the reform. Barriers to entry exist in relation to market ancillary services these are related to the requirements to comply with the market ancillary services specification, the Rules obligations imposed on market participants and the limited revenue available in these markets.

Potential interactions with network operations

Generally, network service providers [229] were supportive of ancillary services unbundling but they raised some issues. Network service providers note that synchronised demand response switching at a greater scale may have an adverse impact on system stability and reliability. The emergence of market ancillary service providers presents potential operational risk for the networks. Where demand response arrangements are geographically concentrated, synchronised switching (i.e. simultaneous aggregated load switching) may lead to network implications. In the short term, this is not likely to be material enough to adversely affect networks, but over-time it is likely to grow to the point where they cause voltage disturbance issues and adversely impact network reliability. They proposed a few solutions how such impact may be mitigated. Suggestions include that:

225 AGL, Submission to draft determination, p. 2

226 AGL, Submission to draft determination, p. 2

227 Energy Australia, Submission to Draft determination, p. 2.

228 Stanwell, Submission to Draft determination, p. 2.

229 ENA Submissions to Draft determination, p. 2

- AEMO should consult with NSPs prior to approving applications for aggregated load;[230]
- A load management protocol should be developed that all demand response provider would need to comply with and/or switching agreements should be required to be entered by market ancillary service providers[231]; and
- information should be made available to NSPs about demand response activity in their area (for example, in the form of the NMI and size of DR). For example, AusNet[232] and Ergon Energy[233] note that network businesses currently have little visibility of retailer initiated demand response arrangements and hence would need to model the predicted demand response behaviour based on historical data.

Furthermore, network service providers [234] sought clarification whether they could register as market ancillary services providers.

6.2.3 Commission's analysis

The Commission is of the view that the ASU proposal would result in a net benefit that would be in the long term interest of customers. The relevant costs and benefits are considered below. Given that changing the NER to implement the ASU proposal would not result in a structural design change to the spot market as with the DRM, the Commission does not find relevant the consideration of potential market distortions from implementing the ASU proposal.

Benefits

The Commission considers that enabling a new category of market participant to offer FCAS services through individual loads or the aggregation of loads would increase the level of demand side participation in FCAS markets. This would lead to a greater number and diversity of FCAS suppliers and deliver a more competitive FCAS markets.

This new market participant would be able to register in the spot market to offer a retail customer’s load into the FCAS market without either it or the customer whose loads they would seek to manage, having to become a Market Customer. Further, any such new participant would not be required to engage with the customer’s retailer to offer load into the FCAS markets, thereby reducing the transactions costs for this participant to offer FCAS. The introduction of the new participant would also stimulate competition between Market Customers and such participants to deliver FCAS using

230 See for example, ENA Submission to draft determination, p.2; Energex Submission to Draft determination, p.1

231 For further description, see AusNet Submission to Draft determination, p.2. and also Energex Submission to Draft determination, p.1, ENA Submission to draft determination, p.2-3

232 AusNet, Submissions to Draft determination, p. 2

233 Ergon Energy, Submission to draft determination, p. 2.

234 See for example, AusNet Submission to Draft determination, p. 2;

the retail customers' loads. This will lead to more competitive FCAS markets through increased demand side participation resulting in more efficient FCAS prices.

Box 6.1 describes an example of a business model that relies on the aggregation of loads to provide ancillary services.

Box 6.1 Case study - Reposit Power[235]

Reposit Power has developed a software solution to aggregate the capability of residential storage systems. The company's GridCredits platform is designed to capture the value of residential solar PV and storage systems on the customer's behalf. Batteries under Reposit Power's control are also delivering contingency frequency control ancillary service. They are integrated with distributed energy dispatch tools which could enable network support agreements, with the batteries discharged at critical peak times to avoid network augmentation.

However, to meet the NEO, the Commission considers that the creation of the framework with which this new market participant must comply when offering load into FCAS markets, should be based on competitive neutrality principles. This is discussed further below in section 6.3.

Issues with the market ancillary service specifications (MASS)

The Commission understands that the current terms of the MASS contain a technical restriction that would mean that the market ancillary service provider would not be able aggregate load for the purpose of providing regulation FCAS services despite the rule change.[236] The market ancillary service provider will be able to provide regulation FCAS using an individual load (but not through aggregated load) and contingency FCAS using individual and aggregation of loads. The restriction relates to the technology enabling the provision of these services. It is important to note that the restriction in providing regulation FCAS services using aggregation of load by market ancillary service providers is not based in the Rules but is part of the requirements imposed on all potential service providers (including market ancillary service providers and Market Customers) by the MASS.

Stakeholders noted that the benefit from the rule change would be greater if market ancillary service providers were able to offer aggregated loads into the regulation

235 See AEMC, Integration of Energy Storage, Discussion Paper, 9 October 2015, available http://www.aemc.gov.au/Major-Pages/Technology-impacts/Documents/Integration-of-Storage-Discussion-Paper.aspx

236 The following are the regulation FCAS specified in the NER: fast lower service: used to arrest a rise in the frequency; • fast raise service: used to arrest a fall in the frequency; • slow lower service: used to stabilise a rise in the frequency; • slow raise service: used to stabilise a fall in the frequency; • delayed lower service: used to lower the frequency to within the normal operating frequency band; and • delayed raise service: used to raise the frequency to within the normal operating frequency band. The following are the contingency FCAS specified in the NER: • regulating lower service: used to lower the frequency of the power system; and • regulating raise service: used to raise the frequency of the power system

lower and regulation raise FCAS markets. The Commission agrees and encourages AEMO to review the MASS as soon as possible to resolve such technical restrictions.

The Commission considers there is still benefit in unbundling the provision of FCAS services regardless of the current technical restriction identified above. The unbundling allows the market to develop and will facilitate more providers of FCAS to participate in those markets as the technical restrictions are resolved and technologies evolve.

The Commission recommends that AEMO review the MASS as soon as possible in order to consider whether any technical restrictions preventing market ancillary service providers from providing raise and lower regulation FCAS using aggregation of loads can be removed. [237] The Commission understands that AEMO is aware of these limitations imposed by the MASS and the review of these requirements is part of their upcoming work program.

It is important to further note that the MASS only applies to demand response services that are provided to the market through AEMO's dispatch system. Network service providers demand response programs are independent of this and hence do not require compliance with the MASS. Therefore, the Commission understands that some businesses have been successfully able to provide demand response to services to network service providers through the aggregation of loads. The current limitations in the MASS, therefore, have implications for the regulation raise and regulation lower FCAS services but not to wider demand response programs.

System-wide costs and benefits

The Commission notes that the ASU proposal has the potential to result in system-wide benefits. Greater demand side participation would create a more diverse and potentially increased supply in the FCAS service markets. This would allow AEMO to manage the power system more securely.

Implementations costs

AEMO has confirmed that the creation of a new market participant that would be allowed to participate in FCAS markets without a requirement to become a Market Customer would not require significant system changes or incur system development costs to support the activity of this new participant.

Costs to retailers

The Commission notes that there might be instances where the actions of a customer providing FCAS services through changes in load via an arrangement with the new participant could negatively impact the Market Customer (i.e., the retailer). For example, this might happen when the provision of a FCAS service through the market ancillary service provider requires the customer to increase consumption at times of high spot prices which would increase the retailer's costs of supplying the customer.

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237 This issue is further discussed in Section 6.3.

Potential interactions with network operations

As noted above, network service providers noted that synchronised demand response switching at a greater scale may have adverse impact on system stability and reliability and thus requested that AEMO consult with network service providers prior to approving applications for aggregated load and/or that appropriate load management protocol should be developed that all demand response would need to comply with by the market ancillary service providers. Network service providers also prefer to have information made available to them about any demand response that is active demand response in their areas.

The power to use loads or aggregation of loads for the purpose of FCAS has been in the Rules for several years, before this rule change request. While the issues raised by network service providers may be a valid concern under higher uptake of demand response arrangements, addressing these issues goes beyond the scope of the rule change request. The issue raised in the rule change request was the 'unbundling' of the provision of ancillary services from the sale of electricity and to allow a new market participant to compete in the market for ancillary services using customers' loads. Given that the current rules contain no requirements for the Market Customer to consult AEMO or to comply with protocols or provide information, the Commission considers that there is no need to impose such requirements on the market ancillary service provider.

The Commission considers that a network service provider wishing to take on the market ancillary service provider role in a competitive segment of the market should be subject to some form of ring-fencing[238] from its business. This is so as to avoid an unfair advantage being conferred on its market ancillary service provider by cross-subsidising its contestable services through its regulated services or providing it with access to commercially sensitive information.

The Commission notes that the AER is currently in the process of developing an electricity distribution ring-fencing guideline that will apply across the NEM. The review process commenced early in 2016 and is now well under way.[239] The Commission understands network service providers have been actively engaged in the AER's stakeholder consultation processes.

238 Ring-fencing refers to the separation within a network service provider of regulated services from contestable business activities or non-regulated services. Regulated services—like traditional monopoly networks regulated by the AER—are separated from those services that are delivered by the competitive market, like energy retailing or demand response aggregation for the purpose of achieving wholesale or retail market related benefits.

239 For further details, please see AER's website: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/electricity-ring-fencing-guideline-2016

6.3 The final rule

In light of the Commission's analysis in sections 6.1.3 and 6.2.3 above, the Commission has made a more preferable final rule to allow third-party services providers to enable retail customers' loads to be offered to the FCAS markets without having to register as a Market Customer (the final rule). The final rule does not differ significantly from how AEMO's detailed design (submitted with the rule change request) contemplated a demand response aggregator could provide ancillary services through the aggregation of load in the proposed rule.

As noted above, for the new framework created by the final rule to meet the NEO, it must meet competitive neutrality principles where relevant. The final rule does this by extending the current procedures and obligations relevant to offering load into FCAS markets (i.e. complying central dispatch and making FCAS offers) which apply to Market Customers to the new market participant. Key features of the final rule are discussed below.

6.3.1 Creating a new class of market participant

Stakeholder views

In its submission to the Draft determination, AEMO[240] noted that a market ancillary service provider should be able to i) identify units of load under its ownership, operation or control, ii) demonstrate that the load has the requisite assets and equipment, and iii) that the load can meet relevant performance standards and specifications, in each case to AEMO's satisfaction. To that end, AEMO considers that the generator eligibility criteria (clause 2.2.1(e) of the Rules), rather than the customer eligibility criteria (clause 2.3.1 (b) of the Rules upon which the proposed rule 2.3AA is based) are a more appropriate model in setting eligibility criteria for the market ancillary service classification.

AEMO[241] also notes that their interpretation of the draft rule is that once registered, a market ancillary service provider must seek AEMO's approval to designate each market load to provide ancillary services. That is, any additional load acquired or aggregated by the market ancillary service provider would then require the further approval of AEMO.

Although clause 18 of the final rule indicates that in accordance with clause 3.8.3(a1) AEMO would have to approve any application for an aggregated load as made by either a Market Customer or a market ancillary service provider, and would need to be satisfied that "power system security is not materially affected by the proposed aggregation"[242] ENA recommends that network service providers should also be

240 AEMO, Submission to Draft determination, p.1

241 AEMO, Submission to Draft determination, p.2

242 NER Rule 3.8.3 (b)(3)

consulted prior to approval of loads or aggregations of loads being approved as an ancillary service load to ensure this would not adversely affect the network[243].

Snowy[244] considers there needs to be a requirement for the market ancillary service provider to inform the Market Customer (i.e. retailer) that it has an arrangement in place with the customer for the provision of ancillary services. Snowy considers that the information given to the retailer must include at a minimum, the quantity and type of the ancillary service contracted and the duration of the contract. In the absence of this requirement, the retailer is in a difficult position whereby the actions of the market ancillary service provider may undermine its financial hedging position. This can arise because the ancillary services offered to the market by the market ancillary service provider may affect the energy consumed by the customer thereby creating an imbalance in the retailer's hedging volumes. This imbalance creates financial risks and uncertainty for the retailer which would ultimately be factored into increased risk premiums to manage the consumption profile of the customer.

Stanwell[245] seeks clarification that unbundling will not apply to scheduled loads, thereby avoiding the co-optimisation issues highlighted in Stanwell's previous submission. Stanwell notes that where an ancillary service load is not a scheduled load, there appears to be an unresolved issue in relation to dispatch targets and enablement trapeziums. The obligation for scheduled load to follow energy market dispatch instructions does not appear to have a parallel in respect of non-scheduled ancillary service loads.

The final rule

The final rule amends chapter 2 of the NER to create a new class of market participant in the spot market, in this case a market ancillary service provider. A market ancillary service provider would have the ability to provide FCAS services through individual or an aggregation of market loads without the requirement to register as a Market Customer.

The market ancillary service provider will be able to operate a Market Customer's market load to provide FCAS services, once it has classified such market loads as market ancillary loads. However, there are no changes to the NER arrangements in relation to Market Customers and their market loads. For example, a Market Customer would still remain financially responsible for the settlement of its market loads even though the market load can be operated by the market ancillary service provider to provide FCAS.

In practice, this will be facilitated by a contract between the relevant customer and the market ancillary service provider which is separate to but would effectively operate alongside or as an overlay to the customer's retail supply contract with its retailer (the Market Customer). The required change in load may be automated or be controlled by

243 ENA, Submission to Draft determination, p.2-3.

244 Snowy Hydro, Submission to Draft determination, p.2-3.

245 Stanwell, Submission to Draft determination, p.2

the market ancillary service provider. Alternatively, the required change in load may require positive action from the customer.

The Commission agrees with AEMO's submission in relation to the eligibility criteria to be used when market ancillary service providers seek to register with AEMO. In order to address AEMO's concerns, under the final rule, in order for a market ancillary service provider to be eligible for registration, it must i) identify units of load under its ownership, operation or control, ii) show those loads are under its ownership, operation or control, iii) demonstrate that the load has the requisite assets and equipment, and iv) demonstrate that the load can meet relevant performance standards and specifications, in each case to AEMO's satisfaction.

The final rule makes some minimal changes with respect to the existing arrangements under the NER with respect to a Market Customer and its current ability to provide FCAS services through its own market loads or an aggregation of them (see next section 6.3.2). A party registering as Market Customer will not be prevented from seeking registration as a market ancillary service provider with respect to market loads for which it is not the relevant Market Customer. This will allow retailers to potentially compete for the ancillary load of customers that are not otherwise their retail customers.

6.3.2 Classification of ancillary services load

Similarly to existing processes for Market Customers, a market ancillary service provider will be able to apply to AEMO for approval to classify a market load as an ancillary service load. As previously explained, such classification will then allow that market load to be offered into the FCAS markets the market ancillary service provider is seeking to participate in. The market ancillary service provider will be able to make ancillary services offers with respect to its ancillary service loads in the relevant FCAS markets it has approval to participate in, and AEMO will schedule the ancillary service load through the existing central dispatch process.

As set out in the Energy Council's proposal, there will be no minimum consumption thresholds with respect to a particular spot market load that a market ancillary service provider, or a Market Customer, must have regard to when applying for approval to classify a spot market load as an ancillary services load.[246] However, similarly to the proposed rule, the market ancillary service provider will be prevented from applying to classify a market load as an ancillary service load with respect to scheduled loads in the spot market. Only the relevant Market Customer would be allowed to classify these loads as an ancillary service loads.

Under the final rule a market ancillary service provider will need to comply with the existing application process to classify a load as ancillary service load. AEMO will approve a market ancillary service provider's application to classify a load as ancillary service load if it is reasonably satisfied that:

246 See page 12 of COAG's Energy Council rule change request. Issues associated with the absence of minimum consumption thresholds are discussed in section 6.4.1 below.

(a) The spot market load is able to be used to provide FCAS services referred to in the application in accordance to the technical standards set out in AEMO's market ancillary services specification (MASS); and

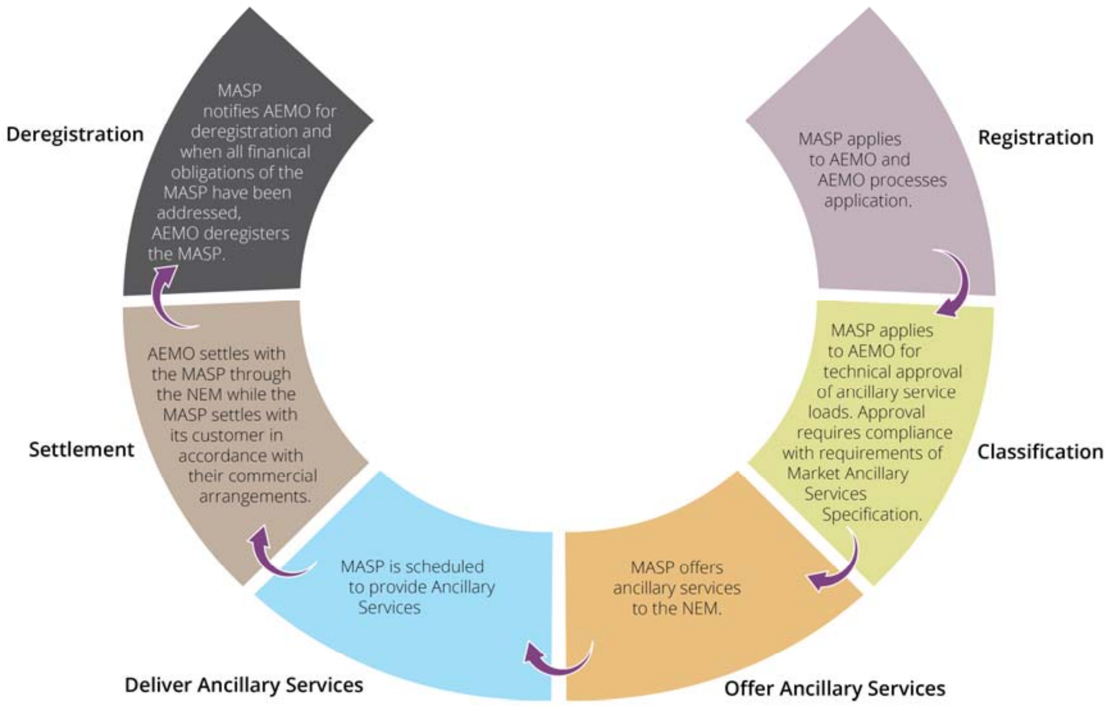
(b) The market ancillary service provider has adequate communications and/or telemetry to support the issuing of dispatch instructions and the audit of responses.

