DEMAND RESPONSE MECHANISM AND ANCILLARY SERVICES UNBUNDLING – DETAILED DESIGN

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Contents

1 Executive Summary

1.1 Introduction

This report presents the detailed design of a demand response mechanism (DRM) and ancillary services unbundling (ASU) arrangements to be implemented in the National Electricity Market (NEM).

AEMO has been tasked by the Standing Council on Energy and Resources (SCER) to develop and implement the DRM and ASU in consultation with industry. This document is intended to provide a design that can be used in developing market rule changes and later system and process changes.

The DRM and ASU are two of the recommendations from the Australian Energy Market Commission's (AEMC) Power of Choice review.[1] The package of recommended reforms is intended to provide households, businesses and industry with more opportunities to make informed choices about the way they use electricity and manage expenditure. The AEMC has found that under the current arrangements consumers are limited in their ability to respond to changes in the wholesale electricity spot price. While consumers are able to physically reduce their consumption under specific contractual arrangements such as interruptible tariffs, spot pass-through and scheduled loads, these involve a degree of risk and transaction costs that for most commercial and industrial users cannot be efficiently managed.

1.2 Demand Response Mechanism

The DRM will initially be available to industrial and commercial end users of electricity. While there are a number of requirements, the key requirements are linked to the National Metering Identifier (NMI)[2] associated with the demand response and are:

- The NMI has a classification of "large" in the Market, Settlements and Transfer Solution. This corresponds to a large user under the National Energy Customer Framework (NECF), which, depending on jurisdiction, is expected to limit participation to those with annual consumption of above 100 MWh, 150 MWh or 160 MWh (depending on Jurisdiction/ NECF categorisation).
- The NMI is associated with type 1, 2, 3 or 4 interval metering installations;
- For sites with multiple NMIs, participation is not permitted if it is possible to shift demand between NMIs at that site so as to appear to provide a demand response on a demand response NMI without actually reducing site consumption;[3]
- The load measured by that NMI is predictable within a set tolerance and that adequate historic meter data is available to test this.

The end-users load is called demand response load. A demand response load can be provided by reducing consumption or by employing on-site generation behind the meter, though the generator cannot be registered as a generator in the NEM. An end user will participate indirectly through a registered Demand Response Aggregator (DRA) or directly by registering itself as a DRA.

A DRA will be a new category of registered participant in the NEM. Any existing market participants (retailers or generators for example) will be able to register as a DRA. In addition, new specialist aggregators will also be able to register. The Australian Energy Regulator is considering whether

[1] Power of Choice Review – Giving Consumers Options in the way they use Electricity. Final Report. AEMC 30 November 2012.

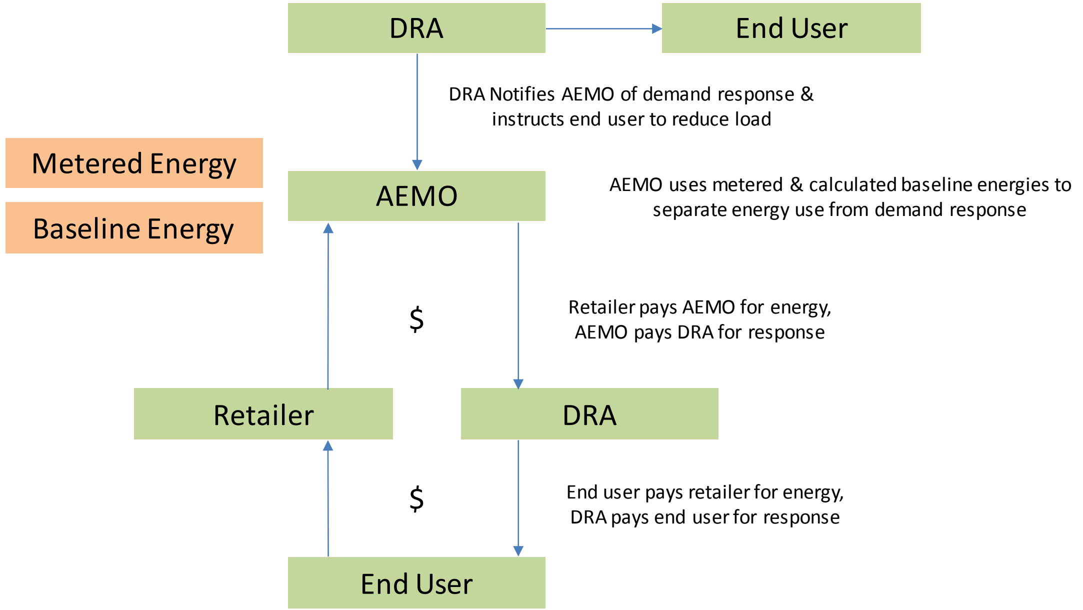
[2] The DRM arrangements will only employ meters with a NMI and all calculations of baseline energy will be performed at the resolution of a NMI. This would exclude customers and meters that are not visible or registered in the NEM systems (e.g. sub-meters).

[3] This is only an issue when inter-changeable processes exist at each NMI. It is not an issue, for example, if one NMI runs industrial processes and another NMI has a site office or other unrelated functions.

there should be restrictions on network service providers, though this design imposes no restrictions.

Figure 1 presents the workings of the DRM for a demand response interval.

Figure 1 Demand Response Mechanism



In summary:

- A DRA notifies AEMO of an imminent or commenced load reduction, forming what is termed a Demand Response Interval.
- After the event, AEMO calculates the baseline energy for this interval, reflecting what demand is expected to have been had there been no demand response. The baseline energy is based both on historic data and data from the day the demand reduction occurred. A baseline consumption methodology (BCM) associated with the end user's NMI defines the method for setting the baseline energy.
- In settlement, the calculated baseline energy is compared with actual energy used to unbundle the amount of demand response energy from the energy usage had the response not occurred. Outside of the demand response interval settlement will operate as it does today, but during the demand response interval:
  - DRAs will be paid (at the NEM spot price) for the difference between baseline energy and actual consumption, with appropriate loss adjustment. For symmetry, the DRA will be charged if actual consumption exceeds baseline energy.
  - End users would be paid by the DRA for their response based on their commercial arrangements with the DRA.
  - Retailers will be charged for energy consumption (at the NEM spot price) based on the baseline energy.
  - End users would be charged by their retailer (at their retail rate) based on the baseline energy.

Different baseline consumption methodologies will be used to determine the baseline energy on weekdays excluding (local) state public holidays and weekends / (local) state public holidays. The non-holiday weekday baseline energy for a trading interval and NMI will be based on the CAISO 10 of 10 method, which typically takes the average of the meter data for the same trading interval over ten prior business days for which that NMI provided no demand response under DRM. The weekends/public holidays values will typically be based on the highest two metered values for the trading interval from the prior four weekend and (local) state public holidays for which that NMI provided no demand response under DRM. In each case an additional additive adjustment is applied to correct the baseline based on metered data just during the trading intervals prior to the demand response.

Demand response will be non-scheduled at the commencement of the DRM, although the possibility exists to evolve to an AEMO scheduled response in the future. It is proposed that AEMO's annual report on DRM performance could be the mechanism that identifies evolution and amendments to the DRM.

DRAs will be required to "classify" the loads providing the demand response by providing AEMO with the NMI for those loads. For the purposes of DRM reporting, DR loads will be categorised by the type of load (e.g. mining, manufacturing, transport and storage) and the mechanism by which DRM is provided (e.g. electricity generation, plant shutdown, batteries etc.).

DRAs will be subject to the NEM's prudential requirements which act to minimise the exposure of the market to payment default. From 28 November 2013, these controls will consist of a seasonal assessment of credit limits and a daily assessment of financial position. Normally, a DRA will be a creditor to the NEM. Prudential requirements for retailers will be assessed using baseline energy during demand response intervals.

1.3 Ancillary Services Unbundling

The Ancillary Services Unbundling changes will enable DRAs to register ancillary service load and sell Frequency Control Ancillary Service (FCAS) using individual load or aggregated loads independently of the retailer. Ancillary service load will define an individual or aggregated load from which ancillary service is provided. An ancillary service load need not have any relation to a demand response load.

DRAs will be able to offer ancillary service load as FCAS if it satisfies the NEM's technical requirements. The existing technical and procedure requirements will apply to the DRAs. Ancillary services are funded by the broader market and not solely by the retailer associated with the load.

Restrictions apply to which parties "own" a load for the purpose of participation in DRM and ASU and there will be restrictions on how demand response load and ancillary service load are provided to the market so as to prevent incompatibility between the servicers.

There will be no minimum annual consumption requirements for individual loads providing ancillary services.

2 Introduction

The Australian Energy Market Commission's (AEMC) Power of Choice final report sets out a substantial reform package of the National Electricity Market (NEM).[4] The package is intended to provide households, businesses and industry with more opportunities to make informed choices about the way they use electricity and manage expenditure.

The AEMC recommendations are designed to increase the responsiveness of demand to market conditions in two ways:

- Enabling consumers to see and be rewarded for taking up options for demand side response.
- Enabling the market to support consumer choice through better incentives to capture the value of demand side participation options and through decreasing transaction costs and information barriers.

The two recommendations relating to the wholesale market changes are:

- Demand Response Mechanism (DRM) - a DRM that pays an end user for reducing demand via the wholesale electricity market. Under the mechanism, end users are able to be rewarded for demand response that would be provided through a demand response aggregator. A calculated baseline energy is compared with actual energy used to unbundle the amount of demand response energy from an estimate of energy usage had the response not occurred. The end user would pay its retailer based on the baseline energy but would receive income from the demand response aggregator based on its assessed level of demand response energy.
- Ancillary Services Unbundling (ASU) – to unbundle the sale and supply of energy to allow a third party to register and sell ancillary services using aggregated loads independently of the retailer. The scope of the ASU is to allow third parties to register and sell ancillary services using aggregated loads independently of the retailers. The existing technical and procedure requirements will apply to third parties.

The AEMC recommended that AEMO be tasked with drafting the rule change proposal for the DRM and ASU changes and that AEMO establish an industry reference group to provide expert guidance in developing the rule change proposal.

The AEMC also published draft specifications for the framework of the rule change proposal, requiring AEMO to submit the rule change proposal by December 2013 so that the framework would be in operation by early 2015. The Standing Council on Energy and Resources (SCER) accepted the AEMC recommendations and subsequently requested AEMO to undertake the work recommended by the AEMC.

Between February and June 2013, AEMO established a project to undertake the work and established a working group and a number of sub-working groups to advise AEMO on a set of initial business requirements covering the major aspects of DRM and ASU – dispatch and notification, metering, registration, reporting and settlements. At the culmination of that work AEMO developed and published a high level design for DRM"[5] which encapsulated the high level features of the design.

Subsequently AEMO worked with the Demand Response Mechanism and Ancillary Services Load Working Group to develop this Detailed Market Design document. This document will drive system development planning, rules development and project budgeting.

This report is structured as follows.

- Section 3 presents an overview of the design.

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[4] Power of Choice Review – Giving Consumers Options in the way they use Electricity. Final Report. AEMC 30 November 2012.

[5] Demand Response Mechanism And Ancillary Services Unbundling - High Level Market Design. AEMO, 30 July 2013.

- Section 4 describes the new market participant class of Demand Response Aggregator (DRA)
- Section 5 describes the registration process and lifecycle of DRAs
- Section 6 describes the requirements on loads that a DRA can provide services from and how DRA relationships with end users are captured.
- Section 7 describes how a DRA interacts with AEMO's Market, Settlements and Transfer Solution (MSATS) system.
- Section 8 describes how demand response energy and ancillary services are provided by a DRA.
- Section 9 describes the baseline consumption methodologies used to estimate what consumption would have been had there been no demand response, and the processes for updating these methodologies.
- Section 10 describes changes to metering processes required to support DRM.
- Section 11 describes changes to business-to-business (B2B) processes required to support DRM.
- Section 12 describes how the MSATS system processes data to produce settlement ready data.
- Section 13 describes the settlement and prudential processes associated with the provision of demand response energy and ancillary services.
- Section 14 describes the reports that will be provided to the market.
- Section 15 illustrates the high level process flows associated with this design.

A number of appendices provide additional examples, summaries of obligations, and definitions.

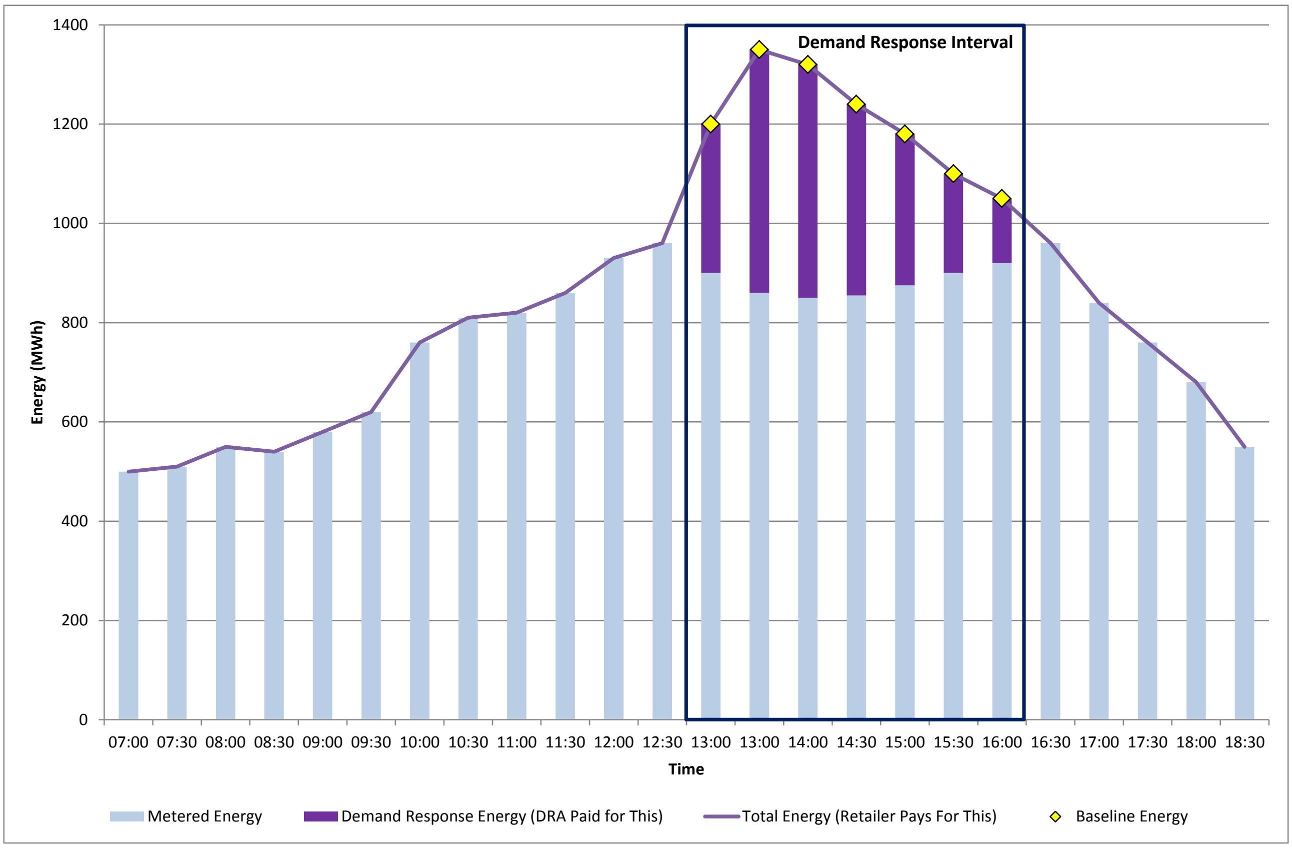
3 Overview of the Design

3.1 Key Concepts

3.1.1 Demand Response

Figure 1 illustrates how demand response is provided. The figure depicts the treatment in NEM settlement of the demand response provided by an end user's load[6] identified by a single National Metering Identifier (NMI). The demand response starts during the trading interval ending at 13:00 hours and lasts until the trading interval ending 16:00 hours. This is the demand response interval. A Demand Response Aggregator (DRA) has an arrangement with the customer at the NMI to reduce load. During this period the metered quantity drops. AEMO, having been notified of the demand response by the DRA, determines the baseline energy, being a derived estimate based on historic data of what the energy consumption would have been without the demand response.

Figure 1 – Illustration of Demand Response



The retailer for this load is normally charged by AEMO for energy at the NEM half hour spot price in the region of the NMI. During the demand response interval the retailer will be charged as if the baseline energy was the quantity of energy consumed at the NMI (appropriately loss adjusted). The retailer will also charge the end user in the retail market based on this same quantity. The DRA will be paid by AEMO based on the demand response energy, being the difference between the baseline energy and the metered load (and including appropriate loss adjustments), at the NEM half hour spot price in the region of the NMI. The DRA will pay the end user for the demand response based on the arrangements they have agreed.

In effect, the end user buys energy from the retailer at the retail price and sells it to the DRA at a mutually agreed price. The DRA sells demand response energy to the NEM and the NEM's payments to the DRA are funded by the retailer buying the baseline energy from the NEM. If the baseline matches what demand would have been, the retailer is an unchanged position – it has

[6] In this document we use "load" even if the response is provided by generation embedded behind the meter of the load.

purchased the energy it would have expected to buy in the NEM had there been no demand response, and it receives the retail market revenue from selling it to the end user that it would have expected to receive.

Demand response is associated with 30 minute trading intervals rather than 5 minute dispatch intervals. A DRA is only required to notify the market of a demand response before the end of the trading interval in which the demand response commences. This means that a demand response could commence at any time during a trading interval. The later in the interval that a demand response starts then the smaller the response will tend to be, as illustrated in Figure 2.

Figure 2 – Impact of the Commencement of the Demand Response on Demand Response Energy

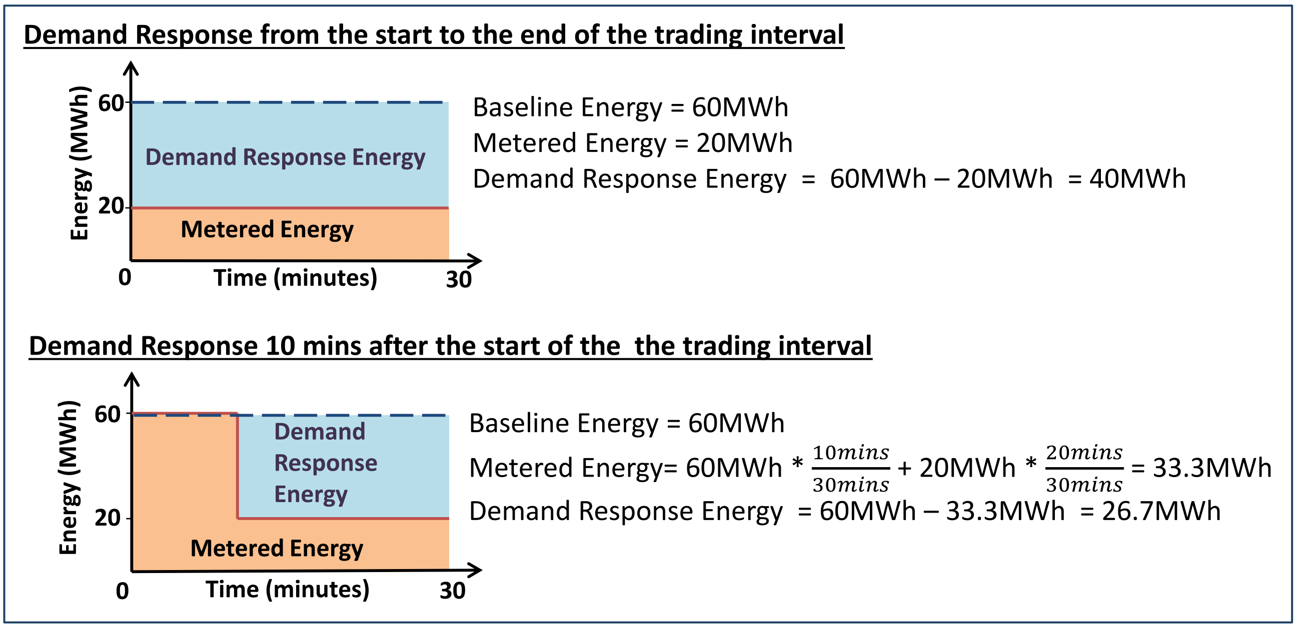
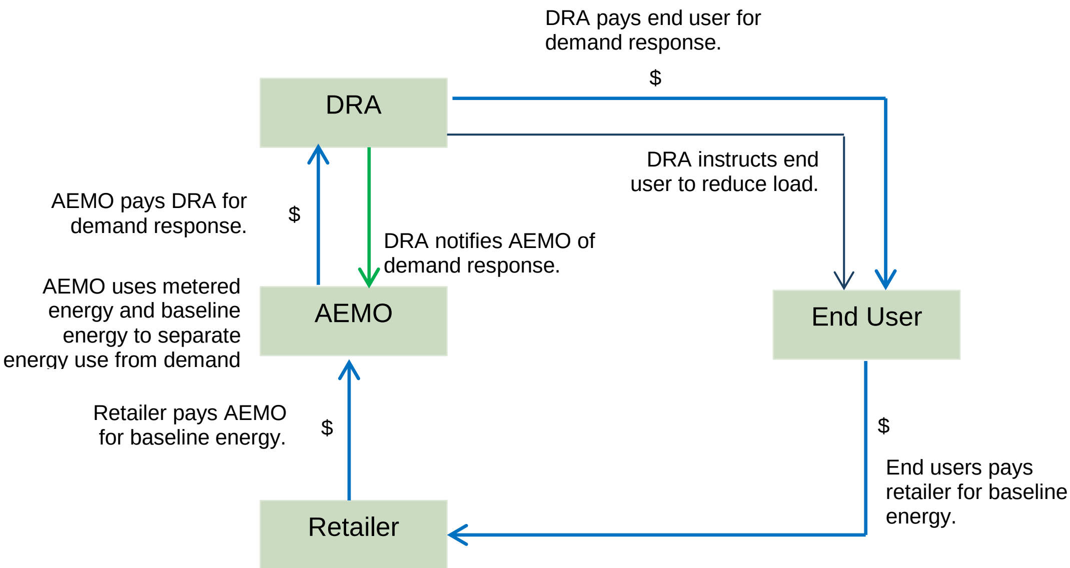


Figure 3 presents an overview of the workings of energy settlement for a demand response trading interval, where a demand response trading interval is a trading interval during a demand response interval.

Figure 3 - Demand Response Mechanism



Demand response is self-scheduled by a DRA. In contrast, central dispatch for energy is mandatory for generation above 30 MW and market network services, and is optional for all loads. Although the AEMC contemplated scheduling of demand response as part of DRM, this is not currently proposed. If any self-scheduled option for demand response is available then it is expected that DRAs would opt for that over any scheduled option. Individual demand responses will likely be much less than the 30 MW mandatory level for generation so the imposition of any significant mandatory minimum load requirement for inclusion in scheduling would be a barrier to demand response. The cost of implementing scheduled demand response for numerous DRAs with low levels of demand response capacity is not considered justified.

3.1.2 Ancillary Services

Ancillary services are services used by AEMO that are essential to the management of power system security, 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 loads the most relevant services are frequency control ancillary services (FCAS) used to maintain the frequency of the system under normal conditions and to restore operating frequency following a contingency event. Only a sub-set of the FCAS services are likely to have technical requirements that can be satisfied by a load.

A load providing FCAS is paid for being enabled by AEMO rather than for energy. The service tends to be used over time frames of several minutes.[7] Thus half hourly metering of the type so important for DRM is not meaningful or relevant in the settlement of these ancillary services.

Currently load can provide ancillary services in the NEM. A load that meets the requirements for this is called an ancillary service load. DRAs will be able to offer ancillary services from ancillary service loads and may aggregate end user load as ancillary service load. An ancillary service load need not be involved in DRM.

The payments to those providing ancillary services are funded by the broader market.

3.2 Key Players and Roles

3.2.1 Demand Response Aggregator

Demand Response Aggregator (DRA) is a new class of participant. It can self-schedule demand response and will be paid at the relevant regional spot price for this response. It can also offer ancillary services from load which will be scheduled by AEMO. Other classes of participants will be able to register as DRAs, though some participants, such as network operators, may need regulatory approval to participate.

A DRA will be registered with AEMO. After registration it will “classify” with AEMO the demand response load from which demand response will be provided. This process will involve the DRA taking on a new DRA role associated with the National Metering Identifier (NMIs) of those loads.

A DRA may also offer scheduled ancillary services to AEMO from ancillary service loads. These loads may be aggregated across locations and need not be demand response loads.

3.2.2 Demand Response Load

Demand response load is an end user that provides demand response to a DRA. An end user providing demand response load is not a participant in the NEM. A DRA will contract for the supply of demand response load. The demand response load will be paid by the DRA for the response based on the commercial arrangements between them. The demand response energy provided by a demand response load will be associated with a single NMI with all calculations of demand response energy performed at that resolution.

Eligibility requirements will define which load can provide demand response under DRM. Key requirements are that the NMI is classified as large (consumption typically over 100 MWh per annum), that the meter is an interval meter of type 1, 2, 3 or 4 (which can provide half hourly

[7] That is, if the load is tripped out of service due to a low frequency event, it is usually able to be returned to service within several minutes.

settlement data essentially daily), and that the load can be predicted within an acceptable tolerance via the methods used to calculate baseline energy.

Demand response load might be provided by running a house generator at the site, by shutting down industrial processes for a period of time, or through energy conservation measures.

3.2.3 Ancillary Services Load

Ancillary services load is end user load that is providing scheduled ancillary service. Unlike demand response load, the volume of ancillary service sold by a DRA to the market can be aggregated across sites.

There will be no minimum annual consumption requirements for individual loads providing ancillary services.

3.2.4 Financially Responsible Market Participants (FRMPs)

The Financially Responsible Market Participants (FRMPs) will be the Market Customer (the retailer) for a NMI. The DRM is designed to have minimal impact on the FRMP. The end user may sell its demand response to a DRA under DRM or it can sell it to its retailer or its local network operator outside of DRM. If the retailer is also a DRA then it has the option to call a demand response from the end user within DRM or outside of DRM.

For a trading interval in which a NMI is included in a demand response notification, the FRMP for that NMI will be settled in the energy spot market based on the baseline energy for the NMI rather than actual load.

3.2.5 Distribution Network Service Providers

Distribution Network Service Providers (DSNPs) provide the distribution network that connects a NMI to the broader network. DNSPs are not required to take any specific actions in DRM, however they will receive information about which of the NMIs connected to their network are providing demand response and may have interest in monitoring that activity. The design does not restrict them from also becoming DRAs themselves and offering DRM, though regulatory restrictions beyond the scope of this design have the potential to prevent this.

3.2.6 Metering Data Provider

A Metering Data Provider (MDP) is an entity that currently provides metering services to an end user, typically via a retailer. The commercial relationship for the provision of these services is outside the scope of the NEM. This relationship will not change under DRM, though the MDP will be required to provide current meter data to the DRA associated with the end user's NMI and the MDP will be able to charge for these services.

3.2.7 AEMO

The Australian Energy Market Operator (AEMO) has the role of registering DRAs and maintaining data on the eligibility in the DRM of NMIs associated with each DRA. AEMO determines the baseline data when notified of a demand response by a DRA and implements the settlement between the market and the DRA and the market and the retailer.

3.3 Provision of Demand Response

Demand response will be self-scheduled by DRAs. A DRA must issue a demand response notification to AEMO indicating the start and end times of the response and the NMIs involved. The start time indicated in a demand response trading interval cannot be prior to the start of the current trading interval.

AEMO will 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. The baseline energy will be derived using a baseline consumption methodology (BCM) (discussed below) based on historic demand patterns for that NMI. The DRA will be paid the half hour wholesale NEM energy price in the region of the load for the demand response.

The retailer for the NMI will be settled based on the baseline energy. As the baseline energy equals the metered energy plus the demand response energy the payment by the retailer (which it passes on to the end users) funds the demand response.

3.4 Provision of Ancillary Service

Ancillary service will be provided to the market as per other scheduled services. Currently the only loads providing these services are pumped storage generation and smelters. This change may allow aggregation of services like interruption of hot water heating to also participate in the NEM.

