Government of **Western Australia**
Department of **Mines, Industry Regulation and Safety**
Energy Policy WA

Meeting Agenda

Meeting Title:	Market Advisory Committee (MAC)
Date:	Thursday 31 August 2023
Time:	9:30 AM – 11:30 AM
Location:	Online, via TEAMS.

Item	Item	Responsibility	Type	Duration
1	Welcome and Agenda • Conflicts of interest • Competition Law	Chair	Noting	2 min
2	Meeting Apologies/Attendance	Chair	Noting	2 min
3	Minutes of Meeting 2023_07_20	Chair	Noting	2 min
4	Action Items	Chair	Noting	5 min
5	Market Development Forward Work Program	Chair/Secretariat	Discussion	5 min
6	Update on Working Groups			
	(a) AEMO Procedure Change Working Group	AEMO	Noting	5 min
	(b) Reserve Capacity Mechanism Review Working Group (RCMRWG) – no paper	RCMRWG Chair	Noting	5 min
	(c) Cost Allocation Review Working Group (CARWG) - no paper	CARWG Chair	Noting	5 min
7	Rule Changes			
	(a) Overview of Rule Change Proposals	Chair/Secretariat	Noting	4 min
8	Coordinator NCESS Guideline/ WEM procedure update	Secretariat	Noting	10 min
9	Demand Side Response Review - Consultation Paper	Chair/Secretariat	Discussion	60 min
10	MAC Meeting Schedule for 2024	Chair/Secretariat	Discussion	5 min
11	General Business	Chair	Discussion	10 min
	Next meeting: 9:30am Thursday 12 October 2023			

Please note, this meeting will be recorded.

Competition and Consumer Law Obligations

Members of the MAC (**Members**) note their obligations under the *Competition and Consumer Act 2010* (**CCA**).

If a Member has a concern regarding the competition law implications of any issue being discussed at any meeting, please bring the matter to the immediate attention of the Chairperson.

Part IV of the CCA (titled "Restrictive Trade Practices") contains several prohibitions (rules) targeting anti-competitive conduct. These include:

(a) **cartel conduct**: cartel conduct is an arrangement or understanding between competitors to fix prices; restrict the supply or acquisition of goods or services by parties to the arrangement; allocate customers or territories; and or rig bids.

(b) **concerted practices**: a concerted practice can be conceived of as involving cooperation between competitors which has the purpose, effect or likely effect of substantially lessening competition, in particular, sharing Competitively Sensitive Information with competitors such as future pricing intentions and this end:

- a concerted practice, according to the ACCC, involves a lower threshold between parties than a contract arrangement or understanding; and accordingly; and
- a forum like the MAC is capable being a place where such cooperation could occur.

(c) **anti-competitive contracts, arrangements understandings**: any contract, arrangement or understanding which has the purpose, effect or likely effect of substantially lessening competition.

(d) **anti-competitive conduct (market power)**: any conduct by a company with market power which has the purpose, effect or likely effect of substantially lessening competition.

(e) **collective boycotts**: where a group of competitors agree not to acquire goods or services from, or not to supply goods or services to, a business with whom the group is negotiating, unless the business accepts the terms and conditions offered by the group.

A contravention of the CCA could result in a significant fine (up to $500,000 for individuals and more than $10 million for companies). Cartel conduct may also result in criminal sanctions, including gaol terms for individuals.

Sensitive Information means and includes:

(a) commercially sensitive information belonging to a Member's organisation or business (in this document such bodies are referred to as an Industry Stakeholder); and

(b) information which, if disclosed, would breach an Industry Stakeholder's obligations of confidence to third parties, be against laws or regulations (including competition laws), would waive legal professional privilege, or cause unreasonable prejudice to the Coordinator of Energy or the State of Western Australia).

Guiding Principle – what not to discuss

In any circumstance in which Industry Stakeholders are or are likely to be in competition with one another a Member must not discuss or exchange with any of the other Members information that is not otherwise in the public domain about commercially sensitive matters, including without limitation the following:

(a) the rates or prices (including any discounts or rebates) for the goods produced or the services produced by the Industry Stakeholders that are paid by or offered to third parties;

(b) the confidential details regarding a customer or supplier of an Industry Stakeholder;

(c) any strategies employed by an Industry Stakeholder to further any business that is or is likely to be in competition with a business of another Industry Stakeholder, (including, without limitation, any strategy related to an Industry Stakeholder's approach to bilateral contracting or bidding in the energy or ancillary/essential system services markets);

(d) the prices paid or offered to be paid (including any aspects of a transaction) by an Industry Stakeholder to acquire goods or services from third parties; and

(e) the confidential particulars of a third party supplier of goods or services to an Industry Stakeholder, including any circumstances in which an Industry Stakeholder has refused to or would refuse to acquire goods or services from a third party supplier or class of third party supplier.

Compliance Procedures for Meetings

If any of the matters listed above is raised for discussion, or information is sought to be exchanged in relation to the matter, the relevant Member must object to the matter being discussed. If, despite the objection, discussion of the relevant matter continues, then the relevant Member should advise the Chairperson and cease participation in the meeting/discussion and the relevant events must be recorded in the minutes for the meeting, including the time at which the relevant Member ceased to participate.

Government of **Western Australia**
Department of **Mines, Industry Regulation and Safety**
Energy Policy WA

Minutes

Meeting Title:	Market Advisory Committee (MAC)
Date:	20 July 2023
Time:	9:30am –11:30am
Location:	Microsoft Teams

Attendees	Class	Comment
Sally McMahon	Chair	
Martin Maticka	Australian Energy Market Operator (AEMO)	
Toby Price	AEMO	Proxy for Dean Sharafi
Zahra Jabiri	Network Operator	To 10:30am
Genevieve Teo	Synergy	
Noel Schubert	Small-Use Consumer Representative	
Christopher Alexander	Small-Use Consumer Representative	
Timothy Edwards	Market Generator	
Jacinda Papps	Market Generator	
Adam Stephen	Market Generator	
Paul Arias	Market Generator	From 9:50am
Geoff Down	Contestable Customer	Proxy for Peter Huxtable
Geoff Gaston	Market Customer	
Patrick Peake	Market Customer	
Noel Ryan	Observer appointed by the Minister	
Rajat Sarawat	Observer appointed by the Economic Regulation Authority (ERA)	

Also in Attendance	From	Comment
Dora Guzeleva	MAC Secretariat	Observer
Laura Koziol	MAC Secretariat	Observer
Shelley Worthington	MAC Secretariat	Observer
Tim Robinson	Robinson Bowmaker Paul	Presenter