In addition, the Commission has included a new requirement before AEMO can approve an application to classify a market load as an ancillary service load. AEMO will need to be satisfied that the market ancillary service provider has appropriate arrangements in place with the retail customers at the relevant connection point for the supply of FCAS services using those market loads. As noted above, such an arrangement between a retailer customer and the market ancillary service provider will sit alongside the customer's retail contract with the Market Customer. To maintain competitive neutrality, this new requirement will also be extended to apply to Market Customers. The objective is to avoid parties classifying spot market loads as ancillary services load without having an appropriate arrangement in place with the relevant market ancillary service provider or Market Customer (as applicable). It will also prevent market loads being offered as ancillary load into FCAS markets by differing participants.

Market ancillary service providers must seek AEMO approval to designate each market load to provide ancillary services. Any additional load acquired or aggregated by the market ancillary service provider will require the further approval of AEMO.

Figure 6.1 provides details of the registration, service delivery, settlement and other stages of the market ancillary service provider's lifecycle.

Figure 6.1 Figure 6.1 Lifecycle of market ancillary service provider



6.3.3 Changes to the rules' bid and offer aggregation guidelines

As with Market Customers, the NER's bid and offer guidelines will be amended to allow market ancillary service providers to provide FCAS services from aggregated market loads for the purposes of central dispatch. The market ancillary service provider will have to apply to AEMO to aggregate loads for the purposes of providing FCAS services following the processes that are currently in place for Market Customers. AEMO will be required to approve an application for an aggregation of market loads if the following conditions are satisfied:

(a) the aggregated market loads are connected within a single region and operated by a single party that is appropriately registered with AEMO as either a Market Customer, a market ancillary service provider or both;

(b) power system security is not materially affected by the proposed aggregation; and

(c) control systems satisfy the technical requirements in relation to points (a) and (b) above after aggregating the spot market loads.[247]

6.3.4 Participation in the FCAS markets

Similarly to Market Customers, a market ancillary service provider that participates in FCAS markets will have to ensure that it complies with central dispatch processes and submits FCAS offers in accordance with chapter 3 of the NER.

Effectively, the final rule will extend all the relevant requirements under the NER in relation to central dispatch and spot market operation applicable to Market Customers that participate in FCAS markets to the market ancillary service provider with no exceptions. For example, under clause 3.8.7A of the NER, a market ancillary service provider will be required to:

- submit FCAS offers in the form prescribed in the Rules;
- ensure that the FCAS offers in relation to the ancillary services loads it operates is at all times capable of responding in the manner contemplated in the MASS;
- ensure that the values associated with the submitted FCAS offers represent the technical characteristics of the ancillary service load; and
- ensure that rebids of the values associated with a FCAS offer represent the technical characteristics at the time of dispatch of the ancillary service load.

As noted in earlier discussions (see section 6.2.3), AEMO notes that the market ancillary service provider would be ineligible to offer regulation ancillary services under the current MASS, and only be eligible for contingency ancillary services. This is because the MASS (under section 1.3) does not accommodate aggregated dispatch for the purposes of regulating raise service or regulating lower service. As such, a market ancillary service provider (or indeed Market Customers and Small Generation Aggregators) is currently ineligible to offer FCAS regulation services.

[247] NER Rule 3.8.3 (b)

6.3.5 Participant fees and prudential requirements

The market ancillary service provider participation fees should mirror the existing process set out in the Rules for parties that just register as a Market Customer for the sole purposes of providing FCAS services. In this case, AEMO would develop the structure of the market ancillary service provider participant fees in consultation with registered participants and in accordance with the Rules consultation procedure. The fixed component of the market ancillary service provider participation fees would be allowed to be zero.

In the draft determination the Commission noted that, as with other market participant, the market ancillary service provider will be subject to the prudential requirements under the NER for their activities as a market ancillary service provider in the spot market. However, the Commission also noted that it is unlikely that the market ancillary service provider would be required to provide any credit support given that would be net recipient of funds from AEMO. This prompted AEMO[248] to note in their submission to the draft determination that the market ancillary service provider would not be required to be subject to the prudential requirements as no other providers of market ancillary services currently provide credit support or have other prudential requirements.[249] The Commission is satisfied that there is no need for market ancillary service providers to be subject to prudential requirements.

6.3.6 Commencement of final rule

Stakeholder views

In its submission to the Draft determination, AEMO notes[250] that appropriate transitional arrangements will need to be put into place to allow AEMO to establish appropriate registration fees without reopening AEMO's current fee structure determination. In March 2016, AEMO completed a review of its fee structure.[251] AEMO recommended that the transitional rules be drafted to allow AEMO to charge registration fee to the new participants without needing to reopen AEMO's current fee structure determination. The amount of the registration fee would be set by AEMO as part of its annual budget (as the current fee structure allows).

The final rule

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248 AEMO submission to the Draft determination, p. 3

249 Under rule 3.3 the only prudential requirements that apply to MASPs are clause 3.3.1 the Market Participant criteria. This details the requirement that all Market Participants must, while participating in the market, be a resident or have a permanent establishment in Australia, not be under external administration, and being able to be sued. The remaining prudential rules (from clause3.3.2 to 3.3.19) will not apply to market ancillary service providers.

250 AEMO, Submissions to Draft determination, p. 2

251 AEMO, Final report – Structure of participant fees in AEMO's electricity markets, March 2016 https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/Electricity_Consultations/Structure-of-Fees/Final-Report--Structure-of-Participant-Fees-in-AEMOS-Electricity-Markets-2016-170316.ashx

The final rule now includes transitional arrangements to allow AEMO to charge registration fees to the new participants seeking to register as a market ancillary service provider without needing to reopen AEMO's current fee structure determination (as made recently in March 2016). The Commission expects that AEMO will set the fees as part of its annual budget.

Appropriate transitional arrangements to allow AEMO to establish appropriate registration fees are now also included in the final rule.

The arrangements under the final rule will otherwise commence on 1 July 2017.

6.4 Small customers and the need for energy specific consumer protections

6.4.1 No minimum consumption threshold

As noted above in section 1.4.2, the final rule does not impose a consumption threshold on the consumers whose market load could be bid into FCAS markets by a market ancillary service provider. Minimum annual consumption thresholds are used to define the difference between small and large customers. The intention of the proposed rule is to not to restrict eligibility of the ASU proposal to large customers (as is the case for the proposed DRM). Small customers will therefore be able to offer their demand response into FCAS markets through a market ancillary service provider. Small customers include both residential customers and a business customer who consumes below a specified consumption threshold.[252]

To offer their demand response into FCAS markets, a customer will need to enter into a commercial arrangement with a market ancillary service provider. As explained in section 6.3.1 this new arrangement between a market ancillary service provider and a customer would be negotiated outside of the NER and would sit alongside the customer's retail electricity supply contract and comprise an agreement by the relevant customer to reduce load in certain circumstances.

The commercial arrangement and relationship between the market ancillary service provider and a small customer is likely to sit outside the scope of the National Energy Retail Law (NERL) and corresponding National Energy Retail Rules (NERR) (together the NECF arrangements), and the equivalent legislation for those participating jurisdictions that have not yet adopted the NECF arrangements. This is because ancillary services can be characterized as non-energy services and accordingly the relationship between the market ancillary service provider and the small customer would not necessarily involve 'the activity of selling energy to a person'.[253]

252 Chapter 10, NER. The definition in chapter 10 imports the definition of the 'small customer' from the National Energy Retail Law (NERL)for those jurisdictions that are part of the National Energy Customer Energy Framework (NECF) and have applied the NERL in their jurisdiction. For those jurisdictions that have not applied the NERL - currently only Victoria – the chapter 10 definition of 'small customer' used in local jurisdictional electricity legislation has been included. The Victorian definition of 'small customer' is largely consistent with that in the NERL.

253 Section 88, NERL. A retail authorisation is necessary for those persons who intend to engage in this activity.

6.4.2 Asymmetric obligations

The effect of the above is that the relationship between the market ancillary service provider and a small customer would be subject to the general consumer protection arrangements under the Australian Consumer Law (ACL)[254] but may not be subject to any of the energy specific consumer protections provided as part of the NECF arrangements, or in the case of Victoria, its local energy legislation. Note that large customers primarily fall outside of the NECF enabled consumer protections and so are not relevant to this analysis.

However, retailers (Market Customers) seeking to offer a small customer's load into FCAS markets may be subject to energy specific consumer protections. This is because that service would need to be offered within the supply relationship between the retailer and the small customer which is then captured by the NECF.[255] This would arise if the retailer offered such services:

(a) as part of its existing supply arrangements with a small customer;[256] or

(b) alternatively, under a contract separate to the existing supply arrangement.

The retailer may, given the importance of maintaining its retailer authorisation,[257] still feel compelled to meet the standards of the existing energy specific consumer protections, regardless of the uncertainty as to whether to provision of this non-energy service falls within NECF arrangements.

This raises the possibility of asymmetrical obligations between retailers and market ancillary service providers offering the same services to the same customers. Asymmetrical obligations potentially mean different forms of consumer protection being available for comparable products and services. It could also create incentives to structure business in ways that avoids the energy consumer protection obligations and their associated costs, leaving an increasing number of customers outside the energy consumer protections framework.

Even if the provision of these new non energy services were considered to fall within the 'activity of selling energy to a person', and so within the scope of NECF arrangements, given the unique nature of this offering, the Australian Energy Regulator (AER) may seek to manage this offering by granting such business models an exemption from the requirement to hold a retailer authorisation. In granting such exemptions the AER has discretion as to the conditions that can be imposed on such exempted bodies. Such conditions are subject to certain policy principles that conditions of exemption should replicate, as far as practical, consumer protections

254 The ACL is a generic national consumer law. Its key objective is to improve consumer wellbeing through consumer empowerment and protection, to foster effective competition and to enable the confident participation of consumers in markets in which both consumers and suppliers trade fairly.

255 At the very least some of the disclosure requirements regarding other services the retailer provides

256 At the very least some of the disclosure requirements regarding other services the retailer provides

257 Issued under section 88 of the NERL.

otherwise available under NECF arrangements.[258] Again, this raises the possibility of asymmetrical obligations between retailers and such exempted persons offering the same services to the same customers.

The Commission notes that the Energy Council officials in 2015 identified similar issues for further consideration as part of their work on the regulation of new products and services in the electricity market and the appropriateness of existing consumer protections.[259]

6.4.3 Is there a need for energy specific consumer protections?

The rule change request was made under the NEL and set out proposed changes to the NER, and did not propose any changes to the NERR. Under section 91B of the NEL, the Commission has the power to make, in relation to the Energy Council's request:

- 'necessary or consequential' rules under the NEL; and
- 'Corresponding' rules under either the National Gas Law (NGL) or the NERL.[260]

Therefore, in order to consider and make changes to the NERR, the Commission is limited by its rule making powers to only making those changes that are corresponding.

Issues relevant to the need, or otherwise, for energy specific consumer protections are not changes that can be considered to be 'corresponding'. Therefore the Commission does not have the power to make any necessary changes to the NERR, even if they were considered necessary.

Despite this, the Commission notes that in its work to date the Energy Council officials' ministerial advice concluded that for many new products and services, such as energy efficiency services, direct load control and home energy management services, the Australian Consumer Law and the Privacy Act provide an appropriate level of consumer protection. The nature of the services to be offered by a market ancillary service provider is broadly similar to direct load control and home energy management services.

The Commission expects that the Energy Council officials' above mentioned work stream will, as part of developing a decision making framework for deciding what products and services should be subject to energy specific consumer protections, address relationships such as the market ancillary service provider small customer relationship as part of the range of third party service provides offerings emerging with developing energy markets.

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258 Section 114(1) of the NERL

259 See http://www.scer.gov.au/publications/new-products-and-services-electricity-market-advice-ministers-july-2015/ The Energy Council will also be pursuing this work further, commencing in the later half of 2016: http://coagenergycouncil.gov.au/publications/energy-market-transformation-bulletin-no-1-release-energy-market-transformation

260 While the precise nature of 'corresponding' is not defined in the NEL, it suggests that for any changes to the NERR to be within power, the changes would need to be equivalent to those being made under the NER.

Abbreviations

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ASU	Ancillary Services Unbundling
ATA	Alternative Technology Association
BCM	Baseline Calculation Methodology
Commission	See AEMC
DNSP	Distribution Network Service Provider
DR	Demand Response
DRM	Demand Response Mechanism
DRN	Demand Response Notification
DSM	Demand Side Management
DSP	Demand Side Participation
EEC	Energy Efficiency Council
EMMS	Electricity Market Management System
FCAS	Frequency Control Ancillary Services
MASS	Market Ancillary Services Specification
MCE	Ministerial Council on Energy
MEU	Major Energy Users Inc.
NECF	National Energy Customer Framework
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NMI	National Meter Identification
OGW	Oakley Greenwood
PoC	Power of Choice review

A. Summary of issues raised by stakeholders

A.1 Summary of issues raised in submissions to the consultation paper

DRM - Barriers to demand side participation		
AGL Energy Ltd	There are already avenues for large customer loads to provide a demand response to wholesale market signals. The suggested barriers to retailers offering contracts with a demand response component and/or partial spot price exposure – such as lack of incentives, fails to recognise that it is a very highly competitive retail market. (p.1)	See chapter 3, sections 3.3.1 and 3.3.2 for the Commission's analysis on barriers to demand side participation for large customers' to become exposed to the spot price or participate in a retailer's demand response program, and the role of DSM service providers.
EnergyAustralia Pty Ltd	The retail market, especially in the commercial and industrial sector, is extremely competitive. Some of the perceived obstacles to demand side participation, such as the alleged preference among retailers to only offer volume-based contracts, are not genuine obstacles in practice. The market is currently delivering load-shape management and energy efficiency to suit customer needs. (p.2)	See chapter 3, sections 3.3.1 and 3.3.2 for the Commission's analysis on barriers to demand side participation for large customers' to become exposed to the spot price or participate in a retailer's demand response program, and the role of DSM service providers.
ERM Power Ltd	DR arrangements are already common in NEM and a number of service providers are offering innovative and information solutions to end users. (p.2) The largest barrier to a customer participating in demand response programs is the customer's risk appetite. The proposed rule change will not address this genuine barrier. (p.4)	See chapter 3, sections 3.3.1 and 3.3.2 for the Commission's analysis on barriers to demand side participation for large customers' to become exposed to the spot price or participate in a retailer's demand response program, and the role of DSM service providers.
Energy Supply Association of Australia and Energy Retailers Association of Australia (ESAA and ERAA)	There are existing commercial arrangements between retailers and their customers in the National Electricity Market (NEM) that already facilitate a demand side response. These include arrangements such as interruptible contracts, scheduled and unscheduled DR, and spot price pass-through, etc. (p.2) Too little demand response in the wholesale market can be attributed to falling demand, improvements in energy efficiency and investment in solar PV. The latter two can be considered a form of DR. (p.3)	See chapter 3, sections 3.3.1 and 3.3.2 for the Commission's analysis on barriers to demand side participation for large customers' to become exposed to the spot price or participate in a retailer's demand response program, and the role of DSM service providers.
GDF Suez Australian	Barriers to entry are low. Many new retailers have emerged over time and continue to emerge. Some new entrant retailers have successfully	See chapter 3, sections 3.3.1 and 3.3.2 for the

DRM - Barriers to demand side participation		
Energy	started with just a few customers. In such an environment, a retailer's willingness to provide all possible benefits to customers, especially large customers likely to provide DR, is acute. In fact, supply to large customers is hotly contested as evidenced by the very low retail margins in this market segment. (p.3) It is chronically oversupply in the wholesale market and low pool price that have not encouraged DR. (p.4)	Commission's analysis on barriers to demand side participation for large customers' to become exposed to the spot price or participate in a retailer's demand response program, and the role of DSM service providers.
PG Energy	The barriers to entry are low. Many new retailers have emerged over time and continue to emerge. Supply to large customers is hotly contested as evidenced by the very low retail margins in this market segment. Retailers already offer and settle demand side response contracts. It is the chronically low wholesale prices that do not stimulate a major demand side response. (p.2)	See chapter 3, sections 3.3.1 and 3.3.2 for the Commission's analysis on barriers to demand side participation for large customers' to become exposed to the spot price or participate in a retailer's demand response program, and the role of DSM service providers.
Origin Energy Ltd	Low level of demand response in the NEM is not indicative of the existence of significant barriers, but due to little appetite for demand response offerings from the following reasons: • Prevailing oversupply, and generally low prices and low volatility in the NEM. • Customers can elect to include pool pass through and flexible purchasing products in their contracts. These products allow them to respond to high spot market prices similar to DR. • Increasing uptake of solar PV and battery storage would continue to reduce opportunities for demand response by effectively shifting or smoothing demand peaks. (p.2)	See chapter 3, sections 3.3.1 and 3.3.2 for the Commission's analysis on barriers to demand side participation for large customers' to become exposed to the spot price or participate in a retailer's demand response program, and the role of DSM service providers.
Red Energy and Lumo Energy	A competitive retail market will provide a suitable outcome to meet consumer demands. Retailers who are looking to manage their wholesale exposure by demand response may be the most likely to invest in educating consumers and offering retail products to those consumers. These retail products provide voluntary DR. (p.2)	See chapter 3, sections 3.3.1 and 3.3.2 for the Commission's analysis on barriers to demand side participation for large customers' to become exposed to the spot price or participate in a retailer's demand response program, and the role of DSM service providers.
Snowy Hydro Ltd	Electricity retailing is a very competitive and small margin business. There are strong commercial incentives to negotiate with consumers of	See chapter 3, sections 3.3.1 and 3.3.2 for the Commission's analysis on barriers to demand side