As much of the process around ancillary services is already established in the NEM, this document focuses on the new elements relating to DRAs and the relationships with DRM rather than the specifics of how ancillary services are offered.

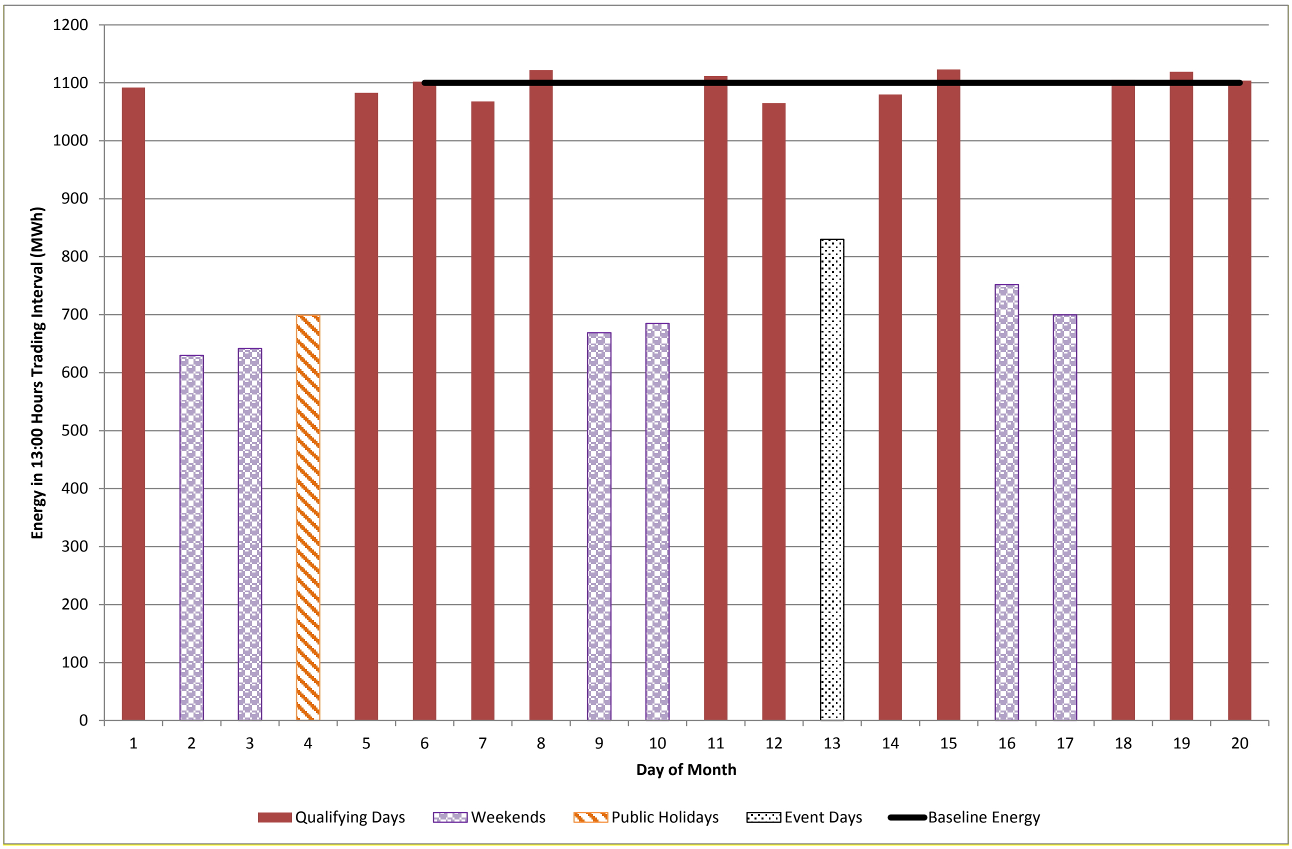
3.5 Introduction to Baseline Energy and Demand Response Energy

For a demand response interval a baseline consumption methodology (BCM) is used to derive an estimate of what the NMI's consumption would have been had it not been for the demand response. There are numerous methods for doing this, though the most common ones involve looking back at meter data from the same time period on suitable past recent days and forming either an average of all of that data or the average of a subset of the data (e.g. excluding the largest and smallest values). In this section we use an example to illustrate the basic concepts.

Suppose that a DRA includes a NMI in demand response for the 21st day of the month, which is a weekday, for the trading intervals from that ending at 13:00 hours to that ending at 16:00 hours.

We first illustrate the concept for how the unadjusted baseline energy is determined for the trading interval ending at 13:00 hours. This is shown in Figure 4.

Figure 4 – Deriving Unadjusted Baseline Energy

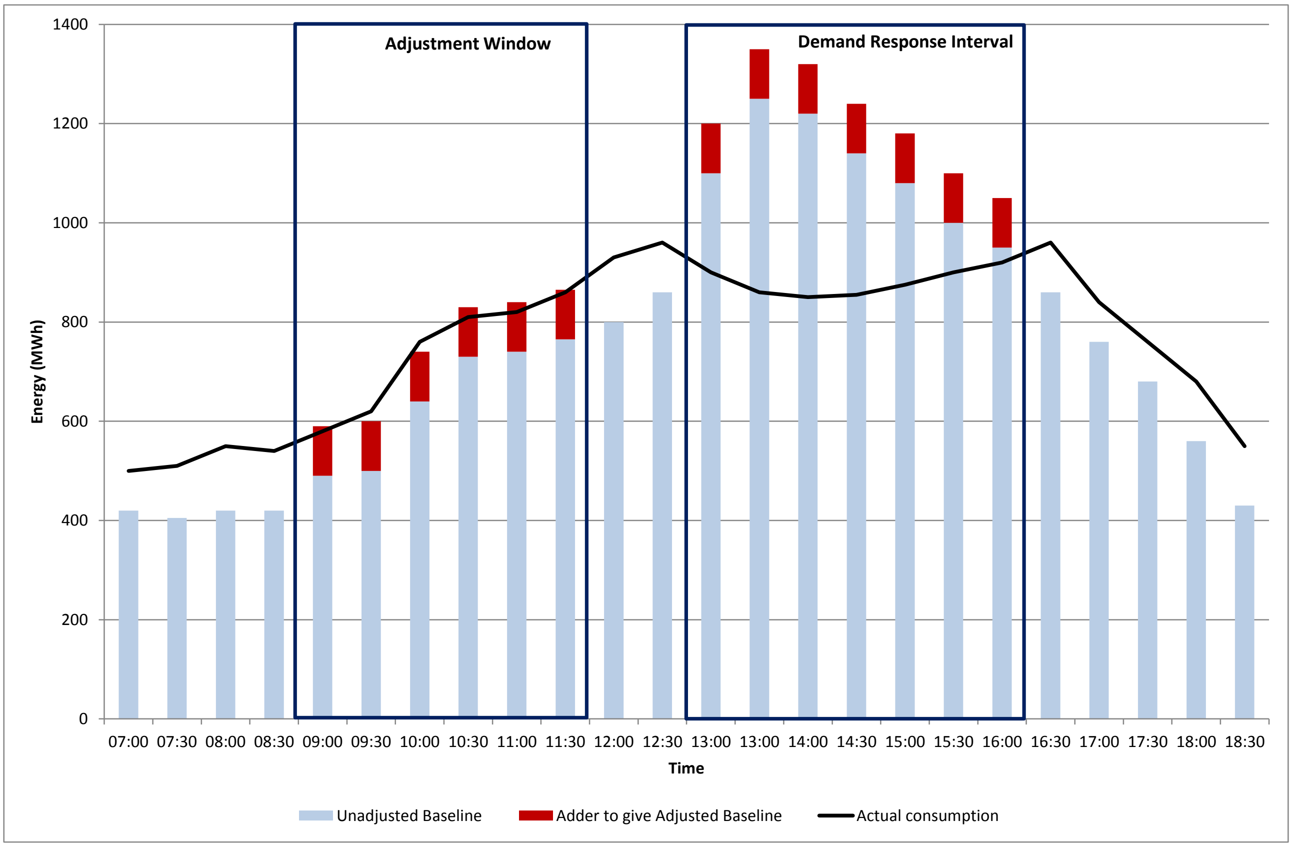


The demand response for the trading interval ending at 13:00 hours happens on the 21st of the month which is a weekday. If our method is based on applying the average of the metered demand for that trading interval for the prior ten qualifying days then we need to identify those ten days. We exclude days which are not comparable, including weekends, public holidays, and prior days on which demand response was associated with the NMI (so called 'event days'). This leaves the qualifying days shown in Figure 4. We take the average of the most recent ten qualifying days which gives an unadjusted baseline energy of 1100 MWh for the trading interval ending at 13:00 hours.

It may be that the current day, the 21st of the month, has a higher or lower average load than the average of the qualifying day. Consequently the unadjusted baseline may not be a good estimate for the current day.

To correct for this we can apply an adjustment. Here we apply an additive adjustment. This is illustrated in Figure 5.

Figure 5 – An Adjusted Baseline



To form the adjustment we might select a period of time called the adjustment window from the day of the demand response but prior to the demand response. For the adjustment window we have metering data which includes no demand response and can calculate an unadjusted baseline for each of the trading intervals in this period. By comparing the average unadjusted baseline and the metered energy for the adjustment window we can derive a single number being the incremental adjustment required to be applied to the unadjusted baseline to make it match the metered energy on average. This incremental adjustment is then applied to the unadjusted baselines in the demand response interval to produce the adjusted baseline.

Thus for the trading interval ending at 13:00 hours the unadjusted baseline was 1100 MWh but the adjusted baseline is increased by 100 MWh to 1200 MWh. The demand response energy is then calculated as the difference between 1200 MWh and the metered energy.

3.6 Accredited Baseline Consumption Methodology Combinations

The baseline energy associated with a NMI will be a function of the accredited Baseline Consumption Methodology (BCM) combination associated with that NMI. The BCM combination defines a BCM to be employed on weekdays excluding (local) state public holidays and a BCM to be employed on weekends and (local) state public holidays. It is proposed that two BCM combinations be available at the commencement of DRM.

For non-holiday weekdays BCM Combination One employs the CAISO 10 of 10 BCM, which typically sets the baseline energy for a trading interval based on the average of the metered energy for that trading interval for each of the prior ten most recent non-holiday weekdays that were not event days. An additive adjustment is also applied.

For weekends and public holidays BCM Combination One employs a Middle 2 of 4 BCM, which typically sets the baseline energy for a trading interval based on the average of metered energy for that trading interval using two of the four most recent weekend days or holidays that were not event days where the smallest and largest metered values are excluded. An additive adjustment is also applied.

BCM Combination Two is the same as BCM Combination One but does not allow demand response on weekends and public holidays.

A BCM Combination can only be applied to a NMI if a test of load predictability is passed. BCM Combination Two is provided for those NMIs that would fail this test due to more variable weekend load.

3.7 Metering and Load Conventions

Energy settlement in the NEM is performed by a calculation of settlement by difference. This means that a Local Retailer is settled on the gross energy taken from a transmission node, less the energy sold at the transmission node to other retailers.

The DRM will allow first tier loads, being loads served by the Local Retailer, to provide demand response via a separate DRA subject to the requirements on the meter and the NMI being met. The demand response from these loads will be settled separately, while the baseline energy associated with them will be used in the aggregated energy settlement of the Local Retailer. Second tier loads, being loads supplied by other retailers, will similarly be able to participate in DRM and will be settled separately from the energy settlement of those retailers.

3.8 Settlements

When a DRA provides demand response into the energy market, the settlement for the retailer is based on the baseline energy, being the energy estimated to have been consumed if there were no demand reduction, while settlement for the DRA is based on the derived demand response load, being the level of demand reduction.

When AEMO enables an ancillary service load offered by a DRA the DRA will be paid by the market for this service while the retailer associated with that load will be responsible for settlement with AEMO of the energy consumed. As with other FCAS, there is no payment for the use of the service and the DRA must factor this in to its FCAS offer prices.

To accommodate these changes the following aspects of the settlement and prudential systems are updated:

- Energy settlement
- Ancillary services (AS) payments
- Ancillary services recovery
- Participant fees
- Compensation recovery

- Settlement statements
- Calculation of Participant credit limits and outstandings for prudential purposes
- Reallocations
- Settlement Reporting

3.9 Reporting

AEMO will provide notification to the market that a demand response notification has been received and will notify the relevant FRMPs, MDPs and DNSPs for each NMI that the NMI has been included in a demand response notification.

AEMO will provide metering data reports showing the level of demand response at different levels of aggregation to those associated with the NMIs.

An annual report of the statistics of demand response provision will also be prepared and made public by AEMO.

4 Demand Response Aggregators

4.1 New Demand Response Aggregator (DRA) class

Demand Response Aggregator (DRA) is a new class of participant which will be the only class of participant that can offer demand response within the DRM.[8] A DRA can also offer ancillary services. Anyone registered as a DRA would be a Market Participant in the National Electricity Market and would be subject to the National Electricity Rules (NER).

Demand response is measured at the level of an individual NMI. A Demand Response Aggregator is an aggregator of energy services for DRM only in the sense that the demand response provided under DRM is an accumulation of the response provided by, and measured at the level of, individual NMIs.

The situation is different for Ancillary Services, in that case the service can be provided across an aggregation of sites, though there are technical and communication requirements that must be satisfied before this can be done.

4.2 Who can be a DRA

There will be no explicit restriction on who can register as a DRA, provided the applicant can be a Market Participant. A Market Customer, a Market Generator, and a Market Small Generator Aggregator would all be able to register as DRAs. A Network Operator could become a DRA subject to any regulatory restrictions on the commercial activates it can participate in.

4.3 Relationship between DRAs and End Users

4.3.1 Commercial Arrangements

A DRA will secure demand response from end users under a commercial arrangement between the DRA and the end user. The end user's load could be one or both of a demand response load and an ancillary service load, where these will be included in the definition of market load.[9] This allows loads that are the responsibility of Local Retailers (i.e. "first-tier" loads), which are not normally market loads, to provide demand response in DRM and ancillary services.

A DRA can self-schedule the provision of demand response for DRM from a demand response load. A DRA can offer ancillary service load into the NEM's ancillary services markets and these loads will be scheduled by the market.

The DRA will be settled by the market for the service it provides the market. The DRA will then settle with the end users based on its commercial arrangement with them.

4.3.2 Associating the DRA with the End User

The end user who provides demand response capability to DRAs would not be a Market Participant in the NEM. The end user would continue to be supplied energy by its retailer. It would effectively buy energy from the retailer under its contract with the retailer, and sell demand response to the DRA under its arrangements with the DRA. The DRA will take on the "role" of DRA for that end user's NMI, creating a link between the end user and the DRA within the market systems.

[8] Though demand response can continue to be provided as it has been provided traditionally outside the DRM without requiring registration as a DRA.

[9] There are size limits on how large a load must be before being allowed to be included in a demand response. With aggregation across loads allowed for the purpose of ancillary service provision these same limits do not apply for ancillary service provision. Consequently, a DRA may supply ancillary services from loads that are not eligible to provide demand response in the DRM.

4.3.3 Embedded Networks

NMIs that are part of an embedded network and that are registered in MSATS will be able to participate in DRM provided that they meet the standard requirements for participation in DRM.

4.3.4 Restrictions on Demand Response Loads

There will be restrictions imposed on how demand response can be sold to the market:

- A DRA cannot take on the role of DRA for a NMI if the end user has generation measured at that NMI which is sold as generation to the NEM via a market generator or market small generation aggregator.[10] However, if the generation is not sold to the NEM as generation then the DRA can take on the DRA role for the NMI.
- A DRA cannot take on the role of DRA for a NMI 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 DRA.
- Each of its demand response loads is at all times able to comply with any relevant demand response notification.
- Additional “operational” restrictions as to when a DRA can include a NMI in a demand response notification are described in Section 8.1.4.
- The demand response load must be accredited and classified[11] in accordance with Sections 6.1 and 6.2.

It will be the responsibility of the DRA to establish compliance of its demand response load customers with these requirements.

4.3.5 Restrictions on Ancillary Service Loads

There will be restrictions imposed on how ancillary service load can be sold to the market:

- A DRA 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 DRA can include the load as an ancillary service load.[12]
- 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.
- Where a DRA 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:
- The ancillary service load must be accredited and classified in accordance with Sections 6.3 and 6.4.

It will be the responsibility of the DRA to establish compliance of its ancillary services load customers with these requirements.

[10] Such generation is settled at the wholesale market spot price in the NEM. Any load electrically connected to such a generator is required to be on the same NMI and would also be settled at the wholesale market spot price. An intermediary could trade the generation and load in the NEM while separately having a retail contract with the load. This load would be prohibited from participation in demand response.

[11] The terms ‘accredited’ and ‘classified’ are used for convenience in this document and are not intended to be read as to have the meanings they may have under rules or procedures.

[12] Provided that ancillary service technical standards are met – which may not be trivial for generators that are not normally running - this would provide a mechanism for small generators not registered in the NEM to contribute to ancillary services. Note that a generator that is part of a small generator aggregation is not eligible to provide ancillary services.

4.3.6 Connection Points for Demand Response Loads

The connection point for a demand response load will be the same connection point as the corresponding market load so that the price of electricity for the baseline load and demand response will be the same (must have the same loss factor). A DRA will have no ability to change the location of a connection point associated with a demand response load.

4.3.7 Demand Response and Network Support Services

DNSPs contract demand response within their distribution networks and use it to help manage the operation of the distribution network so as to avoid the need for increased network investment. This network support service (NSS) response is typically funded as payment for the capacity, or capability, to respond to events. There will be no restrictions on such demand response also participating in DRM and receiving payments for demand response energy from the NEM. DRM will respond to NEM prices and will tend to occur at times of NEM system peak demand or in response to transmission network issues and will tend to occur at different times to when distribution networks face constraints requiring demand response.

AEMO has considered the issue of the eligibility of a NMI providing demand response under the DRM to simultaneously provide NSS and receive payments for both services. Both services do have a value to the market and to the end use consumers and the customer should be free to provide both services.

Network service providers (NSPs) also have NSS agreements with generators connected to their networks. Under these agreements the generator is paid to by the NSP to make the service available and if called to generate by the NSP to mitigate a network constraint, the generator does receive payment from AEMO at the spot price for the generation they deliver to the market.

The situation for an end user providing demand response in response to an agreement with an NSP is analogous to the generator providing the service and the DRA should be free to notify AEMO of a demand response event and receive market payments for the demand response energy provided.

The physical outcome in each situation is similar, potential load shedding is avoided by the addition of generation or the controlled reduction of load to maximise the supply to price insensitive customers.

The ability to access both revenue streams will potentially unlock further supplies of DRM where the costs associated with the provision of the service are too high to make either service attractive individually. For instance it may encourage additional businesses to justify the costs and risks of installing the equipment to allow on-site emergency generators to synchronise with the grid supply.[13]

The additional services will bring more value to the market lowering or deferring investment in new generation and network augmentation.

This design feature reflects the AEMC's position in the Power of Choice reforms.

4.4 Relationship between DRAs and MDPs

Metering data used in DRM is collected in the first instance by MDPs.

[13] It has been suggested that NSP's should be required to issue a notification like a demand response notification when calling NSS (at least for NMI's that are part of DRM). This information would be treated by AEMO as an event day for demand response. While no payment would be made to the NSP, this day would be excluded from the set of qualifying days from which baseline energy is derived, except when there were no non-event days available. This design suggestion has not been adopted on the grounds that: (a) it would be difficult to require NSPs, which are not energy market participants, to provide such notifications; (b) the DRA for the NMI would most likely be offering that NSS response as DRM away; and (c) given the instance of an NSS response on a NMI registered in DRM but not offered as part of a demand response is not likely to be great and given that NSS is rarely used, the potential impacts on accuracy are unlikely to warrant the effort or cost of such a proposal.

A DRA will have the right to access metering information for a NMI and for the period for which it holds the DRA role.[14] The DRA will receive metering reports from AEMO, as discussed in Section 12.6. A DRA wishing to receive and query metering data directly from the MDP will need a relationship and contract with the MDP. The NER require that where a party is getting information from MDPs there must be an agreement between those parties and that the MDP can charge for its costs. A bilateral relationship would be for the DRA to establish and would be unrelated to the Rules and NEM procedures.

A DRA supplying ancillary services from a load that is not a demand response load will not as a result have any right to the meter data of the load. Ancillary services are a real-time service and half hour meter data is not used in their measurement.

4.5 Compliance & Prudential Supervision of DRAs

DRAs will have obligations under the National Electricity Rules, which may be subject to regulatory oversight by AEMO and the Australian Energy Regulator (AER).

The AER has the role of monitoring the wholesale electricity market to ensure compliance with the legislation and rules and can take enforcement action.

A DRA will have the following explicit responsibilities with respect to demand response load and ancillary service loads:

- It will be accountable for the eligibility to provide demand response of the NMIs for which it holds the DRA role. See Sections 4.3.4 and 6.1.
- It will be required to have called a demand response from each of its demand response loads for which it notifies the market that it is providing a demand response.
- It will be required to maintain systems and to meet the verification requirements of the Market Ancillary Services Specification.
- 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. See Section 4.3.5.

AEMO’s powers of enforcement are restricted to registration, applying prudential obligations and managing settlement defaults. As DRAs are expected to be creditors, AEMO is unlikely to require prudential support from a DRA or to suspend a DRA due to a default. It is possible that a DRA is a net debtor, either due the demand response energy being negative or the spot price being negative.

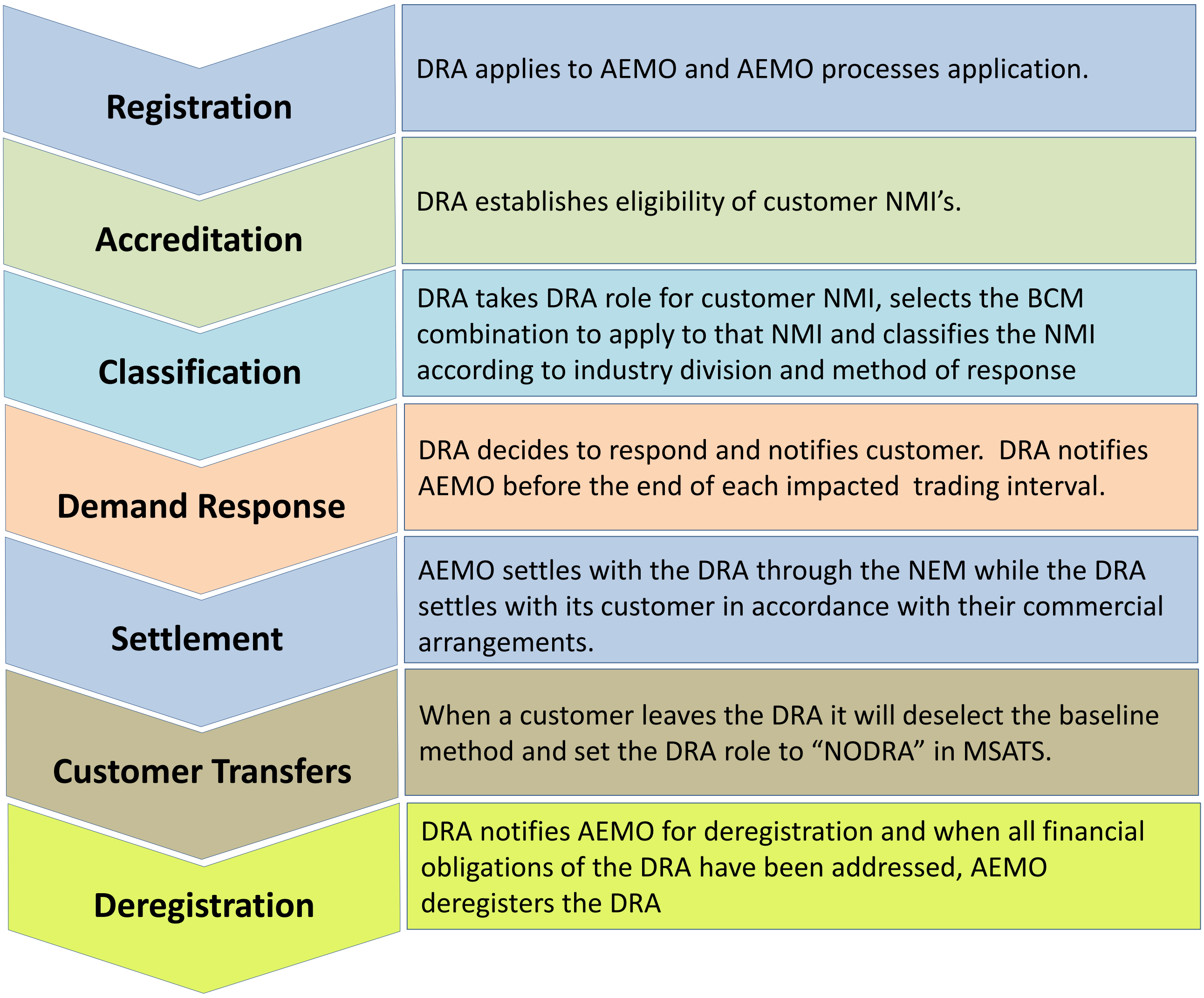
[14] Updates may be made to the metering Service Level Procedures/Service Level Requirements to add the DRA to have the same data access rights as per the network and local retailer.

5 DRA Registration

5.1 Process Overview

Figure 6 illustrates the key events in the life cycle of a DRA with respect to Demand Response.

Figure 6 – Lifecycle of a Demand Response Aggregator in the Demand Response Mechanism



An organisation wishing to provide demand response through the DRM must register with AEMO as a DRA. Having registered, a DRA will then seek to have end-users' NMIs accredited as being able to be demand response loads. The DRA must register its role as DRA for the NMI in MSATS and must classify the nature of the demand response and select the baseline consumption methodology combinations used to calculate the level of demand response.

From that time the DRA can self-schedule the demand response by notifying AEMO and impacted parties when it has initiated a demand response. AEMO will settle it for the provision of demand response.

A customer transfer process will allow customers to join and leave the DRA's collection of NMIs over time. When a customer leaves the DRA it will have to set the NMI DRA role to "NODRA".

To exit the role of DRA an organisation in that role must have transferred all its customers and must have completed settlement of all its financial obligations before being deregistered.

Figure 7 illustrates the key events in the life cycle of a DRA with respect to Ancillary Services.

Figure 7 – Lifecycle of a Demand Response Aggregator with respect to Ancillary Services

Registration	DRA applies to AEMO and AEMO processes application.
Accreditation	DRA applies to AEMO for technical approval of ancillary service loads. Approval requires compliance with requirements of Market Ancillary Services Specification
Classification	DRA provides necessary information to record ancillary service load in AEMO systems.
Offer Ancillary Services	DRA offers ancillary services to the NEM.
Deliver Ancillary Services	DRA is scheduled to provide Ancillary Services
Settlement	AEMO settles with the DRA through the NEM while the DRA settles with its customer in accordance with their commercial arrangements.
Deregistration	DRA notifies AEMO for deregistration and when all financial obligations of the DRA have been addressed, AEMO deregisters the DRA

Ancillary service load offered by a DRA assumes that the DRA is registered, so Figure 7 assumes the DRA is registered and does not focus on the deregistration process. A DRA seeking to provide FCAS must seek accreditation[15] from AEMO to establish that the load or aggregate load providing that service meets technical standards. Once approved the DRA must classify ancillary service load in AEMO systems. Ancillary services are scheduled by AEMO so the DRA must make offers to the market. Only when these offers are accepted and the service scheduled, can ancillary services be provided and settled.

The level of detail of ancillary service processes in this document are less than for demand response as ancillary service processes are already established in the NEM. The only change is that a DRA can now provide these services.

5.2 Registration

Registration is the process by which an organisation is admitted by AEMO into the NEM to allow it to participate in the market. Once registered, such organisations are Market Participants. Under DRM a new registration category of Demand Response Aggregator will be created. This will allow the DRA to undertake its two primary functions:

[15] The use of 'accreditation' and 'classification' are simply for ease of discussion and for consistency with terminology around DRM. Accreditation is about establishing that a load is eligible to provide the service while classification relates to setting up systems so that demand response load and ancillary load can actually participate. These terms are not rules terms. In practice accreditation and classification for ancillary service may be a single process.