Apologies	From	Comment
Dean Sharafi	AEMO	
Peter Huxtable	Contestable Customer	

Item	Subject	Action
1	**Welcome** The Chair opened the meeting at 9:30am with an Acknowledgement of Country. The Chair noted that MAC members are to participate in the interests of the stakeholder group they represent. The Chair noted that any advice to the Coordinator from the MAC presents the views of the MAC and not necessarily the views of the Chair	
2	**Meeting Apologies/Attendance** The Chair noted the attendance and apologies as listed above.	
3	**Minutes of Meeting 2023_06_08** The MAC accepted the minutes of the 8 June 2023 meeting as a true and accurate record of the meeting. **Action: The MAC Secretariat to publish the minutes of the 8 June 2023 MAC meeting on the Coordinator's Website as final.**	**MAC Secretariat**
4	**Action Items** The Chair noted that there were no open action items, and the paper was taken as read.	
5	**Market Development Forward Work Program** The Chair noted the updates in the paper and the paper was taken as read.	
6	**Update on Working Groups**	
	(a) AEMO Procedure Change Working Group (APCWG) Mr Maticka summarised the update in the paper and the paper was taken as read.	
	(b) Reserve Capacity Mechanism Review Working Group (RCMRWG) Update The paper was taken as read.	
	(c) Demand Side Response Working Group (DSRWG) Update The Paper was taken as read. The Chair of the DSRRWG noted that:	

Item	Subject	Action
	• the working group is very well attended with 20 attendees at the last meeting; • the next meeting will be held on 2 August to discuss participation of Demand Side Programs (DSP) and loads in the Real-Time Market and the Essential System Services (ESS) markets; and • the Consultation Paper was currently been drafted and was planned to be discussed at the 31 August MAC meeting.	
7	**Rule Changes** **(a) Overview of Rule Change Proposals** The Chair noted the updates in the paper and the paper was taken as read.	
8	**Terms of Reference for the WEM Investment Certainty (WIC) Review Working Group (WICWG)** The Chair noted that the MAC was asked to: • note the updated Scope of Work for the WIC Review; • approve the establishment of a WICWG to assist in the WIC Review; and • approve the Terms of Reference for the WICWG. Ms Guzeleva noted that EPWA: ○ had amended the Scope of Work to reflect the feedback from the last MAC meeting; ○ would seek nominations for the WICWG and that this would not be restricted to MAC members; ○ was planning to hold the first meeting of the WICWG in mid-August 2023; and ○ will seek to engage a consultant to support EPWA with the analysis. • Mr Peake asked if the support for renewable resources can be in the form of capital investment support as these are highly capital intensive investments. Ms Guzeleva indicated that this had been discussed at the last MAC meeting and that contributions to capital investment are out of scope. • Mr Maticka asked if the priority of the proposed initiatives reflect the priorities for investors. Ms Guzeleva noted that the schedule for the review has been adjusted to stagger the initiatives as discussed at the last MAC meeting. • Mr Stephen asked if the timeframe for the review could be extended if significant new issues were identified.	

Item	Subject	Action
	Ms Guzeleva indicated that the scope of the review is limited to the five initiatives that have been identified but that the schedule could be extended if more time is required to consider these initiatives. The MAC approved the establishment of the WICWG to assist with the WIC Review and the Terms of Reference for the WICWG.	
9	**Update on the Supplementary Reserve Capacity Review** Ms Guzeleva noted that since the papers had been circulated to the MAC members: • the Amending Rules have been approved by the Minister and published in the Gazette on Tuesday 18 July 2023; and • an Information Paper with the outcomes of the SRC Review have been published on Tuesday 18 July 2023 including marked up Amending Rules; and Ms Guzeleva noted that the majority of the Amending Rules will commence on 22 July 2023, with the exception of changes to the head of power for the WEM Procedure which will commence on 1 April 2024. This had been requested by AEMO as they have recently published the WEM Procedure for supplementary reserve capacity and are about to commence SRC procurement for this coming summer. Ms Guzeleva noted that another SRC Review will be required following the next call or procurement of SRC, which may lead to further changes next year. • In response to a question from Mr Arias, Mr Price clarified that AEMO was generally supportive of the testing requirement but noted that the rules over eligibility for SRC required further clarity. Mr Price noted that EPWA had clearly communicated the principles but considered there may be a need to revisit the actual drafting to make it crystal clear which additional capacity AEMO can procure. Ms Guzeleva noted EPWA had consulted with AEMO throughout this process and that all comments AEMO provided had been addressed. Ms Guzeleva noted that stakeholders had provided very useful feedback and thanked those who had contributed.	
10	**Reserve Capacity Mechanism Stage 2 – Information Paper** Ms Guzeleva indicated that EPWA is working on an exposure draft of the Amending Rules for the implementation of the Stage 1 Review Outcomes and some related Stage 2 issues. Ms Guzeleva indicated that EPWA plans to publish exposure drafts for the implementation of all Review Outcomes for consultation and to hold one or two RCMRWG meetings in August to discuss the drafting. Ms Guzeleva noted that EPWA does not plan to provide draft Amending Rules to the MAC for review before the public	

Item	Subject	Action
	consultation and asked MAC members whether they agreed with this approach. • Mrs Papps agreed that the RCMRWG was the right body to review the drafting and that a review by the MAC would just extend the timeframe. All stakeholders can review the drafting in detail and make comments during the formal consultation process. The MAC members agreed with Mrs Papps. Ms Guzeleva and Mr Robinson presented the Review Outcomes in the Stage 2 Information Paper. <u>Review Outcome 1 – Individual Reserve Capacity Requirement (IRCR) for Peak Capacity</u>: Mr Robinson summarised Review Outcome 1, as presented in Attachment 1 to the cover paper. The MAC did not have any comments on Review Outcome 1. <u>Review Outcome 2 – IRCR for Flexible Capacity</u>: Mr Robinson summarised Review Outcome 2, as presented in Attachment 1 to the cover paper. • Mr Edwards suggested that removal of the Non-Temperature Dependent Load (NTDL) status would likely slightly reduce the IRCR for the many Temperature Dependent Loads (TDLs) and result in a larger increase of the IRCR for the few NTDLs. Mr Robinson confirmed that this is the likely impact. • Mr Edwards considered that this will add significant cost to a few small industries and that they might look at alternative electricity supply options if their costs for capacity increase too much. Mr Robinson indicated that NTDLs are also more likely to be able to take steps to reduce their IRCR than TDLs. Ms Guzeleva agreed with Mr Robinson, and pointed out that both NTDLs and TDLs contribute to the Reserve Capacity Requirement, irrespective of whether they have a flat or peaky demand profile, and should both contribute to the cost of capacity. The MAC did not have any other comments on Review Outcome 2. <u>Review Outcome 3 – Demand Side Programme (DSP) Certified Reserve Capacity (CRC)</u>: Mr Robinson summarised Review Outcome 3, as presented in Attachment 1 to the cover paper. The MAC did not have any comments on Review Outcome 3. <u>Review Outcome 4 –DSP Dispatch</u>: Mr Robinson summarised Review Outcome 4, as presented in Attachment 1 to the cover paper.	