DRM - Barriers to demand side participation		
	all sizes to derive mutually beneficial products. The 5 minute dispatch and 30 minute settlement could be a structural issue that influences incentives for demand side participation. (p.5)	participation for large customers' to become exposed to the spot price or participate in a retailer's demand response program, and the role of DSM service providers. The impact of the 5 minute dispatch and 30 minute settlement on demand side participation will be considered as part of 5 minute settlement rule change request.
Stanwell Corp Ltd	DR can, and does, occur under the current market design. Large loads can use a pool pass-through retail agreement supplemented by financial hedge contracts. Under either arrangement, consumers have the ability to curtail consumption either unilaterally or in agreement with their retailer. demand response can be observed in the market in response to relatively high and volatile market prices. The greatest inhibitor of demand side participation in the current market is the lack of high prices and volatility, and therefore, commercial return. (p.7)	See chapter 3, sections 3.3.1 and 3.3.2 for the Commission's analysis on barriers to demand side participation for large customers' to become exposed to the spot price or participate in a retailer's demand response program, and the role of DSM service providers.
Alternative Technology Association	The main barrier is that retailers see demand response as a competitive threat to the generators which they contract with or own. Another major barrier is that many large consumers are in long term retail contracts for the sale of energy with their retailer. Competition in demand response is restricted because customers can only sell demand response to the retailer they buy their power from. Customers choose retailers mainly on the basis of energy prices, so there is little competitive pressure on retailers to offer demand response deals. To be effective a DRM will ultimately need to allow consumers to contract with a demand response aggregator regardless of their retail contract. Another barrier is that there is a lack of specialist aggregators competing with retailers for customers' demand response capabilities. (p.6-7) The incumbent industry has too much influence. (p.2)	Retailers have an efficient incentive to engage in demand response activities with their customers. (See section 3.3.2) Customers can already resort to brokering services for competitive deals for their retail supply and their demand response capabilities. (See section 3.3.1). Survey responses also reports that the length of supply contracts has decreased over the past several years. (See section 2.7, OGW survey report) Customers can already resort to a competitive DSM service market (See OGW's survey report) to bypass the retailer and manage the spot price risk themselves. (See section 3.3.1)
Energy Efficiency Council	There are a number of specific barriers that impede demand side participation that are relevant to this proposed rule change, specifically that energy consumers currently can't sell demand side participation into	Barriers to become exposed to the spot price have reduced. (See OGW's survey report and section 3.3.1.) The 'bundling' is an outcome of a large consumer's decision

DRM - Barriers to demand side participation		
	the wholesale energy market unless they make an arrangement with a retailer or face the complexity of the spot market. (p.2) • Exposure to the wholesale market price is too complex for most energy users. • Mandatorily bundling demand response and retail services has led to suboptimal provision of demand response services. • Load reduction cannot be packaged up in a way that enables it to compete with supply in the wholesale energy market. (p.4)	to engage a retailer to manage spot price exposure on its behalf. Given that the retailer is requested to both supply the customer and bear the risk of spot price exposure on the customer's behalf, it follows that a customer's demand response services become only valuable to that retailer. The large customer is free to negotiate a contract with a retailer that allows full or partial exposure to the spot price and such arrangement effectively 'unbundles' the retail supply of electricity and opportunities for demand responses. (See section 3.3.2)
EnerNOC Pty Ltd	The key barriers, namely: 1) no competition to procure DR, and 2) that demand response is not allowed to compete with generation. • The consumer has no ability to shop around for a better deal for their DR, so there is no competitive pressure for these parties to provide good value to the consumer for their demand response capabilities. Furthermore, these parties are often reluctant buyers of DR, due to conflicts with their core businesses, which lead to more inefficient under-use of DR. (p.3) • In the NEM, demand-side resources such as load curtailment are not treated equivalently to supply-side resources such as scheduled generation, despite being technically able to offer all the same services. Specifically, there is no mechanism for a consumer who reduces their demand at a time of high wholesale prices to be paid the spot price for doing so. There is also no practical way for a consumer to set the spot price—this can only be done by scheduled resources. As a direct consequence of this asymmetry, there is little demand response in the NEM. (p.3)	Customers can already resort to brokering services for competitive deals for their retail supply and their demand response capabilities. (See section 3.3.1) DRM arrangements do not result in demand response setting the price in the spot market in the same way as scheduled resources in the spot market. The DRM arrangements would impact on the spot price determination process in the way as any other demand response that AEMO does not schedule in the spot market. (See section 4.3.1) Demand response delivered through the DRM does not offer the same level of service as scheduled resources in the spot market. Therefore, allowing demand response participating under the DRM arrangements to access the spot price on the same basis as other scheduled resources in the spot market creates a spot market distortion. (See section 5.3.1)
Major Energy Users Inc (MEU)	As electricity market is not the core focus of end users, they want to have as little to do with the electricity market as is possible while minimising their costs for electricity. The more barriers put in the way of end users, the less end users will participate and less DSR will occur. The MEU has noted that generators and retailers seek to maintain their	Retailers have an efficient incentive to engage in demand response activities with their customers (See section 3.3.2) Customers can already resort to brokering services for competitive deals for their retail supply and their demand

DRM - Barriers to demand side participation		
	benefits through maximising barriers and minimising competition. (p.5) The current arrangements are a barrier; the current rules effectively impose a restraint on consumers being able to reduce their demand when prices are high and to receive a benefit for doing so. (p.7) Under the current rules, either an end user becomes a Market Participant or accesses electricity via a retailer. However, the costs and complexity of being an end user Market Participant do not warrant the potential benefits. End users currently select their retailer based on where the bulk of the costs are incurred (i.e. in the provision of electricity), rather than on the basis that the retailer relationship might be able to add value to the end user experience through other means. This means that unless a retailer is willing to provide a benefit to an end user seeking to provide DR, then it is unlikely that the end user will participate in DR. (p.8) In practice, a retailer acts in the own interests and only in its end user client's interests when these coincide with those of the retailer. The large retailers are also generators in their own right (gentailers) and have conflict of interest with end users. (p.9)	response capabilities. (See section 3.3.1) Customers can already resort to a competitive DSM service market (See OGW's survey report) to bypass the retailer and manage the spot price risk themselves.(See section 3.3.1)

DRM - Spot market benefits: efficient dispatch outcomes and efficient long term price signals		
AGL Energy Ltd	The ability of demand response aggregator to self-schedule outside of AEMO's central dispatch may impact the market's ability to reach efficient equilibrium. (p.2)	The impact on the equilibrium price would be the same as any other demand response that occurs outside the spot market. (See section 4.3.1)
EnergyAustralia Pty Ltd	There is little value in wholesale demand response in an oversupplied and less volatile wholesale market. New technologies such as batteries will be better alternatives to offer values to customers than the proposed DRM. (p.3)	The Commission agrees that the value of demand response will fluctuate with market conditions.
ERM Power Ltd	The wholesale market is oversupplied with generation and additional generation as a result of the RET will be added over the next five years.	AEMO would be required to forecast any demand response delivered through the DRM as it would be required with any

DRM - Spot market benefits: efficient dispatch outcomes and efficient long term price signals		
	DRM can only add further inefficiency to already stressed generation returns. The majority of NEM regions have experienced very few high prices for a number of years, reducing economic benefit of the DRM. (p.2) Including demand response in dispatch forecasts and dispatch pricing outcomes will likely lead to less accurate outcomes than is currently the case. This is because the non-firm nature of demand response makes it difficult to forecast with any accuracy. (p.7)	demand response that is not scheduled by AEMO. (See section 4.3.1)
ESAA and ERAA	If the DRM increases participation of unscheduled DR, there will be adverse consequences to the efficiency of central dispatch as scheduled generators face increasingly non-transparent market conditions (the marginal cost of the demand response service will not be reflected in pool prices) in which they try to optimise their dispatch. (p.3)	The Commission notes that demand side participation in the NEM has been generally unscheduled (with some very minor exceptions), as has been like that since the creation of the NEM. The Brattle Report also reports minimal demand side participation in central dispatch in other energy-only markets such as Texas and Alberta. The reason for this low appetite are related the costs of purchasing real-time telemetering equipment and the loss of a load's operational flexibility by becoming scheduled by a market operator. See the Brattle Report p. iv.
GDF Suez Australian Energy	Under the proposed DRM, there is no incentive for the call to be made before the trading interval. As a result, a demand response event is unlikely to provide useful information about upcoming trading intervals. Similarly, demand response events provide minimal additional information about trading intervals that have already happened, which can usefully inform forecasts about future trading intervals. For these reasons it is unlikely that the proposed DRM will provide system-wide benefits or improvements to system security and reliability management. (p.9)	This analysis is aligned with that presented in section 4.3.1.
PG Energy	Same/similar comment as made by GDF Suez. (p.6)	This analysis is aligned with that presented in section 4.3.1.

DRM - Spot market benefits: efficient dispatch outcomes and efficient long term price signals		
Origin Energy Ltd	The non-firm nature of the proposed DRM could impede price signals and hamper investors' ability to recover long run costs and hence impact the long term efficient generation mix in the NEM. (p.3)	The Commission notes that demand side participation in the NEM has been generally unscheduled (with some very minor exceptions), as has been like that since the creation of the NEM. The Brattle report also reports minimal demand side participation in central dispatch in other energy-only markets such as Texas and Alberta. The reason for this low appetite are related the costs of purchasing real-time telemetering equipment and the loss of a load's operational flexibility by becoming scheduled by a market operator. See the Brattle Report p iv. Demand response delivered through the DRM does not offer the same level of service as scheduled resources in the spot market. Therefore, allowing demand response participating under the DRM arrangements to access the spot price on the same basis as other scheduled resources in the spot market creates a spot market distortion. (See section 5.3.1)
Snowy Hydro Ltd	Current market prices are already providing little incentive for new investment in the NEM. The introduction of the DRM would further distort and dampen high spot price signals which hurt longer term customer interest. (p.2) Demand response aggregator is a non-scheduled market participant and is likely to exasperate the current inefficiencies in the price discovery process due to non-scheduled loads. (p.5)	AEMO would be required to forecast any demand response delivered through the DRM as it would be required with any demand response that is not scheduled by AEMO. (See section 4.3.1) Demand response delivered through the DRM does not offer the same level of service as scheduled resources in the spot market. Therefore, allowing demand response participating under the DRM arrangements to access the spot price on the same basis as other scheduled resources in the spot market creates a spot market distortion. (See section 5.3.1)

DRM - Spot market benefits: efficient dispatch outcomes and efficient long term price signals		
Stanwell Corp Ltd	Simply reducing wholesale prices in the short term is not efficient, and may not be in the long term interests of consumers. The net impact could be an increase in wholesale prices, since the uplift from forced plant retirement (decreased competition) is greater than the reduction from DRM ("increased competition"). (p.8) For all demand response to be non-scheduled would result in a lack of transparency contradicting to the strong desire for the provision of reliable information to the market discussed at length in a number of other rule change processes. (p.2)	The Commission notes that demand side participation in the NEM has been generally unscheduled (with some very minor exceptions), as has been like that since the creation of the NEM. The Brattle report also reports minimal demand side participation in central dispatch in other energy-only markets such as Texas and Alberta. The reason for this low appetite are related the costs of purchasing real-time telemetering equipment and the loss of a load's operational flexibility by becoming scheduled by a market operator. See the Brattle Report p iv. Demand response delivered through the DRM does not offer the same level of service as scheduled resources in the spot market. Therefore, allowing demand response participating under the DRM arrangements to access the spot price on the same basis as other scheduled resources in the spot market creates a spot market distortion. (See section 5.3.1)
Dr Archie Chapman (U of Sydney)	The proposed DRM does not directly address sources of price volatility to better balance supply and demand. (p.1) The proposed DRM does not address the information asymmetry on the demand and supply side, nor does it give retailers incentive to share the information with AEMO to aid the price determination processes and ensure efficient dispatch. (p.2)	The Commission agrees that the DRM's self-scheduling arrangements will not improve the existing information asymmetry between the demand and supply side. In this direction, demand response delivered through the DRM would need to be forecast as any demand response that is not scheduled by AEMO.
EnerNOC Pty Ltd	The significant level of demand-side participation resulting from the introduction of demand-side bidding will introduce competition to generation sources and efficient procurement of DR, (p.4) The proposed DRM would result in customers directly, or their representative DRAs providing the market with data comparable to that	The DRM's self-scheduling arrangements are not comparable to demand-side bidding. (See section 4.31) Therefore, they would not enhance economic efficiency in the same way (See section 4.3.1 and Brattle Report p iii-iv) DRM arrangements do not result in demand response

DRM - Spot market benefits: efficient dispatch outcomes and efficient long term price signals		
	provided by each scheduled generator. The DRM provides better real-time visibility than unscheduled generation. It also provides much better after-the-fact visibility (and hence modellability and predictability) than general spot exposure, behind-the-meter generation and retailers' own demand response programme. (p.5)	setting the price in the spot market in the same way as scheduled resources in the spot market. The DRM arrangements would impact on the spot price determination process in the same way as any other demand response that AEMO does not schedule in the spot market (See section 4.3.1)
Energy Efficiency Council	The DRM design will significantly improve understanding of demand side behaviour in a low cost way. The DRM will generate useful information for managing transmission constraints. The DRM would reduce the relative bias towards generation resources. (p.5)	The DRM's self-scheduling arrangements are not comparable to demand-side bidding. (See section 4.31) Therefore, they would not enhance economic efficiency in the same way (See section 4.3.1 and Brattle report p iii-iv) and they would not facilitate the dispatch of demand response as a function of transmission constraints (See section 4.3.1)
MEU	To apply load movement scheduling at the end user level will be excessively expensive, but networks, retailers and aggregators with demand response previously accessed and ready to deliver could provide this information to AEMO as and when the demand response is proposed to be used. Supply of such information would be a benefit to the market. (p.13)	The DRM's self-scheduling arrangements are not comparable to demand-side bidding. (See section 4.31) Therefore, they would not enhance economic efficiency in the same way (See section 4.3.1 and Brattle report p iii-iv) and they would not facilitate the dispatch of demand response as a function of transmission constraints. DRM arrangements do not result in demand response setting the price in the spot market in the same way as scheduled resources in the spot market. The DRM arrangements would impact on the spot price determination process in the way as any other demand response that AEMO does not schedule in the spot market (See section 4.3.1)
Ergon Energy Corp Ltd	As the DRM is not a bid system, it is not expected that any new pre-dispatch information would be generated. Information generated would be post event only, and market participants could only use historical performance and capability as a guide to expected responses. (p.5)	The Commission's analysis is aligned with this observation (See section 4.3.1)

DRM - Spot market benefits: efficient dispatch outcomes and efficient long term price signals		
AEMO	AEMO's detailed market design (as per terms of reference) was designed as a response mechanism, i.e. responds to the spot price rather than sets it, which may not satisfy some of the new assessment criteria. (p. 3)	The Commission agrees. The DRM's self-scheduling arrangements are not comparable to demand-side bidding. (See section 4.31) Therefore, they would not enhance economic efficiency in the same way (See section 4.3.1 and Brattle report p iii-iv) and they would not facilitate the dispatch of demand response as a function of transmission constraints (See section 4.3.1)

DRM - Wealth transfer		
ESAA and ERAA	Benefits of the DRM can be overstated. For example, Lower prices do not in themselves constitute an economic benefit to society, where they simply represent a transfer from producers to consumers. (p.3)	Demand response delivered through the DRM does not necessarily result in lower prices (See section 4.3.1) Payments under the DRM arrangements that retailers make to demand response aggregators can be interpreted as a wealth transfer from retailers to demand response aggregators (See Annex F)

DRM - Network benefits		
Stanwell Corp Ltd	Given the incentives already in place for networks to procure, and customers to provide, network support services through demand management, a wholesale DRM is unlikely to create network benefits. (p. 9)	Network benefits from demand response triggered in response to spot market prices are coincidental. The network benefits identified for the DRM can also be delivered through existing demand side participation arrangements (See sections 3.3.3 and 4.4.2)
Alternative Technology Association	There will be opportunities for DRM consumers to provide support for distribution and transmission networks. (p.12)	These opportunities are also available and are currently materializing under current demand side participation arrangements without the need of a DRM. (See section 3.3.1.)
Energy Efficiency	The DRM would enable demand response aggregators to develop	These opportunities are also available and are currently

DRM - Network benefits		
Council	portfolios of demand side participation that could be used to reduce further investment in electricity transmission and distribution networks. (p.5)	materializing under current demand side participation arrangements without the need of a DRM. (See section 3.3.1.)
EnerNOC Pty Ltd	If NSPs are receptive to demand response as an alternative to capital expenditure on network infrastructure, then the presence of a vibrant demand response sector based around the wholesale market will make it much easier to procure demand response for network purposes. (p.10)	Commission agrees with this statement. Although a DRM is not required to deliver these spill-over effects (See section 4.4.2)
MEU	If there are demand response options that are available at a lower cost than constraining on higher priced generation, then clearing congestion through demand response should be possible. In this regard, networks can provide a valuable service to AEMO by identifying, accessing and pricing demand response in their networks to reduce congestion. (p.13) The DRM has the potential to reduce the need for network investments. A system wide benefit depends on how the network investments are incentivised and network rules are crafted for implementing DR. (p.15)	It is likely that the proposed DRM would either alleviate or exacerbate a network's constraint depending on the time and location of a demand response, as peak spot price events may or may not coincide with a network constraint at a particular location. However, the same is true for any demand response that is scheduled outside the spot market. (See section 4.3.1) The benefits estimated at OGW's cost benefit analysis are allocated at the network level of the energy supply chain. Any network benefits emerging from the DRM are pure coincidental, and as such, can also be delivered through existing demand side participation arrangements without incurring the costs from implementing the DRM. (See sections and 3.3.3 and 4.3.2)
AusNet Services (Distribution) Ltd	Demand response aggregators will target the most valuable demand response payments, which may be in the wholesale market or from network service providers. However, as a result of these alternative markets, the availability of demand response for the networks when required may become less certain. (p.1) AEMC should consider what broader obligations exist between NSPs serving customers contracting with demand response aggregators. For example, it should be clarified that the network business is not liable for the demand response aggregator's lost opportunity costs in the event of	Demand response delivered through the DRM could either alleviate or exacerbate a network's constraint depending on the time and location of the demand response, as peak spot price event may or no coincide with a network constraint at a particular location. However, this is also true for any demand response that is not scheduled by AEMO. (See section 4.4.1)

DRM - Network benefits		
	a network outage. (p.2)	
Energy Network Association (ENA)	The Oakley Greenwood analysis is only marginally positive and there are already mechanisms which could realise some of the network benefits quantified. New initiatives need to take into account any relevant existing AEMO work programs in order to avoid unnecessary implementation costs and duplication. Detailed design should minimise the risk of demand response providers being paid twice for the same service (p.3)	The benefits estimated at OGW's cost benefit analysis are allocated at the network level of the energy supply chain. Any network benefits emerging from the DRM can also be delivered through existing demand side participation arrangements without incurring the costs from implementing the DRM. (See sections and 3.3.3 and 4.3.2)
Energex Ltd	Any potential DRM should not be developed in isolation from existing programs but should form part of an integrated suite of demand response measures. (p.1)	The Commission's analysis shows that the DRM would not deliver an extra benefit over and above the benefits that are currently provided through existing demand side participation arrangements and incentives. (see for example, Demand side management incentive rule described in section 1.5).
Ergon Energy Corp Ltd	DRM is capable of providing network management opportunities, particularly in mitigating the impacts of significant and growing penetration rates of solar PV systems and in managing network costs. (p. 2) DRM can reduce peak demand. However, there is no assurance that demand response aggregators will offer to DNSPs the services specifically required in this regard. Therefore it is vital that DNSPs are able to act as demand response aggregators. (p.2) Same comment as in ENA. (p.2)	The benefits estimated at OGW's cost benefit analysis are allocated at the network level of the energy supply chain. Any network benefits emerging from the DRM are purely coincidental, and as such, can also be delivered through existing demand side participation arrangements without incurring the costs from implementing the DRM. (See sections and 3.3.3 and 4.3.2)
TransGrid	It is possible that technical, commercial and market depth factors may result in end-users effectively having to choose providing demand response to wholesale market or network support. If this were to be the case, there is a potential that the total system benefits possible from demand response may not be realised. The DRM, if implemented, should be developed in such a way that it allows the value of demand	The proposed DRM is unlikely to address this coordination issue.