- To indicate loads that are able to provide demand response or ancillary service to the market.
- To provide demand response and ancillary services from those loads and to be settled.

AEMO will produce an application form and guide for registration as a Demand Response Aggregator. The existing guides and forms for the Small Generation Aggregator category of participant will be used as a model for developing the new form and guide. AEMO's registration systems will be modified to allow the new category of participant to be registered.

Following the convention for Customers and Small Generation Aggregators, eligibility for registration will require demonstration of

- An ability to comply with the National Electricity Rules.
- An intention to classify a load as a demand response load or an ancillary service load within a reasonable period of time.

The existing registration database structure will be used for registration of DRAs. AEMO will register company information it needs to provide the new DRA access to its systems and to allow AEMO to bill and settle with the DRA. Existing participants will also be able to register with AEMO as a DRA and there will be no design restrictions on which participants can register as DRAs.[16]

5.3 Accreditation and Classification

Following registration, a DRA will need to take up the role of DRA for the NMIs associated with its customers. This involves first establishing the eligibility of the NMI to participate in DRM through an accreditation process, and then providing to AEMO information required for actively participating in DRM and for statistical purposes for that NMI through a classification process.

DRAs providing ancillary services must apply for AEMO's approval to classify a load (which may be aggregate loads) to provide ancillary services. As there are technical standards to be satisfied AEMO's approval is required.

These processes are described in Section 6, though as the classification process for ancillary services occur under existing NEM processes and are not described in this document.

5.4 Participation

A DRA will interface between the end-user and the NEM by:

- Entering into agreements with end-users to provide demand response in the NEM.
- Provide notifications to AEMO of intended and actual demand response.
- Instruct end-users to reduce demand.
- Provide bids to AEMO for the provision of ancillary services.
- Comply with FCAS dispatch instructions to enable automatic tripping schemes to provide FCAS, either directly or by instructing end-users.
- Be responsible and accountable for compliance with the requirements of the National Electricity Rules relating to DRAs.
- Receive payments for demand response from AEMO through AEMO's clearing facility.
- Be subject to AEMO's prudential management and default procedures in the event a DRA owes money.

[16] The detailed design does not over-ride any pre-existing restrictions or exemption requirements on trading in the energy market that may exist with respect to organisations in other roles, such as network operators.

5.5 Deregistration

AEMO is not entitled to forcibly remove a participant from the market. If a participant wishes to exit the market, it must send a notification[17] to AEMO but will not be able to leave the market until it has met all its financial obligations.

Note that market suspension is managed through the default processes rather than through deregistration.

5.6 Fees

Participant fees will be charged as follows:

- Applicants will pay a registration fee based on AEMO's costs of processing an application.
- Energy-based fees and compensation payments will be charged as part of market settlement as described in Section 13.

There is no explicit fee for the accreditation or classification of loads as demand response or classification as ancillary services under the current fee determination. AEMO costs for this activity (which may be substantial if there are a large number of applications) will be covered as part of the general energy fee to all participants. This may be revisited as part of the next AEMO fee determination due in 2016.[18]

[17] Not to be confused with a demand response notification.

[18] Alternatively, the rule change could direct AEMO to amend the fee determination outside the normal structure of fees cycle.

6 Accreditation and Classification

6.1 Demand Response Load Accreditation

6.1.1 Process

The process of accreditation may actually happen in parallel to the entry of most classification process data (as described in Section 6.2), though accreditation must be achieved before the DRA will take the DRA role for the NMI.

The onus will be on the DRA to acknowledge that the technical eligibility requirements for a NMI to participate in demand response are satisfied and this will be the basis of accreditation. Where technical eligibility is not tested by AEMO systems at the time of application or in the course of periodic review, the DRA will be subject to periodic manual audit by AEMO. Any material non-compliance found in the audit would be reported by AEMO to the AER and AEMO would have the ability to remove the accreditation of the NMI.[19] The AER may impose civil penalties on the DRA.[20]

The requirements for accreditation would be specified in the DRM Procedures. These requirements are detailed in Section 6.1.2.

The requirements that can be tested automatically are:

- The inclusion of the customer's NMI in the Market, Settlements and Transfer Solution (MSATS) system.
- The eligibility of the meter(s) associated with the NMI
- The availability of meter data history in MSATS for that NMI.
- The NMI has a NMI Classification code of "LARGE"
- The variability of the load

The DRA will need to self-assess the eligibility of a NMI with respect to the following requirements that cannot be tested automatically:

- The existence of a contractual arrangement between the DRA and customer.
- That there are no conflicts in the services provided by the customer.
- The appropriateness of the wiring configuration of the site.

In classifying a demand response load in MSATS the DRA will effectively be indicating that it has successfully performed this self-assessment. In the event of an audit the DRA will need to be able to: prove that it has a contract with its customer; provide evidence that its customer has confirmed it is not providing any services which would make it ineligible for DRM; provide wiring diagrams for the site; and for sites with multiple connection points provide evidence of the assessment of the appropriateness of that wiring.[21]

If accreditation is rejected because of failure to pass the automated testing then the DRA would be able to reapply as soon as any changes occur that remedy the reasons for rejection.

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[19] For the avoidance of doubt, if a NMI that was eligible for demand response ceases to qualify simply as a result of failing an automated test at the time of a review of its eligibility – e.g. of the variability of its load – then it may lose its eligibility to participate in DRM on prospective basis but will not be referred to the AER.

[20] It was suggested that the demand response delivered by that NMI should be cancelled retrospectively for the time periods still within the six month window for updating settlement. This approach is not proposed based on precedent. For example in 2007 the operator of a smelter was found to have failed to withdraw offers to provide FCAS after pot lines were shut down. The smelter operator was not eligible to offer FCAS but did. In that case the AER imposed a civil penalty but settlement was not reversed.

[21] This would involve identifying the types of equipment at each connection point to establish that the functions performed by equipment at one connection point cannot be substituted for by instead running equipment at the other connection point.

There will be no specific fee applied for NMI accreditation.

6.1.2 Requirements for Accreditation - Demand Response Load

For a NMI to be accredited for the provision of the DRM it must satisfy the NMI eligibility requirements. These eligibility requirements will be applied whenever a NMI is first associated with the DRA role, when the customer changes, when the DRA changes and as a result of periodic reviews.

Contractual Requirements

A DRA will be required to have a commercial arrangement with its customer.

No Conflict in Services Provided by the Customer

A DRA must confirm with its customer that the load at the NMI is not a scheduled load in the NEM and that load is not classified as providing ancillary services to the NEM via another NEM participant.

MSATS Requirements

It is required for the NMI to be registered in AEMO’s consumer transfer system (MSATS), since this is a pre-requisite in order for AEMO to obtain all the necessary information of a specific connection point for settlement, auditing, and discovery purposes.

Metering Requirements

The NMI must have a type 1, 2, 3 or 4 interval metering installation, since the DRM requires daily interval meter reads and only 1, 2, 3, and 4 interval meters have daily meter data delivery timeframes that support these DRM requirements.[22] The use of other meters, including sub-meters[23], is not allowed. The datastream associated with the NMI cannot be measuring market generation.

Wiring Requirements of Site

A diagram of the wiring at the site is required so that it will be possible for AEMO to assess if an apparent demand response on a NMI can occur as a result of the customer shifting load from that NMI to another NMI on the same site without changing the ultimate consumption.[24] This will only be relevant if there is more than one connection point on the site. This situation could arise, for example, if a company has four interchangeable manufacturing machines with two on one connection point and two on another. They could create an apparent demand response at the NMI for one connection point by shutting down a unit there, and starting up a unit on the other connection point, even though their total consumption is unchanged. There would be no issue, however, if all the manufacturing units were on one connection point, while the factory office was on the other connection point.

Where there is more than one NMI eligible for participation in DRM at a site then it will be required in procedures that if one of those NMIs participates in DRM then all of those NMIs must participate in DRM. They must all have the same DRA and if one is included in a demand response notification then they must all be included. This requirement will not be reflected in, or validated by, AEMO’s systems. However, it will facilitate a simple assessment by AEMO or the AER of whether load shifting is occurring. In such cases the requirement in Section 8.1.4 that the DRA or customer take some deliberate action to provide demand response at a NMI should be interpreted as applying across the set of NMIs participating in DRM at the site.

[22] AMI meters (Type 5), while they record interval data, do not have the same data delivery requirements i.e. they could be read only monthly or quarterly and as such does not meet the requirement for DRM.
[23] Sub-meters are not governed by market rules and procedures.
[24] Restrictions on this behaviour are described in Section 8.1.4.

The DRA must be in a position to provide AEMO with evidence that there is only one connection point for the site and otherwise to provide suitable wiring diagrams for the site as soon as practical upon request by AEMO. A request would arise as a result of an audit of the eligibility of a NMI.

Meter Data for the Eligibility Test Data Window

A minimum set of meter data will be required before an eligibility test is performed on a NMI.

The NMI must have 60 non-event days of interval meter data available and the current customer must have been associated with that NMI for that period. This is the "eligibility test data window".

A period of 60 days is proposed for the data to be used in eligibility testing as this provides a reasonable basis for assessing the average daily consumption of a NMI. Other markets such as PJM and California require that the eligible days come from a period of similar duration. . This level of data also removes the need for additional manual processes to assess the eligibility of a new load.

Threshold Requirement

The threshold requirement for NMI participation will be that the NMI Classification code in MSATS associated with a NMI is set to "LARGE". The NMI classification code is based on the local network service provider's determination of the annualised consumption of the NMI. The NMI classification code must be set to "LARGE" if the determination of the annualised consumption for the NMI exceeds the upper consumption threshold as defined in the National Energy Customer Framework (NECF) or any over-riding limit set in a jurisdiction or any alternative threshold specified by jurisdictions not party to NECF. Table 1 presents what the effective MWh per year limits would be by jurisdiction.

Table 1 – Annualised consumption levels driving Upper Consumption Threshold for each region.

Jurisdiction	Upper Consumption Threshold	Basis for Upper Consumption Threshold
ACT	100 MWh p.a.	NECF
New South Wales	100 MWh p.a.	NECF
Tasmania	150 MWh p.a.	NECF, with higher jurisdictional limit.
South Australia	160 MWh p.a.	NECF, with higher jurisdictional limit.
Victoria	Expected to be 100 MWh p.a. by January 2014[25]	Victoria is not currently party to NECF but is transitioning to it. Network operators are requiring the field to be set to align with NECF.
Queensland	100 MWh p.a.	Not party to NECF, state based limit.

Load Predictability Requirement

The NMI must have a predictable load for which baseline energy can accurately be estimated. A BCM combination will be associated with each NMI. As discussed in Section 9, a BCM combination may comprise up to two BCMs, where one is used for weekdays that are not (local) state public holidays, the other being used for weekends and (local) state public holidays. In some cases a BCM combination will not allow demand response to be provided on weekends or (local) state public holidays.

[25] As proposed in Section 6.2 of the "Harmonisation of the Energy Retail Code and Guidelines with the National Energy Customer Framework".

The specified accuracy test requires that a relative root mean square error (RRMSE) metric has a value not exceeding 20%. The RRMSE tests how closely a BCM predicts the NMI's actual load.

The RRMSE test will be performed for each of the available BCM combinations with the test performed separately for BCMs used for weekdays excluding (local) state public holidays and for BCMs for weekends and (local) state public holidays. The test will be applied in each case to a set n of trading intervals.

- For the weekday excluding (local) state public holidays test, the set n comprises all trading intervals between 2 PM and 5 PM market time[26] occurring on non-state public holiday (in that location) [27] weekdays, excluding event days, in the eligibility test data window.
- For the weekend/ (local) state public holiday test, the set n comprises all trading intervals between 2 PM and 5 PM occurring on weekends and state public holidays (in that location), excluding event days, in the eligibility test data window.

To meet the load predictability requirement, both the weekday and the weekend RRMSE values must not exceed 20%. The 20% accuracy limit proposed is based on a limit used by PJM in the eastern United States. To address the possibility that a baseline is accepted on weekdays but rejected on weekends, a BCM combination will be made available that includes the weekday methodology to be applied on weekdays but has no methodology set for weekends/public holidays. If such a BCM combination is selected for a NMI then demand response will only be accepted from it on weekdays.

The test will identify all BCM combinations that pass the test, with these ranked from best performing to worst performing. The best performing BCM combination will be assessed based on the accuracy identified in the weekday excluding public holidays test, though in a tied situation a BCM combination which allows demand response on weekends and (local) state public holidays will rank ahead of one that does not.

The formula that is used to calculate the relative mean squared error (RMMSE) is:

$$RRMSE = \frac{\sqrt{\dfrac{\sum_{n \in N} (L_n^{baseline} - L_n^{actual})^2}{N}}}{\dfrac{1}{N} \times \sum_{n \in N} L_n^{actual}}$$

Where:

- n is the set of trading intervals from which meter data is taken for the performance of the calculation.
- *N* is the number of elements in set n
- $L_n^{baseline}$ is the calculated baseline load associated with a trading interval in set *n*.
- L_n^{actual} is the actual metered load associated with a trading interval in set *n*.

RRMSE expresses the baseline's average half hourly accuracy as a fraction of average hourly load. The RRMSE is based on squared prediction errors, so weights large errors much more heavily than small or midsized errors.

6.1.3 Review of NMI Accreditation

There are a number of situations under which NMI accreditation can be reviewed and potentially ceased.[28]

[26] This is based on the convention used by PJM, thought they use the time window of 2 PM to 7 PM.
[27] We are using the Metrology Procedure Part B convention on meter substitution which uses public holidays (as a non-defined term) rather than the NEM rules term which would only account for public holidays across the entire NEM.

1. Meter changes
2. Customer changes
3. Implementation of a new BCM combination since the last eligibility test.
4. DRA changes
5. Periodic reviews

The first situation would arise if a change request was raised in MSATS to change the meter type for the NMI to a type that no longer meets the requirements for demand response. The change request could only be accepted if the DRA also changed the status to NODRA.

If the customer changes then the DRA must reset the NMI role to NODRA and the eligibility test must be performed again for any new customer at that NMI.

If a new BCM combination is accredited and a DRA wishes to use it then it will need to have the eligibility test performed on that BCM combination before selecting it.

The DRA changing is included primarily because the DRA needs to accept accountability that the NMI meets the eligibility requirements. As the validation test would be automated there would be little overhead in performing it.

A review of the predictability of the load for each of the accredited BCM combinations would be performed approximately every six months by AEMO. This would provide some ability to assess seasonality issues.

It is proposed that if the period review test fails then it would be performed again several weeks later and if the test failed again the DRA would be advised that the NMI is no longer eligible. A time frame would be set for the DRA to set the NMI's role to NODRA.

6.1.4 Audits

AEMO will conduct periodic audits of the eligibility of a NMI to participate in DRM. An audit may also be triggered by AEMO being notified by another market participant that it has reason to believe that the NMI is not eligible for demand response.

An audit will entail requiring that the DRA provide, at its own cost, evidence that its customer has confirmed it is not providing any services which would make it ineligible for DRM; wiring diagrams for the site; and for sites with multiple connection points evidence of the assessment of the appropriateness of that wiring.

In developing the procedures for audit, a notification time will be specified describing how long the DRA has to provide the required information. The DRA will be required to provide this information within that time frame.

If AEMO is not satisfied that a NMI is eligible for DRM then it may take actions including removing the DRA role from the NMI and referring the conduct of the DRA to the AER for review.

6.2 Classification of Demand Response Load

There are two aspects of the classification of Demand Response Load:

- Associating the DRA with the DRA Role for the NMI in MSATS
- Providing statistical reporting information for the NMIs to AEMO.

[28] In the event that the NMI Classification code changed so as to cease to be LARGE then the DRA would be notified of this change and would then need to set the DRA role on the NMI to NODRA.

6.2.1 Associating the DRA with the DRA Role

This process involves registering in MSATS that the DRA is taking the DRA Role for the NMI and selecting an accredited BCM combination to be used by AEMO for the purpose of calculating demand response energy for that NMI.

If only one accredited baseline were available, or if the validation test defined the baseline, then the act of passing the test could select the baseline to be registered in MSATS. If multiple accredited BCM combinations were available then this process may need to allow for testing more than one baseline and allowance for dispute may be required.

6.2.2 Statistical Reporting Information

AEMO is required to provide annual reports relating to the level and sources of demand response. These reports are described in Section 14.2.

The information recorded in MSATS relates to the site of the NMI and does not provide customer specific information, such as how the demand response is provided.

To facilitate this annual reporting, DRAs will be required to provide AEMO with the following information relating to NMIs:

- The Australian and New Zealand Standard Industrial Classification for the load.
- Which of the following methods is to be used in delivering the response:[29]
    - electricity generation, with the fuel identified as one of:
        - coal
        - diesel
        - natural gas
        - oil
        - petrol
        - kerosene
        - propane
        - wood
        - landfill gases
        - waste products
    - plant shutdown
    - heating, ventilation and air conditioning
    - lighting
    - refrigeration
    - manufacturing processes
    - water heating
    - batteries
    - plug load[30]

These specific requirements will be recorded in a new procedure relating to DRM. As the information is only required for periodic reporting it is proposed that a simple communication mechanism be used, such as requiring that the DRAs periodically submit to AEMO a standard form

[29] These are based on conventions used by PJM.
[30] This represents other electronic devices that are plugged in, including computing equipment, printing equipment, and other appliances.

spreadsheet listing this information for the NMIs for which they have had the DRA role over that period. The DRA might also be required to provide the range of dates within the period for which it was the DRA for a given NMI.

6.3 Ancillary Service Load Accreditation

6.3.1 Process

The existing process for a load to be accredited to provide ancillary services is as follows:

- A load is classified by a registered Customer but only requires AEMO's approval in certain circumstances. A first-tier, second-tier or market load does not require AEMO's approval. However, a market load can also be classified as a scheduled load or an ancillary services load but this requires AEMO's approval.
- Market loads can also be aggregated as ancillary service load with AEMO's approval, if it is satisfied:
  - The market load can be used to provide market ancillary services in accordance with the market ancillary services specification (MASS).
  - There is adequate telecommunications and/or telemetry for dispatch and auditing purposes.
- Registration as a Customer and classification of loads are separate processes.

A DRA will be able to seek accreditation for a load as an ancillary service load. This load need not be a demand response load but only a DRA will be able to seek accreditation of a demand response load as an ancillary services load. A DRA will be allowed to aggregate load to form an ancillary load. A demand response load included in such an aggregation can simultaneously be offered as demand response load. An aggregated ancillary services load must be able to meet the market ancillary services specification (MASS).[31] The MASS may need to be changed to provide guidance on classifying demand response loads as ancillary service loads.

AEMO will employ an arrangement similar to the approval of other ancillary service loads, including aggregated ancillary service loads. That is, classification of ancillary service loads by a DRA would be a separate process to participant registration and be a largely technical assessment of a proponent's ability to provide frequency control ancillary services as described in the Market Ancillary Services Specification.

Ancillary service loads use the same application form as is used for Market Participant registration. However, the processes can be, and usually, are separate. As a result, the fees applicable for an application to classify a load as an ancillary service load can be different to those for a registration application.

No design restrictions will be placed on the Ancillary Services that can be offered. It is expected that for technical reasons a demand response load will generally only be able to offer three frequency raise services – fast, slow and delayed[32], though new technologies may allow some loads to satisfy the technical requirements of the other services (frequency lower fast, slow and delayed, and raise and lower frequency regulation services).

6.3.2 Requirements for Accreditation – Ancillary Service Load

AEMO must approve the application if it is satisfied the loads or aggregated loads meet the requirements of the Market Ancillary Services Specification.[33]

[31] Available from the AEMO website.
[32] Also known as contingency raise 6-second, 60-second and 5-minute services.
[33] These specifications are unrelated to the eligibility requirements for DRM and it is not required that a load be eligible for DRM to receive accreditation as an Ancillary Service Load.

AEMO is required to maintain power system security. Market ancillary services are dispatched by AEMO to manage power system security, to facilitate orderly trading and ensure acceptable electricity supply. AEMO assesses and classifies the performance parameters and requirements of market ancillary services to ensure it has an understanding of what response is available to manage power system security. Individually, market ancillary services do not have a significant impact. However, when needed, these are used as a collective response to manage power system security and it is important that the service performs as indicated.

If AEMO did not need to approve AS load classification AEMO would not perform due diligence on prospective ancillary services and would have difficulty discharging its power system security obligations. This would introduce inconsistencies in the classification of ancillary service load between DRAs and other Market Participants.

6.4 Classification of Ancillary Service Load

The classification of Ancillary Service Load involves recording the information of these loads in the Market Management System. This is an existing process and is therefore beyond the scope of this document.

Loads classified to provide market ancillary services will be scheduled through the central dispatch process.

Loads are generally not able to provide ancillary services if the load is out of service. As with a Market Customer, a DRA 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 that is found to have been 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, there will be no provision for a mechanism to “claw back” ancillary service payments made to a DRA that is found to be unable to provide the service. Instead, this would be a rule breach and the DRA may incur penalties if this occurred.

An ancillary service load will be able to be transferred from a DRA to another DRA or a Market Customer with AEMO’s approval.

7 MSATS Setup

7.1 Roles of MSATS

The Market, Settlements and Transfer Solution (MSATS) system is a system maintained by AEMO which stores for each NMI:

- standing data pertaining to that NMI
- who is responsible for the various roles associated with a NMI, such as who is the financially responsible market participant (e.g. the retailer), who is responsible for metering, who is the distribution network operator, etc.
- the metering data associated with the NMI.

The processes for transferring customers or changing roles are all implemented via MSATS. MSATS also compiles settlement ready data for the settlement system.

7.2 NMI Set Up

A Demand Response Aggregator (DRA) can only include in a demand response notification NMIs that are already identified within MSATS as providing a demand response. Currently a NMI has a Financially Responsible Market Participant (FRMP) role associated with it. A new DRA role will be created to also associate the DRA with a NMI that is providing demand response. However, this new role will not be applied to all NMIs in MSATS. Instead, the role will be associated with a NMI only when that NMI is first identified as a demand response load through having a DRA associated with it. Once the DRA role is set up for a NMI it cannot be removed. When a NMI ceases to be a demand response load, a dummy DRA Participant ID (e.g. 'NODRA') will be assigned to the NMI. This dummy DRA Participant ID will be administered by AEMO.

The Rules will be changed to recognise that the DRA will have financial responsibilities associated with this role. However it is not proposed that the DRA be treated as a FRMP as currently defined in the Rules. The Rule change proposal will define the DRA role as financially accountable in relation to the demand response energy, while the FRMP will remain financially responsible for the sum of the metered energy and demand response energy (i.e. the baseline energy) at the site.

The DRA role for a NMI provides for a clear and simple business process across market participants. It provides transparency and scalability to demand response activities.

7.2.1 Roles and Responsibilities

The MSATS roles and responsibilities of DRAs, including timeframes for updating MSATS, will be defined in the MSATS Procedures.

The general participant obligations that are stated in Section 2.2 of the Consumer Administration and Transfer Solution (CATS) Procedures would also apply to DRAs.

A new section will be required in the MSATS Procedures to detail the DRA-specific obligations. Some MSATS terminology used in the proposed obligations for DRAs is listed in Table 2 below for reference.

Table 2– MSATS Terminology

Term	Meaning
Change reason code	Participants submit a change request in MSATS using a change reason code for example a Change Request (CR) 1000 – is a 'Change Retailer' transaction.
Change request	Participants submit change requests to change current or create new data in MSATS. For example, an LSNP submits a CR2001 to create a NMI.
DRA ID assignment process	Term used to indicate a NMI is participating in demand response for the first time. *Note: MSATS system does not treat the DRA ID assignment process and DRA transfer process differently. These different terminologies will be used in the MSATS Procedures.*
DRA transfer process	Term used to indicate the DRA on a NMI is changing. *Note: MSATS system does not treat the DRA nomination and transfer process differently. The different terminology will be used in the MSATS Procedures.*

The DRA must have a contract in place with the consumer prior to assignment of the NMI as a DR NMI in MSATS. This contract must be provided if requested by the AER.

A DRA taking on the role for a NMI for the first time must:

- Confirm with the consumer that signing it up for DRM does not conflict with other demand-side agreements that the consumer may have with the distributor or retailer.
- Initiate a change request to assume responsibility for the NMI. Subject to the prospective periods[34] in MSATS, the DRA must initiate the change having the mandatory information required to initiate a valid DRA ID assignment in MSATS.[35]
- Manage the DRA ID assignment process if there are any matters that require attention in regard to the NMI, either from the operation of the MSATS system or from events that are external to the operation of the MSATS system. For example, managing relationships with the NMI's other role participants as needed.
- Withdraw a change request as soon as practicable, and within two business days, of being aware that the DRA ID assignment cannot be completed.
- Nominate the accredited BCM combination to be used on the NMI and update this information in MSATS.

An incumbent DRA for a NMI must:

- Take responsibility for the demand response wholesale spot market settlement in respect of a NMI until the actual date of the NMI transfer to another party taking over the DRA role for that NMI (or it changes to a Participant ID of 'NODRA') or until the NMI is classified as extinct (i.e. preventing participants to be associated with the NMI).
- As the DRA has a relationship with the consumer at the NMI rather than with the site, the DRA is responsible to update MSATS and end its DRA role if the consumer at the NMI

[34] MSATS permits prospective changes to data. These time periods are defined for each change reason code. For example, a change of retailer is permitted for 65 prospective business days.

[35] Although the DRA and consumer engaged in a contract prior to the NMI assignment in MSATS, it is not possible for a DRA to call a DR event retrospectively, thereby negating the need for a retrospective change request.

moves out of the property. The DRA must update MSATS within two business days of receiving the information from its consumer.[36]

- As the DRA has a relationship with the consumer at the NMI rather than with the site, the DRA is responsible to update MSATS and update the selected BCM combination if the consumer at the NMI moves out of the property. The DRA must update MSATS within two business days of receiving the information from its consumer.
- If the consumer or the DRA terminates their contract, then the DRA is responsible to update MSATS (to a Participant ID of 'NODRA') and update the selected BCM combination (to 'NOBCM'). The DRA must update MSATS within two business days of consumer becoming aware of this change.

An incumbent DRA for a NMI may:

- If applicable, object to a change request from another DRA seeking the DRA role for that NMI (e.g. because the incumbent has a contractual relationship with the consumer) using one of a number of pre-defined objections.
- Update the BCM combination to be used on the NMI in MSATS.

New obligations on AEMO (likely to be created in Section 2.11 of the CATS Procedure) will stipulate that AEMO continue to invoice (as per Rules requirements) the incumbent DRA for a NMI until either the NMI is transferred to another DRA or the DRA notifies AEMO that it is ceasing its relationship with the NMI.

The DRA's data access rights would be configured in MSATS (by AEMO) in accordance with current practice which sets rights according to data requirements. These rights can be modified over time as appropriate. The DRA will always have access to MSATS NMI standing data for a NMI for the time period for which it has the DRA role.

7.2.2 NMI Standing Data

The following new demand response related standing data will be collected, stored and distributed from MSATS:

- Baseline Consumption Methodology Combination.
  - Only an accredited BCM combination name or 'No BCM' would be the permitted options.
  - A new change reason code would be introduced to allow the incumbent DRA to update this information in MSATS. DRAs will be permitted to change the BCM combination prospectively only. See Section 7.4.1.
  - DRAs will be able to create and update the BCM combination by using the CR1060 and CR1062. See Section 7.4.1.
- The meter type (Type 1, 2, 3 or 4).
- A NMI must have a datastream identified by a suffix to participate in the wholesale settlement process (see Table 3 below). The following modifications will be required for DRM:
  - A new derived datastream type, "D", will be created in MSATS. Only AEMO can create and be responsible for the "D" datastream as it will determine and populate the (delivered) demand response energy values.
  - A new suffix "ZZ" will appear in the MSATS NMI datastream table.
  - For NMIs with datastream type "D", the demand response energy will be populated against this datastream and suffix for demand response trading intervals involving this NMI.

[36] It is not necessary that the retailer at the NMI will change when a consumer moves out.