Item	Subject	Action

	Mr Robinson provided further clarification on the changes to the 200 hour dispatch limit for DSPs:
	• If the dispatch limit was set based on the expected dispatch to serve a 10% POE peak demand forecast, then DSPs would only be dispatched in a very small number of hours per year, but AEMO would need perfect foresight to get the hours exactly right;
	• instead, the proposal is to set the dispatch limit by:
	  ○ subtracting the number of current DSP Capacity Credits from the 50% POE peak demand forecast; and
	  ○ determining the number of hours that the demand in the 10% POE peak demand scenario exceeds this value; and
	• this will result in a higher dispatch limit when more Capacity Credits are issued to DSPs.
	Mr Robinson noted that examples will be added to the Information Paper to show the outworking of the proposed dispatch limit.
	• Mr Schubert supported the proposal and Review Outcome 4.
	• Mr Stephen pointed out that one DSP, providing 20 MW, has recently been called on multiple occasions, while 80-90 MW of DSP is actually certified, and asked if that was considered in the proposal for the new dispatch limit.
	Ms Guzeleva asked AEMO to explain how they dispatch DSPs in real time.
	• Mr Price indicated that AEMO would provide an explanation of how it dispatches DSPs at the next MAC meeting.
	Mr Robinson indicated that, depending on AEMO's response, consideration could be given to the dispatch of DSPs in the drafting of the WEM Rules.
	In response to a question from Mr Edwards, Mr Robinson indicated that there are currently 86 MW of DSP Capacity Credits in the WEM. If AEMO were to perfectly forecast, the DSPs would only be dispatched for two hours in a Capacity Year, whereas the proposed method to determine the dispatch limit would be set at about 20 hours.
	Mr Robinson indicated that examples would be added to the Information Paper, but if there were 300-400 MW of DSP Capacity Credits in the WEM, the dispatch limit would be 70-90 hours.
	• Mr Edwards suggested that a requirement of 100 hours would not be workable, as industrial loads cannot be offline for this long.
	Mr Robinson indicated that:
	  ○ the limit would depend on the shape of the load duration curve (LDC) in each year, and even with 300 MW of DSP capacity, you would only get a limit of 70-80 hours; and	

Item	Subject	Action
	○ a DSP is unlikely to get dispatch for 70-80 hours every year and that the expected average dispatch over a 10-year period would be much lower. • Mr Edwards pointed out that this risk would likely prevent a portfolio of DSPs to enter the WEM because only distributed embedded generators would be able to sign up as DSPs. Mr Robinson pointed out the role for DSP aggregators – while individual loads may only be prepared to be available for 20-40 hours, an aggregator could spread the risk of dispatch across multiple loads. Ms Guzeleva indicated that: • EPWA received feedback from industrial loads and aggregators indicating that they would rather focus on reducing their IRCR if the DSP dispatch limit was above 20-30 hours; • from a system security point of view, trying to reduce IRCR is not as certain as having a DSP with reserve capacity obligations that can be called upon; • measures are being introduced to ensure performance of DSPs that are certified; and • there is a tradeoff if the dispatch requirement is reduced – the DSPs will need to be available because they are paid the same for their capacity as generators. Mr Robinson pointed out that loads have a trade-off when choosing between participating as a DSP or trying to reduce their IRCR – the load will: ○ have to reduce consumption in a number of intervals in every year when trying to reduce IRCR; and ○ have a risk of having to reduce consumption for a larger number of intervals as a DSP in any given year, but would likely have to reduce consumption in fewer intervals in reality. • Mr Alexander agreed with the points made by Mr Edwards and suggested that the proposed methodology appears robust. Mr Alexander supported the proposed changes to the DSP dispatch limit. The MAC did not have any other comments on Review Outcome 4. <u>Review Outcome 5 – Reserve Capacity Testing</u>: Mr Robinson summarised Review Outcome 5, as presented in Attachment 1 of to the cover paper. The MAC did not have any comments on Review Outcome 5. <u>Review Outcome 6 – Outage Planning</u>: Mr Robinson summarised Review Outcome 6, as presented in Attachment 6 to the cover paper.	

Item	Subject	Action
	• Mr Arias suggested that approval of Planned Outages will be a bigger issue in the future and asked if EPWA has an idea of the volume of flexible capacity required and therefore the likelihood of Planned Outages for flexible capacity being approved. Mr Robinson indicated that the analysis had indicated a need for 1,000-1,200 MW of flexible capacity which should be within the capability of the current facilities. Therefore, this is not expected to be an issue, at least initially. Mr Robinson pointed out that the periods in which those facilities are needed are likely be outside of the Hot Season when participants generally want to take their outages, so the outage scheduling could get more constrained. Ms Guzeleva pointed out that the purpose of the flexible capacity arrangement is to attract new capacity that meets the flexibility requirements, and that new fast start generators and storage will have lower outage rates than older facilities. In response to a question from Mr Edwards, Ms Guzeleva indicated that the intent is for the flexible capacity arrangements to commence for the 2024 Capacity Cycle. The MAC did not have any other comments on Review Outcome 6. <u>Review Outcome 7 – Refunds</u>: Ms Guzeleva summarised Review Outcome 7, as presented in Attachment 1 to the cover paper. In particular. Ms Guzeleva noted amendments that were made to the Review Outcomes following submissions on the Consultation Paper, including that: • there will be separate pools for refunds for peak vs flexible capacity; and • the Maximum Facility Capacity Refund for DSPs will be 125% of reserve capacity payments. Ms Guzeleva indicated that a RCMRWG meeting had been held to discuss the issue of the distribution of capacity refunds back to participants serving loads and noted the following:. ○ RCMRWG members made good points on the distribution of refunds to either customers or generators; ○ views were split about 50/50 between the two options: ▪ it was noted that those that opposed the proposal were generators with no retail function and generators that have a large generation portfolio compared to their retail portfolio; ▪ it was noted that those that supported the proposal included loads, independent retailers and retailers that have a large retail portfolio, and the Expert Consumer Panel;	

Item	Subject	Action
	- taking into account that the market is no longer oversupplied with capacity and that customers will pay for both SRC and for capacity procured through the Non-Co-Optimised Essential System Services (NCESS) process, the policy intent is that customers should not have to pay for capacity twice; and - while generators have an incentive to avoid paying refunds that benefit their competitors, the rules specify that refunds are based on supply over the past 30 days, so a portfolio generator that experiences a partial outage will get some of the refunds back. - Ms Papps indicated her concern that: - the majority of the wealth transfer to retailers will not be passed through to consumers because of the disconnect with the regulated retail tariff; - there is a revenue adequacy problem for generators in the WEM, as targeted by the WIC Review; and - generators increasingly need to take Planned Outages as Forced Outages and pay refunds because of a conservative reserve margin. - Mrs Papps suggested a compromise to use refunds for outages that cause SRC to cover the SRC costs, but to hold off any further reform of the refund arrangements pending the outcomes of the WIC Review to avoid exacerbating the revenue adequacy issue. Ms Guzeleva asked Mrs Papps who would pay for NCESS: - Mrs Papps asked whether NCESS is procured due to Forced Outages or forecasting and other issues. Ms Guzeleva indicated that the last NCESS process was primarily due to the risk of generation not being available, and only in part due to demand forecast. - Mrs Papps indicated that she had not considered NCESS, but could do so and come back to the MAC, but it would come down to the reasons for calling NCESS – if it could be specifically attributed to generator availability or other issues in the market. - Mr Alexander considered that: - the question whether retailers will pass the refunds through to customers should not stop the decision, otherwise this question would need to be asked for every reform. - the current refund model presents a form of collective generator insurance as generators pay refunds in one interval but receive rebates in others. - Mr Arias indicated that:	