DRM - Network benefits		
	response to be effectively maximised. (p.2) There are potential efficiencies of scale which can be captured from the integration of the demand response aggregator role with network planning and operations. An appropriately ring-fenced network business should not be precluded from becoming a demand response aggregator. (p.2)	

DRM - System security and reliability		
ERM Power Ltd	There is the risk that a demand response may be located in the wrong place in the network and when initiated may lead to the overload and failure (tripping) of a critical network element at a time of power system stress. (p.9) The proposed DRM would facilitate the entry of inefficient or uneconomic DR. If that is the case, system reliability and possibly security issues will emerge if the economic signal for firm peaking generation is removed from the market. (p.7)	Demand response delivered through the DRM would either alleviate or exacerbate a network's constraint depending on the time and location of the demand response, as peak spot price event may or no coincide with a network constraint at a particular location. However, this is also true for any demand response that is not scheduled by AEMO. (See section 4.4.1) The Commission acknowledges that demand response delivered mainly through the DRM would result in a market that would not encourage entry of more efficient scheduled energy resources. (See section 5.3.1)
Origin Energy Ltd	Distortion of price signals caused by the non-firm DRM could result in a reduction in the stock of peaking generation below the levels needed to maintain system reliability. Demand response is unlikely to have the flexibility or firmness of peaking plant. (p.3)	The Commission acknowledges that demand response delivered mainly through the DRM would result in a market that would not encourage entry of more efficient scheduled energy resources (See section 5.3.1)
EnerNOC Pty Ltd	Reducing demand affects the balance of supply and demand in exactly the same way as starting a peaking generator. On a longer timescale, assembling and contracting a portfolio of dispatchable demand-side resources can contribute to the security of supply in exactly the same way as building a new peaking generator. (p.10)	Demand response delivered through the DRM does not have the same operating characteristics as scheduled peaking generation. For example, contrary to demand response delivered through the DRM, these characteristics allow AEMO to issue dispatch instructions to peaking

DRM - System security and reliability		
		generators based on system-wide demand/supply conditions and network constraints. Therefore, demand response delivered through the DRM cannot contribute in the same way to system reliability as peaking generation resources. (See section 5.3.1)
Department of State Development (South Australia)	The DRM could assist with potential impacts of South Australia's generation mix shifting away from conventional generation to intermittent renewables. For example, the DRM could minimise the risk of insufficient supply resulting from the intermittent nature of renewable generation. (p.1)	Demand response delivered through the DRM does not have the same operating characteristics as scheduled peaking generation. For example, contrary to demand response delivered through the DRM, these characteristics allow AEMO to issue dispatch instructions to peaking generators based on system-wide demand/supply conditions and network constraints. Therefore, demand response delivered through the DRM cannot contribute in the same way to system reliability as peaking generation resources. (See section 5.3.1) OGW's survey findings indicate that some large customers are now opting to become exposed to spot prices. This form of demand side participation is likely to better facilitate the integration of renewable energy into the system in comparison to a scenario where demand side participation is done through the DRM. Current demand side participation will deliver greater reliability benefits in comparison to demand side participation through the DRM.
AusNet Services (Distribution) Ltd	Network businesses have little visibility of demand response arrangements between retailers and customers. Recommend detailed design to improve transparency: • Identification of the demand response aggregators at the NMI level in MSATS. • Provision of confidential reports at the NMI level of events to the Local Network Service Providers (LNSPs) as soon as possible. (p.1) There is emerging operational risk for the networks. Increasing	It is likely that the proposed DRM would either alleviate or exacerbate a network's constraint depending on the time and location of a demand response, as peak spot price events may or may not coincide with a network constraint at a particular location. However, the same is true for any demand response that is scheduled outside the spot market. (See section 4.3.2)

DRM - System security and reliability		
	penetration of demand response capability may lead to the emergence of network implications from synchronised switching. The establishment of a Load Management Protocol (or agreements with demand response aggregators) to control synchronised demand response switching would be required. It is essential that the regulatory framework for DRM addresses these risks at the outset, to ensure the framework is robust. (p.2)	
Energex Ltd	Network business should not be precluded from undertaking the role of demand response aggregator for purposes such as managing reliability in constrained locations on their networks. The issue of synchronised demand response switching must be addressed to prevent adverse impacts on system stability and reliability. (p.1)	As the Commission has decided not to make a draft rule that would implement a DRM in the spot market, this issue does not need to be addressed.
Ergon Energy Corp Ltd	There are a number of risks associated with a DRM that must be carefully managed for unintended consequences, such as increased augmentation to manage new and swinging periods of peak demand. (p.1) Strongly support COAG Energy Council proposed work program to develop a Load Management Protocol and connection agreements between DNSPs and demand response aggregators. (p.2) Load restoration must be managed by the demand response aggregator to respect network constraints and therefore avoid any adverse impacts on the security and stability of electricity supply. (p.5)	As the Commission has decided not to make a draft rule that would implement a DRM in the spot market, this issue does not need to be addressed.
TransGrid	The provision of greater levels of demand response may have implications for the planning and operation of transmission networks. In some instances, demand response may not be reliable enough to meet these standards given that the end-user will often retain the ability to opt-out of providing the resource when called. This will need to be taken into account in the planning and operating decisions of a transmission network. In addition to implications to the overall network planning processes, there are also potential interactions with specific projects	As the Commission has decided not to make a draft rule that would implement a DRM in the spot market, this issue does not need to be addressed.

DRM - System security and reliability		
	under the Regulatory Investment Test for Transmission which merit further consideration. (p.2)	
AEMO	AEMO would not be in a position to factor expected DRM related demand responses into its operations to improve system security (p. 5.)	Agreed.

DRM - Implementation and operation cost		
AGL Energy Ltd	Demand side response can and does occur under the existing regulatory arrangements. The rule change will introduce a different mechanism which relies on fundamental changes to the role of AEMO and the settlement process. Software changes to participant systems will be expensive. Therefore the proposed rule change introduces significant additional costs without additional benefits. (p.7)	The Commission has found that implementing the DRM would not result in a net benefit relative to current market arrangements. (See section 4.3)
EnergyAustralia Pty Ltd	The DRM will add unnecessary costs and complexities to all retail business but provide only limited value to a very small number of customers. (p.1)	The Commission has found that implementing the DRM would not result in a net benefit. (See section 4.3)
ESAA and ERAA	The demand response would impose significant implementation costs. (p.4)	The Commission has found that implementing the DRM would not result in a net benefit relative to current market arrangements. (See section 4.3)
GDF Suez Australian Energy	The voluntary model as proposed is highly unlikely to have incremental net benefits over the current arrangements, because the model adds complexity and costs in an attempt to ‘facilitate’ something that can and does already occur. (p.3)	The Commission has found that implementing the DRM would not result in a net benefit relative to current market arrangements. (See section 4.3)
Origin Energy Ltd	There are likely to be significant system development and ongoing administrative costs to AEMO for the DRM. All AEMO costs related to the DRM should be recovered solely from the new class of demand response aggregator market participants. This is a more equitable	The Commission has found that implementing the DRM would not result in a net benefit relative to current market arrangements. (See section 4.3)

DRM - Implementation and operation cost		
	approach than smearing the potentially large costs across all market participants. (p.3)	
PG Energy	The rule change will introduce a different mechanism which relies on fundamental changes to the role of AEMO and the settlement process. Software changes to participant systems will be expensive. Therefore the proposed rule change introduces significant additional costs without additional benefits. (p.4)	The Commission has found that implementing the DRM would not result in a net benefit relative to current market arrangements. (See section 4.3)
Red and Lumo	According to a report by Seed Advisory, the cost implications for retailers to implement and administer the DRM were estimated to be $112 million over a 10 year period without an equivalent benefit to retail customers. This cost will be ultimately borne by consumers. (p.2)	The Commission has found that implementing the DRM would not result in a net benefit relative to current market arrangements. (See section 4.3)
Snowy Hydro Ltd	The implementation costs of the DRM are potentially significant. Duplicate metering, increased regulatory oversight and working groups to establish the consumption baseline methodology are a number of tangible costs that will be incurred to establish the DRM. The DRM will also require rigorous monitoring by an institutional body to ensure there is no gaming. (p.2)	The Commission has found that implementing the DRM would not result in a net benefit relative to current market arrangements. (See section 4.3) The Commission has found that the DRM can result in gaming costs that will ultimately be recovered from consumers. (see Section 5.3.5)
Alternative Technology Association	The Oakley Greenwood's cost benefit analysis found a net benefit for all consumers. Given this, allowing any retailer to restrict any consumer from participating in the DRM, represents an unambiguous failure to prioritise the long term interests of all consumers. (p.1)	The benefits estimated at OGW's cost benefit analysis are allocated at the network level of the energy supply chain. Any network benefits emerging from the DRM are pure coincidental, and as such, can also be delivered through existing demand side participation arrangements without incurring the costs from implementing the DRM. (See sections and 33.3 and 4.3.2)
Energy Efficiency Council	The costs of removing barriers to demand response are minimal. The Oakley Greenwood's review into the DRM found that, in the short run, the benefits of the DRM outweigh the (inflated) costs due to increased competition and choice in the energy market. The potential benefits will	The benefits estimated at OGW's cost benefit analysis are allocated at the network level of the energy supply chain. Any network benefits emerging from the DRM are pure coincidental, and as such, can also be delivered through

DRM - Implementation and operation cost		
	increase dramatically over time, as generation technologies change and the over-supply of capacity in both generation and network infrastructure ameliorates. (p.2)	existing demand side participation arrangements without incurring the costs from implementing the DRM. (See sections 3.3.3 and 4.4.2)
Embertec	Firstly there must be a clear date after which it becomes mandatory for retailers to allow their customers to participate in the DRM; if retailers don't let their customer participate then the program itself risks becoming irrelevant. Secondly, while it is reasonable to start the DRM with single site large energy users, a plan, including a firm starting date, to incorporate aggregated loads of smaller energy users, including individual households, into the DRM. Technology to provide this level of aggregated demand response services exists now and there are already network operators in other jurisdictions including California that are making it happen. (p.2)	The Commission has decided not to make a draft rule that would implement a DRM in the spot market. The Commission has found that implementing the DRM would not result in a net benefit relative to current market arrangements. (See section 4.3)
AEMO	The costs for development of procedures, systems and processes required to support DRM and ASU are to be borne by AEMO. The recovery of AEMO's implementation costs may need some additional clarity. The initial consultation document outlines that operational cost recovery arrangements under DRM will require DRAs to pay a fee at a rate per MWh of demand response and retailers pay customer fees based on baseline energy. If the costs are to be recovered on the principle of the user pays, i.e. the participating DRAs bear the cost, this in itself could act as a disincentive for participation in the DRM. Under voluntary arrangements there could be a scenario where there are no DRA participants, meaning that AEMO would not being able to recover its costs. Recovering in this way could also have the unintended consequence of discouraging participation as fees may be high if only a small number participate and the costs must be shared between them. If cost recovery is intended to be recovered via participant fees the risk to AEMO would be mitigated and the costs would be shared across participants, even those that do not participate. Further consideration is	The Commission has found that implementing the DRM would not result in a net benefit relative to current market arrangements. (See section 4.3)

DRM - Implementation and operation cost		
	required with respect to the fee recovery approach.	

DRM - Distortions in spot and related markets		
AGL Energy Ltd	High quality service delivery by retailers becomes far more difficulty where a demand response aggregator is making potential high impact decisions regarding the customer's load without the retailer having any involvement in, or visibility of, the arrangement. (p.3)	The Commission notes that the DRM might result in retail market distortions. (See section 5.3.2)
ESAA and ERAA	The demand response would distort the contracts market. (p.4)	The Commission notes that the DRM might result in financial market distortions. (See section 5.3.3)
GDF Suez Australian Energy	The proposed rule change seeks to treat different technologies selectively in the NEM. This creates an uneven playing field between retailers and demand response aggregators in relation to retail license obligations. The rule change may perversely curtail existing demand side response in the hope of stimulating new responses under the modified rules.(p.5)	The Commission notes that the DRM might result in retail market distortions. (See section 5.3.2)
PG Energy	The rule change harms existing demand response retailers by creating an un-level playing field for existing retailers such as PG Energy by allowing non-retail entities to compete for some services but under a "softer" set of regulatory arrangements. (p.6)	The Commission notes that the DRM might result in retail market distortions. (See section 5.3.2)
Red and Lumo	The Commission notes that the DRM might result in retail market distortions. (See section 5.3.2)	The Commission notes that the DRM might result in retail market distortions. (See section 5.3.2)
Snowy Hydro Ltd	The net effect of the proposed DRM arrangements is to increase hedging risks for both generators and retailers, causing distortion to the contract/financial markets. (p.2)	The Commission notes that the DRM might result in financial market distortions. (See section 5.3.3)
Dr Archie Chapman	The requirement that a load at a National Meter Identifier is predictable is a bias towards those customers and technologies with such load	The Commission notes that the DRM might result in distortions to competition and innovation in demand

DRM - Distortions in spot and related markets		
	characteristics. (p.1)	response services (See section 5.3.4)
Australian Energy Regulator	Any DRM must be tailored to work effectively within the Australian wholesale market design.	The Commission has found that implementing the DRM in the spot market would distort spot market outcomes. See section 5.3.1.

DRM - Baseline setting and gaming risks		
AGL Energy Ltd	Accurate the reliable baseline setting is inherently challenging. There are inefficient costs involved in a retailer requiring ongoing physical and financial hedge cover for baseline consumption that may not actually occur. (p.2)	The Commission notes that the DRM might result in financial market distortions. (See section 5.3.3)
ERM Power Ltd	The proposed baseline methodology will encourage gaming, as a demand response aggregator is motivated to maximise the baseline and correspondingly maximise the 'observed' demand reduction. (p.8)	The Commission has found that the DRM can result in gaming costs that will ultimately be recovered from consumers. (see Section 5.3.5)
Snowy Hydro Ltd	There are serious gaming risks because once a baseline is known in advance of the next dispatch period the demand response aggregator have a free option to exploit this knowledge for commercial gain. (p.6)	The Commission has found that the DRM can result in gaming costs that will ultimately be recovered from consumers. (see Section 5.3.5)
Dr Archie Chapman	Any baselining procedure seems fraught with additional sources of error, or even the opportunity for outright misrepresentation or gaming. The baselining and accreditation of new loads participating in the DRM will act as a costly barrier to entry to the DRM. (p.2)	The Commission has found that the DRM can result in gaming costs that will ultimately be recovered from consumers. (see Section 5.3.5)
Alternative Technology Association	Recommend discussion of gaming risks (and implementation costs) in a forum with stakeholders that include proponents of the DRM to ensure some balance in the discussion. (p.9) Transparency is a high priority in the baseline methodology. (p.10)	The Commission has found that the DRM can result in gaming costs that will ultimately be recovered from consumers. (see Section 5.3.5)
EnerNOC Pty Ltd	A prohibition against signalling false or misleading demand response events would sufficiently address any concerns of gaming risks. (p.10)	The Commission has found that the DRM can result in gaming costs that will ultimately be recovered from

DRM - Baseline setting and gaming risks		
	The costs for energy users to artificially increase their energy use for large periods would far exceed any benefits from the DRM, minimising the incentive to gaming. (p.10)	consumers. (see Section 5.3.5)
Energy Efficiency Council	If mechanisms proposed by AEMO are adopted the risk of gaming under the DRM will be minimal. The DRM will also substantially increase competition in the wholesale market and therefore reduce the existing risk of gaming in the wholesale market. (p.5)	The Commission has found that the DRM can result in gaming costs that will ultimately be recovered from consumers. (see Section 5.3.5) The Commission has also found that the DRM might result in distortions to competition and innovation in demand response services. (See section 5.3.4)
MEU	DRM has the potential to provide some counter to the gaming practices of generators. (p.16)	The Commission has found that the DRM can result in gaming costs that will ultimately be recovered from consumers. (see Section 5.3.5)
Ergon Energy Corp Ltd	There is a gap which could enable a demand response aggregator to impact a distribution network by exacerbating peaks or creating new constraints. Some form of oversight and enforcement/penalty regime would be required to address this issue. (p.5)	The Commission has made a decision to not to implement the DRM in the spot market.

DRM - Voluntary and staged approach		
Alternative Technology Association	The biggest risk is that under ‘voluntary’ models, energy retailers will restrict participation in the DRM, limiting the ability to best achieve consumer choice (and the NEO) when compared to a ‘non-voluntary’ DRM model. ATA recommends: • Consider ‘voluntary’ DRM options that do not prevent a consumer from participate in DRM. • Implementing the DRM at the earliest practical opportunity. • Move to a ‘non-voluntary’ model by the end of 2018. (p.3)	The Commission has made the decision to no to implement the DRM in the spot market. The Commission has not found evidence of a relevant market failure that would justify mandating retailers to incur the costs from implementing the DRM (See chapter 3). Further, as argued in chapter 4, incurring these costs would not result in an extra benefit to consumers.