- Currently MDPs create datastreams in MSATS; however the "D" datastream type will be created and maintained by AEMO as part of initial setup for each NMI participating in DRM. Similar to the current create datastream change request notifications, the following roles will receive a notification when AEMO creates the datastream: DRAs, FRMPs, LR, LNSP, MDP, MPB, RP.
- The demand response energy will be identified against the "D" datastream type in MSATS settlement reconciliation reports. Participants will be able to run current MSATS Meter Data Management (MDM) reports to retrieve this demand response energy at the datastream level. A new MSATS report will be delivered to DRAs and FRMPs each time the demand response energy is used in a published settlement run by MSATS. The new report will be in the MDFF specification.
- The NMI Procedure and the NMI Standing Data document will be revised to reflect the new demand response datastream type and suffix.

Table 3 – Current and new datastream types and suffixes

Current Datastream Types[37]	**Current suffix examples**[38]
I = Interval C = Consumption P = Profile 1 = NonMarketActiveImport 2 = NonMarketActive 3 = NonMarketReactiveImport 4 = NonMarketReactive	N1 = for interval meters 11 = for basic meters
New Datastream Type	**New suffix proposed**
D= Demand Response	ZZ = derived demand response energy

7.2.3 BCM Combination Selection

A DRA would select an accredited BCM combination. This must pass the test of load predictability. If more than one accredited BCM combination is available and passes the test of load predictability, if the DRA selects the best performing accredited BCM combination[39] then there will be no basis for another participant with a role for that NMI to challenge the registration in MSATS based solely on that choice.

If the DRA wishes to use another of the acceptable accredited BCM combination's that passed the test of load predictability then that may be rejected by the retailer for that customer. This approach allows the retailer and the DRA to agree to the use of another BCM combination but does not prevent the DRA from registering the most accurate BCM combination.

7.3 NMI Discovery Process

When a search is performed for a NMI the NMI standing data will be available. The only change proposed is that if the NMI is actively participating in demand response i.e. it has a DRA role assigned then the BCM combination and datastream will also be returned in a NMI discovery search. Existing participants allowed to use the NMI discovery process (prospective retailers,

[37] Described in the NMI Standing Data Document
[38] Described in the NMI Procedure
[39] As discussed in the Threshold Requirement section of Section 6.1.2 the assessment of the best BCM combination uses only the non-public holiday weekday predictability result and tied situations gives preference to a BCM combination that allows demand response on a weekend.

FRMPs and the current LNSP for the NMI) will also receive this information when performing a NMI discovery search. This would allow a prospective retailer to know the BCM combination in advance of a consumer change.

A DRA will be permitted to undertake NMI discovery searches in MSATS for the purposes of contracting a consumer for DRM purposes only, and will receive the same set of NMI standing data currently received by prospective retailers.

A DRA will not be permitted to perform a NMI Discovery Type 3, which currently allows a retailer to identify the current or previous retailer. It is the expectation that if there is a need for a DRA to contact the retailer of a site as part of signing up a consumer for DRM e.g. to establish or confirm requirements such as metering, or understand existing contractual agreements, that this would be facilitated by discussions with the consumer.

7.4 MSATS Transfer Process

Similar AEMO business rules that apply to customer churn and changes to standing data for market loads will apply to demand response loads.

DRM is not subject to consumer protection frameworks of jurisdictions or in the National Energy Retail Rules, such as cooling off periods or sales conduct.

The transfer, notification and objection process mirrors the existing retailer transfer process. Participants are required to update and maintain their data in MSATS when changes occur and will receive notifications on other proposed data changes on a need to know basis.

7.4.1 DRA Initiated Transfer

MSATS already includes a process to change the retailer associated with a NMI. When a retailer nominates to take over a NMI it submits a ‘change retailer’ change request in MSATS. This associates the intending retailer with the NMI but does not complete the change. Other parties associated with that NMI can raise objections. In many cases the retailer needs to discuss the objection with the objecting party. If the issue is resolved then the objector withdraws the objection and the change request completes with the retailer taking the FRMP role for the NMI in MSATS. If the objection is not withdrawn within a stipulated timeframe then MSATS automatically cancels the change request.

A similar process will be used for DRAs. Table 4 shows the proposed new change reason codes introduced for DRA.

Table 4 – Proposed change reason codes

Change reason code	Name	Submitted by
CR1060	Assign DRA and BCM - Prospective	DRA
CR1062	Assign “NODRA” and update BCM - Prospective	DRA

When a DRA wishes to assign its DRA Participant ID to a NMI it will nominate that NMI in MSATS by submitting a new CR1060. This new change reason code would only be applicable to changing the DRA role. When another DRA wants to win a NMI the DRA can submit a CR1060 change request in MSATS. The DRA will be able to nominate the BCM combination for the NMI in the same CR1060 change request.

After the CR1060 changes to ‘Requested’ status then AEMO will carry out the eligibility tests. If the NMI passes the eligibility checks then the transfer will proceed as normal. If the NMI fails the test then AEMO will lodge an objection automatically. If no other information becomes available to confirm the change request then the change request will be cancelled (and hence not complete).

Participants will be able to object within the standard (usually 5 business days) objection logging time period.

Changes of any other participant role associated with a NMI will not affect the DRAs association with the NMI.

DRAs will action any error corrections required by submitting a request to AEMO and AEMO submitting an existing change request - CR5100 or CR5101 (AEMO only standing data updates) to correct the data.[40]

DRAs will not be permitted to retrospectively transfer their customers. This is because DRAs need to submit the NMI in a demand response event notification to AEMO. These notifications are not permitted retrospectively. Thus even if retrospective transfers were permitted DRAs would not be able to participate in past demand response events. The error correction process described above would provide for the correction of manifest errors.

A DRA may only include a NMI in a demand response notification if it is the 'current' DRA of the NMI in MSATS. If the DRA has submitted a transfer to take on the role of DRA for that NMI but the transfer has not yet completed then the NMI will be excluded from demand response data when MSATS prepares data for settlement.

DRAs can end their relationship with a NMI by submitting a new change reason code, CR1062 to assign a 'NODRA' participant ID. The 'NODRA' participant ID will be administered by AEMO. Only the current DRA for the NMI will be permitted to submit change requests and use this new 'NODRA' participant ID. DRAs can assign the 'NODRA' participant ID prospectively only.

The current DRA for the NMI will be able to remove the accredited BCM combination for a NMI by choosing 'NOBCM' in the same CR1062 change request.

Information on the CR1060 and CR1062 change requests will be of interest to the following other roles associated with the NMI:

- MDP,
- LNSP and
- FRMP.

These relevant participants would receive notifications at various stages of the change request process, including at the completion of the change request process. These new notifications are described in Table 5.

Table 5 – Change request status notification rules

Notification To	Change Request Stage	Notification Reason
Current LNSP	REQUESTED, OBJECTED, COMPLETED, CANCELLED	To be aware of DR activity and use this information for network planning purposes.
Current FRMP	REQUESTED, OBJECTED, COMPLETED, CANCELLED	To be aware of DR activity and use this information for consumer billing purposes.
Current MDP	REQUESTED, OBJECTED, COMPLETED, CANCELLED	To be aware of DR activity and use this information for meter data validation purposes.
Current DRA	REQUESTED, REJECTED, OBJECTED, COMPLETED, CANCELLED	To be aware of the change request's progress.

[40] If in the future volumes are high then specific error correction change reason codes could be considered.

As per current practise, the DRA (party that raises the change request) would receive one extra notification if and when the change request is rejected by MSATS (‘Rejected’ stage).

Upon receiving the notification, relevant participants would be permitted to raise one of a set of standard objections. For example, the current DRA may object to a prospective DRA erroneously raising a transfer request for a NMI that is already under contract to the current DRA. Table 6 describes the proposed objections associated with demand response.

Table 6 – Proposed objection codes

Objection Code	Objection Reason	Raised By Role
CONTRACT	Customer is under a current DR contract	Current DRA
CONTRACT	Customer contract issue	Current FRMP
ANCILOAD	Customer contract issue – customer is contracted to retailer for an ancillary services load	Current FRMP
NOELGBLE	NMI has not passed the automated eligibility checks (including accuracy, NMI size etc.)	AEMO

As per existing MSATS processes, when the CR1060 completes along with the change request completion notification, the DRA will receive an MSATS report (C4 report) containing NMI information and the current roles associated with the NMI. The DRA Role will be reported and will be available to other participants who receive the C4 Report. This report provides the new role with adequate NMI information to set up the NMI in its systems.

7.4.2 Amendment to notifications sent from current change requests

The DRA needs to know the identity of the FRMPs, MDPs and LNSPs for its NMIs. Each time one of these participants change on a NMI associated with the DRA, the DRA will receive the completed notifications from current change of FRMP, MDP and LNSP change requests.

7.5 NMI Eligibility Test Function

MSATS will provide an automated functionality to carry out the agreed eligibility tests as follows:

- Where a DRA has no existing relationship with a NMI, but has satisfied the self-assessment requirements described in Section 6.1.1, it can submit that NMI for testing.
- Where a DRA has a relationship with a NMI but wants to change the BCM combination then it can update the BCM combination and submit that for testing.
- A DRA or FRMP with an existing active relationship for a NMI can submit that NMI for testing.

In each case, MSATS will provide the accuracy for each of the accredited BCM combinations utilising the meter data that AEMO currently holds. The method will identify the accredited BCM combination with the greatest accuracy for weekdays excluding (local) state public holidays, giving preference to a BCM combination that also passes the weekend/public holiday variability test over a BCM combination that does not allow demand response on a weekend/public holiday. A pass/fail will be reported in situations where a change to the BCM combination is being made.

The NMI eligibility test function will not be applied when the BCM combination is changed to “NODRA”.

AEMO will also use this functionality to carry out periodic reviews of the accuracy of the chosen BCM combination.

8 Provision of Demand Response Services

8.1 Provision of Demand Response Energy

8.1.1 Demand Response Notification

Demand response under DRM is not scheduled by the market. Rather, a demand response under DRM is initiated solely by a DRA based on a Demand Response Notification submitted to AEMO.

The DRA will make the decision to initiate demand response based on standard market information, such as pre-dispatch price information.

DRAs will submit a Demand Response Notification via AEMO's real time wholesale Electricity Market Management System (EMMS).

The notification to AEMO will include the following information:

- Identifier of the DRA (DRA Participant ID)
- DR Notification ID (unique demand response event identifier)
- DR Notification Type (Initial, Revised, Cancelled)
- Timestamp (i.e. when the notification file was created)
- NMI list (list of NMIs providing response)
- Demand response start date and trading interval
    - The trading interval will be denoted by the trading interval end time.
- Demand response end date and trading interval
    - The trading interval will be denoted by the trading interval end time.

A DRA will be required to provide a demand response whenever it activates a demand response. The start time of a notification must be no earlier than the start of the trading interval during which a notification is received by AEMO, and no later than 24 hours after the submission time of the notification[41]. For example, a notification received by AEMO at 12:25 hours can have a starting time no earlier than 12:00 hrs. The maximum span of a demand response notification will be 24 hours.

A DRA will be able to provide, change or cancel a notification at any time up to the end of an affected demand response trading interval. This means that if a demand response interval crosses multiple trading intervals then the notification must first be provided before the end of the first affected trading interval. If DRA changes its expected duration of the demand response interval then the notification must be updated before the end of the latest trading interval included in both the original and revised notification. The latest start time for a demand response notification will be 24 hours into the future and the maximum span of a demand response notification will also be 24 hours.[42]

AEMO will respond on receipt of a demand response notification with an acknowledgement of receipt of the notification. The effective start of a demand response notification will be based on the processing time within AEMO's systems (similar to the current bidding process). AEMO's acknowledgment will advise the starting and ending trading interval of the demand response event. If the end trading interval in the notification is prior to the current trading interval then the notification will be rejected. If the start trading interval in the notification is earlier than the current trading interval then the start trading interval will be reset to the current trading interval. Validation of notifications (other than simple formatting validations) would be carried out as part of the

[41] Because baseline energy is calculated for each half-hour, the start time of a valid demand response notification is effectively back-dated to the start of the half hour.
[42] This is intended to limit potential gaming opportunities.

settlement process. AEMO will generate the demand response trading intervals associated with the interval between the start and end trading interval of the response.

MSATS will receive the list of NMIs included in demand response notification and the trading intervals for which they are responding from the EMMS.

8.1.2 AEMO Notifications of Demand Response Events

Information Requirements

NEM participants will have interest in knowing when demand response is occurring. Further, entities associated with a NMI have a requirement to know that NMI is included in a demand response. Specifically:

- Any trading participant will be interested in demand response activity to allow it to be considered in trading activities.
- Local network operators have interest in demand response activity to the extent it impacts their network planning activities.
- Metering data providers require knowledge of demand response activity at the NMI level to support meter data validation. This information is required within hours of the event.

To facilitate these various needs and to minimise barriers for DRA participation AEMO will generate the required reports.

An MSATS / EMMS Interface

On an ongoing basis, AEMO’s MSATS system will send the following information to the EMMS system for all NMIs participating in DRM:

- Relevant NMI parameters (e.g. start date and end date).
- Its Transmission Network Identifier (TNI)
- Its FRMP[43]
- Its MDP
- Its LNSP

To generate the reports described below it will be necessary for EMMS to associate the NEM region with the NMI.

Public Market Notice of Demand Response

On receipt by AEMO of Demand Response Notification, a notice will be published by AEMO through the EMMS and the AEMO website containing the following information:

- Demand response event identifiers
- Demand response start date and trading interval
- Demand response end date and trading interval
- Region
- TNI
- NMI count

[43] NMI standing data is updated in MSATS daily to take into account the latest customer transfers and other information. This generally is available between 0200 and 0300 each day. NMI standing data that changes during the period of a notification or commences before the latest data is available could be affected. For example, AEMO could provide a notification to the old retailer for a NMI.

If the DRA wants to withdraw its notification, changes the timing of its original demand response event, or changes the set of NMIs included in the demand response, then it will do so by sending a new notification which AEMO will publish as a new public market notice containing the new information. The new market notice would have a later date time stamp.

The notice will be published as soon as possible after AEMO receives the demand response notification from the DRA.

AEMO will also publish amended notifications at a later time based on updated MSATS transactions which may result in a NMI being excluded from the notification or the DRA ceasing to be active for that NMI. This will continue until AEMO issues the preliminary settlement statement for that day. After that time updates will be reflected in settlement reconciliation reports described in Section 12.6.

Private Participant Notice of Demand Response

Private reports will be sent from AEMO to FRMPs, MDPs and LNSPs and will contain the following information:

- Demand response event identifiers
- Demand response start date and trading interval
- Demand response end date and trading interval
- Region
- TNI
- NMIs

If AEMO releases a new notice it will have a later date time stamp.

The notice will be published within 1 to 2 hours of AEMO receiving the demand response notification from the DRA.

AEMO will also publish amended notifications later based on updated MSATS transactions which may result in a NMI being excluded from the notification or the DRA ceasing to be active for that NMI.

8.1.3 Revisions of Demand Response Notification Data

AEMO will require the ability to modify after the event the list of NMIs associated with a trading interval to which a demand response notification relates. Such modifications would be applied if and when AEMO is made aware of a valid reason as to why a NMI should not be included as demand response in that trading interval . This modification could be made any time within the settlement revision period. As part of each settlement run, AEMO would also need to provide an updated notification to the relevant participants for the NMIs that are/are not included in a trading interval within a given demand response event.

The specific situations where this could occur are:

- If, as a result of an audit or an AER action, the DRA was found to have falsely classified a NMI as a demand response load, or failed to update that classification, when it did not meet the requirements to be a demand response load.[44] See Section 6.1.4.
- If, as a result of AER action, the DRA was found to have included a NMI in a demand response notification despite restrictions on when the NMI can be included. See Section 8.1.4

[44] A retest of the eligibility of a NMI to provide demand response (as described in Section 6.1.3) could result in the NMI ceasing to be able to provide demand response but would not result of itself in a retrospective removal of the NMI from a prior demand response.

- If AEMO is notified by the FRMP and/or the DRA that the NMI should be removed from the demand response associated with a trading interval where the NMI was unable to provide the demand response during a trading interval as a result of the NMI not being supplied with energy at all during that trading interval (e.g. as a result of involuntary load shedding). See Section 8.1.4

8.1.4 Restrictions on Provision of Demand Response

The demand response procedure will describe circumstances in which a DRA is not to include a NMI in a demand response notification. These provide a reference point for the AER to establish whether the DRA has operated in good faith. AEMO will not specifically police these situations.

The DRAs 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. E.g., turning equipment on deliberately during the baseline period having already planned to provide demand response some hours later, or continuously calling demand response solely to limit the set of available qualifying days to days with unusually high demand.
- The DRA or customer is not taking any deliberate action to provide the demand response. E.g., the 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.

Demand response cannot be provided for a trading interval if the NMI from which that demand response is being provided is not energised for that trading interval (e.g. as a result of an involuntary curtailment including mandatory restrictions). In the event that a NMI is included in a demand response notification and subsequently loses supply of power then a DRA that becomes aware of this will be obliged to notify AEMO of this in accordance with Section 8.1.4. A FRMP may advise AEMO if the DRA does not.

8.2 Provision of Ancillary Services

Loads classified to provide market ancillary services will be scheduled through the central dispatch process.

Loads are generally not able to provide ancillary services if the load is out of service. As with a Market Customer, a DRA 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 that is found to have been 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 DRA that is found to be unable to provide the service. Instead, this would be a rule breach and the DRA may incur penalties if this occurred.

8.3 Impacts on System Operation

Based on historic experience of demand response it is not expected that the demand response mechanism will have any effects as significant as to impact operation of the power system requiring demand response to be factored into system operation.

This situation could change in the future, potentially requiring some degree of scheduling of demand response. However, under the design proposed in this paper all demand response is self-scheduled by the DRA.

9 Accredited Baseline Consumption Methodologies

9.1 Introduction

9.1.1 Terminology

When taking on the role of DRA for a NMI, a DRA will need to select one of the accredited BCM combinations. This section introduces the terminology used in subsequent discussions.

A BCM can be specified by a combination of components including the baseline window, the exclusion rules, the calculation type, the baseline adjustments and the adjustment window, that are combined in order to accurately calculate the baseline energy.

The baseline window is the period of time preceding a demand response event from which meter data is used for the purpose of establishing a baseline. Examples of baselines windows include the last 45 calendar days or the last 10 non-holiday weekdays.

Exclusion rules are the rules for excluding data from the baseline window such as the days (or trading periods) with demand response events or days with the highest or lowest loads.

Calculation type is the method of developing the baseline value using data from the baseline window with examples of calculations types including the average value for the last 10 days for that trading interval or highest 4 of 5 values for that trading interval.

A baseline adjustment is an additional calculation applied after the basic calculation type, to align the baseline with observed conditions of the event day. The basic calculation type is applied to an adjustment window, being a period of time before the demand response occurred, for which actual meter data is available. This window might be the first 3 hours of the 4 hours prior to the demand response. Then:

- Under an additive approach, the average difference between the baseline and actual data for the adjustment period is determined and that average difference is applied to the baseline during the demand response interval.
- Under a multiplicative approach, the ratio of the average demand energy to the average baseline energy during the adjustment period is applied to the baseline during the demand response interval.
- Under a capped multiplicative approach, the ratio of the average demand energy to the average baseline energy during the adjustment period, with a floor and cap applied to the ratio (e.g. between 0.8 and 1.2) is applied to the baseline during the demand response interval.

An illustrative example of some of some of these features is presented in Appendix A.

9.1.2 The Importance of Simplicity and Transparency

There are many factors which can impact what the consumption of a load will be on a day. In principle very complicated mathematical methods can be applied to produce a relatively accurate forecast of consumption. Alternatively, simpler mathematical approaches could be used but with many exclusions on the types of past days that can be included in the baseline calculation. However, such methods have a significant disadvantage in that they require that more data be collected and consequently they tend not to be easily reproducible for DRAs and retailers owing to the complex relationships between data and the calculations.

For this reason the most widely used methods for determining baseline energy employ simple mathematics, such as simple averages of data drawn from recent days with the only exclusions being for things that are known to all relevant parties, such as the days on which the NMI has been involved in demand response events.

Simplicity and transparency does give rise to some inaccuracy in the baseline energy for a given trading interval. The degree of inaccuracy can be reduced by placing an upper limit on the acceptable accuracy for a baseline consumption methodology. This can result in some proportion of potential demand response providers being excluded from DRM.[45]

9.2 The Initial BCM Combinations

The set of baseline consumption methodologies will be described in a new demand response procedure. This section describes the BCM combinations proposed for implementation from the commencement of the DRM. The design presented was informed by research commissioned by AEMO and conducted by DNV KEMA (KEMA) to test the performance of a number of baseline methodologies. KEMA initially conducted a review of methodologies used in the United States[46]. KEMA then analysed the performance of a set of methodologies in the context of the NEM.[47] KEMA was provided with a large, two year, sample of NMI data from potential demand response providers. KEMA tested nine established methodologies for determining an initial unadjusted level of baseline energy and also tested two baseline adjustment methodologies to modify the unadjusted levels.

KEMA assessed the methods against the following metrics:[48]

- Accuracy – how closely a baseline method predicts customers' actual loads in the sample;
- Bias – the systematic tendency of a baseline method to over- or under-predict actual loads;
- Variability – the measure of how well the baseline 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 methodology to program participants; and
- Administrative costs– the associated level of investment in activities such as data transfer, data quality review, analysis, training and IT systems requirements.

KEMA recommended that only one BCM combination be employed initially, comprising of a single weekday method and a single weekend method. For the weekday method they identified the best performing methods as CAISO 10 of 10, PJM's high 4-of-5, and middle 4-of-6 methods. The CAISO 10-of-10 method was the best performing though KEMA suggested that the other two methods may be preferred as requiring less data. The middle 2-of-4 was identified and recommended as the best performing weekend method.

[45] Some markets do offer a BCM that can be used in such situations. The BCM is based on the lowest historic loads and as such are unlikely to facilitate the provision of much demand response. These baselines are very inaccurate, but are used to provide some option for participation. This type of approach is used in markets where DRM is funded by the market as a whole, rather than by the retailer. Such an approach is not proposed for the NEM as a very inaccurate and low level of baseline energy would impact what retailers can charge their customers in the energy market.

[46] Development of Demand Response Mechanism: Baseline Consumption Methodology – Phase 1 Results. Report for AEMO by DNV KEMA, July 2013.

[47] Development of Demand Response Mechanism Baseline Consumption Methodology – Phase 2 Results. Report for AEMO by DNV KEMA, October 2013.

[48] Where these criteria are restated later in this report we change "Administrative costs" to "Implementation and Operating Costs" which would appear to be a more precise wording. We also refer to 'baseline consumption methodology' rather than 'baseline method'.

9.2.1 BCM Combination One

Weekdays excluding Local State Public Holidays

This BCM is based on the CAISO 10 of 10 method with a symmetric additive adjustment

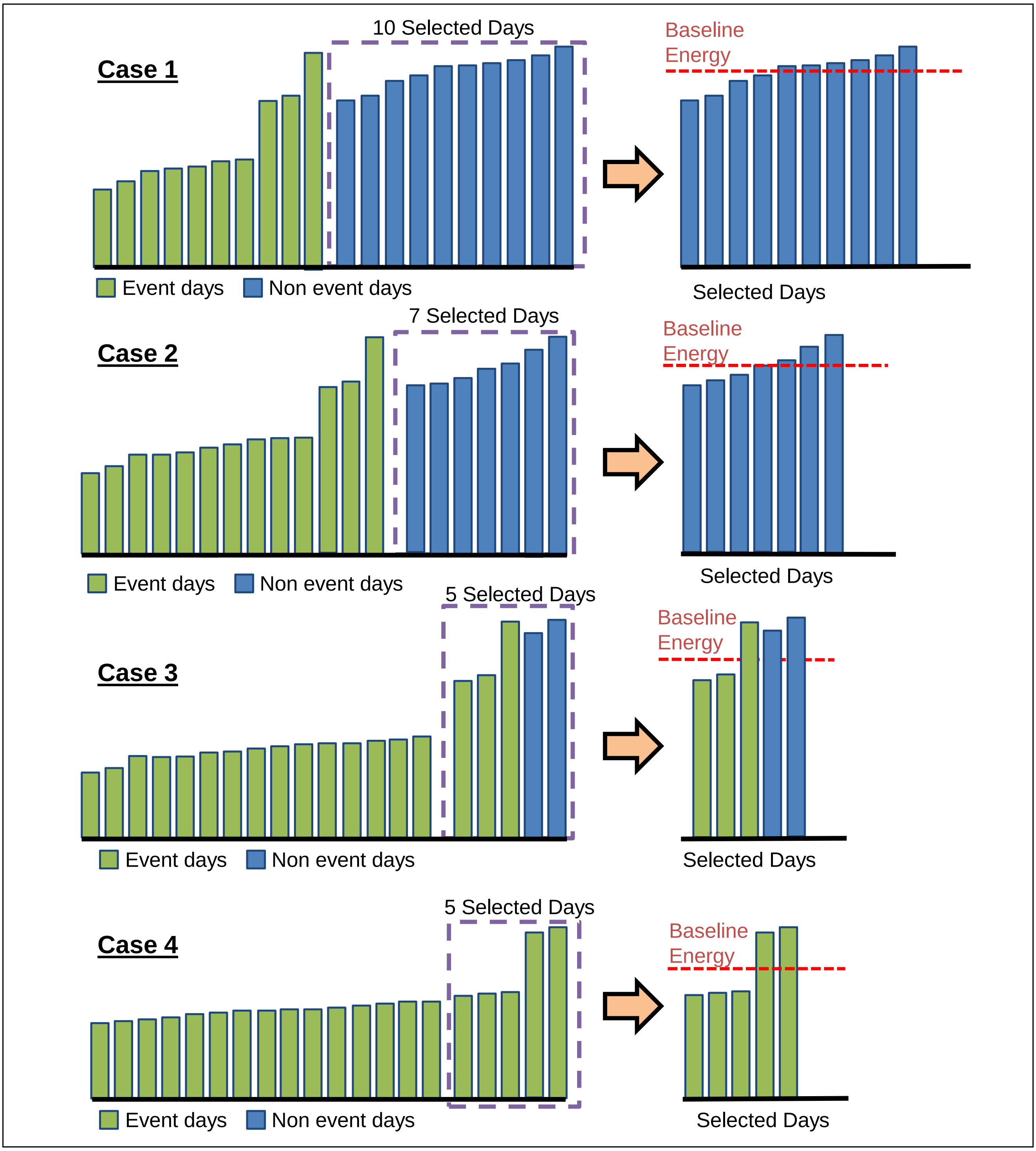
Table 7 –BCM Combination One: Weekdays that are not (Local) State Public Holidays

Component	Detail
baseline energy	unadjusted baseline energy + additive adjustment
unadjusted baseline energy	For a trading interval, the average metered values for the corresponding trading interval on each of the selected days.
selected days	The most recent 10 qualifying days within the baseline window. If less than 10 qualifying days exist but 5 or more qualifying days exist then use the number of qualifying days available. If less than 5 qualifying days are available then select those event days with the greatest metered energy during the trading interval corresponding to the current day demand response trading interval to make up the number of selected days to 5. Thus if there were only 3 qualifying days available then 2 event days would be selected to produce 5 days. The days with the greatest metered energy are used as these are less likely to be days in which demand response occurred during that particular trading interval and are therefore less likely to lower the baseline energy. This is illustrated in Figure 8 below.
qualifying days (as defined by exclusion rules)	Calendar weekdays which are not public holidays (in that location)[49] and on which demand response events have not been called for the NMI.[50]
baseline window	45 calendar days. This time range is long enough to allow for a significant number of qualifying days but not so long as to create serious distortions due to changing seasons.
additive adjustment	Average actual adjustment window energy – average baseline adjustment window energy This may be positive or negative.
average actual adjustment window energy	The simple average of the metered energy over the adjustment window.
average baseline adjustment window energy	The simple average of the unadjusted baseline energy over the adjustment window.

[49] We are using the Metrology Procedure Part B convention on meter substitution which uses public holidays (as a non-defined term) rather than the NEM rules term which would only account for public holidays across the entire NEM.
[50] The design could include a "low load" exclusion – e.g. exclude days with peak load which is an outlier. This might eliminate odd things like outages or maintenance periods. However, it is not the normal intent of the 10 of 10 approach to do this, as this is what approaches like 2 of 4' do, though also excluding the high outliers.