Item	Subject	Action
	- the capacity price is set based on a level of demand and a level of capacity; - if those sources of capacity are not there, then the price would have been higher and the generators that are there should have received higher compensation; - if there is no level of service degradation, then there is no reason to transfer wealth to retailers; and - SRC and NCESS are problems, but these are specific issues rather than broad policy questions. - Mr Schubert indicated that refunds should pay for SRC and NCESS irrespective of whether it is caused by fuel supply risk or load growth because, in either case, the refunds ought to pay for any additional required capacity. - Mr Stephen agreed with Mrs Papps and Mr Arias and suggested that consideration should be given to Mrs Papps' proposal. The Chair asked for views on whether there are market efficiency implications of allocating the refunds or whether it is just a matter of who gets the refunds. Ms Guzeleva indicated that: - some RCMRWG members are proposing to target refunds at generators that have caused SRC, but the intent is that SRC should only be procured infrequently as a last resort; - the RCMRWG members' views were split between generators that have no or smaller retail activity vs market participants with significant retail activity; and - the WEM started in 2004 and refunds were paid to consumers for the first 10 plus years and this was changed in 2017 as part of a compromise, and at a time the market was oversupplied with capacity and consumers would have not paid for capacity twice, as they would today. - Mr Gaston fully supported Review Outcome 7 and argued that: - there is no revenue gap for existing generators and the WIC Review is intended to look at a potential revenue gap in the future when the market is dominated by generators with zero short-run marginal cost; - the change to provide refunds to generators in 2017 was not properly scrutinised – there was never an economic justification for the change; - it is not correct that the reserve capacity price would be higher to compensate generators if some generators are not available, because a higher price would likely have incentivised other generators to enter the market;	

Item	Subject	Action
	○ there is a fundamental principle that customers should receive a refund if they are not getting what they paid for; ○ trying to tie refunds to fund SRC or NCESS would be very complicated; ○ SRC is an unheadgeable risk, so refunds should go back to customers to address this risk; and ○ while regulated retail tariffs may stop some refunds from flowing to customer, the tariffs are a matter of Government policy, and Government policy dominates all aspects of the WEM, so this is not a valid argument. • Mr Peake suggested that there is a current revenue gap for existing generators, but paying refunds to generators will be considered more as a windfall than a sound cash flow and will not impact investment decisions. • Mrs Papps agreed with Mr Peake that refunds may not incentivise new investment, but suggested that refunds are a factor to plug the revenue gap for existing facilities. • Ms Teo indicated that she has no comments. • Mr Maticka, Mr Gaston and Mrs Papps discussed whether the changes to the refund mechanism in 2017 were adequately debated at that time. The Chair noted that the discussion in 2017 does not necessarily detract from the current reasons for changing the allocation of refunds, but there may be benefit to understanding the rationale in 2017, and asked Ms Guzeleva to reflect this rationale in the Information Paper. Ms Guzeleva indicated that the discussion in 2017 was broader than just changing the refund allocation, and that the rationale is not particularly relevant now, given that the market has changed substantially since 2017. Ms Guzeleva indicated that a link to the decision papers from 2017 will be inserted into the Information Paper. The Chair summarised that the Coordinator should be advised of the concerns with Review Outcome 7 that were raised by generators. <u>Review Outcome 8 – The Expected Unserved Energy (EUE) Target in the Planning Criterion</u>: Ms Guzeleva summarised Review Outcome 8, as presented in Attachment 1 to the cover paper. The MAC did not have any comments on Review Outcome 8. <u>Review Outcome 9 – Determination of the Benchmark Reserve Capacity Price (BRCP) Technology</u>: Ms Guzeleva summarised Review Outcome 9, as presented in Attachment 1 to the cover paper.	

Item	Subject	Action
	The MAC did not have any comments on Review Outcome 9. <u>Review Outcome 10 – RCM Expression of Interest</u>: Ms Guzeleva summarised Review Outcome 10, as presented in Attachment 1 to the cover paper. • Mr Edwards, Mr Peak and Mr Arias supported Review Outcome 10. The MAC did not have any other comments on Review Outcome 10. <u>General</u>: The Chair summarised that the MAC: • generally supported the Review Outcomes in the Stage 2 Information Paper; • raised some concerns with the incentives that will be created by Review Outcome 4; • some members raised concerns with Review Outcome 7 that transferring refunds to retailers rather than generators will impact on generators to the extent that they rely on those refunds and may impact on incentives for generator availability; and • noted the compromise position that Mrs Papps outlined for the allocation of refunds.	
	Action: AEMO is to provide an explanation of how it dispatches DSPs.	**AEMO (31/08/23)**
11	**General Business** There was no general business. The next MAC meeting is scheduled for 31 August 2023.	

The meeting closed at 11:30am.

Agenda Item 4: MAC Action Items

Market Advisory Committee (**MAC**) Meeting 2023_08_31

Shaded	Shaded action items are actions that have been completed since the last MAC meeting. Updates from last MAC meeting provided for information in RED.
Unshaded	Unshaded action items are still being progressed.
Missing	Action items missing in sequence have been completed from previous meetings and subsequently removed from log.

Item	Action	Responsibility	Meeting Arising	Status
12/2023	MAC Secretariat to publish the minutes of the 20 July 2023 MAC meeting on the Coordinator's Website as final.	MAC Secretariat	2023_07_20	**Closed** The minutes were published on the Coordinator's Website on 20 July 2023.
13/2023	AEMO is to provide an explanation of how it dispatches Demand Side Programs.	AEMO	2023_07_20	**Closed** AEMO provided a response via email on 22 August 2023.

Agenda Item 5: Market Development Forward Work Program

Market Advisory Committee (**MAC**) Meeting 2023_08_31

1. Purpose

- To provide an update on the Market Development Forward Work Program.
- Changes to the Market Development Forward Work Program provided at the previous MAC meeting are shown in red font in the Tables below.

2. Recommendation

- The MAC Secretariat recommends that the MAC notes the updates to the Market Development Forward Work Program provided in Tables 1-4, including that:
  - the Chair of the Reserve Capacity Mechanism Review Working Group (RCMRWG) will provide a verbal update to the MAC on the progress of the Reserve Capacity Mechanism (RCM) Review;
  - the Chair of the Cost Allocation Review Working Group (RCMRWG) will provide a verbal update to the MAC on the progress of the Cost Allocation (CAR) Review; and
  - the Chair of the Demand Side Response Review Working Group (DSRRWG) will provide an update to the MAC on the progress of the Demand Side Response (DSR) Review.