DRM - Voluntary and staged approach		
	What should be voluntary for a retailer is whether or not they are required to modify their settlement and billing systems to accommodate DRM, rather than whether or not a customer participates per se. (p.14)	
Embertec Pty Ltd	The staged implementation approach for the DRM should provide specific clarification on implementation dates for the following key aspects: • • There must be a clear date after which it becomes mandatory for retailers to allow their customers to participate in the DRM. • • There should be a plan, including a firm starting date, to incorporate aggregated loads of smaller energy users, including individual households, into the DRM. (p.2)	The Commission has made the decision to no to implement the DRM in the spot market. The Commission has not found evidence of a relevant market failure that would justify mandating retailers to incur the costs from implementing the DRM (See chapter 3). Further, as argued in chapter 4, incurring these costs would not result in an extra benefit to consumers.
Energy Efficiency Council	The voluntary approach will be ineffective. Recommend: • • mandatory for retailers to allow their customers to participate in the DRM no later than 1 Jan 2018. • • aggregated loads of smaller energy users are allowed to participate in the DRM no later than 1 Jan 2018. (p.1)	The Commission has made the decision to no to implement the DRM in the spot market. The Commission has not found evidence of a relevant market failure that would justify mandating retailers to incur the costs from implementing the DRM (See chapter 3). Further, as argued in chapter 4, incurring these costs would not result in an extra benefit to consumers.
MEU	Allowing a voluntary take up will result in DRM being minimised as the retailers (and more particularly the gentailers) have a vested interest in not promoting demand response. (p.10, 18)	The Commission has made the decision to no to implement the DRM in the spot market. The Commission has not found evidence of a relevant market failure that would justify mandating retailers to incur the costs from implementing the DRM (See chapter 3). Further, as argued in chapter 4, incurring these costs would not result in an extra benefit to consumers.
Origin Energy Ltd	The voluntary concept requires further examination. The proposed rule change is not clear on the extent of the obligations on retailers who do, or do not, enable their customers to participate in the DRM. (p.3)	The Commission believes that a “voluntary” model is unviable because retailers would not have an incentive to offer access to the DRM to their customers (See section

DRM - Voluntary and staged approach		
		4.3.4)
Energy Network Association	ENA endorses the proposed staged and voluntary implementation approach. (p.2)	The Commission believes that a “voluntary” model is unviable because retailers would not have an incentive to offer access to the DRM to their customers (See section 4.3.4)
Energex	Support the proposed future participation of smaller customers in the DRM. (p.1)	The Commission believes that a “voluntary” model is unviable because retailers would not have an incentive to offer access to the DRM to their customers (See section 4.3.4)
AEMO	AEMO considers that participation in the DRM would be reduced if retailers could veto all of their customers of their customers participating (p.4.)	The Commission believes that a “voluntary” model is unviable because retailers would not have an incentive to offer access to the DRM to their customers (See section 4.3.4)

DRM - Settlement		
GDF Suez Australian	The proposed rules would move away from the settlement of physical energy and introduce the settlement of financial instruments by AEMO. AEMO should not be expanding into the settlement of financial products and this should be left to the competitive market. (p.6)	Agreed.
PG Energy	Same comment as in GDF. (p.2)	Agreed.

DRM - Recent reforms		
AGL Energy Ltd	Recent complimentary regulatory reforms and technological developments, e.g. cost-reflective pricing, communications-enabled digital meters, are providing new opportunities for the demand side to participate and deliver real value and improved market efficiency. (p.4)	The Commission had found that customers, retailer and network business can already resort to a DSM service competitive market to benefit from demand response should they require that assistance.
Origin Energy Ltd	The combination of the AEMC's recent metering and distribution pricing rule changes will allow for increased uptake of smart meters and cost reflective network pricing. This will enable consumers to observe changes in the spot price and for retailers to offer products that would allow consumers to tailor their consumption patterns if they so desire. (p.3)	Agreed.
Red and Lumo	With the advent of new technologies, the implementation of the Distribution Network Pricing Arrangements and the competition in metering rule change, the rule change is no longer required. (p.3)	The Commission had found that customers, retailer and network business can already resort to a DSM service competitive market to benefit from demand response should they require that assistance.

DRM - Urgency of the reform		
Alternative Technology Association	There is no better time to implement the DRM, as: • • Significant generation retirements already, along with a slowing of demand reductions, returning price volatility to the market. • • The dramatically inaccurate demand forecasts that have contributed to the current oversupply of capacity are unlikely to be repeated, and energy businesses are placing less stock in them in any case. • • Future is uncertain, but given the growing role of variable renewable energy generation, price volatility would increase. • • In the context of this heightened uncertainty, increased demand	The market has already moved ahead. The DRM is a design conceived for a world where retailers play a key role in managing spot price risk on behalf of customers. The OGW survey indicates that the market has already moved away from this paradigm, and customers are already participating more actively and choosing to manage this risk by themselves. The Commission had found that customers, retailer and network business can already resort to a DSM service competitive market to benefit from demand response should they require that assistance. See OGW's survey report. The market has already moved towards ways of demand side

DRM - Urgency of the reform		
	response participation will be extremely valuable, as it will avoid the need to build new peaking generation. • • The reform process is slow. It will then take at least 2 years for a competitive demand response market to develop, so shouldn't delay until more demand response is urgently needed. (p.4)	participation that are more effective at integrating renewable intermittent generation in comparison to the DRM. For example, customers exposed to spot prices responding directly to price fluctuations caused by intermittent renewables would shift demand to periods where renewable generation is more abundant (and therefore prices are lower). Under the DRM, while customers are incentivised to curtail load they are not efficiently incentivise to shift load to periods where renewable generation is more abundant and prices are lower.
Embertec Pty Ltd	DRM will become increasingly important as generation technologies change, more intermittent renewables come on-line and the over-supply of capacity in both generation and network infrastructure eases. Therefore, it is critical to immediately introduce the DRM so that the market can move through its growing pains and quickly mature. (p.2)	The market has already moved ahead. The DRM is a design conceived for a world where retailers play a key role in managing spot price risk on behalf of customers. The OGW survey indicates that the market has already moved away from this paradigm, and customers are already participating more actively and choosing to manage this risk by themselves. The Commission had found that customers, retailer and network business can already resort to a DSM service competitive market to benefit from demand response should they require that assistance. See OGW's survey report. The market has already moved towards ways of demand side participation that are more effective at integrating renewable intermittent generation in comparison to the DRM. For example, customers exposed to spot prices responding directly to price fluctuations caused by intermittent renewables would shift demand to periods where renewable generation is more abundant (and therefore prices are lower). Under the DRM, while customers are incentivised to curtail load they are not efficiently incentivise to shift load to periods where renewable generation is more abundant and prices are lower.

ASU – Barriers to demand side participation in FCAS markets		
GDF Suez	GDF Suez does not agree that the current market arrangements represent an unreasonable barrier to entry that restricts demand side participation in FCAS markets. Loads that wish to provide FCAS are able to register directly with AEMO as a market load, or enter into a commercial arrangements with an existing market customer (p. 12)	The Commission has found that current arrangements under the NER constitute a barrier to demand side participation in the FCAS markets. (See section 6.1.3)
Stanwell	The current rules already allow for market loads to be classified as ancillary service loads, but it likely that uptake has been minimal for the same reasons as the registration of scheduled loads – that the obligations associated with registration significantly outweigh the potential commercial benefit for most consumers (p. 4.)	The Commission agrees with this point raised. The Commission has also found that current arrangements under the NER constitute a barrier to demand side participation in the FCAS markets. (See section 6.1.3)
Snowy Hydro	There are no genuine barriers to demand side participation in the FCAS markets (p. 7)	The Commission has found that current arrangements under the NER constitute a barrier to demand side participation in the FCAS markets. (See section 6.1.3)
ERM Power	ERM Power notes that demand side participation in the FCAS markets is currently limited to those participants who can meet the technical requirements of the MASS and receive active five minute dispatch instructions from AEMO. (p. 12)	The Commission has found that current arrangements under the NER constitute a barrier to demand side participation in the FCAS markets. (See section 6.1.3)

ASU – Policy issues		
GDF Suez	The more substantial hurdle for FCAS to meet is that they are able to comply with the market ancillary services specification (MASS) which imposes a number of stringent obligations. (p. 12)	The Commission's policy position is that greater competition from FCAS has to be 'competitive neutral'. Therefore, any load offered through ASU will necessarily have to meet the MASS, and other requirements under the NER. (See section 6.3)
Stanwell	Where ancillary services and energy are both offered, these services may be offered by separate participants. It appears likely that AEMO would need to adjust its systems to be to co-optimise the offers received to ensure the lowest cost to consumers while ensuring that response is not double-counted. (p. 4)	The Commission's policy position is that unbundling will not apply to scheduled market loads (See section 6.3.2)
AGL	Whatever mechanism is used to open up the FCAS market should be competitively and technological neutral (p. 3)	The Commission's policy position is that greater competition from FCAS has to be 'competitive neutral'. Therefore, any load offered through ASU will necessarily have to meet the MASS, and other requirements under the NER. (See section 6.3)
Origin	It is important that the load offered must meet the existing technical requirements for providing ancillary services. (p. 4)	The Commission's policy position is that greater competition from FCAS has to be 'competitive neutral'. Therefore, any load offered through ASU will necessarily have to meet the MASS, and other requirements under the NER. (See section 6.3)
EnerNOC Pty Ltd	For large scale provision by aggregations of much smaller facilities to become feasible, a simple, standardised approach is needed. For example, rather than requiring high resolution frequency data to be recorded for each event, some reliance can be placed on type testing before a roll-out of cheaper, simpler devices.	The Commission's policy position is that greater competition from FCAS has to be 'competitive neutral'. Therefore, any load offered through ASU will necessarily have to meet the MASS, and other requirements under the NER. (See section 6.3)
ERM Power	Allowing entry of greater demand response in the provision of FCAS contingency services may result in a reduction in the quality of FCAS contingency services unless the demand side provider has the ability to provide suitable and accurate data to allow reliable audit of actual FCAS response. (p. 12)	The Commission's policy position is that greater competition from FCAS has to be 'competitive neutral'. Therefore, any load offered through ASU will necessarily have to meet the MASS, and other requirements under the NER. (See section 6.3)

ASU - Impact on FCAS markets		
GDF Suez	The ASU proposal, which relies on complex interactions between a demand response aggregator and DRL, will even more complex that the current arrangement framework, which allow a load to offer FCAS more directly through a market customer. Therefore, ASU will not have any positive impact on FCAS liquidity or costs (p. 12)	The Commission considers that enabling a new category of market participant to offer FCAS services, without a requirement to become a market customer in the spot market, would result in greater number and diversity of FCAS suppliers and deliver a more competitive FCAS market. (See section 6.2.3)
Stanwell	Anecdotal evidence from AEMO that registration interest in the provision of FCAS has increased in South Australia following the recent high price events, rather than in response to regulatory intervention. (p. 4)	The Commission considers that enabling a new category of market participant to offer FCAS services, without a requirement to become a market customer in the spot market, would result in greater number and diversity of FCAS suppliers and deliver a more competitive FCAS market. (See section 6.2.3)
Ergon	Entry is more likely into FCAS raise services (fast, slow and delayed) will be most likely. (p. 8)	The Commission considers that enabling a new category of market participant to offer FCAS services, without a requirement to become a market customer in the spot market, would result in greater number and diversity of FCAS suppliers and deliver a more competitive FCAS market. (See section 6.2.3)
Government of South Australia	Increasing competition in the provision of ancillary services through unbundling will provide the market with increased and various suppliers and therefore assist AEMO with its role of ensuring a secure and reliable electricity system. (p. 2)	The Commission considers that enabling a new category of market participant to offer FCAS services, without a requirement to become a market customer in the spot market, would result in greater number and diversity of FCAS suppliers and deliver a more competitive FCAS market. It may also deliver system-wide benefits in terms of greater system security and reliability. (See section 6.2.3).
AEMO	ASU may enable a broader number and new types of frequency control ancillary services (FCAS) providers into the market, potentially expanding competition. This could potentially provide	The Commission considers that enabling a new category of market participant to offer FCAS services, without a requirement to become a market customer in the spot market,

ASU - Impact on FCAS markets		
	improvements in system security and reliability through increased levels of FCAS being offered into the market. (p. 5 and 6)	would result in greater number and diversity of FCAS suppliers and deliver a more competitive FCAS market. It may also deliver system-wide benefits in terms of greater system security and reliability. (See section 6.2.3).

A.2 Summary of issues raised in the submissions to the draft determination

Demand Response Mechanism		
ATA	The Commission's analysis did identify some deficiencies (such as the implications of all demand responses being unscheduled), but missed the opportunity to make a more preferable decision for a modified DRM that addresses them. (p.2)	The Commission's assessment of barriers to demand side participation are outlined in Section 1.3 and Section 2.2.1
ATA	We disagree that there is no evidence of barriers to demand side participation (DSP). The survey conducted by Oakley Greenwood shows that energy retailers have a stranglehold on the DSP market, with even three quarters of third party DSP simply facilitating access to standard or bespoke retailer programs. (p.2-3)	The Commission's assessment of barriers to demand side participation are outlined in Section 1.3 and Section 2.2.1
ATA	Relying on retailers and distributors to gate keep DSP will never be enough to fully realise its potential. The retail business model is predicated on managing the risk inherent in volatile pricing – it will never be worthwhile for retailers to give this up at any material scale. Retailer ownership of generators – that compete directly with DSP – adds to their interest in not encouraging large-scale demand response. Networks have some more rationale for facilitating strategic demand response, especially as other regulatory changes roll out. But network-driven demand response by nature tends to be locationally specific and infrequent. Third party arbitrated DSP can encompass both network- and spot price-driven opportunities, making it more worthwhile for customers and side-stepping retailers holding the keys. (p.3)	The Commission's assessment of barriers to demand side participation are outlined in Section 1.3 and Section 2.2.1
ATA	We agree that scheduled demand response will be more effective at driving efficient pricing in the spot market. The move away from scheduling DR is a deficiency of the revised DRM proposal. To truly put DR on an equal footing with generation – necessary for efficient pricing and technology neutrality – consistency with generation is entirely appropriate. Generators over 30 MW must be scheduled, so DR above 30 MW (whether a single or an aggregated load) should be too. Generators	See the discussion in section 4.3.1. The Commission notes that these issues are currently the subject of a separate rule change request: http://www.aemc.gov.au/Rule-Changes/Non-scheduled-generation-in-central-dispatch.

Demand Response Mechanism		
	below 30 MW need not be scheduled, and neither should DR below 30 MW.	
ATA	The Commissions' analysis of potential market distortions should also be revisited. Some of the problems raised could equally be hypothesised in the current market; others would only arise if the DRM at the same time has a significant effect on the market but no effect on market behaviour. In fact the lack of efficient DR on a level playing field with generation is itself a distortion of the current market – one that can only be remedied with a well-designed DRM.	The Commission's assessment of the benefits of the DRM and potential market distortions are outlined in Chapters 4 and 5.
AusNet	It is unclear whether the establishment of either the DRM or ASU rule change proposals would be beneficial or detrimental to network businesses in leveraging demand response arrangements. We expect customers with demand response resources will target the most valuable demand response payments, which may be in the FCAS markets, wholesale market or from network service providers. As a result of these alternative markets, the availability of demand response for the networks when required may become less certain. (p.1)	The Commission's assessment of barriers to demand side participation are outlined in Section 1.3 and Section 2.2.1
Department of State Development (DSD)	In an event that renewable generation is not providing sufficient supply, a demand response mechanism will facilitate the reduction in market demand in order to facilitate a balance in the market (p.1)	The Commission notes that the DRM was not designed to address issues relating to renewable energy penetration. Consequently the DRM's ability to respond to events that drive the variance in the generation levels of renewable energy generators is not existent. To the extent that renewable energy generators' varying generation levels within a dispatch interval necessitates FCAS, this increased requirement for FCAS services will manifest itself in the dispatch system without the implementation of the DRM. The ancillary service unbundling provided for in the final rule may address such increased demand.
Department of State	Concerned with the finding that demand response can and is already happening in the market. This conclusion is based on surveying of	The Commission notes the distinction made between barriers that exists due to commercial complexities and difficulties and

Demand Response Mechanism		
Development (DSD)	retailers and without seeking the views of customers. The analysis by AEMC is therefore flawed to the extent that it does not consider the views of electricity consumers. (p.1)	barriers that may be located in the Rules. The Commission also notes the example provided by the DSD of a customer unable to access demand response (SA Water). The Commissions further investigations regarding SA Water are set out in (section 3.3.2. The Commission notes SA Water is a textbook example of the type of arrangement where customers negotiate a spot-price pass through contract with their retailer and thus essentially 'unbundle' their demand response capabilities from their retail contract
Department of State Development (DSD)	Unless there is a benefit to the retailer from reducing demand at a given time, a retailer will not activate customer's curtailment even if it would benefit the customer. The retailers' objectives are not always aligned with maximising demand response at times of high market price and volatility. (p.2)	The Commission's assessment of barriers to demand side participation is outlined in Section 1.3 and Section 2.2.1. Retailers' (and gentailers') incentives to carry out demand response are discussed in section 3.3.5.
Department of State Development (SA)	AEMC needs to conduct a targeted customer consultation to establish whether demand response can readily be accessed by customers and whether demand response is not only activated when it benefits the retailers. (p.2)	The Commission, as part of the OGW survey and through its own investigations, consulted with a wide range of customers, as detailed in chapter 2. Further investigations in relation to SA Water are set out in section 3.3.2. The Commission found no evidence of customers who were unable to access demand response arrangements of their choosing. While the Commission acknowledges that there are currently commercial barriers for some consumers in accessing demand response, the Commission does not consider that implementing a market wide mechanism, at considerable cost to the consumer, will not necessarily address such barriers, not are the Rules the appropriate vehicle for addressing them
Embertec	Embertec strongly supports the introduction of a Demand Response Mechanism (DRM) in the NEM including the introduction of a new class of	The Commission's assessment of barriers to demand side

Demand Response Mechanism		
	market participant; empowering AEMO with discretion on the implementation of an appropriate and standardised baseline calculation methodology (BCM) to apply to a demand response events; and to have DR capacity settled and paid (or penalised for under delivery) at the prevailing spot price. (p. 1)	participation is outlined in Section 1.3 and Section 2.2.1.
Embertec	The Commission has taken an extremely narrow view of the potential benefits of a DRM mechanism. The Commission's response to the rule change request is limited to citing the experience of very large customers, who are capable of dealing with retailers, or indeed the NEM, entirely on their own. (p.1)	The Commission's assessment of barriers to demand side participation is outlined in Section 1.3 and Section 2.2.1. The Commission notes that the proposed DRM was limited to large customer involvement so consideration of small customer demand side participation options was beyond the scope of the rule change request If there are any benefits to the market from demand response this does not arise from the individual size of customers that carry out demand response but rather from the aggregate MW value of demand response that occurs under certain conditions. While the Commission recognises that there may be commercial reasons complicating and complexities in carrying out demand response, and these may be more acute for small customers, the Commission was unable to identify any barriers in the Rules that would prevent demand response from taking place in the wholesale market
Snowy Hydro	Snowy Hydro strongly believes that the DRM was a complex solution looking for a problem that simply does not exist. The DRM was unjustified, distorts the current market design where both the supply and demand side have clear pricing signals/incentives to either produce or to consume energy, would impose significant implementation costs, distort the contract/financial markets and benefit a small group of large consumers at the expense of a much broader group of consumers. (p.3)	Noted.