Component	Detail
adjustment window	If the event starts in trading interval t, then this is trading intervals t-8, t-7, t-6, t-5, t-4 and t-3 (i.e. the 3 hours ending one hour before the start of the event). The adjustment will apply across all demand response trading intervals within the demand response interval. If the adjustment interval contains a demand response interval then the adjustment window would be defined relative to the start time of that earlier demand response interval or 4 AM market time, whichever is later. This ensures that the adjustment window does not start before midnight. Note: This last feature ensures that adjustment windows are never earlier than just before the start of the day. If as a result of this provision the adjustment period includes a demand response then so be it. The DRA can manage this by not declaring demand responses during the impacted overnight period.

Figure 8 – Examples of How “Selected Days” Are Identified



Based on KEMA’s recommendation the Working Group narrowed the choices down to the CAISO 10 of 10 method and the PJM High 4 of 5 method, both with additive adjustments applied. These were the best performing X of Y methods. The CAISO 10 of 10 was selected as, with the additive adjustment, it was on average the most accurate baseline (10.3% average error vs. 10.7% for the PJM High 4 of 5) and it excluded less NMIs (24.0% vs. 25.1%). The CAISO 10 of 10 also was found to have a bias of 0.000 rather than 0.0008, though both these figures are sufficiently close to zero to be of little consequence.

The CAISO 10 of 10 methods has some limitations in the North American context in requiring more meter data, since most market operators there do not hold the meter data. As AEMO has all the meter data and both methods would require 45 days of data anyway, this was not considered a material consideration.

Some stakeholders with existing systems used in other jurisdictions had some preference for specific methods, but as it was only a choice between alternative X or Y methods, the differences seem trivial from an IT perspective.

Weekend and Local State Public Holidays

This BCM is based on the Middle 2 of 4 method with a symmetric additive adjustment.

Table 8 –BCM Combination One: Weekend and (Local) State Public Holidays

Component	Detail
baseline energy	unadjusted baseline energy + additive adjustment
unadjusted baseline energy	For a trading interval, and based on the metered values for the corresponding trading interval on each of the selected days, the two median values of the four (i.e. exclude the highest and lowest value and take the average of the other two).
selected days	The most recent 4 qualifying days within the baseline window. If less than 4 qualifying days are available then select those event days with the greatest metered energy during the trading interval corresponding to the current day demand response trading interval to make up the number of selected days to 4.
qualifying days (as defined by exclusion rules)	Calendar weekend days and public holidays (in that location)[51] and on which demand response events have not been called for the NMI.
baseline window	45 calendar days. This time range is long enough to allow for a significant number of qualifying days but not so long as to create serious distortions due to changing seasons.
additive adjustment	average actual adjustment window energy – average baseline adjustment window energy This may be positive or negative.
average actual adjustment window energy	The simple average of the metered energy over the adjustment window.
average baseline adjustment window energy	The simple average of the unadjusted baseline energy over the adjustment window.
adjustment window	If the event starts in trading interval t, then this is trading intervals t-8, t-7, t-6, t-5, t-4 and t-3 (i.e. the 3 hours ending one hour before the start of the event). The adjustment will apply across all demand response trading intervals within the demand response interval. If the adjustment interval contains a demand response interval then the adjustment window would be defined relative to the start time of that earlier demand response interval or 4 AM market

[51] We are using the Metrology Procedure Part B convention on meter substitution which uses public holidays (as a non-defined term) rather than the NEM rules term which would only account for public holidays across the entire NEM.

Component	Detail
	time, whichever is later. This ensures that the adjustment window does not start before midnight. Note: This last feature ensures that adjustment windows are never earlier than just before the start of the day. If as a result of this provision the adjustment period includes a demand response then so be it. The DRA can manage this by not declaring demand responses during the impacted overnight period.

9.2.2 BCM Combination Two

A second BCM combination will be offered which includes the weekday methodology of BCM Combination One but has a null weekend methodology. A NMI with a variable load on the weekend might fail the load predictability test for BCM Combination One but could pass the test for BCM Combination Two. The DRA for the NMI could select BCM Combination Two and provide DRM during the weekdays. If this NMI were to be included in a demand response notification on a weekend then that NMI would be rejected.

9.2.3 Information to Support Baseline Calculations

This section describes the information to be made available to the baseline energy calculation systems to support the calculations of baseline energy for the current and potential future BCMs.

The data associated with the NMI to be available will be:

- Trading interval meter data
- Past demand response trading intervals
- NMI standing data
- A list of state public holidays in a form that can be associated with NMIs.

9.3 Process for Updating BCM Combinations

The set of BCMs available to DRAs is defined by the set of accredited BCM combinations. The demand response procedure will allow for reviews to be conducted of accredited BCM combinations. During these reviews the performance of the accredited BCM combinations would be confirmed and alternative proposed BCMs and BCM combinations could be considered and assessed.

In determining whether to retire accredited BCM combinations or to accredit proposed new BCM combinations a procedure change process will be followed in accordance with the Rules consultation procedures. A review of the accredited BCM combinations will 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.

An expedited process would be allowed for in the event of a significant material problem being identified and requiring remedy.

The procedures will specify the following assessment criteria to be applied when assessing baseline consumption methods. The following criteria are proposed:

- 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.

10 Metering

10.1 Metering Relationships

Although DRAs are settled on demand response energy and will receive reports from AEMO in regard to metering data used in settlements, DRAs will want underlying meter data so that they can calculate baselines themselves for operational purposes, as well as to validate AEMO's baseline and demand response energy values. DRAs will also want this data to verify with the MDP meter data that seems erroneous. The DRA could be affected by meter data errors that might go unnoticed in normal retail operations.

MDPs send meter data to participants and MSATS. MSATS receives only a sub-set of the meter data sent to participants. DRAs require the entire set of meter data. Thus MDPs rather than AEMO are the most appropriate provider of this meter data to DRAs.

DRAs wishing to receive and query meter data may need a relationship and contract with MDPs. This bi-lateral relationship would be for the DRA to establish and would be unrelated to the Rules and NEM procedures. The NER requires that MDPs must provide metering data services to those authorised to have access to that data for a NMI, such as its DRA. The NER does allow the MDP to recover costs for services such as queries of meter data.

10.2 Metering Obligations

The Service Level Procedures for MDPs define obligations on MDPs to send meter data to participants. These obligations will be extended to include DRAs. The new obligation will require MDPs to provide metering data from revenue meters to DRAs associated with a NMI. Most MDPs provide metering data to participants in the Meter Data File Format (MDFF)[52] using B2B Processes. Alternatively MDPs and DRAs can agree on bi-lateral delivery (e.g.: email, FTP etc.) arrangements for sending meter data.

10.3 Accessing Historic Meter Data

A DRA is likely to be interested in accessing historical meter data from a site for which they are the DRA, including for periods before they became the DRA for the site, going back far enough into history to be able to apply baseline accuracy tests. This allows the DRA to test the accuracy of a baseline consumption methodology. No provision for this is allowed for in the design. DRAs will have to request their consumers to provide this historical meter data.

Historical data cannot be provided by AEMO. MSATS has no checks and balances for previous relationship periods.

10.4 Meter Data and MSATS

DRAs will also be able to view metering data online via MSATS. Currently all suffixes are displayed, so other participants associated with the NMI for the given period will also be able to see the DR related suffix

[52] The MDFF specification is defined in the document titled 'Meter Data File Format Specification NEM12 & NEM13' and is available on AEMO's website.

11 B2B Processes

Currently MDPs send meter data to participants via B2B processes. This process will be extended to include DRAs. The current B2B “Provide and Verify Meter Data Process” will be utilised to allow DRAs to raise queries with MDPs. The B2B Procedures will be revised to facilitate this. No changes are proposed to the “Provide and Verify Meter Data Process”. DRAs will use the existing investigation codes.

Chapter 7 of the Rules will be amended to include DRAs as a B2B participant.

No changes are anticipated to other B2B processes such as Service Orders or Customer and Site Details Notifications (CSDN).

12 Preparation of Demand Response Settlement Data by MSATS

12.1 Demand Response Notification Data

MSATS will receive the list of NMIs included in demand response notification and the trading intervals for which they are responding from the EMMS. Once in MSATS, this data may be modified by AEMO to manually remove NMIs from some trading intervals, as described in Section 8.1.2.

12.2 Meter Data

MSATS receives meter data for NMIs from MDPs.

When meter data is not available for a NMI, an MDP creates substituted meter data using one of the approved substitution methodologies. The Metrology Procedure defines meter data estimation and substitution methods. These methods will continue to apply. The MSATS system will receive information from MDPs indicating whether meter data is actual (A) data or substituted (S) data. MSATS receives no information as to why or how data is substituted. If AEMO receives no data from an MDP it will substitute for that data using the same substitution methods until such time as data is received from the MDP. Additional one letter substitution codes apply when AEMO substitutes meter data.

Data that is initially substituted may later become actual data as and when the data is extracted from the meter. This could happen because the original absence of data was a problem in getting data from the meter to the MDP. As settlement revision processes run for approximately six months, actual data could become available at any time in that period. As demand response will be limited to Large NMIs with type 1, 2, 3 or 4 interval metering installations it would be very rare for actual data not to become available by the completion of the settlement revision process. An absence of actual data by that time will tend to reflect catastrophic events such as fire or flood at that site.

A special process to derive demand response energy for settlement purposes where data is substituted, or to retrieve additional MDP data on substitution methods, would add significant complexity to DRM and is not considered justifiable given the infrequency of its use.

Where a NMI has substituted meter data available - whether substituted by an MDP or AEMO - and has been included in an interval demand response notification then that NMI will be included in the demand response data sent to settlements at that time.

During each settlement run (Preliminary, Final, Revisions) MSATS will update the demand response based on the latest data. If actual meter data is available then the NMI's demand response energy will be based on that data in the next settlement run. If actual meter data is not available then the NMI continues to be settled on substituted data.

12.3 MSATS Processing of Demand Response

During each settlement run, MSATS will check that the DRA that submitted the demand response notification is the NMI's 'current DRA' for the DR event time period. A DRA may only include a NMI in a demand response notification if it is the 'current' DRA of the NMI in MSATS. If the DRA has submitted a transfer to take on the role of DRA for that NMI but the transfer has not yet completed then the NMI will be excluded from demand response data when MSATS prepares data for settlement.

In situations where the DRA role for the NMI is held by the FRMP for that NMI it will be forbidden for the DRA and the FRMP to have identical participant IDs. This approach is taken because were the DRA role for the NMI held by the FRMP for that NMI with the DRA and the FRMP having identical participant IDs then MSATS would, without additional modification, combine the energy data for these. This would mean that the participant will simply be billed for its actual metered demand (which will already have reduced consumption reflected in it). In effect, since both the baseline energy and demand response energy are associated with the same entity, settlements would not resolve them. The approach taken is considered to be the simplest approach for ensuring that demand response provided through DRM is subject to fees in settlement.

Table 9 – MSATS treatment of NMI and energy types

NMI type	Treatment for settlement
First tier DR energy	Will be settled separately
First tier other energy	Not settled separately, no changes to current settlement process
Second tier DR energy	Will be settled separately
Second tier other energy	Settled separately, no changes to current settlement process

12.4 Determination of Baseline Energy and Demand Response Energy

Baseline energy calculations will be performed whenever data is generated for the settlement systems. This means that each settlement run is based on the most current baseline energy data.

If a NMI is excluded from the set of NMIs used to evaluate the level of demand response, then the energy for that NMI will be settled as if there were no demand response. Note that a NMI excluded (included) from DRM at one point in time could be included (excluded) in a later update of settlement data, and would only be settled under DRM when included.

MSATS will determine the following for a given Trading Interval:

- For a NMI included in a demand response:
  - The baseline energy, where this data is associated with the FRMP[53].
  - The demand response energy, where this data is associated with the DRA.
- Otherwise
  - The metered energy, where this data is associated with the FRMP.

This combination of data will ensure that there is no double counting of energy associated with a NMI.

The demand response calculation will be determined within MSATS (or in a separate system called by MSATS).

In the case of a dispute regarding the calculation of baseline energy the dispute resolution process described in Rules 8.2 will be followed.

12.5 Information Sent to the EMMS for Settlement

This section describes the energy-related data relevant to DRM that will be provided by MSATS to AEMO's settlement system EMMS (Electricity Market Management System) for use in AEMO's settlements and prudentials process.

MSATS converts NMI level information to wholesale connection point information by applying a distribution loss factor (DLF) to the NMI data and by summing over all NMIs associated with the FRMP or DRA, as applicable, to produce TNI level data. This gives rise to the following new terms:

- Adjusted baseline energy (ABE) in respect of a Market Customer for a trading interval means the distribution loss factor adjusted baseline energy for a specified TNI.

[53] Financially Responsible Market Participant

- Adjusted demand response energy (ADRE) in respect of a Market DRA for a trading interval means the distribution loss factor adjusted demand response energy for a specified TNI. In this paper it is assumed that the demand response energy is positive in AEMO's settlements system if the metered energy is below the baseline energy.

12.6 MSATS Settlement Reconciliation Reports

After data to be settled is approved in MSATS, four reports are made available to participants to help them reconcile the data used in settlements by AEMO with the data they receive from their MDPs. These reports will allow participants to clearly identify demand response energy in their MSATS settlement reconciliation reports and allow DRAs and FRMPs to receive both revenue meter data and demand response data.

12.6.1 Revisions to Level 1 settlement reconciliation report – TNI level

The level 1 report provides settlement energy data aggregated at the Transmission Node Identifier (TNI), FRMP and LR level. The modified report will include demand response values as a separate line item.

An illustrative example is show in Table 10. The first seven columns contain reference material. This is followed by 48 columns showing trading interval energy data, while the sequence number is a row index. The first two rows are shaded as they relate to a TNI at which demand response has been provided. The first row contains meter data for a single settlement date at TNI1 for Financially Responsible Market Participant (FRMP) FPARTID and Local Retailer (LR) LRPARTID. A second row relates to the demand response. This row only appears because the settlement date included a demand response interval for the TNI. The demand response energy is that associated with FRMP FPARTID's NMIs at TNI1. The DRA will be identified in the LR column. The DRA and the FRMP will receive both revenue meter data (row 1) and demand response data (row 2).

Table 10 – Revised Level 1 settlement reconciliation report

TNI	Data Type	FRMP	LR	MDP	Creation DT	Settlement Date	Period 1	Period 2 to 47	Period 48	Seq No
TNI1	I	FPARTID	LRPARTID	MPARTID	29/05/2012 22:03	19/01/2012	100	5,5,5,7	500	1
TNI1	**D**	**FPARTID**	**DRAPARTID**	**MPARTID**	**29/05/2012 22:03**	**19/01/2012**	**0**	**0,3,3,0**	**0**	**2**
TNI2	I	FPARTID	LRPARTID	MPARTID	29/05/2012 22:03	19/01/2012	101	…	101	3
TNI3	I	FPARTID	LRPARTID	MPARTID	29/05/2012 22:03	19/01/2012	103	…	103	4
TNI4	I	FPARTID	LRPARTID	MPARTID	29/05/2012 22:03	19/01/2012	103	…	103	5
TNI5	I	FPARTID	LRPARTID	MPARTID	29/05/2012 22:03	19/01/2012	103	…	103	6

12.6.2 Revisions to Level 2 settlement reconciliation report – daily NMI level data

The level 2 report provides daily settlement energy data for each TNI, LR and NMI. The modified report will include demand response values as a separate line item.

An illustrative example is shown in Table 11. The first seven columns contain reference material. This is followed by daily energy data, while the sequence number is a row index. The first two rows are shaded as they relate to a TNI at which demand response has been provided. The first row contains meter data for a single settlement date at TNI1 for local retailer (LR) LRPARTID. A second row relates to the demand response. This row only appears because the settlement date included a demand response interval for the TNI. The demand response energy is for the same TNI1. The DRA will be identified in the LR column. The DRA and the LR will receive both revenue meter data (row 1) and demand response data (row 2).

Table 11 – Revised Level 2 settlement reconciliation report

TNI	LR	MDP	Settlement Date	NMI	Data Type	MSATS Est	Total Energy	Seq No
TNI1	LRPARTID	MDPPARTID	18/11/2012	1234567 891	I	N	500	1
TNI1	**DRAPARTID**	**MDPPARTID**	**18/11/2012**	**1234567 891**	**D**	**N**	**100**	**2**
TNI1	LRPARTID	MDPPARTID	19/11/2012	1234567 891	I	N	200	3
TNI1	LRPARTID	MDPPARTID	20/11/2012	1234567 891	I	N	300	4
TNI1	LRPARTID	MDPPARTID	21/11/2012	1234567 891	I	N	100	5
TNI1	LRPARTID	MDPPARTID	22/11/2012	1234567 891	I	N	600	6

12.6.3 Revisions to Level 3 settlement reconciliation report – Datastream level

The level 3 report provides settlement energy data at the datastream level. The modified report will include demand response values as a separate line item.

An illustrative example is shown in Table 12 below. The first four columns contain reference material. The next 48 columns are energy data by trading interval. The status flag indicates the status of each trading interval value. For meter data rows the fields are “A” for actual or “S” for substituted while for demand response rows they are “N” for no response and “D” for demand response. The final column is the sequence number which acts as a row index. The first two rows are shaded as they relate to datastreams associated with a NMI for which demand response has been provided. The first row contains meter data for a single settlement date for a single NMI’s N1 datastream while the second row contains demand response energy data associated with the ZZ suffix for that same NMI. The second row only appears if there is a demand response interval during that settlement day (as further indicated by the DRM flag). The DRA and the FRMP will receive both revenue meter data (row 1) and demand response data (row 2).

Table 12 – Revised Level 3 settlement reconciliation report

Settlement Date	NMI	Suffix	Creation DT	Period 01	Period 02 to 47	Period 48	Status Flags	Seq No
18/11/2012	1234567891	N1	19/11/2012 00:43	3.281	5,5,5,7	3.255	AAAAAAAAAAAAAAA AAAAAAAAAAAAAAA AAAAAAAAAAAAAAA AAA	1
18/11/2012	**1234567891**	**ZZ**	**19/11/2012 00:43**	**0**	**0,3,3,0**	**0**	**NNNNNNNNNNNNNNN NNNNNNNNNNNNNNN NNDDDDNNNNNNNNN NNN**	**2**
19/11/2012	1234567891	N1	20/11/2012 00:39	3.246	…	2.911	AAAAAAAAAAAAAAA AAAAAAAAAAAAAAA AAAAAAAAAAAAAAA AAA	3
20/11/2012	1234567891	N1	21/11/2012 00:38	2.947	…	2.884	AAAAAAAAAAAAAAA AAAAAAAAAAAAAAA AAAAAAAAAAAAAAA AAA	4
21/11/2012	1234567891	N1	22/11/2012 00:39	2.833	…	2.815	AAAAAAAAAAAAAAA AAAAAAAAAAAAAAA AAAAAAAAAAAAAAA AAA	5
22/11/2012	1234567891	N1	23/11/2012 00:33	2.833	…	2.761	AAAAAAAAAAAAAAA AAAAAAAAAAAAAAA AAAAAAAAAAAAAAA AAA	6

12.6.4 Included and Excluded NMIs Report

An additional report will be produced providing a list of NMIs included in demand response notifications that passed validation and a list of NMIs that did not. A rejection reason code would be provided with the NMIs which did not pass validation. The report generated for FRMPs and DRAs will only show the NMIs they are associated with.

12.7 Baseline Energy Report

A new MSATS report will be produced after each settlement run to provide baseline energy to FRMPs and DRAs in the Meter Data File Format (MDFF) Specification. This will allow FRMPs to easily load this data in to their customer billing systems to produce customer bills.

13 Settlement and Prudentials

13.1 Overview

The data used in AEMO's settlements and prudentials processes in regards to DRM (for a NMI included by MSATS in the demand response) will be:

- For the creation of settlement statements:
  - The adjusted demand response energy and adjusted baseline energy from MSATS at the time of an MSATS Preliminary, Final, or Revision run, which is done in accordance with the Metering Data Delivery Dates calendar published by AEMO.
- For daily settlement estimates for prudential assessments:
  - The demand response will not be included in the daily settlement estimates, that is the adjusted demand response energy will be treated as zero for a DRA, while the energy estimate for the retailer will be derived from existing settlement estimation processes.
- For interim settlement estimates for prudential assessments:
  - The adjusted demand response and adjusted baseline energy from MSATS at the time of an MSATS Initial run (done daily from the end of D+2 until Preliminary data is available).

A summary of settlement charges is given in Table 13, where a reference to a Retailer relates to the Retailer associated with a demand response site.

Table 13 Summary of Settlement Charges

		Additional Arrangements under DRM	
Type/Service	Current Arrangements	DRA	Retailer
Energy	Market Customers pay for consumption based on metered energy. Market Generators and Market SGAs are paid for generation, and pay for consumption, based on metered energy.	DRAs are paid for demand response below baseline, and pay for demand response above baseline.	Retailers pay for consumption based on Baseline Energy.
AEMO 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.	DRAs pay customer fees at a rate per MWh of demand response (whether above or below baseline).	Retailers pay customer fees based on Baseline Energy.
Ancillary Services Recovery			
Network support and control ancillary services (NSCAS)	Recovered from Market Customers	N/A	Retailers pay recovery based on Baseline Energy.

Type/Service	Current Arrangements	Additional Arrangements under DRM: DRA	Additional Arrangements under DRM: Retailer
System restart ancillary services (SRAS)	Recovered from Market Customers (50%) and from (Market Generators & Market Small Generation Aggregators based on net generation only) (50%).	DRA pay recovery like Market Generators, based on demand response energy below the baseline only.	Retailers pay recovery based on Baseline Energy.
FCAS Contingency Raise	Recovered from Market Generators & Market SGAs based on net generation only.	DRA pay recovery like Market Generators, based on demand response energy below the baseline only.	N/A
FCAS Contingency Lower	Recovered from Market Customers	N/A	Retailers pay recovery based on Baseline Energy.
FCAS Regulation Causer Pays	Recovered from Market Customers and Market Generators, distributed according to Causer Pays	N/A	According to causer pays if applicable (based on SCADA data).
FCAS Regulation Residual	Recovered from Market Customers	DRA pay recovery like Market Customer, based on demand response energy below the baseline only.	Retailers pay recovery based on Baseline Energy.
Compensation Recovery			
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 recovery 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 based on Baseline Energy.

Type/Service	Current Arrangements	Additional Arrangements under DRM	
		DRA	Retailer
Mandatory Restrictions RSA positive	Paid to Market Customers	N/A	Retailers paid based on Baseline Energy.

On occasions, energy can have the opposite sign to that expected. For example:

- A generator can be a net consumer if their auxiliary use exceeds generation.
- The demand response energy for a DRA can be negative if the metered energy exceeds the baseline energy.
- The baseline energy for a demand response NMI could represent net generation if generation exceeds consumption for the NMI.

Note that embedded generation that is not registered in the NEM can offset consumption, such that the customer's energy (as provided to AEMO) represents the consumption net of such generation. Such generation must be purchased in its entirety by the Local Retailer or by a customer at the same connection point otherwise the generator must be registered in the NEM. Therefore, total customer energy for a retailer should not be 'negative' (i.e. represent net generation) as the consumption by the Local Retailer or customer should exceed such embedded generation.

In AEMO's systems, negative customer baseline energy will be treated as an offset against customer energy.

Settlement estimates, and the difference between daily and interim settlement estimates, are discussed in more detail in Section 13.10.3.

Each time the settlement process is run for the purpose of creating settlement statements or interim settlement estimates, the most recently loaded data from MSATS will be used.

In order to fully describe the proposed settlement approach, a number of terms, for example adjusted baseline energy and adjusted demand response energy, are explicitly represented as new mathematical terms in the equations presented in this section.

The proposed rule change takes an alternative approach in describing these changes by amending the definitions of existing customer energy or generator energy terms in those equations to incorporate these new terms.

13.2 Energy Settlement

Energy settlement is the process by which settlement transactions (trading amounts) are calculated based on distribution loss factor adjusted energy. Energy settlement is performed by a calculation of settlement by difference.[54]

DRM energy settlement for a trading interval will involve calculations based on the half-hourly spot price and the half-hourly energy assessed using demand response energy and baseline energy information.

In trading intervals which are not demand response trading intervals, there will be no change to the settlement of energy, that is:

- The Financially Responsible Market Participant (FRMP) for a NMI is charged by AEMO (at the NEM spot price) for energy consumption at the NMI based on the metered consumption. This becomes a payment from AEMO if the NEM spot price is negative.
- End users are charged by their retailer (at their retail rate) for metered consumption at their NMIs. AEMO has no involvement in this process.

[54] i.e. the Local Retailer is settled on the total adjusted gross energy at the TNI less the adjusted gross energy purchased at the TNI by retailers other than the Local Retailer.

In trading intervals which are demand response trading intervals for NMIs at which there was a demand response:

- AEMO is to pay DRAs (at the NEM spot price) for the demand response energy. This becomes a payment to AEMO if the NEM spot price is negative or if metered consumption exceeds baseline energy causing the derived demand response energy to be negative.
- Retailers will be charged by AEMO for energy consumption at a NMI (at the NEM spot price) based on the baseline energy.

Outside of the AEMO settlement processes (assuming a positive demand response):

- End users will receive a payment from the DRA for their response based on their commercial arrangements with the DRA.
- End users will be charged by their retailer (at their retail rate) based on the baseline energy.

Note that, while the underlying metered energy data is at a NMI level, for use in AEMO's settlements system, energy for a participant is aggregated up to the TNI level.

13.2.1 Wholesale Energy Settlement for DRA

In each trading interval at each TNI, the wholesale value of the demand response energy will be calculated as:

$TA_{DRA} = ADRE \times TLF \times RRP$

where

TA_{DRA} (in \$)	is a transaction with respect to the DRA (which will be a positive or negative amount for each trading interval);
ADRE (in MWh)	is the adjusted demand response energy (can be positive, if metered consumption is below the baseline consumption, or negative, if metered consumption is above the baseline energy);
TLF	is the transmission loss factor for the TNI associated with the energy; and
RRP ($/MWh)	is the regional reference price for the regional reference node (RRN) to which the TNI is assigned.

13.2.2 Wholesale Energy Settlement for Retailer

In line with Rules clause 3.15.6, in each trading interval at each TNI, the wholesale value of retailer energy will be calculated as:

$TA = (AGE + ABE) \times TLF \times RRP$

where

TA (in $)	is the trading amount to be determined;
AGE (in MWh)	is the adjusted gross energy (representing energy for NMIs at which there is no demand response);
ABE (in MWh)	is the adjusted baseline energy (representing energy for NMIs at which there is a demand response);
TLF	is the TLF for the TNI associated with the energy; and
RRP ($/MWh)	is the regional reference price for the regional reference node to which the TNI is assigned.

In having the DRA responsible for both positive (reward) and negative (risk) DR amounts, this provides the most efficient party to manage the risk of non-delivery whilst avoiding opportunities for the DRM process to be disorderly.

13.3 Ancillary Service Provision Settlement

The existing settlements processes will apply to ancillary services provided by a DRA[55] as outlined below:

- Using existing processes, AEMO pays the DRA for dispatched Frequency Controlled Ancillary Services (FCAS) on the basis of enabled MW x FCAS clearing price.
- FCAS payment and recovery mechanisms as they apply to generation will apply equally to DRAs with aggregated ancillary services load.
- Payments to DRA for provision of FCAS will be recovered using standard recovery mechanisms.
- DRAs will not be subject to a fee for participating as an ancillary services provider under the existing fee determination.

13.4 Ancillary Service Cost Recovery Settlement

Ancillary services are services used by AEMO to manage power system safety, security and reliability. These services maintain key technical characteristics of the system, including standards for frequency, voltage, network loading and system restart processes. Ancillary services involve several distinct categories:

- FCAS regulation (2 markets): Used to maintain the frequency of the system under normal conditions
- FCAS contingency (6 markets): Used to restore operating frequency following a contingency event
- SRAS (contracted): Used to restart the system after a black-out
- NSCAS, NLCAS, RPAS (contracted): Used to manage voltage standards and control power flows to within physical limits.

where:

- FCAS = Frequency Control Ancillary Services
- SRAS = System Restart Ancillary Services
- NSCAS = Network Support and Control Ancillary Services
- NLCAS = Network Loading Control Ancillary Services
- RPAS = Reactive Power Ancillary Services

The costs associated with ancillary services are currently recovered from market customers, market generators, and market small generation aggregators. The general principle applied is "causer pays" – i.e. where a participant causes a service to be required (or is a beneficiary from the service), they should pay a commensurate share of the costs.