3. Process

Stakeholders may raise issues for consideration by the MAC at any time by sending an email to the MAC Secretariat at energymarkets@dmirs.wa.gov.au.

Stakeholders should submit issues for consideration by the MAC two weeks before a MAC meeting so that the MAC Secretariat can include the issue in the papers for the MAC meeting, which are circulated one week before the meeting.

Table 1 – Market Development Forward Work Program		
Review	**Issues**	**Status and Next Steps**
RCM Review	A review of the RCM, including a review of the Planning Criterion.	• The MAC has established the RCM Review Working Group (**RCMRWG**). Information on the Working Group is available at https://www.wa.gov.au/government/document-collections/reserve-capacity-mechanism-review-working-group, including: ○ the Terms of RCMRWG, as approved by the MAC; ○ the list of RCMRWG members; ○ meeting papers and minutes from the RCMRWG meeting on 20 January 2022, 17 February 2022, 17 March 2022, 5 May 2022, 2 June 2022, 16 June 2022, 14 July 2022, 2 July 2022, 13 October 2022, 24 November 2022; 15 December 2022, 1 February 2023, 16 February 2023, 2 March 2023, 22 March 2023 and 6 July 2023; and ○ minutes for the RCMRWG meeting on 13 July 2023: and ○ meeting papers from the RCMRWG meeting on 30 August 2023 • The following papers have been released and are available on the RCM Review webpage at https://www.wa.gov.au/government/document-collections/reserve-capacity-mechanism-review: ○ the Scope of Works for the review, as approved by the Coordinator; ○ the Stage 1 Consultation Paper; ○ the Paper on the Review of International Capacity Mechanisms; ○ submissions on the Stage 1 Consultation Paper; ○ the RCM Review Information Paper (Stage 1) and Consultation Paper (Stage 2); and ○ submissions on the RCM Review Consultation Paper (Stage 2).

Table 1 – Market Development Forward Work Program		
Review	**Issues**	**Status and Next Steps**
		○ EPWA plans to publish an Exposure Draft of the proposed WEM Amending Rules to implement the Review Outcomes for consultation in September 2023

Table 1 – Market Development Forward Work Program		
Review	**Issues**	**Status and Next Steps**
Cost Allocation Review	A review of: • the allocation of Market Fees, including behind the meter (**BTM**) and Distributed Energy Resources (**DER**) issues; • cost allocation for Essential System Services; and • Issues 2, 16, 23 and 35 from the MAC Issues List (see Table 3).	• The MAC has established the Cost Allocation Review Working Group (**CARWG**). Information on the CARWG is available at https://www.wa.gov.au/government/document-collections/cost-allocation-review-working-group, including: ○ the Scope of Work for the review, as approved by the Coordinator; ○ the Terms of Reference for the CARWG, as approved by the MAC; ○ the list of CARWG members; ○ the Consultation Paper; ○ the International Review; ○ submissions on the Consultation Paper; ○ meeting papers and minutes from the CARWG meetings on 9 May 2022, 7 June 2022, 30 August 2022, 27 September 2022, 25 October 2022, 29 November 2022, and 21 March 2023 and 2 May 2023; and ○ the Cost Allocation Review Information Paper. • EPWA plans to publish an Exposure Draft of the proposed WEM Amending Rules to implement the Review Outcomes for consultation on 5 September 2023.
Procedure Change Process Review	A review of the Procedure Change Process to address issues identified through Energy Policy WA's consultation on governance changes.	• The MAC discussed a draft Scope of Work for this review at its meeting on 11 October 2022. MAC members provided comments on the draft Scope of Works at that meeting, and were asked to provide further comments by email. EPWA did not receive any further comments. • EPWA will update the Scope of Works to reflect the MAC discussions and, following the Coordinator approval of the Scope, will provide the final scope and a timeline for the review to the MAC in early 2023.

Table 1 – Market Development Forward Work Program		
Review	**Issues**	**Status and Next Steps**
Forecast quality	Review of Issue 9 from the MAC Issues List (see Table 4).	• This review has been deferred.
Network Access Quantity (**NAQ**) Review	Assess the performance of the NAQ regime, including policy related to replacement capacity, and address issues identified during implementation of the Energy Transformation Strategy (ETS).	• This review will be commenced after completion of the RCM Review.
Short Term Energy Market (**STEM**) Review	Review the performance of the STEM to address issues identified during implementation of the ETS.	• This review has been deferred.
Review of the Participation of Demand Side in the Wholesale Electricity Market (**WEM**)	The scope of this review is to: • identify the different ways that Loads/Demand Side Response can participate across the different WEM components; • identify and remove any disincentives or barriers for Loads/Demand Side Response participating across the different WEM components; and • identify any potential for over- or under-compensation of Loads/Demand Side Response (including as part of 'hybrid' facilities") as a result of their participation in the various market mechanisms.	• The MAC endorsed a Scope of Work for this review at its meeting on 16 March 2023. • The MAC has established the Demand Side Response Review Working Group (DSRRWG). Information on the DSRRWG is available at [Demand Side Response Review Working Group (www.wa.gov.au)](), including: ○ the Scope of Work for the review, as approved by the Coordinator; ○ the Terms of Reference for the DSRRWG, as approved by the MAC; ○ meeting papers and minutes from the DSRRWG meeting on 10 May 2023, 7 June 2023, 5 July 2023; ○ meeting papers from the DSRRWG meeting on 2 August 2023.

Table 1 – Market Development Forward Work Program		
Review	**Issues**	**Status and Next Steps**
WEM Investment Certainty (**WIC**) Review	The WIC Review will consider, design and implement the following five reforms that have been announced by the Minister for Energy, which are aimed at providing further investment certainty to assist the decarbonisation of the WEM: (1) changing the Reserve Capacity Price (RCP) curve so it sends sharper signals for investment when demand for new capacity is stronger; (2) a 10-year RCP guarantee for new technologies, such as long-duration storage; (3) a wholesale energy price guarantee for renewable generators, to top up their energy revenues as WEM prices start to decline, in return for them firming up their capacity; (4) emission thresholds for existing and new high emission technologies in the WEM; and (5) a 10-year exemption from the emissions thresholds for existing flexible gas plants that qualify to provide the new flexibility service.	• The MAC has established the WEM Investment Certainty (WIC) Review. Information on the WIC Review is available at https://www.wa.gov.au/government/document-collections/wholesale-electricity-market-investment-certainty-review, including: ○ the Scope of Work for the review, as approved by the Coordinator. ○ the Terms of Reference for the WIC Review Working Group, as approved by the MAC; ○ the list of WICRWG members; and ○ meeting papers from the 31 August 2023 WICRWG meeting.

Table 1 – Market Development Forward Work Program		
Review	**Issues**	**Status and Next Steps**
Review of the Market Advisory Committee (**MAC**)	The scope of this review is to ensure that the purpose, representation, process and operations of the MAC are fit for purpose, and in particular, that it operates efficiently and provides balanced, timely and useful advice to the Coordinator.	• The MAC supported a Scope of Works for this review at its meeting on 8 June 2023, and advised EPWA to further consider the timing of the review. • In response to MAC's comments, EPWA now proposes to commence the MAC Review in early 2024.