Demand Response Mechanism		
Energy Australia	The wholesale market context is important when assessing the current level and potential for DR. The frequency of extreme price events – and their duration and predictability – and overall level of prices was relatively low when the Commission commenced its consultation. This may explain the concerns of some stakeholders about the observed level of DR at that time and their support for the DRM. Competition creates strong incentives for retailers to explore DR options with their customers and for customers to seek out retailers and other market participants who can satisfy their requirements or offer advice about the optimal form of DR for their business. Furthermore, we see few obstacles to customers switching retailers if their current retailer is not willing to consider an arrangement that satisfies their requirements, including DR arrangements that are tailored to their business. (p.1-2)	The Commission's assessment of barriers to demand side participation are outlined in Section 1.3 and Section 2.2.1
Energy Australia	Regulatory developments following on from the Power of Choice review (such cost reflective network tariffs, competition in metering, and customer access to data) will complement the competitive market, enabling more customers to better manage their energy consumption and to receive a commensurate benefit. (p.2)	The Commission's assessment of barriers to demand side participation are outlined in Section 1.3 and Section 2.2.1
EnerNOC	EnerNOC disagrees with the Commission's assertions that the current market structure is bringing sufficient demand response ("DR") to market, that consumers have sufficient options in monetising their DR flexibility, and that a consumer's DR options are sufficiently "unbundled" from their relationship with their electricity supplier. (p. 1)	The Commission has not made assertions that the available demand response is sufficient, noting that in the absence of any Rules based barriers to demand response, the market will decide efficient levels of demand response It is not for the Commission to decide what is a sufficient level of demand response. The Commission acknowledges there may be commercial complexities in demand response contracts and notes that it has not found any barriers in the Rules that would prevent demand response from taking place in the wholesale market In relation to unbundling consumers' relationship with electricity retailers please see section 3.3.

Demand Response Mechanism		
EnerNOC	The Commission has drawn several incorrect conclusions from the Oakley Greenwood report – to us, this report depicts a NEM in which only the largest, most sophisticated industrial consumers are able to bring their DR flexibility to market, with other consumers remaining disengaged and inelastic. (p. 1)	In relation to any potential benefit that may arise from demand response, it is the overall size of demand response that matters and not the number of customers. That is, a single large customer of 100MW may deliver the same level of demand response as an aggregation of a large number of small customers (e.g. 100 small 1MW customers). When considering potential benefits of demand response the two are indistinguishable.
EnerNOC	The Commission has erred in concluding that the DRM would not result in lower prices for customers, and has inaccurately represented market distortions that may arise from the DRM. (p. 1)	The short term wholesale market outcomes are difficult to assess and would be uncertain. Demand response may, under certain circumstances, have the potential to decrease dispatch prices. Given the continued need to provide hedging by retailers under the DRM, it is uncertain how much of the price decrease would be passed onto consumers. Market distortions are discussed in chapter 5.
EnerNOC	In the initial design it was envisaged that DR would be dispatched by the market operator as part of the same merit order as generation resources. Further, the same compliance mechanisms would apply to the DRA as apply to other scheduled resources if they were unable to deliver the volume of DR dispatched. In general, DR would directly compete with scheduled generation; EnerNOC supported this initial design of the DRM, and we still do today. (p.2)	Noted. The proposed DRM did not contain scheduling as part of its design.
EnerNOC	There are few opportunities for consumers to respond to scarcity pricing, and those opportunities almost always have to be accessed through a retailer (i.e. are “bundled” with retail supply), who may not be interested in offering customers access to DR options and programs. Retail competition simply is not sufficiently near perfect (in this, or any other electricity market) to ensure that major retailers – especially vertically-	Retailers have several options of which pursuing demand response is not necessarily the most efficient one. Retail competition has the potential to create incentives for retailers to seek out options that are beneficial and lowest cost for all customers.

Demand Response Mechanism		
	integrated ones – offer meaningful rewards for customer flexibility.	Please see further discussion in section 3.3.
EnerNOC	The purpose of DR is to serve as an alternative to, and to compete with, the provision of additional generation to meet demand. By competing with generation, DR can reduce the cost of the entire system. In an efficient market: Where the spot price exceeds the cost of the supply side increasing supply, the supply side responds by increasing the supply to the market; and where the spot price exceeds the value the customer derives from consuming electricity, the demand side should equally be able to respond by reducing demand.	Because demand response under the proposed DRM would not be scheduled through central dispatch, it cannot compete directly with scheduled generation. It therefore does not serve as an alternative. Demand is already equivalent to non-scheduled generation. For example, just like non-scheduled generation, loads are not required to indicate to AEMO their generation or consumption intentions prior to dispatch. Currently very similar obligations are placed on non-scheduled generating units and loads.
EnerNOC	EnerNOC is very concerned that the Draft Decision is silent on the merits of increasing levels of DR participation in the energy market. Even if the Commission is fundamentally not supportive of the design of the DRM proposed to it by COAG, EnerNOC believes it is critical for the Commission to express a view to the market as to the benefits of DR as a competitor to generation and as a mechanism to determine or impact spot prices. For example, if the Commission considers that it is impossible for a DR to drive efficient market outcomes without being a scheduled resource that participates in central dispatch, we believe the Commission should provide such guidance.	The Commission recognises that demand response that is efficient, can deliver benefits to some market participants. The Commission has expressed its views on the design of the DRM that was presented to in the rule change request and has assessed the benefits and costs arising from the implementation of the proposed DRM. The Commission remains open to assessing alternative designs that the stakeholders consider may lead to improvements while satisfying the NEO and remaining consistent with the market design principles on which the NEM is based.
EnerNOC	The OGW Survey Report confirms EnerNOC's view of the current DR landscape in the NEM: Only "very large" loads are participating in DR, and most of this consists of spot price exposure arrangements which may not involve much, if any, actual responsiveness to real-time prices. There is no DR happening in a transparent fashion that adds information to the market, there is very little "dispatchable" DR happening, and very little mass-market DR happening. In our view the status quo is a failure. Just because a load is spot exposed does not mean it is able to, willing	In the NEM the spot exposure is the strongest form of incentive to carry out demand response. While the market price cap sets limits to these incentives, it is otherwise up to customers to decide how they may wish to respond to prices. The Commission has no reason to assume that consumers' consumption levels with spot price exposure would not be efficient for the customer even if it does not involve demand response.

Demand Response Mechanism		
	to, or does react to high spot prices with any regularity or certainty. Simply put, spot exposure is not the same as DR.	
EnerNOC	The decision to accept spot exposure is not one a consumer can take lightly, and would typically need to be approved at the board level, as the financial risks can be large relative to the size of the business. Outside of the "very large" industrial segment, most consumers can't afford to, or don't have the bandwidth to administer, or don't have the risk appetite to participate in the electricity market via any mechanism other than a fully hedged retail contract. This is why a DRM is important: it will allow DR specialists to unlock the value of DR for consumers of all sizes, despite the consumer's preference for a fully hedged retail contract, whilst their retailer remains unaffected by (and no worse off as a result of) the consumer's DR participation. Importantly, the proposed DRM is truly "unbundled" in that it would allow a consumer to invest in DR technology and processes, and retain that capability each time they change retailers in pursuit of the most competitive retail energy contract.	There is a demand side management industry that is evolving and it is now providing a range of services to reduce these costs. The Commission considers the level of competition depicted in the OGW report indicative of a competitive DSM service market. In relation to the distortionary impact on retail market, the Commission does not necessarily accept that retailers are "not worse off". For an analysis of the potential retail market distortions, please see section 5.3. The Commission also notes that the proposed DRM was limited to large customer involvement so consideration of smaller customer demand side participation options was beyond the scope of the rule change request
EnerNOC	The Draft Determination concludes that "The DRM would not result in overall savings to consumers through lower electricity prices", and cites four specific factors. EnerNOC believes the Commission has drawn incorrect conclusions in four cases: "Under the DRM, spot prices will not reflect competition from demand response" "The DRM requires costly changes to the wholesale market and retailer systems " All changes to markets have associated "The DRM will not necessarily alleviate network constraints and defer network expenditure" "The DRM can have unintended consequences and create distortions in the spot market and other related markets"	The Commission's assessment of barriers to demand side participation are outlined in Section 1.3 and Section 2.2.1 The Commission considered the points raised by EnerNOC and refers to sections 4.3 and 5.3 in respect of these issues.

Demand Response Mechanism		
EnerNOC	DRAs are not going to engage in baseline gaming, as the costs far outweigh the potential benefits, it's difficult to do, the good faith provisions clearly prohibit it, and the risk of reputational damage is simply too great. EnerNOC is disappointed that the Commission has not acknowledged these stakeholder perspectives in the Draft Determination, and request that they be addressed in the Final Determination.	Noted, The Commission refers to section 5.3.

Ancillary Services Unbundling		
AEMO	A MASP should be able to i) identify units of load under its ownership, operation or control, ii) demonstrate that the load has the requisite assets and equipment, and iii) that the load can meet relevant performance standards and specifications, in each case to AEMO's satisfaction. To that end, AEMO considers that the generator eligibility criteria, Section 2.2.1(e) of the National Electricity Rules (the "Rules") rather than the customer eligibility criteria (Section 2.3.1 (b) of the Rules upon which Proposed Rule 2.3AA is based) are a more appropriate model in setting eligibility criteria for the MASP classification	Noted.
AEMO	Appropriate transitional arrangements will need to be put into place to allow AEMO to establish appropriate registration fees without reopening AEMO's current fee structure determination. AEMO recommends that the transitional rules be drafted to allow AEMO to charge registration fee to the new participants without needing to reopen AEMO's current fee structure determination. The amount of the registration fee would be set by AEMO as part of its annual budget (as the current fee structure allows). (p.2)	Agreed. The Commission refers to section 6.3.
AEMO	AEMO notes that the MASP would be ineligible to offer regulation ancillary services under the current market ancillary services	Noted, The Commission recommends a review of the MASS.

Ancillary Services Unbundling		
	specification, and only be eligible for contingency ancillary services. The MASS (under section 1.3) does not accommodate aggregated dispatch for the purposes of regulating raise service or regulating lower service. As such, a MASP (or indeed Market Customers and Small Generation Aggregators) is currently ineligible to offer FCAS regulation services.	
AEMO	For clarification, our interpretation of the Proposed Rule is that once registered, a MASP must seek AEMO approval to designate each market load to provide ancillary services. Any additional load acquired or aggregated by the MASP will then require the further approval of AEMO.	Agreed.
AEMO	From a technical perspective, FCAS is not currently able to be provided across regions, and therefore bid and offer aggregation guidelines (under Clause 3.8.3) should require that a MASP seeking to aggregate multiple market loads to treat them as one ancillary service load must ensure all such loads are located within the same NEM region.	Noted. The Commission recommends a review of the MASS.
AGL	A key issue will be modifying (as appropriate) the accepted means by which would-be providers of FCAS are able to participate in central dispatch. Currently, AEMO requires all providers to conform to the Automatic Generation Control System (AGCS). Such a system is impractical and costly for an aggregation of load from Distributed Energy Resources (DER) to comply with. This creates an effective barrier to entry for DER participation in FCAS markets. This issue exists even without the current rule change. Conformance to the AGCS has already emerged as potential barrier to, for example, Virtual power Plant (VPP) applications. There are other technological means available to facilitate DER participation in a centrally dispatched market (e.g. frequency sensing devices installed either within the inverter or meter, advanced software platforms). AGL considers it very important to the success of this new rule to explore alternative means for accommodating DER in central dispatch. (p. 2)	Agreed. The Commission recommends a review of the MASS.

Ancillary Services Unbundling		
AusNet	Network businesses have little visibility of retailer initiated DR arrangements. Any new market role established to provide market ancillary service must be identified at the NMI level and network businesses would need to model the predicted demand response behaviour based on historical data. (p.2)	The Commission's assessment in relation to this issue is contained in Section 6.2.3.
AusNet	NSPs should have the ability to access cost effective services, and the mechanisms for this would need to be clarified, including whether NSPs may operate as market ancillary service providers.	The Commission's assessment in relation to this issue is contained in Section 6.2.3.
AusNet	The emergence of market ancillary service providers presents potential operational risk for the networks. Where demand response arrangements are geographically concentrated, synchronised switching (i.e. simultaneous aggregated load switching) may lead to network implications. In the short term, this is not likely to be material enough to adversely affect networks, but over-time it is likely to grow to the point where they cause voltage disturbance issues and adversely impact network reliability. This will necessitate the need to establishment of a Load Management Protocol (or agreements with market ancillary service providers). Unlike invertors that switch off when the voltage spikes, rapid switching by market ancillary service provider is unaffected by voltage spikes, leading to network tripping. Once the network is disrupted those market ancillary service providers can no longer participate in the ancillary service market. Therefore, the establishment of a Load Management Protocol to prevent synchronised ancillary service switching from interrupting the network would be required. In such circumstances, network businesses should not be liable for the market ancillary service providers lost opportunity costs in the event of a network outage. (p.2)	The Commission's assessment in relation to this issue is contained in Section 6.2.3.
Australian Energy Council	Australia's energy market is transforming and consumer choice is driving this evolution. Energy market reform, innovation in technology and service delivery have made it easier for business and households to change the way they use electricity. In this time of structural change, we welcome the AEMC's finding to allow existing market structures and	The Commission's assessment in relation to this issue is contained in Section 6.2.3.

Ancillary Services Unbundling		
	consumer choice to shape the most efficient outcome for consumers by changing the rules to enhance competition in ancillary services. This is especially important as the structural changes which are underway are likely to lead to a larger portion of the value in the market being involved in ancillary services. (p.1)	
Energex	Synchronised demand response switching may have adverse impact on system stability and reliability. Therefore, the final rule should include recommendations for 1) AEMO to consult with NSPs prior to approving applications for aggregated loads 2) the development of an appropriate load management protocol and/or switching agreements with MASPs. (p.1)	The Commission's assessment in relation to this issue is contained in Section 6.2.3.
ENA	It should be noted that most Network Service Providers switch network loads and distributed energy resources (DER) as part of their Demand Side Management programs. In this case the switching is controlled by the Network Service Provider and the performance of the network is pre-determined and predictable. However, when either loads or DER are switched to provide ancillary services or demand response in response to price, this can have implications for network management. Specifically, the performance of the network is not predictable and cannot easily be controlled by the Network Service Provider. AEMO does not have power system performance obligations at the distribution level. Power system performance on the distribution network must be managed by the Network Service Providers. (p.1)	The Commission's assessment in relation to this issue is contained in Section 6.2.3.
ENA	If a Market Ancillary Service Provider aggregates a large number of small loads or DER over a wide area, sudden switching of the aggregated load is unlikely to have a significant effect on the network. However, if the load or DER to be switched is concentrated into a small area e.g. on a single distribution feeder, in addition to possibly significant transient effects, a sudden longer term change in voltage may result. Operation of on-load tap changers on the transformers at substations may be able to compensate for the change in voltage, but this may take several minutes.	The Commission's assessment in relation to this issue is contained in Section 6.2.3.

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	Furthermore, when the load or DER is no longer required for FCAS purposes, and is switched again, further changes in voltages may occur, and again take minutes to correct. Australian Standards exist which nominate the acceptable voltage range at customers' terminals. If switching of large single or aggregated loads results in network voltages that do not comply with the Australian Standards, network rearrangement or augmentation may be required to alleviate further problems. Unless this can be avoided, the costs for these necessary network augmentations would ultimately be passed onto customers. For these reasons, the ENA believes affected Network Service Providers should be consulted prior to the acceptance of any distribution connected load or DER being approved for inclusion in the Ancillary Services Market. (p.2)	
ENA	If load that is normally off, or DER that is normally on, is scheduled to provide a FCAS Lower Response, it may be suddenly switched. For instance, an aggregation of off peak water heaters (traditionally switched off during the day) would be an example of such a load. If the network is already heavily loaded in that area, overloading of that section of the network may result. In extreme cases, this could lead to interruptions to customers. This situation is exacerbated if the network is switched abnormally to facilitate maintenance or under emergency condition. Any load that is normally switched on could be scheduled to provide a FCAS Raise Response. There will generally be some diversity amongst the aggregation of these loads. However, if the aggregated load is switched off, the diversity may be lost when the loads are switched back on. This could lead to a peak in demand and overloading of some heavily loaded section of the network. Unless these situations can be avoided, network augmentation in some areas may be required. (p.2-3)	The Commission's assessment in relation to this issue is contained in Section 6.2.3.
ENA	A number of Network Service Providers already have agreements in place with customers to control appliances with discretionary loads, or to engage DER, at certain times in exchange for payment or lower price tariffs. Such programs are widespread and can be used to manage	The Commission's assessment in relation to this issue is contained in Section 6.2.3.

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	demand in parts of the network. In many cases these demand management programs have avoided the costs associated with augmenting the network. It is noted that the Demand Management Incentive Scheme and Demand Management Incentive Allowance exist to encourage Network Service Providers to implement demand management solutions in lieu of network augmentation. Demand management programs include programs which switch off, or change the temperature settings of discretionary appliances at times of peak load to avoid network augmentation. If loads switched on (or DERs switched off), to meet a FCAS Lower Response are supplied from sections of the network that are utilising demand management to manage local network peaks, overloading of the network may occur; as the switching on of some network loads by the Market Ancillary Service provider will counteract the Network Service Provider's demand management activities (i.e. switching off of loads to manage the network peaks). Similarly, loads switched off (or DER switched on) to meet a FCAS Raise Response may, due to loss of diversity, also cause a later increase in maximum demand in some parts of the network (refer to Point 2), counteracting demand management activities. Furthermore, any FCAS Solution that is coincident with a networks demand management solution may exacerbate the power quality issues described in point 1. (p.3)	
ENA	The issues will only occur if large participants, or a large aggregation of participants are switched in certain parts of the network. Although this scenario is unlikely in the short term, in the longer term it is possible that Market Ancillary Services Provider may be able to offer a significant proportion of the load in an area, potentially resulting in the problems described above. Paragraph 6.3.3 (b) of the Draft Rule Determination indicates that in accordance with Rules Clause 3.8.3(b1) AEMO would have to approve any application for an aggregated load, and would need to be satisfied that "power system security is not materially affected by the proposed	The Commission's assessment in relation to this issue is contained in Section 6.2.3.