Ancillary service recovery amounts are calculated half-hourly using existing processes.

The recovery of ancillary services from DRAs and retailers under DRM is summarised in Table 14 below, with details in Sections 13.4.2 to 13.4.7.

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[55] A load capable of providing a demand response can be offered by (and only by) a DRA for FCAS. The demand response cannot be offered as FCAS and included in DRM simultaneously. FCAS is scheduled by AEMO.

Table 14 Ancillary Services Recovery

Service	Currently recovered from	DRA	Retailer
NSCAS	Market Customers	NA	Based on Baseline Energy
SRAS	Market Customers (50%) and (Market Generators & Market Small Generation Aggregators) (50%)	Like Market Generator	Based on Baseline Energy
FCAS Contingency Raise	(Market Generators & Market SGAs)	Like Market Generator	NA
FCAS Contingency Lower	Market Customers	NA	Based on Baseline Energy
FCAS Regulation Causer Pays	Market Customers and Market Generators distributed according to Causer Pays	NA	Based on SCADA data
FCAS Regulation Residual	Market Customers	Like Market Customer	Based on Baseline Energy

The reasons for these recovery methods are as follows:

- FCAS Regulation – Causer Pays Recovery
  Where a connection point currently has SCADA metering, causer pays factors will be calculated and be applied to the FRMP for recovery of FCAS regulation. If the connection point also involves a DRA, there would be additional complexity in apportioning the causer pays factors to the DR, which is unlikely to have a material benefit given the frequency of DR.

- FCAS Regulation – Residual Recovery
  The use of DR has the potential to increase the residual FCAS regulation cost, as demand response is likely to contribute to frequency deviation, so it is considered appropriate to recover a share of the residual FCAS regulation cost from the DRA (otherwise a greater cost would be imposed on market customers). The recovery of residual FCAS regulation from the retailer is based on baseline energy otherwise, if it were based on metered energy, it would lead to an unfair change in the apportionment of recovery between market customers.

- FCAS Contingency Raise Recovery
  DRAs are to pay a share of FCAS Contingency Raise recovery to ensure that market generators continue to carry an equivalent share of costs for the energy they produce during demand response trading intervals, when the amount of supplied energy is reduced.

- FCAS Contingency Lower Recovery
  The recovery of FCAS Contingency Lower from the retailer is based on baseline energy to ensure that retailers are apportioned a share of recovery costs that is consistent with their energy market participation.

- SRAS Recovery
  DRAs are to pay a share of SRAS recovery to ensure that market generators continue to

carry an equivalent share of costs for the energy they produce during demand response trading intervals, when the amount of supplied energy is reduced.

- NSCAS
  The recovery of NSCAS from the retailer is based on baseline energy to ensure that retailers are apportioned a share of recovery costs that is consistent with their energy market participation.

13.4.1 Definition of Demand Response and Baseline Energy

The implementation of DRM for ancillary services recovery will require changes to the Rules[56] to define the treatment of DRM energy.

The following definitions which apply during Demand Response Trading Intervals are used in the following sections:

'customer baseline energy' in respect of a Market Customer for a trading interval means the sum of the adjusted baseline energy figures calculated for that trading interval in respect of that Market Customer's relevant connection points;

'DRA demand response energy' in respect of a Market Demand Response Aggregator for a trading interval means the sum of the adjusted demand response energy figures calculated for that trading interval in respect of that Market Demand Response Aggregator's relevant connection points;

'Region customer baseline energy' in respect of a Market Customer for a trading interval means the sum of the adjusted baseline energy figures calculated for that trading interval in respect of that Market Customer's relevant connection points in the specified region;

'Region demand response energy' in respect of a Market Demand Response Aggregator for a trading interval means the sum of the adjusted demand response energy figures calculated for that trading interval in respect of that Market Demand Response Aggregator's relevant connection points in the specified region.

13.4.2 NSCAS Recovery

NSCAS is currently recovered from Market Customers. In each trading interval for which there was a demand response, the following process is to be implemented for managing NSCAS recovery under DRM:

- DRAs do not pay NSCAS recovery.
- Retailers pay NSCAS recovery according to their baseline energy.

This approach ensures that retailers are apportioned a share of recovery costs that is consistent with their energy market participation.

In line with rules Clause 3.15.6A:

(c8) In each trading interval, in relation to each Market Customer for each region, an ancillary services transaction occurs, which results in a trading amount for the Market Customer determined in accordance with the following formula:

$$TA_{P,R} = \left(\sum_{for\ all\ 'S'} \left(TNSCAS_{S,P} \times RBF_{S,P,R} \right) \right) \times \frac{\left(TCE_{P,R} + \boldsymbol{TCBE_{P,R}} \right)}{\left(RATCE_{P,R} + \boldsymbol{RATCBE_{P,R}} \right)} \times -1$$

where:

Subscript 'P'	is the relevant period;
Subscript 'R'	is the relevant region;
Subscript 'S'	is the relevant NSCAS;

56 Related to clause 3.15.6A(o)

$TA_{P,R}$ (in $)	=	the trading amount payable by the Market Customer and Demand Response Aggregator in respect of the relevant region and trading interval;
$TNSCAS_{S,P}$	=	the total amount payable by AEMO for the provision of the relevant NSCAS under an ancillary services agreement in respect of the relevant trading interval;
$RBF_{S,P,R}$ (number)	=	the regional benefit factor assigned to the provision of the relevant NSCAS under an ancillary services agreement in respect of the relevant region and trading interval, as determined by AEMO under paragraph (c7);
$TCE_{P,R}$ (in MWh)	=	the Customer energy figures for the Market Customer in that region for the trading interval;
$TCBE_{P,R}$ (in MWh)	**=**	**The Region Customer baseline energy for the Market Customer;**
$RATCE_{P,R}$ (in MWh)	=	the aggregate of the Customer energy figures for all Market Customer in that region for the trading interval.
$RATCBE_{P,R}$ (in MWh)	**=**	**the aggregate of the Region Customer baseline energy for all Market Customers.**

(c9) In each trading interval, in relation to each Market Customer, an ancillary services transaction occurs, which results in a trading amount for the Market Customer determined in accordance with the following formula:

$$TA_P = TNSCAS_P \times \frac{(TCE_P + \boldsymbol{TCBE_P})}{(RATCE_P + \boldsymbol{RATCBE_P})} \times -1$$

where:

TA_P (in $)	=	the trading amount payable by the Market Customer in respect of the relevant trading interval;
$TNSCAS_P$	=	the sum of all amounts payable by AEMO for the provision of NSCAS under ancillary services agreements in respect of the relevant trading interval minus the sum of the trading amounts calculated for all Market Customers in respect of all the relevant trading interval under paragraph (c8);
TCE_P (in MWh)	=	the Customer energy figures for the Market Customer for the trading interval;
$TCBE_P$ (in MWh)	**=**	**the customer baseline energy for the Market Customer;**
$RATCE_P$ (in MWh)	=	the aggregate of the Customer energy figures for all Market Customer for the trading interval.
$RATCBE_P$ (in MWh)	**=**	**the aggregate of the customer baseline energy for all Market Customers.**

13.4.3 SRAS Recovery

SRAS is currently recovered from Market Customers (50%) and Market Generators and Market Small Generation Aggregators (50%). In each trading interval for which there was a demand response, the following process is to be implemented for managing SRAS recovery under DRM:

- DRAs pay SRAS recovery like a Market Generator.
- Retailers pay SRAS recovery according to their baseline energy.

This approach ensures that market generators continue to carry an equivalent share of costs for the energy they produce.

SRAS Recovery for a DRA

In line with rules Clause 3.15.6A:

(d) In each trading interval, in relation to each Market Generator and each Market Small Generation Aggregator **and each Market Demand Response Aggregator**, an ancillary services transaction occurs, which results in a trading amount for the Market Generator or the Market Small Generation Aggregator **or the Market Demand Response Aggregator** determined in accordance with the following formula:

$$TA = \frac{TSRP}{2} \times \frac{TGE + TSGE + \boldsymbol{TDRE}}{ATGE + ATSGE + \boldsymbol{ATDRE}} \times -1$$

Where:

TA (in $)	=	the trading amount to be determined (which is a negative number);
TRSP (in $)	=	the total of all amounts payable by AEMO in respect of the trading interval under ancillary services agreements in respect of the provision of system restart ancillary services;
TGE (in MWh)	=	the generator energy for the Market Generator for the trading interval, floored at zero;
TSGE (in MWh)	=	the small generator energy for the Market Small Generator Aggregator for the trading interval, floored at zero;
TDRE (in MWh)	**=**	**the DRA demand response energy for the Market Demand Response Aggregator, floored at zero;**
ATGE (in MWh)	=	the aggregate of the generator energy figures for all Market Generators for the trading interval, floored at zero for each Market Generator;
ATSGE (in MWh)	=	the aggregate of the small generator energy figures for all Market Small Generator Aggregators for the trading interval, floored at zero for each Market Small Generator Aggregator; and
ATDRE (in MWh)	**=**	**the aggregate of the DRA demand response energy for all Market Demand Response Aggregators, floored at zero for each Market Demand Response Aggregator;**

SRAS Recovery for a Retailer

In line with rules Clause 3.15.6A:

(e) In each trading interval, in relation to each Market Customer, an ancillary services transaction occurs, which results in a trading amount determined in accordance with the following formula:

$$TA = \frac{TSRP}{2} \times \frac{(TCE + \boldsymbol{TCBE})}{(ATCE + \boldsymbol{ATCBE})} \times -1$$

Where:

TA (in $)	=	the trading amount to be determined (which is a negative number);
TSRP (in $)	=	has the meaning given in clause 3.15.6A(d);
TCE (in MWh)	=	the customer energy for the Market Customer for the trading interval;
TCBE (in MWh)	**=**	**the customer baseline energy for the Market Customer;**
ATCE (in MWh)	=	the aggregate of the customer energy figures for all Market Customers for the trading interval.
ATCBE (in MWh)	**=**	**the aggregate of the customer baseline energy for all Market Customers.**

13.4.4 FCAS Contingency Raise Recovery

FCAS Contingency Raise is currently recovered from Market Generators and Market Small Generation Aggregators. In each trading interval for which there was a demand response, the following process is to be implemented for managing FCAS Contingency Raise recovery under DRM:

- DRAs pay FCAS Contingency Raise recovery like Market Generators.

This approach ensures that market generators continue to carry an equivalent share of costs for the energy they produce.

In line with rules Clause 3.15.6A:

(f) …

In each trading interval, in relation to each Market Generator, each Market Small Generation Aggregator and each **Market Demand Response Aggregator** in a given region, an ancillary services transaction occurs, which results in a trading amount for that Market Generator, Market Small Generation Aggregator and **Market Demand Response Aggregator** determined in accordance with the following formula:

$$TA = RTCRSP \times \frac{TGE + TSGE + \boldsymbol{TDRE}}{RATGE + RATSGE + \boldsymbol{RATDRE}} \times -1$$

Where:

TA (in $)	=	the trading amount to be determined (which is a negative number);
RTCRSP (in $)	=	the total of all amounts calculated by AEMO as appropriate to recover from the given region as calculated in this clause 3.15.6A(f) for the fast raise service, slow raise service or delayed raise service in respect of dispatch intervals which fall in the trading interval;
TGE (in MWh)	=	the generator energy for the Market Generator in that region for the trading interval, floored at zero;
TSGE (in MWh)	=	the small generator energy for the Market Small Generator Aggregator in that region for the trading interval, floored at zero;
TDRE (in MWh)	**=**	**the Region demand response energy for the Market Demand Response Aggregator, floored at zero;**
RATGE (in MWh)	=	the aggregate of the generator energy figures for all Market Generators in that region for the trading interval, floored at zero for each Market Generator;
RATSGE (in MWh)	=	the aggregate of the small generator energy figures for all Market Small Generator Aggregators in that region for the trading interval, floored at zero for each Market Small Generator Aggregator; and
RATDRE (in MWh)	**=**	**the aggregate of the Region demand response energy for all Market Demand Response Aggregators, floored at zero for each Market Demand Response Aggregator;**

13.4.5 FCAS Contingency Lower Recovery

FCAS Contingency Lower is currently recovered from Market Customers. In each trading interval for which there was a demand response, the following process is to be implemented for managing FCAS Contingency Lower recovery under DRM:

- Retailers pay FCAS Contingency Lower recovery according to their baseline energy.

This approach ensures that retailers are apportioned a share of recovery costs that is consistent with their energy market participation.

In line with rules Clause 3.15.6A:

(g) …

In each trading interval, in relation to each Market Customer in a given region, an ancillary services transaction occurs, which results in a trading amount for that Market Customer determined in accordance with the following formula:

$$TA = RTCLSP \times \frac{TCE + \boldsymbol{TCBE}}{RATCE + \boldsymbol{RATCBE}} \times -1$$

Where:

TA (in $)	=	the trading amount to be determined (which is a negative number);

RTCLSP (in \$)	=	the total of all amounts calculated by AEMO as appropriate to recover from the given region as calculated in this clause 3.15.6A(g) for the fast lower service, slow lower service or delayed lower service in respect of dispatch intervals which fall in the trading interval;
TCE (in MWh)	=	the customer energy for the Market Customer in that region for the trading interval;
TCBE (in MWh)	**=**	**the Region Customer baseline energy figures for the Market Customer;**
ATCE (in MWh)	=	the aggregate of the customer energy figures for all Market Customers in that region for the trading interval; and
ATCBE (in MWh)	**=**	**the aggregate of the Region Customer baseline energy for all Market Customers.**

13.4.6 FCAS Regulation Recovery – Causer Pays

FCAS Regulation is currently recovered in accordance with causer pays from Market Customers and Market Generators, with the residual recovered from Market Customers. In each trading interval for which there was a demand response, the following process is to be implemented for managing FCAS Regulation recovery through Causer Pays under DRM:

- Whilst DRM is non-scheduled, the DRA is to not be subject to recovery of FCAS regulation through causer pays.
- Where applicable, the retailer will be subject to recovery of FCAS regulation through causer pays based on SCADA data (as per the current arrangement).

i.e. there is no change to the process for managing FCAS Regulation recovery through Causer Pays as outlined in rules clause 3.15.6A(i).

This approach is taken due to the additional complexity required to apportion the causer pays factor to include DRAs, which is unlikely to have a material benefit given the frequency of demand response.

13.4.7 FCAS Regulation Recovery – Residual

FCAS Regulation recovery of the residual is currently recovered from Market Customers. In each trading interval for which there was a demand response, the following process is to be implemented for managing FCAS Regulation recovery of the residual under DRM:

- DRAs pay FCAS Regulation recovery of the residual according to their demand response energy as per a Market Customer.
- Retailers pay FCAS Regulation recovery of the residual according to their baseline energy.

This approach is taken given that the demand response is likely to contribute to frequency deviation, and so should contribute an incremental share in the recovery costs. It also ensures that retailers are apportioned a share of recovery costs that is consistent with their energy market participation, and that other market customers do not carry an increased share as a result.

In line with rules Clause 3.15.6A:

(i)(2) in relation to each Market Customer for whom the trading amount is not calculated in accordance with the formula in subparagraph (1), an ancillary services transaction occurs, which results in a trading amount for that Market Customer determined in accordance with the following formula:

$$TA = PTA \times -1$$

and:

$$PTA = the\ aggregate\ of\ \left(TSFCAS \times \frac{MPF}{AMPF} \times \frac{TCE + \boldsymbol{TCBE - TDRE}}{RATCE + \boldsymbol{RATCBE - RATDRE}}\right)$$

Where:

TA (in $)	=	the trading amount to be determined (which is a negative number);
TSFCAS (in $)	=	has the meaning given in subparagraph (1);
MPF (a number)	=	the aggregate of the contribution factor set by AEMO under paragraph (j) for Market Customers, for whom the trading amount is not calculated in accordance with the formula in subparagraph (1) for the region or regions relevant to the regulating raise service or the regulating lower service;
AMPF (a number)	=	the aggregate of the MPF figures for all Market Participants for the dispatch interval for the region or regions relevant to the regulating raise service or regulating lower service;
TCE (in MWh)	=	the customer energy for the Market Customer for the trading interval in the region or regions relevant to the regulating raise service or regulating lower service;
TCBE (in MWh)	**=**	**the Region Customer baseline energy for the Market Customer in the region or regions relevant to the regulating raise service or regulating lower service;**
TDRE (in MWh)	**=**	**the Region demand response energy for the Market Demand Response Aggregator in the region or regions relevant to the regulating raise service or regulating lower service, floored at zero;**
RATCE (in MWh)	=	the aggregate of the customer energy figures for all Market Customers, for whom the trading amount is not calculated in accordance with the formula in subparagraph (1), for the trading interval for the region or regions relevant to that regulating raise service or regulating lower service.
RATCBE (in MWh)	**=**	**the aggregate of the Region Customer baseline energy for all Market Customers, for whom the trading amount is not calculated in accordance with the formula in subparagraph (1), for the region or regions relevant to that regulating raise service or regulating lower service; and**
RATDRE (in MWh)	**=**	**the aggregate of the Region demand response energy for all Market Demand Response Aggregators for the region or regions relevant to that regulating raise service or regulating lower service, floored at zero for each Market Demand Response Aggregator.**

13.5 Participant Fees

AEMO charges participant fees as a mechanism of recovering its operating costs. Annually AEMO determines a revenue requirement, which is then used to determine the rate of fees for different categories of participation based on an established structure. The current structure applies until 30 June 2016.

It is intended that the current structure of participant fees not be amended for DRM, but rather transitional rules be implemented to define a DRA as a market customer for the purposes of NER clause 2.11. As part of the process of developing and consulting on the new fee determination (to take affect 1-Jul-2016), consideration will be given to the introduction of new fee categories as part of the recovery of costs of establishing DRM and ASU. Detail of the reasoning for the proposed fee approach is provided in Appendix B.

Participant fees for DRAs will be calculated half-hourly, and in each trading interval for which there was a demand response, the following process is to be implemented for managing participant fees under DRM:

- DRAs pay participant fees according to their demand response energy at a rate equivalent to a market customer.
- Retailers pay participant fees according to their baseline energy.

The current customer fee categories that apply are outlined in Table 15 below.

Table 15 Market Customer Fee Categories

Fee Category	Fee ID (in AEMO system)	Notes
NEM General Fees	V_GEN_NEMM	
NEM Allocated Fees – Market Customers	V_ALO_CUST	
FRC Operations	V_GEN_FRC	Applies if they have a retail licence. Fee payable based on energy in Full Retail Contestability (FRC) jurisdictions.
National Transmission Planner	V_CUST_NTP	
Electricity Advocacy Panel	V_EUA	

13.5.1 Participant Fees for DRAs

In each trading interval at each TNI, the participant fees payable for a DRA will be calculated as:

$$TA = |ADRE| \times \sum_{for\ all\ 'F'} Fee\ Rate_F \times -1$$

where:

Subscript 'F'		is the relevant fee category that applies to Market Customers. See Table 15 for the market customer fee categories that currently apply;
TA (in \$)	=	is the trading amount to be determined (which will be a negative amount for each trading interval);
ADRE (in MWh)	=	is the adjusted demand response energy;
Fee $Rate_F$ (in \$/MWh)	=	is the current fee rate in respect of the relevant customer fee category.

13.5.2 Participant Fees for Market Customers

In each trading interval at each TNI, the participant fees payable by a Market Customer will be calculated as:

$$TA = (AGE + ABE) \times \sum_{for\ all\ 'F'} Fee\ Rate_F \times -1$$

where:

Subscript 'F'		is the relevant fee category that applies to Market Customers. See Table 15 for the market customer fee categories that currently apply;
TA (in \$)	=	is the trading amount to be determined (which will be a negative amount for each trading interval);
AGE (in MWh)	=	is the adjusted gross energy;
ABE (in MWh)	=	is the adjusted baseline energy;
Fee $Rate_F$ (in \$/MWh)	=	is the current fee rate in respect of the relevant customer fee category.

13.6 Compensation Recovery

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. Examples of this intervention include:

- Directions
- Administered price, market price cap and market floor price
- Market suspension
- Reserve trading
- Mandatory restrictions

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. In most cases, recovery is allocated to market customers (retailers and wholesale customers) based on the amount of energy they purchase from the wholesale market.

The following process will be implemented for managing compensation with respect to DRM:

- DRAs do not pay compensation recovery
- Retailers pay compensation recovery as a market customer based on baseline energy.

Compensation recovery amounts will be calculated half-hourly according to existing processes.

The following sections detail the recovery for:

- Direction compensation recovery (for energy, ancillary services, and other directions);
- Administered Price Cap (APC) compensation recovery;
- Reserve settlements;
- Mandatory Restrictions (MR) recovery.

13.6.1 Direction Compensation Recovery

This design has retailers funding compensation based on metered data while DRAs do not fund these costs.

Material demand response, where metered energy is less than the baseline, is likely to contribute to system security. Compensation costs are normally allocated to participants who benefit from the service they provide, or participants that cause the service to be required. DRAs neither benefit from enhanced system security, nor contribute to diminished system security, so it is not efficient for DRAs to share in the costs. The likelihood of a compensation payment coinciding with a negative demand response (metered energy higher than the baseline energy) is not considered material enough to warrant the additional complexity to recover compensation costs from the DRA in these circumstances.

The allocation of compensation costs should continue to be equitable for all market customers, based on the share of energy settlement volume (including baseline energy for retailers during demand response intervals). An apportionment based on metered energy (rather than baseline energy) would lead to a reduction in compensation recovery for demand response-associated retailers (compared to no demand response), which would increase the share of costs for other market customers.

Energy Direction Compensation Recovery

Energy direction compensation is recovered from Market Customers in proportion to their energy in the relevant region/s.

In line with rules Clause 3.15.8:

(b) AEMO must, in accordance with the intervention settlement timetable, calculate a figure for each Market Customer in each region applying the following formula:

$$MCP = \frac{TCE + \boldsymbol{TCBE}}{RATCE + \boldsymbol{RATCBE}} \times \frac{RB}{\sum RB} \times CRA$$

where:

MCP (in $)	is the amount payable (if MCP is negative) or receivable (if MCP is positive) by a Market Customer pursuant to this clause 3.15.8(b);
TCE	the Customer energy for the Market Customer in that region of the relevant trading interval for the period of the direction;
TCBE	**the Region Customer baseline energy for the Market Customer in that region summed over the period of the direction;**
RB	is the regional benefit determined by AEMO pursuant to clause 3.15.8(b1) at the time of issuing the direction; and
RATCE	the aggregate of the Customer energy for all Market Customers in that region of the relevant trading interval for the period of the direction.
RATCBE	**the aggregate of the Region Customer baseline energy figures for all Market Customers in that region summed over the period of the direction.**
CRA (in $)	is the compensation recovery amount (a negative CRA represents compensation payable by AEMO).

Ancillary Services Direction Compensation Recovery

Recovery of ancillary services direction compensation is done in the same manner as ancillary services payment recovery, based on the processes outlined in Section 13.4, noting that the DRA would be excluded from the ancillary services direction compensation recovery.

Other Direction Compensation Recovery

Other direction compensation is recovered from Market Customers, Market Generators, and Market Small Generation Aggregators in proportion to their energy in the relevant region/s.

In line with rules Clause 3.15.8:

(g) Any compensation payable by AEMO under clause 3.12.2 and 3.15.7 not recovered under clauses 3.15.8(b) and 3.15.8(e) must be recovered from Market Customers, Market Generators and Market Small Generation Aggregators. AEMO must, in accordance with the intervention settlement timetable, calculate a figure for each Market Customer, Market Generator and Market Small Generation Aggregator in each region applying the following formula:

$$MCP = \frac{TGE + TSGE - TCE - \boldsymbol{TCBE}}{RATGE + RATSGE - RATCE - \boldsymbol{RATCBE}} \times \frac{RB}{\sum RB} \times CRA \times -1$$

where:

MCP (in $)	=	the amount payable (if MCP is positive) or receivable (if MCP is negative) by a Market Customer Market Generator or Market Small Generation Aggregator under this clause 3.15.8(g);
TGE	=	the generator energy for the Market Generator in that region of the relevant trading interval for the period of the direction, floored at zero;
TSGE	=	the small generator energy for the Market Small Generation Aggregator in that region of the relevant trading interval for the period of the direction, floored at zero;
TCE	=	the Customer energy for the Market Customer in that region of the relevant trading interval for the period of the direction;
TCBE	**=**	**the Region Customer baseline energy for the Market Customer in that region summed over the period of the direction;**
RATGE	=	the aggregate of the generator energy for all Market Generators in that region of the relevant trading interval for the period of the direction, floored at zero for each Market Generator.
RATSGE	=	the aggregate of the small generator energy for all Market Small

		Generation Aggregation in that region of the relevant trading interval for the period of the direction, floored at zero for each Market Small Generation Aggregator.
RATCE	=	the aggregate of the Customer energy for all Market Customers in that region of the relevant trading interval for the period of the direction.
RATCBE	**=**	**the aggregate of the Region Customer baseline energy for all Market Customers in that region summed over the period of the direction.**
RB	=	the regional benefit determined by AEMO under clause 3.15.8(b1) at the time of issuing the direction; and
CRA (in $)	=	the compensation recovery amount (a negative CRA represents compensation payable by AEMO).

The implementation of DRM for compensation recovery will require changes to the Rules (related to clause 3.15.8(h)) to define the treatment of DRM energy.

13.6.2 APC Compensation Recovery

APC compensation is recovered from Market Customers in proportion to their energy in the affected region/s.

In line with rules Clause 3.15.10:

(b) AEMO shall determine the amounts payable for each relevant trading interval by each of the affected Market Customers under clause 3.15.10(a) as follows

$$\frac{APC \times (TCE + \boldsymbol{TCBE})}{RATCE + \boldsymbol{RATCBE}}$$

where:

APC (in $)	=	the total amount of any compensation payments awarded by the AEMC to Scheduled Generators, Market Participants which submitted dispatch bids or Scheduled Network Service Providers in respect of that trading interval in accordance with clause 3.14.6;
TCE		the Customer energy for the Market Customer in any region or regions affected by the imposition of an administered price or the market price cap or the market floor price;
TCBE		**the Region Customer baseline energy for the Market Customer in any region or regions affected by the imposition of an administered price or the market price cap or the market floor price;**
RATCE	=	the aggregate of the Customer energy for all Market Customers in any region or regions affected by the imposition of an administered price or the market price cap or the market floor price;
RATCBE	**=**	**the aggregate of the Region Customer baseline energy for all Market Customers in any region or regions affected by the imposition of an administered price or the market price cap or the market floor price;**

13.6.3 Reserve Settlements

Reserve settlements compensation is recovered from Market Customers in proportion to their energy in the relevant region.

In line with rules Clause 3.15.9:

(b) In respect of reserve contracts entered into by AEMO, AEMO must calculate in relation to each Market Customer for each region in respect of each billing period a sum determined by applying the following formula:

$$MCP = \frac{RRC \times (TCE + \boldsymbol{TCBE})}{RATCE + \boldsymbol{RATCBE}}$$

where:

MCP (in $)	=	the amount payable by a Market Customer for a region in respect of a billing period;

RRC (in $)	=	the total amount payable by AEMO under reserve contracts which relate to the relevant region in the billing period as agreed under clause 3.20.3(f);
TCE		the Customer energy for the Market Customer in the relevant region in the billing period as agreed under clause 3.20.3(f);
TCBE		**the Region Customer baseline energy for the Market Customer in the relevant region summed over the billing period as agreed under clause 3.20.3(f);**
RATCE	=	the aggregate of the Customer energy for all Market Customers in the relevant region in the billing period as agreed under clause 3.20.3(f); and
RATCBE	**=**	**the aggregate of the Region Customer baseline energy for all Market Customers in the relevant region summed over the billing period as agreed under clause 3.20.3(f).**

13.6.4 Mandatory Restrictions Recovery

The Restriction Shortfall Amount (RSA) resulting from mandatory restrictions is recovered by AEMO from Market Customers. The process for calculating the recovery amounts payable depends on the value of the RSA where the following ranges are considered:

- RSA between -$100,000 and $0.
- RSA less than -$100,000.
- RSA positive (note this represents a surplus, which is paid by AEMO to Market Customers).