Table 2 – Issues to be Addressed in the RCM Review			
Id	**Submitter/Date**	**Issue**	**Status**
1	Shane Cremin November 2017	**IRCR calculations and capacity allocation** There is a need to look at how IRCR and the annual capacity requirement are calculated (i.e. not just the peak intervals in summer) along with recognising BTM solar plus storage. The incentive should be for retailers (or third-party providers) to reduce their dependence on grid supply during peak intervals, which will also better reflect the requirement for conventional 'reserve capacity' and reduce the cost per kWh to consumers of that conventional 'reserve capacity'.	Closed. Considered in the RCM Review.
3	Shane Cremin November 2017	Penalties for outages.	Closed. Considered in the RCM Review.
4	Shane Cremin November 2017	Incentives for maintaining appropriate generation mix.	Closed. Considered in the RCM Review and the WIC Review.
14/36	Bluewaters and ERM Power November 2017	**Capacity Refund Arrangements:** The current capacity refund arrangement is overly punitive as Market Participants face excessive capacity refund exposure. This refund exposure is more than what is necessary to incentivise the Market Participants to meet their obligations for making capacity available. Practical impacts of such excessive refund exposure include: • compromising the business viability of some capacity providers – the resulting business interruption can compromise reliability and security of the power system in the SWIS; and • excessive insurance premiums and cost for meeting prudential support requirements.	Closed. Considered in the RCM Review.

Table 2 – Issues to be Addressed in the RCM Review			
Id	**Submitter/Date**	**Issue**	**Status**
		Bluewaters recommended imposing seasonal, monthly and/or daily caps on the capacity refund. Bluewaters considered that reviewing capacity refund arrangements and reducing the excessive refund exposure is likely to promote the Wholesale Market Objectives by minimising: • unnecessary business interruption to capacity providers and in turn minimising disruption to supply availability; which is expected to promote power system reliability and security; and • unnecessary excessive insurance premium and prudential support costs, the saving of which can be passed on to consumers.	
30	Synergy November 2017	**Reserve Capacity Mechanism** Synergy would like to propose a review of WEM Rules related to reserve capacity requirements and reserve capacity capability criteria to ensure alignment and consistency in determination of certain criteria. For instance: • assessment of reserve capacity requirement criteria, reserve capacity capability and reserve capacity obligations; • IRCR assessment; • Relevant Demand determination; • determination of NTDL status; • Relevant Level determination; and • assessment of thermal generation capacity. The review will support Wholesale Market Objectives (a) and (d).	Closed. Considered in the RCM Review.

Table 2 – Issues to be Addressed in the RCM Review			
Id	**Submitter/Date**	**Issue**	**Status**
56	Perth Energy July 2019	**Issues with Reserve Capacity Testing** • Market Generators that fail a Reserve Capacity Test may prefer to accept a small shortfall in a test (and a corresponding reduction in their Capacity Credits) than to run a second test. • There is a discrepancy between the number of Trading Intervals for self-testing vs. AEMO testing. • There is ambiguity in the timing requirements for a second test when the relevant generator is on an outage. • There is ambiguity on the number of Capacity Credits that AEMO is to assign when certain test results occur.	Closed. Considered in the RCM Review.
58	MAC October 2019	**Outage scheduling for dual-fuel Scheduled Generators** '0 MW' outages are currently used to notify System Management when a dual-fuel Scheduled Generator is unable to operate on one of its nominated fuels. There is no explicit obligation in the WEM Rules or the Power System Operation Procedure: Facility Outages to request/report outages that limit the ability of a Scheduled Generator to operate using one of its fuels. In terms of the provision of sent out energy (the service used to determine Capacity Cost Refunds), it is questionable whether this situation qualifies as an outage at all. More generally, the WEM Rules lack clarity on the nature and extent of a Market Generator's obligations to ensure that its Facility can operate on the fuel used for its certification, what (if anything) should occur if these obligations are not met, and the implications for outage scheduling and Reserve Capacity Testing. • (See section 7.2.2.5 of the Final Rule Change Report for RC_2013_15.)	Closed.

Table 3 – Issues to be Addressed in the Cost Allocation Review			
Id	**Submitter/Date**	**Issue**	**Status**
2	Shane Cremin November 2017	Allocation of market costs – who bears Market Fees and who pays for grid support services with less grid generation and consumption?	Closed – Considered in the Cost Allocation Review. Refer to the Cost Allocation Review Information Paper. EPWA plans to publish for consultation an Exposure Draft of the proposed WEM Amending Rules to implement the Review Outcomes.
16	Bluewaters November 2017	BTM generation is treated as reduction in electricity demand rather than actual generation. Hence, the BTM generators are not paying their fair share of the network costs, Market Fees and ancillary services charges. Therefore, the non-BTM Market Participants are subsiding the BTM generation in the WEM. Subsidy does not promote efficient economic outcome. Rapid growth of BTM generation will only exacerbate this inefficiency if not promptly addressed. Bluewaters recommends changes to the WEM Rules to require BTM generators to pay their fair share of the network costs, Market Fees and ancillary services charges. This is an example of a regulatory arrangement becoming obsolete due to the emergence of new technologies. Regulatory design needs to keep up with changes in the industry landscape (including technological change) to ensure that the WEM continues to meet its objectives. If this BTM issue is not promptly addressed, there will be distortion in investment signals, which will lead to an inappropriate generation facility mix in the WEM, hence compromising power system security and in turn not promoting the Wholesale Market Objectives.	Closed – Considered in the Cost Allocation Review. Refer to the Cost Allocation Review Information Paper.

Table 3 – Issues to be Addressed in the Cost Allocation Review			
Id	**Submitter/Date**	**Issue**	**Status**
23	Bluewaters November 2017	Allocation of Market Fees on a 50/50 basis between generators and retailers may be overly simplistic and not consider the impacts on economic efficiency. In particular, the costs associated with an electricity market reform program should be recovered from entities based on the benefit they receive from the reform. This is expected to increase the visibility of (and therefore incentivise) prudence and accountability when it comes to deciding the need and scope of the reform. Recommendations: to review the Market Fees structure including the cost recovery mechanism for a reform program. The cost saving from improved economic efficiency can be passed on to the end consumers, hence promoting the Wholesale Market Objectives.	Closed – Considered in the Cost Allocation Review. Refer to the Cost Allocation Review Information Paper.
35	ERM Power November 2017	**BTM generation and apportionment of Market Fees, ancillary services, etc.** The amount of solar PV generation on the system is increasing every year, to the point where solar PV generation is the single biggest unit of generation on the SWIS. This category of generation has a significant impact on the system and we have seen this in terms of the daytime trough that is observed on the SWIS when the sun is shining. The issue is that generators that are on are moving around to meet the needs of this generation facility but this generation facility, which could impact system stability, does not pay its fair share of the costs of maintaining the system in a stable manner. That is, they are not the generators that receive its fair apportionment of Market Fees and pay any ancillary service costs but yet they have absolute freedom to generate into the SWIS when the fuel source is.	Closed – Considered in the Cost Allocation Review. Refer to the Cost Allocation Review Information Paper.