Ancillary Services Unbundling		
	aggregation." ENA is recommending that the final rule ensures that Network Service Providers are also consulted prior to approval of loads, DER, or an aggregation of loads and/or DER, to ensure that switching to provide an FCAS response will not adversely affect the network. Furthermore, ENA would recommend that a Load Management Protocol (or agreements with Market Ancillary Service Providers) be established to ensure proposed switching does not adversely affect the network. p.3-4)	
Energy Australia	We do not see significant market obstacles to customers offering their load to FCAS markets but rather, view the current level as a function of regulatory and technical requirements. The proposed rule does not address these issues so we expect an expansion in FCAS attributable to the proposal will be small and therefore, any incremental benefits may not outweigh implementation costs. More fundamentally, the evolution of the NEM – through the diversification of energy sources and the decentralisation of generation, for example – and recent events in South Australia confirm the need for policymakers and regulators to reassess the incentives for market participants to provide the complete range of support services (through DR of some other mechanism). This might be through the creation of an inertia market, alignment of settlement and dispatch, or more fundamental changes to wholesale market design. The proposed rule change might be redundant in this context. (p.2)	Agreed. The Commission recommends a review of the MASS.
Ergon Energy	Consider the likely network impacts and the DNSPs ability to comply with the regulatory obligations for the managements of its networks. (p.1)	The Commission's assessment in relation to this issue is contained in Section 6.2.3.
Ergon Energy	Distribution network's ability to absorb large changes in load and generation without impact on power quality and reliability is very dependent on network construction, topology, location, existing controlled generation and load; with the impacts of these especially noticeable in radial network such as Ergon Energy's. Step changes of several megawatts, for example, may trigger protection devices and cause outages. Such potential network impact scenarios exist for any controllable device that could be included in a demand management or	The Commission's assessment in relation to this issue is contained in Section 6.2.3.

Ancillary Services Unbundling		
	ancillary service aggregation initiative such as hot water systems, pool pumps or air-conditioners.	
Ergon Energy	While there is no immediate network risk due to low volumes of small scale aggregated demand response, medium or long term risks exist. It will be essential that DNSPs are provided visibility of the level of load under control (such as a NMI and controllable demand).	The Commission's assessment in relation to this issue is contained in Section 6.2.3.
ERM Power	The decision to allow for ancillary services unbundling may benefit the market through a slight reduction in the cost of frequency control ancillary services (FCAS) contingency raise services. ERM Power welcomes the Commission's draft decision requiring demand response aggregators participating in ancillary services markets to meet AEMO's Market Ancillary Services Specification (MASS). Further to this, we believe that the MASS should remain technology neutral to ensure that all technologies providing FCAS can compete on an even basis. (p.2)	The Commission's assessment in relation to this issue is contained in Section 6.2.3.
Snowy Hydro	The Ancillary Service Unbundling proposal may appear in theory to be beneficial but Snowy Hydro is concerned that the economic benefits are unlikely to exceed the costs of the Rule change. (p.2)	
Snowy Hydro	There needs to be a requirement for the Market Ancillary Service Provider to inform the Market Customer (i.e. Retailer) that it has an arrangement in place for the provision of ancillary services from the Customer. The information given to the Market Customer must include at a minimum, the quantity and type of the ancillary service contracted and the duration of the contract. In the absence of this requirement, the Market Customer is in a difficult position whereby the actions of the Market Ancillary Service Provider may undermine its financial hedging position. This can arise because the ancillary services offered to the market by the Market Ancillary Service Provider may affect the energy consumed by the Customer thereby creating an imbalance in the Market Customer's hedging volumes. This imbalance creates financial risks and uncertainty for the Market Customer which would ultimately be factored into	The Commission's assessment in relation to this issue is contained in Section 6.2.3.

Ancillary Services Unbundling		
	increased risk premiums to manage the consumption profile of the Customer. (p. 2-3)	
Stanwell	While the Ancillary Service Unbundling (ASU) proposal appears theoretically beneficial, Stanwell remains concerned that the practical benefits are unlikely to exceed the costs of the reform. Barriers to entry exist in relation to market ancillary services these are related to the requirements to comply with the market ancillary services specification, the Rules obligations imposed on market participants and the limited revenue available in these markets. (p.2)	Partially agreed. The Commission recommends a review of the MASS.
Stanwell	Stanwell seeks clarification that unbundling will not apply to scheduled loads, thereby avoiding the co-optimisation issues highlighted in Stanwell's previous submission. However where an ancillary service load is not a scheduled load, there appears an unresolved issue in relation to dispatch targets and enablement trapeziums – that is, what comfort does AEMO have that unregulated energy market activity will not adversely impact the enablement targets being set? The obligation for scheduled load to follow energy market dispatch instructions does not appear to have a parallel in respect of non-scheduled ancillary service loads. (p.2)	The final rule will not apply to scheduled load. The Commission understands from AEMO there have been many examples of non-scheduled loads providing FCAS Obligations regarding dispatch targets fall on the provider to make sure it can deliver its offer at all times, regardless of whether the enablement trapezium is available to the provider. I
Stanwell	Stanwell also welcomes the explicit inclusion of a requirement on AEMO to confirm that a proposal to register a market load as an ancillary service load is performed with the consent of the relevant customer. (p.2)	Agreed.
Stanwell	Clarify inconsistencies in the draft Rule – or drafting relics in related clauses. For example cl3.8.4 requires the notification of available capacity in relation to scheduled loads but does not refer to ancillary service loads. However the definition of available capacity refers to dispatch, and the definition of dispatch refers to ancillary service loads, so it is unclear whether ancillary service loads are covered, are covered only where they are also a scheduled load, or are not covered. Stanwell would expect that the obligations on participants in relation to providing information to PASA, pre-dispatch and dispatch would be technology and registration	The Commission notes that the issues raised by Stanwell do not relate to inconsistencies in drafting of the final rule but relate to existing clauses. The Commission notes that clause 3.8.4 applies to scheduled generating units, network services and loads. It does not apply to ancillary *service loads* unless they are classified as scheduled loads by Market Customers (which in practicality, does not take place).

Ancillary Services Unbundling		
	class neutral. Also, cl4.9.3A refers to “a Market Participant which has classified one or more of its generating units or market loads as an ancillary service generating unit or an ancillary service load”, which is inconsistent with the anonymization of market loads under draft cl2.3AA and 2.3.5. (p.2)	As far as requiring technology neutral obligations in relation to the PASA, market participants providing ancillary service loads are not required to provide information for the PASA in any event. Should Stanwell have concerns in relation to inconsistencies in existing drafting in the Rules, the Commission encourages Stanwell to lodge a rule change request specifying requested changes it considers may be necessary.
EnerNOC	Interruptible loads add value in that they can react very quickly to frequency deviations – much faster than the majority of the thermal plant currently offering into the raise6sec FCAS market (also known as the “Fast Raise” market). In a future NEM with lower inertia and higher Rate of Change of Frequency (RoCoF), a demand-side load that provides its full FCAS capability in less than one second will provide more benefit to the grid than a thermal plant that ramps linearly to its FCAS quantity over 6 seconds, and this could be recognised through the development of faster FCAS products. As such, ASU should allow this positive side benefit to be realised.	Noted.

B Legal requirements under the NEL

This Annex sets out the relevant legal requirements under the NEL for the AEMC to make this draft rule determination.

B.1 Draft rule determination

In accordance with section102 and 103 of the NEL the Commission has made this rule determination in relation to the rule proposed by the COAG Energy Council.

The Commission's reasons for making this rule determination are set out in section 2.3

A copy of the final rule is attached to and published with this final rule determination. Its key features are described in section 2.3.

B.2 Power to make the rule

The Commission is satisfied that the final rule, which is a more preferable rule, falls within the subject matter about which the Commission may make rules. The final rule falls within section 34 of the NEL as it relates to the operation of the national electricity market and the activities of person (including registered participants) participating in the national electricity market.

B.3 Commission's considerations

In assessing the rule change request the Commission considered:

- the Commission's powers under the NEL to make the rule;
- the rule change request;
- submissions received during first and second rounds consultations and discussions with stakeholders in relation to current demand side participation activity and arrangements;
- interactions with other relevant rule changes and review recommendations;
- the AEMC's Power of Choice review final report;
- the Commission's analysis as to the ways in which the proposed rule will or is likely to, contribute to the NEO.

There is no relevant Ministerial Council on Energy (MCE) Statement of Policy Principles.[261]

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 Australian Energy Market Operator (AEMO)'s declared network

261 Under section 33 of the NEL 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.

functions.[262] The final rule is compatible with AEMO's declared network functions because it is unrelated to, and does not affect the performance of AEMO's declared network functions.

B.4 Application of the final rule in the Northern Territory and modified rule making tests

From 1 July 2016, the National Electricity Rules (NER),[263] as amended from time to time, apply in the Northern Territory (NT), subject to derogations set out in Regulations made under the NT legislation adopting the NEL.[264] Under those Regulations, only certain parts of the NER have been adopted in the NT. The final rule amends chapter 2, 3, 10 and 11 of the NER. Chapters 2 and 3 do not currently apply in the NT. Chapters 10 and 11 apply in the NT but the changes made to those chapters under the final rule will have no practical effect in the NT as they relate to Market Ancillary Service Providers, a participant type that will not exist in the Northern Territory. For this reason, the Commission has:

- for the purposes of applying the rule making test under section 88 of the National Electricity (NT) Law[265], regarded the reference in the NEO to the national electricity system as a reference to the national electricity system as defined in the National Electricity Law; and
- for the purposes of section 88A of the National Electricity (NT) Law[266] made a uniform rule.

B.5 Civil penalties

The Commission's final rule amends clauses 2.3.5(g)(4), 2.3.5(h) and 3.8.20(g) of the NER. These clauses are currently classified as civil penalty provisions under Schedule 1 of the *National Electricity (South Australia) Regulations*.

The Commission considers that the above-mentioned clauses 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.

The Commission does not consider any other provisions of final rule should be classified as civil penalty provisions.

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262 See section 91(8) of the NEL

263 Details about parts of the NER adopted by the Northern Territory can be found on the AEMC's website at: http://www.aemc.gov.au/Energy-Rules/National-electricity-rules/Rules-(NT)/National-Electricity-Rules-(NT)-Version-1.

264 National Electricity (Northern Territory) (National Uniform Legislation) (Modifications) Regulations.

265 The Natrional Electricity Law as modified by the *National Electricity (Northern Territory) (National Uniform Legislation) Act 2015.*

266 The Natrional Electricity Law as modified by the *National Electricity (Northern Territory) (National Uniform Legislation) Act 2015.*

B.6 Conduct provisions

The Commission's final rule does not amend any clauses that are currently classified as conduct provisions under the NEL or National Electricity (South Australia) Regulations.

C Demand response mechanism – AEMO’s detailed design

The following annex describes the key features of the proposed DRM as set out in AEMO's detailed design document[267] included in the COAG Energy Council's rule change request. So that the specific design features are accurately captured, the important elements of the description and the terminology used by AEMO in its detailed design are retained.

C.1 Demand response aggregator

The proposed rule would create a new class of market participant, a demand response aggregator:

- Any existing market participant and new specialist aggregators would be able to register as a demand response aggregator;
- A demand response aggregator would be able to make commercial arrangements with parties who have demand response loads (DRL) to reduce their energy consumption during demand response events;
- A demand response aggregator could self-schedule demand response events via the DRM and be paid at the relevant regional spot price for this response;
- Only market participants registered as demand response aggregators would be able to nominate demand response events via the DRM.

C.2 Demand response load

A demand response load (DRL) would be an end user that provides demand response to a demand response aggregator:

- DRLs would not directly participate in the wholesale spot market but rather through contractual arrangements with demand response aggregators;
- Demand response could be provided by, for example, shutting down industrial processes for a period of time or through energy conservation measures;
- Demand response energy provided by a DRL would be associated with a single national metering identifier (NMI) with all calculations of demand response energy performed with respect to that particular NMI.

Participation in the DRM would only apply to loads that have been accredited and classified with AEMO as demand response loads (DRLs). There would be further eligibility requirements for DRLs. These include that the load would be:

- large (consumption typically over 100 MWh per annum);
- measured at the level of individual NMIs;
- measured with metering installation type 1, 2, 3 or 4, which can provide half hourly daily settlement data; and

267 AEMO, Annex B: Demand response Mechanism and Ancillary Services Unbundling - Detailed Design, AEMO, 15 November 2013.

- predictable within an acceptable tolerance with the methods used to calculate baseline energy.

There would also be restrictions on how demand response could be sold to the market. For example, a demand response aggregator could not take on the role of demand response aggregator

- if the end user has generation measured at that NMI which was sold as generation to the NEM;
- if the end user at that load is classified as a scheduled load by a retailer or an ancillary service load by a retailer or another demand response aggregator; and

It will be the responsibility of the demand response aggregator to establish compliance of its DRL customers with all relevant restrictions and to ensure that the DRL is able to comply with any relevant demand response notification at all times.

C.3 Payments and energy settlements in the DRM

The demand response aggregator would self-schedule demand response in the DRM, and would be paid the trading price (half hour wholesale energy spot price) in the region for the demand response energy. AEMO would determine the demand response energy provided based on the difference between baseline energy - what demand would have been for the NMI without demand response - and the actual metered load of the NMI. However, the demand response aggregator would also be charged at the half hour regional wholesale energy spot price if actual energy consumption exceeds the baseline energy during the demand response event.

During the demand response event, the retailer for the NMI would be settled based on the baseline energy and would be allowed to charge the end user as if it had consumed the baseline energy. As stipulated in their commercial arrangements, the demand response aggregator would share the payments received in the NEM with the customer.

The demand response aggregator would have financial responsibilities associated with this role. However it is not proposed that the demand response aggregator would be treated as a Financially Responsible Market Participant (FRMP) as currently defined in the Rules. The demand response aggregator would be financially accountable in relation to the demand response energy during demand response events, while the FRMP would remain financially responsible for the sum of the metered energy (outside of demand response events) and demand response (baseline) energy (during demand response events).

C.4 Demand response notification to AEMO

Any time the demand response aggregator self-schedules a demand response, it would be required to submit a Demand Response Notification (DRN) to AEMO. When AEMO receives a DRN it would publish it, as soon as possible, through the wholesale Electricity Market Management System (EMMS) and its website as public notification. The notification would contain the following information:

- The demand response start date and trading interval;

- The demand response end date and trading interval;
- The region; and
- The list of NMIs providing demand response and the transmission node identity (TNI).

Procedural requirements relating to valid notifications submitted by demand response aggregators would include:

- That the start of the demand response event would be no earlier than the start of the trading interval during which AEMO received a notification and no later than 24hrs after the submission time of the notification. If a demand interval crosses multiple intervals, up to the maximum of consecutive 24 hours, then the notification would be first provided before the end of the first affected trading interval;
- A demand response aggregator would be able to provide, change or cancel a notification at any time up to the end of an affected demand response interval; and
- Changes to the expected duration of the demand response interval would have to be submitted before the end of the last trading interval included in both the original and revised notification.

C.5 Accredited baseline consumption methodologies

Initially, AEMO would develop and accredit two baseline consumption methodologies (BCM), one relating to the baseline when the demand response occurs on a weekday and another baseline when it occurs during a weekend or public holiday.

BCMs could be specified by a range of components including the baseline window, the exclusion rules, the baseline calculation type, the baseline adjustment, and the adjustment window. These components would be compiled using simple mathematics and data drawn from recent qualifying days:

- **Baseline window:** This would be the period of time preceding a demand response event from which meter data would be used for the purpose of establishing a baseline. Examples of baseline windows include the last 45 calendar days or the last 10 non-holiday weekdays;
- **Exclusion rules:** These are the rules for excluding data from the baseline window. For example, these rules would exclude days (or trading periods) with previous demand response events or days with the highest or lowest loads;
- **Baseline calculation type:** This would be the method of developing the baseline value using data from the baseline window. For the proposed BCM simple averages would be used to calculate a baseline value;
- **Baseline adjustment:** The baseline adjustment would be an additional calculation applied after the basic calculation type, to align the baseline with observed conditions of the event day. The basic calculation type would be applied to an adjustment window. In the proposed BCM an additive approach to baseline adjustment would be implemented. The adjustment would be based on

the average difference between the baseline and actual data for the adjustment period. The average difference would then be added to the baseline during the demand response interval; and

- **Adjustment window:** The adjustment window would be the period of time before the demand response occurred, for which actual meter data is available. For example, the first 3 hours of the 4 hours prior to the demand response.

The demand response aggregator would be able choose a BCM combination for each of its DRLs. As a result, when taking the role of a demand response aggregator for a NMI, a demand response aggregator would be able to select one of the following accredited BCM combinations:

- **BCM combination 1:** This combination will consist of two BCMs. A first BCM to calculate the baseline when demand response occurs on a weekday, and an alternative BCM for when the demand response occurred on weekends or public holidays; and
- **BCM combination 2:** This combination will consist of just one BCM for when demand response occurs on a weekday only. This BCM combination could be used when a demand responsive load fails the predictability test for weekend days only. In this case, the demand responsive load would not be allowed to participate in the DRM on weekend days.

Procedures would be developed to review, assess, and confirm the performance of the accredited and newly proposed BCMs and BCM combinations. A review of the accredited BCM and their combinations would require significant analysis and should not be attempted frequently. Changes stemming from the review are implemented via the procedure change process so as to allow an appropriate level of consultation and impact assessment. The procedures would specify the following assessment criteria to be applied when assessing baseline consumption methods:

- Accuracy – how closely a baseline consumption methodology predicts customers' actual loads in the sample;
- Bias – the systematic tendency of a baseline consumption methodology to over- or under-predict actual loads;
- Variability – the measure of how well the baseline consumption methodology is at predicting hourly load under many different conditions and across many different customers;
- Ease of explanation – the transparency of and ability to explain the baseline consumption methodology to program participants; and
- Implementation and operating costs – the associated level of investment in activities such as data transfer, data quality review, analysis, training, and IT systems requirements.