The settlement process for each of these scenarios is discussed in the following sections.

Restriction Shortfall Amount Between -$100,000 and $0

The recovery of a RSA between -$100,000 and $0 is based on proportion of Market Customer energy.

In line with rules Clause 3.12A.7(f), each Market Customer in the relevant region must pay to AEMO an amount given by:

$$MCP = RSA \times \frac{(TCE + \boldsymbol{TCBE})}{(RATCE + \boldsymbol{RATCBE})}$$

where:

MCP (in $)	=	the amount payable by a Market Customer in accordance with this clause 3.12A.7(f).
RSA (in $)	=	the restriction shortfall amount,
TCE (MWh)	=	the Customer energy for the Market Customer in that region for the mandatory restriction period;
TCBE	**=**	**the Region Customer baseline energy for the Market Customer in that region summed over the mandatory restriction period;**
RATCE	=	the aggregate of the Customer energy for all Market Customers in that region for the mandatory restriction period; and
RATCBE	**=**	**the aggregate of the Region Customer baseline energy figures for all Market Customers in that region summed over the mandatory restriction period.**

Restriction Shortfall Amount Less Than -$100,000

In line with rules Clause 3.15.10B(a), for a mandatory restriction period for which the RSA is less than -$100,000, the Preliminary and Final statements for the billing period in which the mandatory restriction period ends must include details of amounts payable as given:

$$EMCP = RSA \times \frac{(TCE + \boldsymbol{TCBE})}{RATCE + \boldsymbol{RATCBE}}$$

where:

EMCP (in $)	=	the payment to be made by a Market Customer to AEMO;
RSA (in $)	=	the restriction shortfall amount
TCE	=	the Customer energy for the Market Customer in that region for the

		mandatory restriction period expressed in MWh;
TCBE	**=**	**the Region Customer baseline energy for the Market Customer in that region summed over the mandatory restriction period expressed in MWh;**
RATCE	=	the aggregate of the Customer energy for all Market Customers in that region for the mandatory restriction period expressed in MWh; and
RATCBE	**=**	**the aggregate of the Region Customer baseline energy figures for all Market Customers in that region summed over the mandatory restriction period expressed in MWh.**

In line with Rules Clause 3.12A.7(g), AEMO will appoint an independent expert to determine the restriction demand reduction claimed by each Market Customer in a region. Once this has been determined, the RSA recovery amount payable to AEMO by each Market Customer in the relevant region will be recalculated. Any energy data upon which the determination of the restriction demand reduction is determined should be baseline energy in regards to DRM.

Once the restriction demand reductions are determined, as per existing processes, the resultant amounts payable are given by:

$$RCP = (RSA + IE) \times (RD/TRD)$$

where:

RCP (in $)	=	the amount payable to AEMO by a Market Customer in that region following the cessation of the mandatory restriction period;
RSA (in $)	=	the restriction shortfall amount incurred by AEMO upon the cessation of the mandatory electricity restriction period.
RD	=	the Market Customer's restriction demand reduction.
TRD	=	the sum of RD for all Market Customers in the relevant region.
IE	=	the amount of the independent expert's final tax invoice delivered to AEMO in accordance with clause 3.12A.7(i)(11) plus any amounts payable by AEMO on behalf of the independent expert as determined by the dispute resolution panel established in accordance with clause 3.12A.7(m);

Restriction Shortfall Amount is Positive

If the RSA is positive it is paid to Market Customers based on proportion of Market Customer energy.

In line with rules Clause 3.12A.7(h), each Market Customer in the relevant region will be paid an amount given by:

$$RCRP = RSA \times \frac{(TCE + \boldsymbol{TCBE})}{(RATCE + \boldsymbol{RATCBE})}$$

where:

RCRP (in $)	=	the payment to be made by AEMO to a Market Customer pursuant to this clause 3.12A.7;
RSA (in $)	=	the restriction shortfall amount,
TCE (MWh)	=	the Customer energy for the Market Customer in that region for the mandatory restriction period;
TCBE (MWh)	**=**	**the Region Customer baseline energy for the Market Customer in that region summed over the mandatory restriction period;**
RATCE (MWh)	=	the aggregate of the Customer energy for all Market Customers in that region for the mandatory restriction period; and
RATCBE (MWh)	**=**	**the aggregate of the Region Customer baseline energy figures for all Market Customers in that region summed over the mandatory restriction period.**

13.7 A Note About Network Charges

In trading intervals which are demand response trading intervals for NMIs at which there was a demand response, market customers will be debited by the network based on the metered energy.

These charges are not the responsibility of AEMO so have no impact on AEMO's settlement and prudentials systems.

13.8 GST

GST will be applied in line with existing AEMO conventions:

- Demand response energy is a taxable supply from the DRA to AEMO
- Negative performance (i.e. where the demand response energy is negative) is a negative taxable supply from the DRA to AEMO. This means AEMO will offset positive and negative amounts within the billing week.
- The DRA is to receive a recipient created tax invoice
- A retailer is liable for GST based on the baseline energy
- Changes to EMMS to support the GST transaction and statement
- GST will be calculated and applied weekly.

13.9 Statements

Settlement statements and supporting data relating to the transactions in the billing period are issued to all participants who settle with AEMO, including market and some non-market participants. The Settlement report (SR) provides detailed settlement data in a text format which is commonly used to reconcile market transactions. This report, produced as part of the billing process, will be modified to separately identify demand response transactions for DRAs. The format of the following statements will not be modified; though values appearing in the statements will be adjusted to include demand response related amounts in existing line times:

- Tax documents, including tax invoices and adjustment notes:
  - PDFTAXINVOICE
  - PDFRCTAXINVOICE
  - PDFFINALSS
  - PDFADJNOTE
  - PDFRCADJNOTE
- Non-financial statements, including preliminary statements:
  - PDFNONFINALSS
- Regional Summary Report (RSR) which provides region level settlement data.

Detail regarding other supporting data issued is discussed in Section 13.12.

Regarding the provision of ancillary services by DRAs, the detail and layout of the existing reports is considered satisfactory without further modification, and will result in details of payments for these services being included in the statements for DRAs.

13.10 Prudentials

Prudentials in the NEM is a set of controls that minimise the exposure of the market to payment default. These controls consist of an ex-ante assessment of credit limits, and a daily ex-post assessment of financial position. Under normal circumstances, a DRA will be a creditor to the NEM (with regard to the demand response energy), with a payment arising when a DR interval occurs.

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. The process also determines a prudential margin which acts as a buffer during the time taken to remove a participant from the market. Under a revised Credit Limit Procedures, from 28 November 2013 this will become a seasonal process.

The daily prudential assessment aims at estimating a market participant's current position in the market, based on all accrued liabilities and credits that have not been settled. This position (referred to as outstandings) must be maintained within the market participant's trading limit, and this position can be managed using bank guarantees (to change the trading limit), cash or reallocations (to change the outstandings).

Settlement amounts relating to the provision of ancillary services by DRAs will be included in the daily prudential assessments under the existing processes that apply for ancillary services. Under the existing processes these amounts will not be considered in the credit limit assessment.

13.10.1 Credit Limits

The DRA and retailer will have credit limits assessed according to the existing methodology/procedure, with modifications to the Credit Limit Procedures to include consideration of the demand response in the factors to be considered by AEMO in determining prudential settings.

Credit limit assessment for DRAs will be assessed using DR energy. DR energy would normally represent credit energy, though it will be considered as debit energy when the metered energy exceeds the baseline energy or if the regional reference price is negative during a DR interval. As a result, DRAs will have their position assessed in line with the credit limit procedures to determine whether they need to provide credit support.

Credit limit assessment for retailers with regards to DRM will be assessed using baseline energy during demand response intervals.

In line with rules clause 3.3.2, AEMO's regular assessment of credit limits to apply for Market Participants includes the calculation of:

- Maximum Credit Limit (MCL)
- Outstandings limit (OSL)
- Prudential margin (PM)
- Typical Accrual
- Participant Risk Adjustment Factor (PRAF)

The Credit Limit Procedures will be modified to include references to the treatment of DRM in these calculations.

Regarding the provision of ancillary services by DRAs, in line with existing processes, market ancillary services load activity is not considered in credit limit assessment.

Outstandings Limit

The calculation for the OSL is to be based on the value of AEMO's estimate of the Market Participant's average daily load in each region and their average daily generation in each region. The average daily load will be based on metered energy when there is no demand response and on baseline energy during demand response intervals. The average daily generation will incorporate the average daily demand response. The calculation of OSL is shown below:

$$OSL = \sum_{R} MAX\left(OSL_{R,I}\,, OSL_{R,U}\right)$$

where:

$$OSL_{R,U} = (VEL_R + VRD_R + RD\$_R) \times T_{OSL} - (VEG_R + VRC_R + RC\$_R) \times T_{OSL}$$

$$OSL_{R,I} = \frac{(VEL_R + VRD_R) \times T_{OSL}}{VFOSL_R} - \frac{(VEG_R + VRC_R) \times T_{OSL}}{VFOSL_R} + (RD\$_R - RC\$_R) \times T_{OSL}$$

where:

OSL	=	Outstandings Limit
$OSL_{R,U}$	=	The regional OSL with full allowance for regional volatility
$OSL_{R,I}$	=	The regional OSL with no allowance for regional volatility
VEL_R	=	Value of energy load for a market participant in region R. **This is based on metered energy when there is no demand response and on Region baseline energy during demand response trading intervals.**
VEG_R	=	Value of energy generation **and Region demand response energy** for a market participant in region R
VRD_R	=	Value of debit energy reallocations for a market participant in region R
VRC_R	=	Value of credit energy reallocations for a market participant in region R
T_{OSL}	=	The OSL time period (35 days)
$RD\$_R$	=	The average daily dollar amount of prospective (ex ante) dollar reallocations transactions for which the Market Participant is the debit party, in region R;
$RC\$_R$	=	The average daily dollar amount of prospective (ex ante) dollar reallocations transactions for which the Market Participant is the credit party, in region R;
$VFOSL_R$	=	A volatility factor, which is a scaling factor specific to the OSL used to achieve the prudential standard for each region R

Prudential Margin

Likewise with the calculation for the PM, as shown below:

$$PM = MAX\left[\sum\nolimits_R (PM_{R,E}), 0\right] + MAX\left[\sum\nolimits_R (PM_{R,R}), 0\right]$$

where:

$$PM_{R,E} = MAX[(VEL_R - VEG_R) \times T_{RP}, (VEL_R - VEG_R) \times T_{RP}/VFPM_R]$$

$$PM_{R,R} = MAX[(VRD_R - VRC_R + RD\$_R - RC\$_R) \times T_{RP}, (VRD_R - VRC_R)/VFPM_R + (RD\$_R - RC\$_R) \times T_{RP}]$$

where:

PM	=	Prudential margin
$PM_{R,E}$	=	The value of energy in the regional PM with no allowance for regional volatility on net credit amounts.
$PM_{R,R}$	=	The value of reallocations in the regional PM with no allowance for regional volatility on net credit amounts.
VEL_R	=	Value of energy load for a market participant in region R. **This is based on metered energy when there is no demand response and on Region baseline energy during DR trading intervals.**
VEG_R	=	Value of energy generation **and Region demand response energy** for a market participant in region R
VRD_R	=	Value of debit energy reallocations for a market participant in region R
VRC_R	=	Value of credit energy reallocations for a market participant in region R
T_{RP}	=	The OSL time period (35 days)
$RD\$_R$	=	The average daily dollar amount of prospective (ex ante) dollar reallocations transactions for which the Market Participant is the debit party, in region R;
$RC\$_R$	=	The average daily dollar amount of prospective (ex ante) dollar reallocations transactions for which the Market Participant is the credit party, in region R;
$VFPM_R$	=	A volatility factor, which is a scaling factor specific to the PM used to achieve the prudential standard for each region R

Typical Accrual

Likewise with the calculation for the typical accrual, as shown below:

$$TA = DTA \times T$$

where:

$$DTA = \sum_R DTA_R$$

$$DTA_R = (EL_R - EG_R) \times P_R \times (GST + 1) + RD_R \times P_R - RC_R \times P_R + RDS_R \times (P_R - PDS_R) - RCS_R \times (P_R - PCS_R) + (RD\$_R - RC\$_R)$$

where:

DTA	=	Daily typical accrual.
GST	=	The applicable rate for GST.
P_R	=	AEMO's estimate of the average future RRP for each region R.
T	=	The number of days over which the corresponding outstandings are calculated.
EL_R	=	AEMO's estimate of the Market Participant's average daily load in region R. **This is based on metered energy when there is no demand response and on Region baseline energy during demand response trading intervals.**
EG_R	=	AEMO's estimate of the Market Participant's average daily generation **and Region demand response energy** in region R.
RC_R	=	The average daily energy of prospective (ex ante) energy reallocation transactions for which the market participant is the credit party in region R.
RD_R	=	The average daily energy of prospective (ex ante) energy reallocation transactions for which the market participant is the debit party in region R.
RCS_R	=	The average daily energy of prospective (ex ante) swap reallocation transactions for which the market participant is the credit party in region R.
RDS_R	=	The average daily energy of prospective (ex ante) swap reallocation transactions for which the market participant is the debit party in region R.
PCS_R	=	The swap energy-weighted average strike price for prospective (ex ante) swap reallocation transactions for which the market participant is the credit party in region R.
PDS_R	=	The swap energy-weighted average strike price for prospective (ex ante) swap reallocation transactions for which the market participant is the debit party in region R.
RD$R	=	The average daily dollar amount of prospective (ex ante) dollar reallocations transactions for which the Market Participant is the debit party, in region R;
RC$R	=	The average daily dollar amount of prospective (ex ante) dollar reallocations transactions for which the Market Participant is the credit party, in region R;

Participant Risk Adjustment Factor

The equations below show the calculation for a market participant's load and generation PRAFs.

$$PRAF_{L,R} = MAX\left[LWPR_{L,R}, \left(LWPR_{L,R}\right)^2\right]$$

$$PRAF_{G,R} = MAX\left[LWPR_{G,R}, \left(LWPR_{G,R}\right)^2\right]$$

where:

$$LWPR_{L,R} = PLWP_R / RLWP_R$$

$$LWPR_{G,R} = PGWP_R / RLWP_R$$

and:

$$PLWP_R = \sum_{HH} (P_{HH,R} \times EL_{HH,M,R}) \Big/ \sum_{HH} (EL_{HH,R})$$

$$PGWP_R = \sum_{HH} (P_{HH,R} \times EG_{HH,M,R}) \Big/ \sum_{HH} (EG_{HH,R})$$

$$RLWP_R = \sum_{HH} (P_{HH,R} \times ERL_{HH,R}) \Big/ \sum_{HH} (ERL_{HH,R})$$

where:

$PRAF_{L,R}$	=	PRAF (load).
$PRAF_{G,R}$	=	PRAF (generation).
$ERL_{HH,R}$	=	AEMO's estimate of the half hourly expected load for each region R. **This is based on metered energy when there is no demand response and on Region baseline energy during demand response trading intervals.**
$P_{HH,R}$	=	AEMO's estimate of a half hourly future RRP for each region R.
$RLWP_R$	=	AEMO's estimate of the regional load weighted price in each region R.
$EL_{HH,M,R}$	=	AEMO's estimate of the Market Participant's half hourly load adjusted for marginal loss factors in each region R. **This is based on metered energy when there is no demand response and on region baseline energy during demand response trading intervals.**
$EG_{HH,M,R}$	=	AEMO's estimate of the Market Participant's half hourly generation **plus Region demand response energy** adjusted for marginal loss factors in each region R.
$EL_{HH,R}$	=	AEMO's estimate of the Market Participant's half hourly load in each region R. **This is based on metered energy when there is no demand response and on Region baseline energy during demand response trading intervals.**
$EG_{HH,R}$	=	AEMO's estimate of the Market Participant's half hourly generation **plus Region demand response energy** in each region R.
$LWPR_{L,R}$	=	Load weighted price ratio (load).
$LWPR_{G,R}$	=	Load weighted price ratio (generation).
$PLWP_R$	=	Market participant load weighted price.
$PGWP_R$	=	Market participant generation weighted price.

13.10.2 Participant Outstandings

Participant outstandings for DRAs will be assessed daily using DRA demand response energy (which may be positive or negative). Participant outstandings for retailers will be assessed daily using customer baseline energy during demand response intervals.

In line with rules clause 3.3.9, the participant outstandings is calculated based on the settlement amounts which remain unpaid for the current and previous billing periods (up until the end of the day before the calculation is performed). These unpaid settlement amounts may consist of:

- Final settlement amounts
- Preliminary settlement amounts
- Settlement estimates (for dates for which the Preliminary and Final settlement amounts are not yet available).

With regards to DRM, the calculation of Final and Preliminary settlement amounts is done based on DRA demand response energy for the DRA and customer baseline energy for the retailer. The calculation of settlement estimates is discussed in Section 13.10.3.

13.10.3 Settlements Estimates for the Purpose of Prudential Assessments

Settlements estimates for the purpose of prudential assessments are developed in accordance with the NEM Settlement Estimates Policy. The settlement estimates will be calculated based on the following hierarchy of data with regards to DRM:

1. Meter data and baseline energy from MSATS

   Where MSATS has determined that a demand response has occurred and provided the associated meter data and baseline energy to EMMS, settlement estimates will be based on that meter data and baseline energy. That is, the settlement estimation will be based on:

   - DRA demand response energy for the DRA;
   - Customer baseline energy for the retailer.

   This data is available for settlement estimation purposes no earlier than the end of D+2. Therefore, the demand response is considered for the purposes of a prudential assessment no earlier than D+3 after a demand response trading interval. As per existing processes, settlement estimates based on data from MSATS are referred to as Interim settlement estimates.

2. Estimated data

   Where meter data is not provided by MSATS, settlement estimates will be based on:

   - Zero DRA demand response energy for the DRA;
   - Customer baseline energy for the retailer.

   As per existing processes, settlement estimates based on estimated data are referred to as daily settlement estimates.

The NEM Settlement Estimates Policy will be updated to reflect the treatment of DRM-related energy.

Regarding the provision of ancillary services by DRAs, the value of market ancillary services load activity is already calculated in the settlement estimates, and therefore included as a consideration in prudential assessments.

13.10.4 Prudential Dashboard and Prudential Forecast

The Prudential Dashboard and Prudential Forecast are web-based interfaces which allow Participants to view their prudential position.

The Prudential Dashboard displays the Participant’s current prudential position including:

- Outstandings up to the end of the day before
- Reallocations
- Credit support
- Trading limit

As outlined in this paper, various settlement and prudential amounts include costs or payments associated with DRM and/or the provision of ancillary services by DRAs. These amounts will be reflected on the Prudential Dashboard to the same extent (e.g. the amounts displayed on the dashboard will be inclusive of DRM and/or provision of ancillary services by DRAs if they are included in the calculation of the underlying settlement or prudential amount).

The Prudential Forecast displays the Participant’s forecast prudential position, under 10% probability of exceedance (POE), 50% POE and 90% POE scenarios. The forecast billing amounts upon which the Prudential Forecast is based will not include costs or payments associated with DRM and/or the provision of ancillary services by DRAs.

13.10.5 Default Process

DRAs and retailers will be treated in the same manner as any other participant with regards to the Rules default process, as outlined in the 'NEM Settlement Prudential Supervision Process' document available on AEMO's web site. This includes:

- If a participant has defaulted on a settlement payment then AEMO may initially draw down on credit support until it is exhausted in order to make good the defaulted settlement payment. AEMO may also issue a default notice to the participant.
- If a participant's outstandings exceeds their Trading Limit, then a call notice may be issued. If a participant fails to respond as required to the call notice, then a default notice may be issued.
- If rectification of any default notice is not forthcoming to AEMO's satisfaction within the prescribed time, AEMO may issue a suspension notice, and suspend the participant from trading in the NEM.

13.11 Reallocations

A reallocation is a financial arrangement between AEMO and a pair of Participants. When two participants have a reallocation transaction in place with AEMO, one participant will be credited with a trading amount, and the other will be debited with an identical trading amount, for each trading interval for the duration of the reallocation.

A DRA will be permitted to use reallocations (as a Market Participant).

13.12 Settlement Reports

Settlements and prudentials data made available to participants includes data feeds through the EMMS Data Model[57]. The following settlement and billing data relating to DRM, confidential to the relevant participant, will be made available through the EMMS Data Model:

- Energy Settlement (making available energy and value of energy data relating to demand response energy)
- Ancillary services recovery (existing processes)
- Compensation recovery (existing processes)
- Reallocations (existing processes)

The following public settlement and billing data will be available:

- Aggregate energy pertaining to DR activity at the region level

With regards to the provision of ancillary services by DRAs:

- Data will be made available via the EMMS Data Model publishing mechanism as per the current protocols for market ancillary services on a DUID basis.

[57] http://www.aemo.com.au/AEMO%20Home/About%20the%20Industry/Information%20Systems/Data%20Interchange

14 Reporting

14.1 Continuous Reporting

The following tables list the market information to be provided by AEMO under the DRM, separated into public and private information for DRM and ancillary services unbundling. The data would be published through AEMO's NEM participant interface based on the EMMS Data Model[58].

Ancillary services provided by aggregated demand response loads will be dispatched and reported using the existing dispatchable unit identifier (DUID).

14.1.1 Public Data - DRM

Data	Contains	When published	Comment
Participant Registration	• DRA company name • ABN	Ad hoc on change in Electricity Market Management Systems and AEMO's web registration spreadsheet.	Registration reporting will be similar for other registered participants. The registration data currently published includes lists of: • registered participants and the categories for which each participant is registered • current applications • participants who are ceasing registration • market participants who have been suspended from trading
Public Market Notice of Demand Response	For each notification: • DR event ID • Demand response start and end trading intervals • Region • TNI • NMI count	As soon as possible.	.

[58] The EMMS Data Model is described and published on AEMO's website Data Interchange Page http://www.aemo.com.au/AEMO%20Home/About%20the%20Industry/Information%20Systems/Data%20Interchange. Participants can establish an interface to AEMO's market systems or can obtain the information from the website.

Data	Contains	When published	Comment
Demand Response Trading Interval Data	For each demand response trading interval, region, TNI and DRA, the number of notifications received. Similar information for current predispatch schedule.	Released for the previous trading day with pre-dispatch data.	
Baseline Consumption Methodology	Configuration data for each BCM combination.	Ad hoc on change	Mathematical descriptions of each methodology would be documented and published on the website. NMI standing data would identify which methodology is used by a NMI. A list of state public holidays used in the applications of the methodology would also be published.
Billing	Billing calendar, GST information, billing runs	With each billing run or ad hoc (static data)	No changes required for DRM
Demand Forecasting			No changes
Demand Response Energy	For each trading interval and region, the amount of demand response energy.	At each settlement run, the most recent demand response energy will be published.	

14.1.2 Public Data – ASL

Market ancillary services only. Ancillary service loads will be scheduled through the central dispatch process. Some data for ancillary service loads relates to coordination between scheduling energy and scheduling ancillary services. This data is not relevant to DRMASL, which will not allow energy scheduling in the initial implementation.

Non-market ancillary services are by contract and processes/reporting would not change.

Data	Contains	Published	Comment
Registration	• DUID • Bid type (which services) • Maximum capacity	Ad hoc on change	Each ancillary service load or aggregate ancillary service load is explicitly listed in AEMO's databases and the webs registration spreadsheet. Because demand response loads will not be scheduled

Data	Contains	Published	Comment
			loads, the minimum & maximum enablement level, and minimum and maximum angles that are included on the spreadsheet are not relevant. Ancillary service loads will be given a dispatchable unit identifier (DUID) and will be scheduled.
Dispatch	Bid data – DUID, FCAS type, settlement date, offer date, rebid explanation, band prices and availabilities. Dispatch instructions to provide FCAS, amount and service dispatched.	4 am next day	Standard application of bidding to ancillary services loads.

14.1.3 Confidential Data – DRM Data for DRA

Data	Contains	Published	Comment
Registration	Public information plus: • Accredited NMIs • BCM combination for each NMI if active in DRM.	Ad hoc on change	Public information is published in AEMO's databases as well as on a web spreadsheet. Confidential data relating to an individual participant will not be published in the spreadsheet.
Private Participant Notice of Demand Response	For each notification • DR event ID • Demand response start and end trading intervals • Region • TNI • NMIs	As soon as possible.	
Settlements & Prudentials	Settlement configuration data, settlement data and prudential management for each company.	As per settlement timetable	

Data	Contains	Published	Comment
NMI Discovery Data	Existing NMI information plus • BCM combination applied to this NMI if active in DRM.	Ad hoc on NMI discovery (via MSATS)	Data required to permit contestability of DRM between DRAs and Market Customers.
Metering / NMI validation data	Meter data and information on the NMIs included/excluded in settlement.	As data becomes available	DRM specific data is described in Section 12.6

14.1.4 Confidential Data – Retailer

Data	Contains	Published	Comment
Participant Registration	Public information plus: • Accredited NMIs • BCM combination for each NMI if active in DRM.	Ad hoc on change	Public registration information is provided through AEMO databases and the web registration spreadsheet. Confidential information will not be provided via the spreadsheet.
Private Participant Notice of Demand Response	For each notification • DR event ID • Demand response start and end trading intervals • Region • TNI • NMIs	As soon as possible.	
Settlements & Prudentials	Settlement configuration data, settlement data and prudential management for each company.	As per settlement timetable	Settlements & prudentials are managed by company. This is netted off for companies with multiple registrations or that use reallocations.
NMI Discovery Data	Existing NMI information plus • BCM combination applied to this NMI if active in DRM.	Ad hoc on NMI discovery (via MSATS)	Data required to permit contestability of DRM between DRAs and Market Customers.

Data	Contains	Published	Comment
Metering/ NMI validation data	Meter data and information on the NMIs included/excluded in settlement.	As data becomes available	DRM specific data is described in Section 12.6

14.1.5 Confidential Data – LNSP

Data	Contains	Published	Comment
Participant Registration	Public information plus: • Accredited NMIs.	Ad hoc on change	The LNSP will receive a notification from MSATS after a DRA has been assigned to its NMI
Private Participant Notice of Demand Response	For each notification • DR event ID • Demand response start and end trading intervals • Region • TNI • NMIs	As soon as possible.	
Metering	Meter data	As data becomes available	The DRM specific data described in Section 12.6 and does not go to LNSPs.

14.1.6 Confidential Data – ASL Data for DRA

Data	Contains	Published	Comment
Dispatch	Bid data – validation, DUID, FCAS type, settlement date, offer date, rebid explanation, band prices and availabilities. Dispatch instructions to provide FCAS, amount and service dispatched.	Real time	Standard application of bidding to ancillary services loads. Need to confirm operation of breakpoints in absence of energy bids for load.

14.2 Annual Reporting

AEMO is to prepare an annual report for the first five years of the operation of the DRM. This report would cover frequency of events, types of facility used, the magnitude of response and price, and geographic distributions. The report will also include:

- Statistical information on demand response in each region and at transmission node level, including details of ANZIC codes and the methods used for providing demand response.
- Statistical information on demand response activities occurring outside of DRM;
- Analysis of sensitivity of demand response to prices
- Analysis of dispatch of demand response loads providing ancillary services.
- Reporting of participant fees paid to AEMO
- Commentary on power system security impacts of DRM (such as frequency or voltage)
- Commentary on local supply impacts of DRM (such as quality of supply or other connection related issues)
- Commentary on scheduling and forecasting options for DRM in the future.

AEMO will establish a procedure for producing the annual report in consultation with interested parties. AEMO will not be required to use the Rules consultation procedures.

DRAs will provide data to support this process as described in Section 6.2.2. The rules and procedures may also place obligations on NSPs and retailers to provide information on the types, capacity and frequency of use of demand response operating outside of DRM so as to allow AEMO to develop a more complete statistical representation of the overall demand response situation across the NEM and at the local level.