Table 4 – Other Issues			
Id	**Submitter/Date**	**Issue**	**Status**
9	Community Electricity November 2017	Improvement of AEMO forecasts of System Load; real-time and day-ahead.	Consideration of this issue has been deferred.

MARKET ADVISORY COMMITTEE MEETING, 31 August 2023

FOR DISCUSSION

SUBJECT: UPDATE ON AEMO'S WEM PROCEDURES

AGENDA ITEM: 6(A)

1. PURPOSE

Provide a status update on the activities of the AEMO Procedure Change Working Group and AEMO Procedure Change Proposals.

2. AEMO PROCEDURE CHANGE WORKING GROUP (APCWG)

	Most recent meetings	**Next meeting**
Date	14 June 2023	As required
WEM Procedures for discussion	WEM Procedure: Supplementary Reserve Capacity WEM Procedure: Reserve Capacity Security	

3. AEMO PROCEDURE CHANGE PROPOSALS

The status of AEMO Procedure Change Proposals is described below, current as at 16 August 2023. Changes since the previous MAC meeting are in red text. A procedure change is removed from this report after its commencement has been reported or a decision has been taken not to proceed with a potential Procedure Change Proposal.

ID	Summary of changes	Status	Next steps	Indicative Date
Procedure Change Proposal AEPC_2023_02 WEM Procedure: Reserve Capacity Security	AEMO has proposed two separate revisions of the Reserve Capacity Security WEM Procedure to commence 31 July 2023 and 1 October 2023 respectively: Amendments proposed to commence 31 July 2023 include: • updates to the Security Deposit deeds, bank guarantees and bank undertakings requirements to allow Market Participants to submit electronic copies (Originals must still be provided within 20 business days); • migration to AEMO's new WEM Procedure template; and • other minor administrative changes. Amendments proposed to commence 1 October 2023 include: changes to the Required Level calculations to account for Separately Certified Components from the 2023-24 Capacity Year in accordance with the Wholesale Electricity Amendment (Tranche 5 Amendments) Rules.	Consultation Closed	Publication of the first set of proposed amendments	18 August 2023

ID	Summary of changes	Status	Next steps	Indicative Date
Procedure Change Proposal AEPC_2022_02 WEM Procedure: DER Register Information Procedure	AEMO proposed amendments to the Procedure to: • incorporate electric vehicles (EVs) and electric vehicle charging equipment data; • integrate changes following amendments to the Australian Standard AS/NZS 4777.2:2015 which has been superseded by AS/NZS 4777.2:2020; • implement minor changes that better reflect the changed operational expectations of DER in the WEM and SWIS (e.g. implementation of Emergency Solar Management); • improve the completeness and quality of data exchanged between Network Operators and AEMO (e.g. conveying additional context to reinforce clarity in the document; better aligning the Procedure with related technical specifications); and • reinforce alignment to the WEM Rules, and make other minor administrative changes.	Consultation Closed	Procedure Commencement	02/10/2023

Agenda Item 7(a): Overview of Rule Change Proposals (as of 24 August 2023)

Market Advisory Committee (**MAC**) Meeting 2023_08_31

- Changes to the report since the previous MAC meeting are shown in red font.
- The next steps and the timing for the next steps are provided for Rule Change Proposals that are currently being actively progressed by the Coordinator of Energy (**Coordinator**) or the Minister.

Indicative Rule Change Activity Until the Next MAC Meeting

Reference	Title	Events	Indicative Timing
RC_2019_03	Method used for the assignment of Certified Reserve Capacity to Intermittent Generators	Publication of Final Rule Change Report	30/09/2023
RC_2019_01	The Relevant Demand Calculation	Publication of Draft Rule Change Report	30/09/2023

Rule Change Proposals Commenced since the Report presented at the last MAC Meeting

Reference	Submitted	Proponent	Title	Commenced
None				

Rule Change Proposals Awaiting Commencement

Reference	Submitted	Proponent	Title	Commencement
None				

Rule Change Proposals Rejected since Report presented at the last MAC Meeting

Reference	Submitted	Proponent	Title	Rejected
RC_2014_05	2/12/2014	Independent Market Operator	Reduced Frequency of the Review of the Energy Price Limits and the Maximum Reserve Capacity Price	15/08/2023
RC_2018_03	1/3/2018	Collgar Wind Farm	Capacity Credit Allocation Methodology for Intermittent Generators	15/08/2023

Rule Change Proposals Awaiting Approval by the Minister

Reference	Submitted	Proponent	Title	Approval Due Date
None				

Formally Submitted Rule Change Proposal

Reference	Submitted	Proponent	Title	Urgency	Next Step	Date
Fast Track Rule Change Proposals with Consultation Period Closed						
None						
Fast Track Rule Change Proposals with Consultation Period Open						
None						
Standard Rule Change Proposals with Second Submission Period Closed						
RC_2019_03	17/12/2020	ERA	Method used for the assignment of Certified Reserve Capacity to Intermittent Generators	High	Publication of Final Rule Change Report	30/09/2023

Reference	Submitted	Proponent	Title	Urgency	Next Step	Date
Standard Rule Change Proposals with Second Submission Period Open						
None						
Standard Rule Change Proposals with First Submission Period Closed						
RC_2019_01	21/06/2019	Enel X	The Relevant Demand calculation	Medium	Publication of Draft Rule Change Report	30/09/2023
Standard Rule Change Proposals with the First Submission Period Open						
None						

Pre-Rule Change Proposals

Reference	Proponent	Description	Next Step	Date
None				

Rule Changes Made by the Minister and Awaiting Commencement

Gazette	Date	Title	Commencement
2023/48	28/04/2023	Wholesale Electricity Market Amendment (Supplementary Capacity) Rules 2023	• Schedule C will commence at times specified by the Minister in notices published in the Gazette
2023/37	31/03/2023	Wholesale Electricity Market Amendment (Tranche 6A Amendments) Rules 2023	• Schedule B will commence at times specified by the Minister in notices published in the Gazette
2022/184	20/12/2022	Wholesale Electricity Market Amendment (Tranche 6 Amendments) Rules 2022	• Schedule E will commence at times specified by the Minister in notices published in the Gazette
2021/212	17/12/2021	Wholesale Electricity Market Amendment (Tranche 5 Amendments) Rules 2021	• Schedule H will commence on 01/10/2023. • Schedule I will commence at times specified by the Minister in notices published in the Gazette.
2021/166	28/09/2021	Wholesale Electricity Market Amendment (Miscellaneous Amendments No. 2) Rules 2021	• Schedule G will commence at times specified by the Minister in notices published in the Gazette.
2021/96	28/05/2021	Wholesale Electricity Market Amendment (Miscellaneous Amendments No. 1) Rules 2021	• Schedule E will commence at times specified by the Minister in notices published in the Gazette.
20201/17	18/01/2021	Wholesale Electricity Market Amendment (Governance) Rules 2021	• Schedule C will commence immediately after the commencement of the Amending Rules in clauses 50 and 62 of Schedule C of the *Wholesale Electricity Market Amendment (Tranches 2 and 3 Amendments) Rules 2020.*
2020/214	24/12/2020	Wholesale Electricity Market Amendment (Tranches 2 and 3	• Amending Rules in Schedule C will commence at the times specified by the Minister in notices published in the Gazette.