C.6 Restrictions on the provision of demand response

A demand response aggregator would be prohibited from including a NMI in a demand response notification where:

- The customer has, for the sole purpose of influencing the calculations of the baseline energy, artificially inflated historical usage or biased the selection of qualifying days;
- The demand response aggregator or customer is not taking any deliberate action to provide the demand response, e.g., where a load is experiencing an outage unrelated to DRM;
- The customer is providing demand response by moving demand from one connection point at a site to another connection point at the same site so as to show an artificial demand response on one NMI at the site.

These circumstances provide a reference point for the Australian Energy Regulator (AER) to establish whether the demand response aggregator has operated in good faith[268] , but it is not proposed for AEMO to specifically monitor compliance with these situations.

C.7 Interactions with demand side participation mechanisms

An end user would be able to sell its demand response to a demand response aggregator under the DRM. Alternatively, it can also sell it to its retailer or it’s Distribution Network Service Providers (DNSPs) outside of the DRM. If the retailer is also a demand response aggregator then the retailer would have the option to call a demand response from the end user within the DRM or outside of the DRM.

DNSPs contract demand response within the distribution networks to provide network support services (NSS). Loads that provide network support services could also simultaneously participate in the DRM and their demand response aggregators would be entitled to payments for demand response energy from the NEM.

In addition, subject to some restrictions, the demand response aggregator would be able to offer aggregated load simultaneously as ancillary service load into the NEM's ancillary services markets and then as a demand response load in the DRM. However, load offered into the ancillary services markets will be scheduled by the market rather than self-scheduled by the demand response aggregator.

C.8 Prudential requirements

Prudential requirements in the NEM are a set of controls that minimise the exposure of market participants generally to payment default by a retailer. These controls consist of an ex-ante assessment of credit limits, and a daily ex-post assessment of financial position. The credit limit process is used to set the collateral requirements for each market participant, in the form of bank guarantees required to be lodged in advance.

Demand response aggregators and retailers would have their credit limits assessed according to the existing methodology/procedure, with modifications to the credit

268 The AEMC published on 17 September 2015 the Bidding in Good Faith second draft determination. This proposed draft rule has been proposed to enhance the arrangements that govern generator's offers in the wholesale spot market.

limit procedures to include consideration of the demand response in the factors to be considered by AEMO in determining prudential settings.

Demand response aggregators' financial positions would be assessed daily using demand response energy. Under normal circumstances, a demand response aggregator will be a creditor to the NEM with regard to the demand response energy corresponding to the demand response intervals. Debit may arise when the metered energy exceeds the baseline energy or if the regional reference price is negative during a demand response interval. As a result, demand response aggregators would have their position assessed in line with the credit limit procedures to determine whether they need to provide credit support.

Retailers' financial position would also be assessed daily using customer baseline energy during demand response intervals.

C.9 Settlement charges

Settlement charges would apply to recover the procurement of ancillary services, compensation costs and participant fees.

The costs associated with ancillary services are currently recovered from market customers, market generators, and market small generation aggregators. For demand response aggregators the fee calculation, whenever applicable, would be based only on the "demand response energy below the baseline" whereas for retailers that are associated with the demand response site the cost recovery would be based on the "baseline energy". Additional arrangements under the DRM would imply the changes presented in Table C.1 below:

Table C.1 Proposed ancillary services cost recovery

Service	Currently recovered from	Demand response aggregator	Retailer associated with a demand response site
NSCAS	Market Customers	N/A	Based on baseline energy
SRAS	Market Customers (50%) and (Market Generators & Market Small Generation Aggregators) (50%)	Based on demand response energy below the baseline only	Based on baseline energy
FCAS Contingency Raise	Market Generators & Market SGAs	Based on demand response energy below the baseline only	N/A
FCAS Contingency Lower	Market Customers	N/A	Retailers pay based on baseline energy
FCAS Regulation Causer Pays	Market Customers and Market Generators distributed according	N/A	Based on SCADA data

Service	Currently recovered from	Demand response aggregator	Retailer associated with a demand response site
	to Causer Pays		
FCAS Regulation Residual	Market Customers	Based on demand response energy below the baseline only	Retailers pay based on baseline energy

The NEM prioritises system and market security over economically efficient dispatch, and a number of mechanisms exist in which AEMO can intervene to manage system security or to prevent market failure. Where an intervention has occurred, the participants impacted are entitled to compensation to cover reasonable costs they incur.

The costs of compensation are recoverable according to allocations defined in the Rules. We have summarised the proposed changes to the compensation cost recovery procedure. These are presented in Table C.2 below:

Table C.2 Proposed compensation cost recovery

Type	Current arrangements	Demand response aggregator	Retailer associated with a demand response site
Energy direction	Recovered from Market Customers	N/A	Retailers pay recovery based on baseline energy.
Other direction	Recovered from Market Customers, Market Generators (based on net generation only), and Market SGAs (based on net generation only).	N/A	Retailers pay recovery based on baseline energy.
Administered price cap (APC)	Recovered from Market Customers	N/A	Retailers pay recovery based on baseline energy.
Reserve Settlements	Recovered from Market Customers	N/A	Retailers pay based on baseline energy.
Mandatory Restrictions restriction shortfall amount (RSA) - 100,000 to 0	Recovered from Market Customers	N/A	Retailers pay based on baseline energy.
Mandatory restrictions RSA - 100,000	Recovered from Market Customers	N/A	Retailers pay in accordance with determination from independent expert, with supporting data

Type	Current arrangements	Demand response aggregator	Retailer associated with a demand response site
			based on baseline energy.
Mandatory Restrictions RSA positive	Paid to Market Customers	N/A	Retailers paid based on baseline energy.

AEMO also charges participant fees to recover its operating costs. The proposed changes to the operating cost recovery arrangements under the DRM are summarised and presented in Table C.3 below:

Table C.3 Operating cost recovery

Type	Current arrangements	Demand response aggregator	Retailer associated to demand response site
AEMO participants fees	Market Customers and Market SGAs pay customer fees at a rate per MWh of energy consumed and generated respectively. Market Generators pay generator fees at a fixed rate per day.	Demand response aggregators pay customer fees at a rate per MWh of demand response (whether above or below baseline).	Retailers pay customer fees based on baseline energy.

C.10 Other aspects of the proposed DRM mechanism

This consultation paper covers the key features of the DRM proposed in the rule change request. For technical details relating to the registration process, MSATS setup, metering, B2B processes, preparation of demand response settlement data by MSATS, please refer to the detailed design prepared by AEMO. The interested reader is referred to AEMO's specific design document.

C.11 Voluntary and staged approach

The Energy Council proposes a voluntary approach whereby retailers will be able to choose whether to enable their customers, through implementing changes to allow for appropriate billing arrangements, to offer demand response in the DRM. They could do this either by becoming a demand response aggregator themselves or allowing their customers to work through another demand response aggregator. The objective is to minimize the system development costs for retailers who do not offer services to large customers, while retailers with large customers could make a commercial decision on whether to support the DRM for their customers based on an opportunity for securing market share and/or increase revenues.

Under the proposed approach retailers would have to take an all or nothing approach to enabling their customers to participate. They would either be able to accommodate any existing eligible customer's participation in the DRM, or they would not support any participation in the DRM by any of their customers. For example, retailers would not have the discretion to decline an eligible existing customer's participation if their systems enable DRM participation, while allowing another customer to participate.

It is proposed that new billing arrangements would only be affected for those customers who participate in the DRM. The proponent also envisages that retailers may not be required to have all billing systems in place for the commencement of the DRM rule change as manual workarounds may be viable option in the early stages of the DRM.

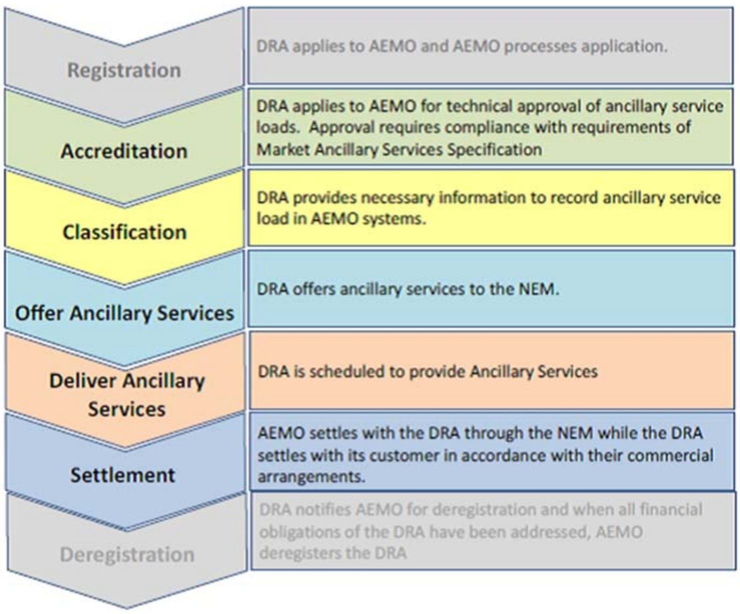
D Ancillary services unbundling – AEMO's detailed design

D.1 Demand response aggregator

Under the proposed rule, the new class of market participant, the demand response aggregator, would be able to provide ancillary services to the market in addition to also participating in the DRM. This is accomplished without requiring the demand response aggregator to be a Market Customer in the spot market effectively unbundling the provision of these services from the purchase of energy in the spot market.

The demand response aggregator would be able to register a spot market load[269] as ancillary services load to sell FCAS using individual spot market load or aggregated spot market loads independently of whether the demand response aggregator is the Market Customer, e.g., the retailer, responsible for those spot market loads. This would be done in accordance with the existing ancillary services accreditation and classification procedures. The spot market load offered to provide must meet all the technical requirements for FCAS services set out in AEMO's Market Ancillary Services Specification (MASS). There will be no explicit restriction on who can register as a demand response aggregator, provided that the applicant registers as market participant. Figure D.1 below shows the potential lifecycle for a demand response aggregator that also registered to provide FCAS services.

Figure D.1 Lifecycle of a Demand Response Aggregator with respect to Ancillary[270]



269 Ancillary services load is a classification category that appears in the NER for market loads. Currently, only Market Customers can classify a market load as ancillary services load as a pre-condition for that market load to participate in the FCAS markets.

270 AEMO, Demand Response Mechanism and Ancillary Services Unbundling – Detailed Design, available http://www.aemc.gov.au/Rule-Changes/Demand-Response-Mechanism

D.2 Eligibility of loads to provide ancillary services

The Energy Council proposes that there is to be no minimum annual consumption requirements for individual loads providing FCAS services through the demand response aggregator as proposed for the DRM. However, the Energy Council does propose some requirements regarding the loads that can provide FCAS through a demand response aggregator. These include that the load is not a scheduled load in the NEM, and that is not classified as providing ancillary services to the NEM via another participant.

D.3 Accreditation of ancillary service load

The new class of market participants, a demand response aggregator, would be able to register an ancillary services load to sell ancillary services to AEMO. An ancillary service load will be defined as either an individual load or an aggregation of loads from which the FCAS services is provided:

- A demand response aggregator will be able to seek accreditation for a load as an ancillary service load;
- A demand response aggregator will be allowed to aggregate load across sites to form an ancillary service load independently of the retailer. In this case, AEMO notes that there are technical and communication requirements that must be meet before such load aggregation for the purposes of registering an ancillary services load can be done. A demand response load included in such aggregation can simultaneously be offered as demand response load in the DRM; and
- An aggregated ancillary services load must be able to meet the market ancillary services specification (MASS). AEMO notes that the MASS may need to change to provide guidance on classifying loads as ancillary services load.

D.4 Classification of ancillary service load

The classification of Ancillary Service Load (ASL) involves recording the information of these loads in the Market Managements System. This is already an existing process. Loads classified to provide FCAS services will be scheduled through the central dispatch process, and payments for FCAS services would be funded by the broader market.

In line with current rules relating to market customers offering FCAS, a demand response aggregator will be responsible for ensuring it does not offer ancillary services that cannot be physically delivered, and must also ensure a load that has been enabled to provide ancillary services is able to provide the service.

Currently, a market customer enabled for a service that it could not provide is still paid for that service but would be in breach of its obligations to follow a dispatch instruction. Similarly, outside the routine revision window, there will be no provision for a mechanism to "claw back" ancillary service payments made to a demand response aggregator that was unable to provide the service. Instead, this would be a rule breach and the demand response aggregator may incur penalties if this occurred, as is the case with a market customer.

D.5 Restrictions on ancillary services loads

There will be restrictions imposed on how ancillary service load can be sold to the market:

- A demand response aggregator cannot include a load as an ancillary service load if the end user has generation measured at its NMI which is sold as generation to the NEM via a market generator or market small generation aggregator. However, if the generation is not sold to the NEM as generation then the demand response aggregator can include the load as an ancillary service load;
- Each of its ancillary service loads is at all times able to comply with the latest market ancillary service offer for the relevant trading interval; and
- It will be the responsibility of the demand response aggregator to establish compliance of its ancillary services load customers with these requirements.

D.6 Interactions with the DRM

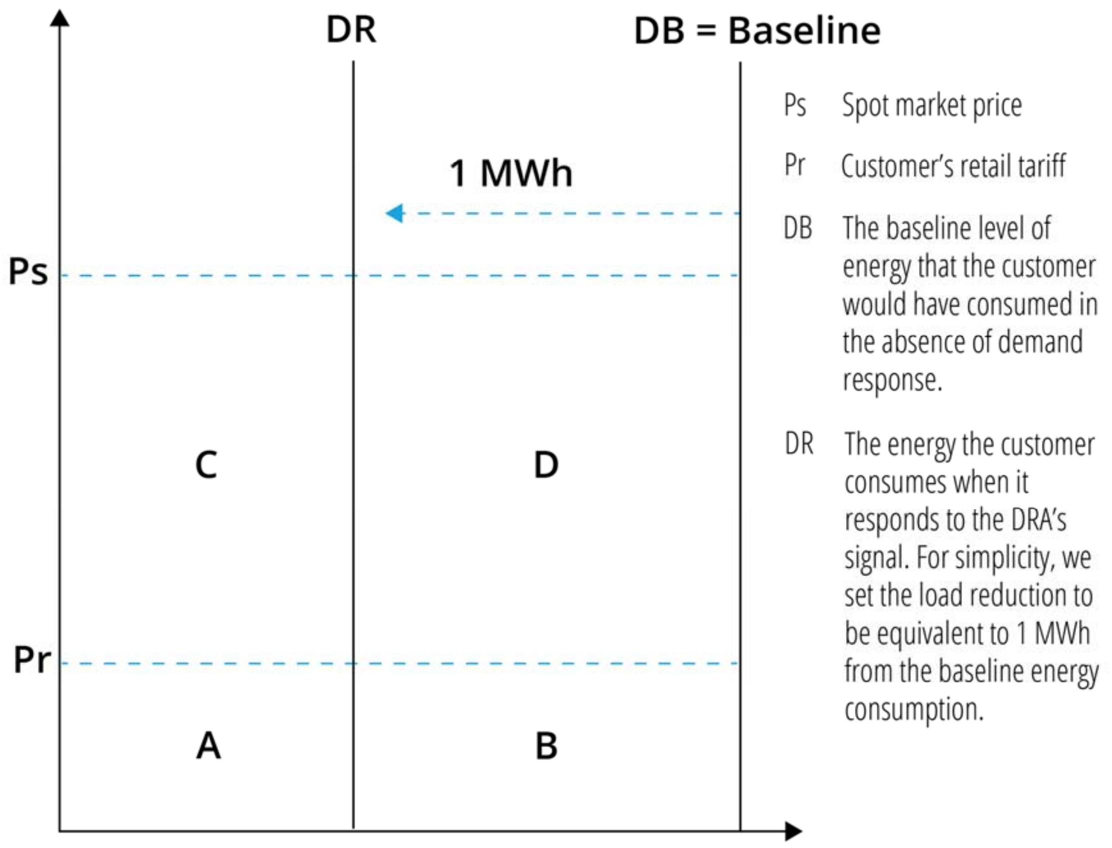
The DRM design would allow any demand response load in the DRM that was also classified as an ancillary service load to be simultaneously offered as a demand response load in the DRM.

Where a demand response aggregator has a load classified as both demand response load and as an ancillary service load then it must ensure that it is able to satisfy its ancillary service obligations when providing demand response. It will be the demand response aggregator's responsibility to establish compliance of its ancillary services load customers with this requirement.

E Wealth transfers under the proposed Demand Response Mechanism

Figure E.1 below explains the financial cash-flows that would occur between generators, demand response aggregators, retailers and a DRM customer under the proposed DRM arrangements.

Figure E.1 DRM Cash Flow



The graph above depicts a DRM demand response event when a customer responds to a demand response aggregator's signal by reducing its load by 1MWh when the spot market price is Ps. The DRM cash-flows would be as follows:

- The retailer would be settled on the baseline consumption and would pay AEMO an amount equivalent to the areas A+B+C+D;
- AEMO would then pay generators an amount equivalent to the area A+C;
- AEMO would also pay demand response aggregators an amount equivalent to demand response aggregator the area B+D;
- The retailer would charge the customer for its baseline consumption at the rate of the retail tariff an amount equivalent to the area A+B;
- The demand response aggregator would pay the consumer a portion of the revenue it received. This would be a portion of the amount B+D. This would be equal or greater than the customer's opportunity cost of not consuming the electricity that was subject to demand response.

In terms of wealth transfers, it is important to note that if the customer did not participate in the DRM but had responded as depicted in the figure above, then the retailer would have made a notional energy cost saving depicted by area D. This is because the retailer would have avoided the notional energy cost of purchasing the demand response energy (DB - DR) at the spot price Ps (area B+D) but selling it at the fixed retail price Pr (area B). However, under the DRM even though it is the retailer supplying the customer and the party that remains exposed to the spot price, the DRM arrangements would transfer via a financial cash-flow an area equal to B+D from the retailer to the demand response aggregator. The retailer would then recover B from the customer from billing the customer based on the baseline energy consumption. Therefore, area D can be interpreted as a welfare transfer loss from the retailer to the demand response aggregator under the DRM in comparison to a situation where the customer did not participate under the DRM arrangements.