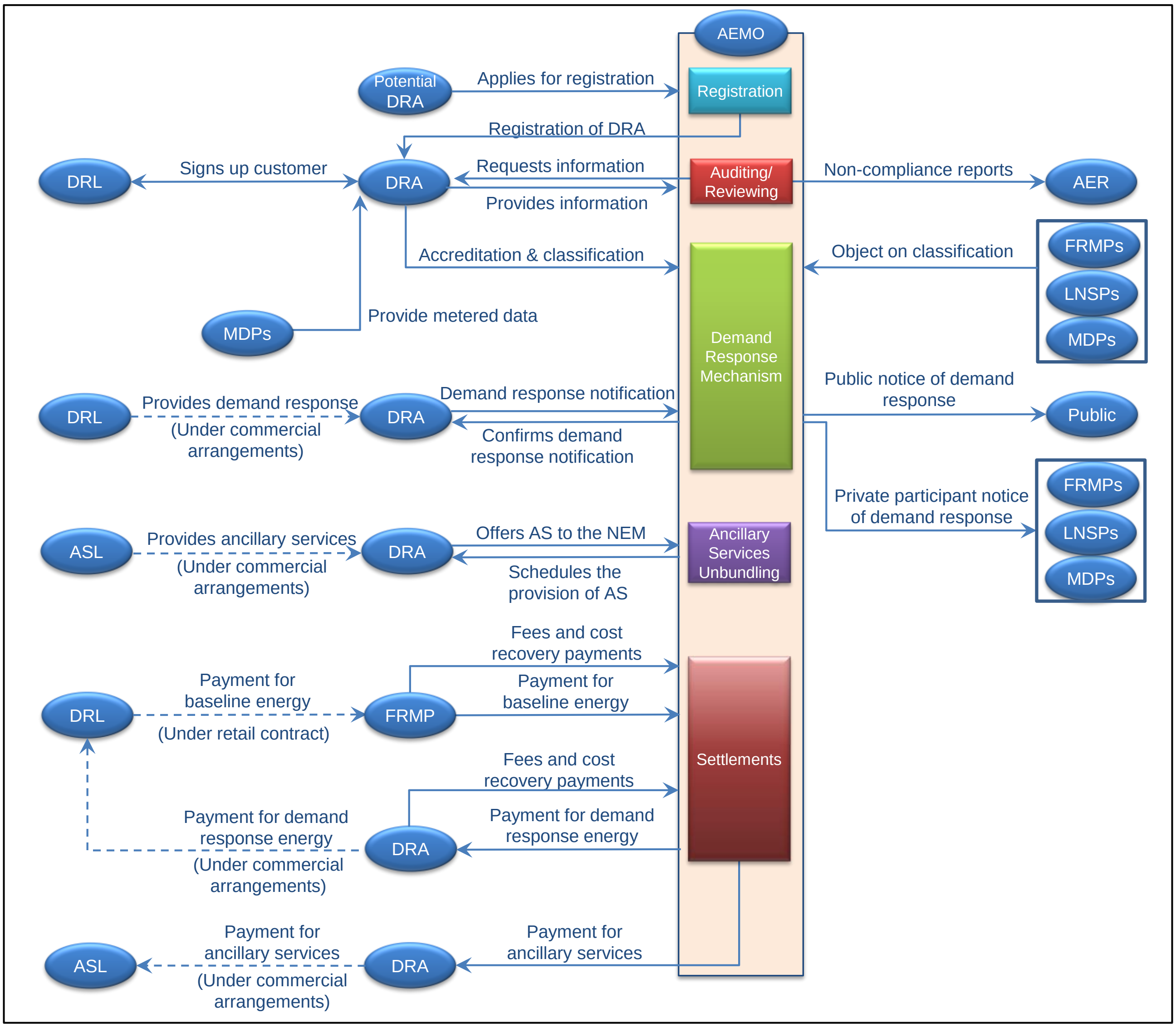
AEMO will conduct a public consultation on the requirement for the annual report after four years of operation of the DRM.

The annual report will be prepared within AEMO’s existing market review and monitoring functions.

15 Process Flows

Figure 9 provides a high level overview of the key information exchanges and payments under DRM and ASU.

Figure 9 – High level process flow for DRM and ASU



Appendix A: Example of Baseline Energy Calculations

Example of a "10 of 10" Unadjusted Baseline for Weekdays Excluding Public Holidays

Consider a DRA is providing demand response on Tuesday 29th of the month for the trading interval ending 1330 hours for a NMI using a "10 of 10" methodology. In order to calculate the baseline energy, the last 10 days ("selected days") that are not public holidays, weekend days or event days are used ("qualifying days"). These are shown in Table 16.

Table 16 - The Selected Days (Shaded) Used in the "10 of 10" Baseline

Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Sunday
	1	2	3	4	5	6
7	8 Prior Event	9	10 Prior event	11	12	13
14	15	16 Prior Event	17	18	19	20
21	22 Prior Event	23	24	25 Holiday	26	27
28	29 **DR Event**	30	31			

For these days the half hour ending 1330 hours metered energy is collected with these averaged to form the unadjusted baseline energy, as shown in Table 17.

Table 17 - Determination of the Unadjusted Baseline Energy

Date	Type	Event	1 PM Meter Value
9 Jan	Weekday	No	840
11 Jan	Weekday	No	910
14 Jan	Weekday	No	800
15 Jan	Weekday	No	780
17 Jan	Weekday	No	810
18 Jan	Weekday	No	860
21 Jan	Weekday	No	900
23 Jan	Weekday	No	890
24 Jan	Weekday	No	910
28 Jan	Weekday	No	800
		Total:	**8500**
		Unadjusted Baseline Energy (Total / 10)	**850**

If there were not 10 eligible days within the baseline window the additional rules would be applied, such as reducing the number of eligible days required.

Example of Symmetric Additive Adjustment

A symmetric additive adjustment allows the unadjusted baseline to be increased or decreased by the adjustment. In the example in Table 18 the adjustment window comprises the 6 trading intervals (1 to 6) ending one hour before the start of the demand response interval, which runs from trading intervals 9 to 16.

An unadjusted baseline energy would be determined for each of trading intervals 1 to 6 and the average difference between this baseline and metered demand would be added to the unadjusted baseline during the demand response interval.

Table 18 - Determination of the Final (Adjusted) Baseline Energy

	Adjustment Window								Demand Response Interval							
Trading Interval	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**
Meter Read	*5*	*6*	*7*	*9*	*10*	*11*	*12*	*14*	*8*	*10*	*12*	*14*	*13*	*12*	*14*	*16*
Unadjusted Baseline Energy	*2*	*2*	*4*	*6*	*8*	*8*	*10*	*12*	*14*	*15*	*20*	*21*	*20*	*20*	*21*	*22*
Additive Adjustment	Average meter read = 8 Average unadjusted baseline energy = 5 Additive adjustment = 3								*3*	*3*	*3*	*3*	*3*	*3*	*3*	*3*
Adjusted Baseline Energy									*17*	*18*	*23*	*24*	*23*	*23*	*24*	*25*
Demand Response Energy									*9*	*8*	*11*	*10*	*10*	*11*	*10*	*9*

In this scenario, usage during the adjustment window is higher than the unadjusted baseline energy and the use of the additive adjustment results in a positive (higher) adjustment to the baseline energy.

Example of an Unadjusted "Mid 2 of 4" Baseline for Weekends and Public Holidays

Consider a NMI providing demand response on Sunday 27th of the month for trading intervals ending 1330 and 1400 hours. Table 19 shows the selected days for this example.

Table 19 - The Selected Days (Shaded) Used in the "Mid 2 of 4" Baseline

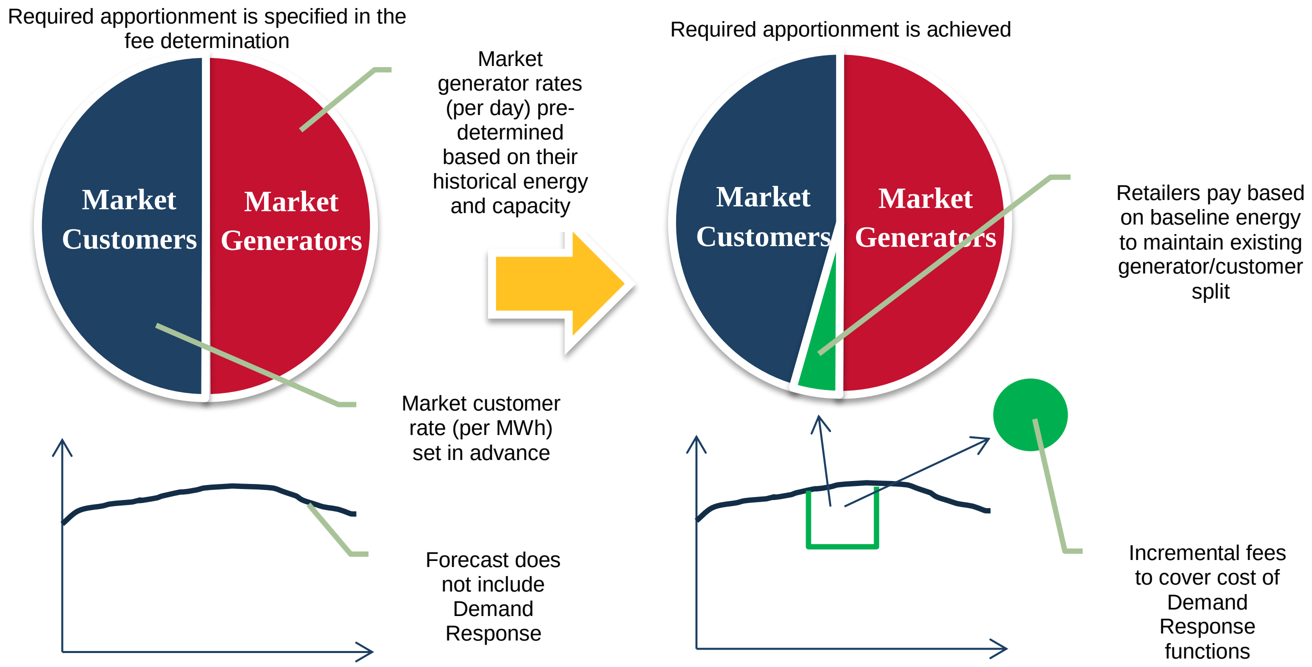
Monday	**Tuesday**	**Wednesday**	**Thursday**	**Friday**	**Saturday**	**Sunday**
	1	2	3	4	5	6
7	8	9	10	11	12	13
14	15	16	17	18	19	20 Prior Event
21	22	23	24	25 Holiday	26	27 **DR Event**
28	29	30	31			

Under a "mid 2 of 4" baseline the four metered demand values for half hour ending 1330 hours for each of the four days are shown. Suppose these are 10 MWh, 12 MWh, 16 MWh, and 18 MWh. The methodology would exclude the smallest and largest values, leaving 12 MWh and 16 MWh, which would be averaged to give an unadjusted baseline energy of 14 MWh.

Appendix B: Fee Treatment

The recommendation relating to retailer fees was based on the principle of equity between market customers and market generators59 under the current structure. The structure will be reviewed and consulted on in 2016, which will necessitate an assessment of the allocation between different categories of participation (including small generator aggregation and DRAs). Under the current structure the apportionment of revenue recovery between Market Customers and Market Generators is defined. For example, the NEM general revenue requirement is to be recovered 67.8% from Market Customers and 32.2% from Market Generators. Based on this apportionment, the fee rate to apply to market customers is determined (in advance as a $/MWh rate) based on forecast energy, and the fee rate to apply to market generators is determined (in advance as a daily rate) based on historical energy volumes and capacity information. If retailers associated with demand response were to pay participant fees based on metered energy, this would lead to a lower recovery of fees compared to the forecast amounts, and would result in a higher proportion of fees being recovered from market generators, as the fees recovered from the generators will not change throughout the year. To ensure an equitable recovery between demand response-associated retailers and other market customers - and between market customers and market generators - retailers should pay fees based on baseline energy.

Figure 10 - Participant Fee Share



By recovering fees from retailers based on baseline energy this maintains the required apportionment between Market Customers and Market Generators. For example, if retailer fee recovery were based on metered energy, the apportionment of the NEM general revenue requirement recovery will vary from 67.8% from Market Customers and 32.2% from Market Generators if there are periods of demand response.

The incremental fees (represented by the green circle in Figure 10) are fees payable by the DRA, over and above fees payable by Market Customers and Market Generators, to cover the cost of demand response functions. This results in an increase in fee recovery by AEMO if there is demand response (assuming all else is equal). This 'over-recovery' would then result in a reduction in the revenue requirement being recovered by AEMO via fees in the following year, reducing the amount recovered from Market Customers and Market Generators.

[59] Market Network Service Providers (MNSPs) are treated as Market Generators for the purpose of fee recovery.

It should be noted that the proposed arrangement for the recovery of NEM participant fees is a transitional arrangement to be implemented for the period from the introduction of DRM (in early 2015) until a new fee determination takes effect on 1 July 2016. This structure of participant fees would be reviewed as part of the new fee determination.

The AEMO NEM general budgeted revenue requirement is recovered from Market Participants in accordance with the current fee determination as per Table 20. Also provided is an example of the recovery split for a total NEM general budgeted revenue requirement of $100M.

Table 20 NEM General Budgeted Revenue Requirement Recovery

Revenue Requirement Type	**Recovered from**	**Example**
NEM general costs (unallocated) (30% of total revenue requirement)	Market Customers (100%)	$30M
NEM allocated costs (70% of total revenue requirement)	Market Customers (54%)	$37.8M
	Market Generators and MNSPs[60] (46%)	$32.2M

The required share of revenue recovery between Market Customers and (Market Generators and MNSPs) is 0.678 : 0.322 (or approximately 2.1 : 1).

A worked example is presented in Table 21. It illustrates that the fee recovery apportionment between Market Customers and Market Generators is as prescribed in the fee determination regardless of the amount of demand response.

[60] Market Network Service Providers

Table 21 - Worked example of NEM general budgeted revenue

	Year 1	Year 2	Year 3	Year 4
Revenue requirement				
General budgeted revenue requirement	$100M			
Adjustment for over/under recovery in the previous year	$0M	$0M	-$0.678M	$0M
Adjusted general budgeted revenue requirement	$100M	$100M	$99.3M = $100M-$0.678M	$100M
NEM unallocated costs (Market Customers)	$30M	$30M	$29.8M	$30M
NEM allocated costs (Market Customers)	$37.8M	$37.8M	$37.5M	$37.8M
NEM allocated costs (Market Generators and MNSPs)	$32.2M	$32.2M	$32.0M	$32.2M
Energy				
Forecast Customer energy	100,000GWh			
Metered energy	100,000GWh	99,000GWh	99,000GWh	99,000GWh
Demand Response	0MWh	1,000GWh	1,000GWh	1,000GWh
Fee rates				
Customer fee rate (costs / forecast customer energy)	$0.678/MWh =$67.8M/ 100,000GWh	$0.678/MWh =$67.8M/ 100,000GWh	$0.673/MWh =$67.3M/ 100,000GWh	$0.678/MWh =$67.8M/ 100,000GWh
Generator & MNSP fee rate ((costs / 2) / generator energy$_{y-1}$ + (costs / 2) / generator capacity$_{y-1}$)	Varies	Varies	Varies (based on reduced energy compared to previous year due to DRM)	Varies
Fees recovered				
Total	$100M	$100M + $0.678M	$99.3M + $0.673M	$100M + $0.678M
Market Customers (based on baseline energy for DRM)	$67.8M = $0.678/MWh x 100,000GWh	$67.8M= $0.678/MWh x (99,000 +1000)GWh	$67.3M= $0.673/MWh x 100,000GWh	$67.8M = $0.678/MWh x (99,000 +1,000)GWh
Market Generators & MNSPs	$32.2M	$32.2M	$32.0M	$32.2M
DRAs	$0	$0.678M = $0.678/MWh x 1,000GWh	$0.673M= $0.673/MWh x 1GWh	$0.678M= $0.678/MWh x 1,000GWh
Over/Under recovery (compared to general budgeted revenue requirement)	$0	$0.678M over recovery	$0	$0.678M over recovery
Customer:Generator split	67.8 : 32.2 2.1 : 1	67.8 : 32.2 2.1 : 1	67.8 : 32.2 2.1 : 1	67.8 : 32.2 2.1 : 1

A similar principle of adjustment for over/under recovery applies for the recovery of other types of revenue.

Appendix C: Obligations Summary

No	Topic	Parties	Obligation
1	Registration	DRA	If seeking registration, to submit an online application provided by AEMO.
2	Registration	AEMO	To process DRA applications.
3	Demand response load accreditation	DRA	To establish compliance of its demand response load provided by end users.
4	Demand response load accreditation	DRA	To apply for eligibility test to be performed on a NMI in classifying a load (including for customer changes) or if changing BCM combination.
5	Demand response load accreditation	AEMO	To perform eligibility test on a NMI on application by a DRA, if the meter or BCM combination changes, and as a result of periodic reviews.
6	Demand response load classification	DRA	To classify demand response NMI in MSATS, and to separately report the ANZSIC code and the method used in delivering the response.
7	Demand response load classification	AEMO	To provide to the FRMP, the MDP and the LNSP associated with the NMI, its BCM combination and the DRAs name.
8	Demand response load classification	AEMO	To provide the DRA with the identities of the FRMP, MDP and the LNSP associated with the NMI.
9	Demand response load accreditation	AEMO	To periodically review the eligibility of a NMI to participate in DRM.
10	Ancillary service load accreditation / classification	DRA	To establish compliance of its ancillary services load provided by end user.
11	Ancillary service load accreditation / classification	DRA	To apply for technical review of ancillary load against the market ancillary services specification.
12	Ancillary service load accreditation / classification	AEMO	To review and confirm whether or not a load meets requirements to be an ancillary service load.
13	Audits	DRA	To comply with audit requirements of eligibility of a load to provide DRM or ancillary services.
14	Demand response	DRA	To submit a demand response notification to AEMO.
15	Demand response	AEMO	To provide a public notice of a demand response.

No	Topic	Parties	Obligation
16	Demand response	AEMO	To provide a private file of demand response information to FRMPs, MDPs, LNSPs.
17	Metering data	MDP	To provide to DRA the metering data of the associated NMIs.
18	Ancillary service	DRA	To provide bids to AEMO when offering ancillary services.
19	Settlements	DRA	To settle with AEMO for: • Demand response provision • Ancillary services provision • Ancillary service cost recovery • Participant Fees
20	Settlements	Retailer	Obligations unchanged, except that settlement calculations based on baseline energy instead of metered energy in some situations during demand response trading intervals.
21	NMI change requests	AEMO	To notify the DRA associated with a NMI of current change requests to change the FRMP.
22	NMI change requests	AEMO	To notify the DRA associated with a NMI of current change requests to change the MDP.
23	NMI change requests	AEMO	To notify the DRA associated with a NMI of current change requests to change the LNSP.
24	Customer move	DRA	To update MSATS and end its DRA role if the consumer at the NMI moves out of the property.
25	Customer move	DRA	To update MSATS and update the selected BCM combination if the consumer at the NMI moves out of the property.
26	DRA - customer contract termination	DRA	To update MSATS (to a Participant ID of ‘NODRA’) and update the selected BCM combination (to ‘NOBCM’).
27	Reporting	AEMO	To provide meter data reports to DRAs.
28	Reporting	AEMO	To provide annually reports of the statistics of demand response provision.
29	Deregistration	DRA	If seeking deregistration, to send notification to AEMO.
30	Deregistration	AEMO	To ensure the DRA has met its financial obligations before deregistration.

Appendix D: Glossary and Abbreviations

Glossary

Term	Definition
accredited BCM combination	A combination of BCMs, including one BCM to be used for weekdays that are not (local) state public holidays and, potentially, another BCM to be used for weekends and (local) state public holidays, which has been accredited for use and is available for selection by DRAs.
additive adjustment	An adjustment applied in baseline calculation to increase or decrease the baseline energy based on the average difference between predicted and metered energy during an adjustment window prior to a demand response interval.
adjusted baseline energy	Within settlement calculations and in respect of a Market Customer for a trading interval this means the distribution loss factor-adjusted baseline energy for a specified TNI[61].
adjusted demand response energy	Within settlement calculations and in respect of a Market Demand Response Aggregator for a trading interval this means the distribution loss factor-adjusted demand response energy for a specified TNI.
adjustment window	The period of hours preceding a demand response trading interval from which qualifying trading intervals are selected for the purpose of comparing metered data with baseline energy (without applying an additive adjustment) for the purpose of deriving an additive adjustment for the demand response trading interval.
ancillary service load	A market load which has been classified in accordance with Chapter 2 as an ancillary service load. New provisions will be added to allow DRAs to classify a load as an ancillary service load (or to aggregate loads for ancillary services). A DRA has the choice of classifying a load as demand response load, ancillary service load or both.
B2B e-Hub	(as defined in the National Electricity Rules) An electronic information exchange platform established by *AEMO* to facilitate *B2B Communications*.
B2B Procedures	B2B Procedures (as defined in the National Electricity Rules) Procedures prescribing the content of, the processes for, and the information to be provided to support, B2B Communications.
baseline consumption methodology (BCM)	A methodology used to calculate baseline energy for a demand response trading interval.

[61] Transmission node identifier

Term	Definition
baseline energy	The MWh energy derived from a baseline consumption methodology and associated with a NMI included in a demand response for settlement purposes for a demand response trading interval. The baseline energy is the sum of the metered energy and the demand response energy.
baseline window	The period of days preceding a demand response trading interval from which qualifying days are selected for the purpose of calculating baseline energy for that demand response trading interval.
CAISO	The independent system operator for the Californian electricity market.
CATS Procedure	MSATS Procedures: Consumer Administration and Transfer Solution (CATS) Procedure (as defined in the CATS Procedure) The CATS Procedures (MT_RT1700v00x.x) contain the principles that govern consumer transfer, the registration of metering installations and the management of standing data. The procedures also identify the obligations placed on CATS participants. These procedures are applicable to National Metering Identifiers (NMIs) that have a classification of small and large.
connection point	The agreed point of supply established between Network Service Provider(s) and another Registered Participant, Non-Registered Customer or franchise customer. *DRAs will play no part in negotiating the location of a connection point. This remains between the Network Service Provider and the Customer.*
customer baseline energy	In respect of a Market Customer for a trading interval this means the sum of the adjusted baseline energy figures calculated for that trading interval in respect of that Market Customer's relevant connection points.
Demand Response Aggregator (DRA)	A person who: a) intends to, or engages in the provision of demand response energy or market ancillary services from one or more demand response loads or frequency control ancillary service loads; and b) is registered by AEMO as a Demand Response Aggregator under Chapter 2 *(of the rules)*
demand response energy	The MWh demand response associated with a NMI included in a demand response for a demand response trading interval
demand response load	A load identified by a NMI classified by a DRA for providing demand response under the DRM. A demand response load will be able to be classified once it has been accredited by AEMO as having a suitable baseline consumption methodology.
demand response notification	A notification issued by a Demand Response Aggregator to AEMO to indicate the time period over which the Demand Response Aggregator is providing demand response. This time period may cross multiple trading intervals.

Term	Definition
demand response trading interval	Trading intervals that are affected by a demand response notification.
DNSP	Distribution Network Service Provider (as defined in the National Electricity Rules) A person who engages in the activity of owning, controlling, or operating a *distribution system*.
DRA demand response energy	In respect of a Market Demand Response Aggregator for a trading interval this means the sum of the adjusted demand response energy figures calculated for that trading interval in respect of that Market Demand Response Aggregator's relevant connection points.
eligibility test data window	The period of days from which meter data is taken for the purpose of conducting NMI eligibility tests.
event day	A calendar day on which a NMI is included in a demand response. *Note: In some markets, though by no means all, days where a meter is ineligible for provision of demand response (e.g. because of blackout, changed operations etc.) are also considered event days and are not included in the baseline calculations.*
exclusion rules	Conditions for excluding days from the set of qualifying days.
financially responsible	In relation to any market connection point, a term which is used to describe the Market Participant which has either: 1. classified the connection point as one of its market loads; 2. classified the generating unit connected at that connection point as a market generating unit; or 3. classified the network services at that connection point as a market network service. *This term describes a Market Participant who has classified a market connection point. This will not apply to a DRA.*
LNSP	Local Network Service Provider (as defined in the National Electricity Rules) Within a local area, a Network Service Provider to which that geographical area has been allocated by the authority responsible for administering the jurisdictional electricity legislation in the relevant participating jurisdiction.

Term	Definition
Local Retailer (LR)	Local Retailer (as defined in the National Electricity Rules) In relation to a local area, the Customer who is: 1. a business unit or related body corporate of the relevant Local Network Service Provider; or 2. responsible under the laws of the relevant participating jurisdiction for the supply of electricity to franchise customers in that local area; or 3. if neither 1 or 2 is applicable, such other Customer as AEMO may determine.
Market Demand Response Aggregator	New definition consistent with existing structures in the NER. Will indicate a Demand Response Aggregator that is registered in the market. *The existing definitions of Market Customer and Market Small Generation Aggregator imply loads or generators need to be classified in advance. This is only the case for Market Generators and Market Network Service Providers.*
market load	A load at a connection point classified by the person connected at that connection point or, with the consent of that person, by some other person, as a market load in accordance with Chapter 2. There can be more than one market load at any one connection point. The definition will be extended to include demand response loads or ancillary service loads classified by DRAs. *The current definition of market loads excludes loads that are the responsibility of Local Retailers (i.e. "first-tier" loads). The design is intended to allow first-tier loads to participate in DRM and ancillary services unbundling.*
Market Participant	A person who is registered by AEMO as a Market Generator, Market Customer, Market Small Generation Aggregator, Market Demand Response Aggregator, or Market Network Service Provider under Chapter 2 (*of the rules)*.
market time	A standard time used in the NEM which corresponds to eastern standard time (i.e. without day light savings).
MDP	Metering Data Provider Metering Data Provider – Category D as defined in the National Electricity Rules.
NMI	A National Metering Identifier as described in clause 7.3.1(d) of the National Electricity Rules.
NMI classification code	A code in MSATS to indicate the level of annualised consumption of a NMI. Generally set to align with the upper consumption threshold in the National Energy Customer Framework (NECF). A NMI with a value of "LARGE" will meet the demand threshold requirements for DRM.
PJM	An electricity market and system operator in the eastern United States.

Term	Definition
proposed BCM combination	A new proposed BCM combination that is yet to be accredited
qualifying days	A set of calendar days within a baseline window for which the exclusion rules do not apply and from which selected days are drawn depending on the BCM.
region customer baseline energy	In respect of a Market Customer for a trading interval this means the sum of the adjusted baseline energy figures calculated for that trading interval in respect of that Market Customer's relevant connection points in the specified region.
region demand response energy	In respect of a Market Demand Response Aggregator for a trading interval this means the sum of the adjusted demand response energy figures calculated for that trading interval in respect of that Market Demand Response Aggregator's relevant connection points in the specified region.
selected days	A subset of the qualifying days within the baseline window associated with a demand response trading interval from which meter data is used for the purpose of calculating baseline energy for that demand response trading interval.
Transmission Node Identifier (TNI)	Transmission Node Identifier (as defined in the CATS Procedure) Is an alpha-numeric code to identify the transmission node (as defined in the National Electricity Rules)

Abbreviations

Abbreviation	Meaning
ABE	Adjusted Baseline Energy
ADRE	Adjusted Demand Response Energy
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ANZSIC	Australian and New Zealand Standard Industries Classification
ASU	Ancillary Services Unbundling
B2B	Business-to-Business
BCM	Baseline Consumption Methodology
CATS	Consumer Administration and Transfer Solution
DNSP	Distribution Network Service Price

Abbreviation	Meaning
DRA	Demand Response Aggregator
DRM	Demand Response Mechanism
EMMS	Energy Market Management System
FCAS	Frequency Control Ancillary Service
FRMP	Financially Responsible Market Participant
LNSP	Local Network Service Provider
LR	Local Retailer
MASS	Market Ancillary Services Specification
MDFF	Meter Data File Format
MDP	Meter Data Provider
MSATS	Market, Settlements and Transfer Solution
NECF	National Energy Customer Framework
NEM	National Electricity Market
NMI	National Metering Identifier
NSP	Network Service Provider
NSS	Network Support Service
SCER	Standing Council on Energy and Resources
RRMSE	Relative Root Mean Square Error
TNI	Transmission Node Identity