Gazette	Date	Title	Commencement
		Amendments) Rules 2020	

Agenda Item 8: Update on the WEM Guideline: Non-Co-optimised Essential System Services and WEM Procedure

Market Advisory Committee (MAC) Meeting 2023_08_31

1. Purpose

- The Secretariat of the MAC to provide an overview on:
  - the Wholesale Electricity Market (WEM) Guideline: Non-Co-optimised Essential System Services (NCESS) Coordinator of Energy Guideline; and
  - the Coordinator's new WEM Procedure: Dispute Resolution Mechanism for the release of Market Information.

2. Recommendation

That the MAC notes:

(1) the proposed WEM Guideline; and

(2) the proposed WEM Procedure.

3. Coordinator of Energy Guideline

- Clause 3.11A.2 of the Wholesale Electricity Market (WEM) Rules outlines the trigger conditions under which Western Power or AEMO (or both) must assess and determine whether to make a written submission to the Coordinator to trigger the NCESS Procurement process.
- Clause 3.11A.2A of the WEM Rules requires the Coordinator, in consultation with AEMO and a Network Operator, must develop, and publish on the WEM Website, a Wholesale Electricity Market Guideline: NCESS (Guideline) providing further details regarding the events described in clause 3.11A.2.
- There are differences between the transitional NCESS framework under the current WEM Rules and the permanent framework that will commence from the New WEM Commencement Date (currently 1 October 2023).
- A guideline has been developed to provide the processes to be followed by the Coordinator and Rule Participants and provides further information on:
  a) The information Western Power, AEMO and the Coordinator must monitor to ensure each party is able to identify circumstances or events for which the procurement of an NCESS may be warranted, relevant to their functions.
  b) The factors Western Power and AEMO must consider when assessing the need for an NCESS and deciding whether to make a submission to the Coordinator under clause 3.11A.2(g) of the WEM Rules.

c) The process Western Power and AEMO must follow in making a submission to the Coordinator under clause 3.11A.2(g) of the WEM Rules and to facilitate the Coordinator's assessment of that application.

d) The factors the Coordinator must consider under clause 3.11A.7 in deciding whether to trigger the NCESS Procurement process in accordance with section 3.11B of the WEM Rules of a submission made under clause 3.11A.2(g) of the WEM Rules.

- A draft Guideline has been published for a three-week consultation period and is available at Draft WEM Guideline: Non-Co-optimised Essential System Services (www.wa.gov.au).

4. WEM Procedure

- The Wholesale Electricity Market Amendment (Tranche 6 Amendments) Rules 2022, Schedule E will introduce the new Chapter 10, which outlines the revised Market Information framework and provides that the Coordinator must resolve disputes about the confidentiality status and disclosure of Market Information.
- The new WEM Procedure has been developed, in accordance with new clause 10.5.2, to provide the processes to be followed by the Coordinator, Information Stakeholders[1], Information Managers[2] and any person requesting information under clause 10.4.6 of the WEM Rules.
- The new WEM Procedure outlines:
- the methods by which notices of dispute are to be provided to the Coordinator;
  - the process by which the Coordinator will resolve disputes;
  - the timeframes for the dispute resolution process; and
  - related processes to be followed by the Coordinator and Rule Participants.
- EPWA consulted on the proposed new WEM Procedure with all other Information Managers. The feedback received is reflected in this proposal.
- The proposed new WEM Procedure: Dispute Resolution Mechanism for the release of Market Information was published on 18 August 2023 for a three-week consultation period and is available at Draft WEM Procedure: Dispute Resolution Mechanism for the release of Market Information (www.wa.gov.au).

[1] An Information Stakeholder is any Rule Participant to which the relevant Market Information relates, in accordance with clause 10.2.7A of the WEM Rules.

[2] The Information Manager is the party responsible for managing the relevant Market Information, in accordance with clauses 10.2.11 and 10.2.12 of the WEM Rules.

Government of **Western Australia**
Department of **Mines, Industry Regulation and Safety**
Energy Policy WA

Agenda Item 9: Demand Side Response Review – Consultation Paper

Market Advisory Committee (MAC) Meeting 2023_08_31

1. Purpose

The MAC is asked to:

- review the draft Demand Side Response Review Consultation Paper (Attachment 1);
- note that consultation paper is in a draft state and that Energy Policy WA is still working on the wording in the paper; and
- provide guidance to the Coordinator on the conceptual design proposals and questions outlined in the draft consultation paper.

2. Recommendation

That the MAC:

(1) provides guidance to the Coordinator on the conceptual design proposals in the draft consultation paper, noting that the paper is in draft form.

3. Process

The Coordinator of Energy, in consultation with the MAC, is reviewing the role of Demand Side Response (DSR) in the Wholesale Electricity Market (WEM) in Western Australia under clause 2.2D.1 of the WEM Rules.

The objective of the review is to:

- identify the different ways Loads/DSR can participate across the different WEM components;
- identify and remove any disincentives or barriers to Loads/DSR participating across all of the different WEM components; and
- identify any potential for over-compensation or under-compensation of Loads/DSR (including as part of "hybrid facilities") as a result of their participation in the various market mechanisms and provision of Network Services.

The review of the treatment of loads in the WEM is proceeding in the following steps:

- Stage 1 was a high level assessment of the participation of Loads and DSR in the WEM. This assessment includes a review of Load and DSR programs in other jurisdictions, identifying flexible loads that could participate, and identifying scenarios of possible over or under-compensation of participants.
- Stage 2 was a gap analysis identifying barriers and disincentives for Loads to participate across all WEM components and provide the services identified in Step 1.

- Stage 3 will be a formulation of recommendations for further action, which will likely include the development of changes to the Rules and will likely also include changes to the Metering Code.

The consultation paper sets out the findings and proposals arising from stage one and stage two of the DSR Review. A table is provided below for the information of the MAC that lists these proposals and provides a high-level summary of the rationale for each proposal.

4. Next Steps

Stakeholder feedback is invited on the proposals, as outlined in the attached consultation paper.

5. Attachments

(1) draft Demand Side Response Review Consultation Paper

Proposals and Rationale

Table 1 lists the proposals outlined in this consultation paper and provides a high-level summary of the rationale for each proposal.

Table 1: Proposals from the first stages of the DSR Review

Design Proposal	Rationale
Proposal 1: Transparency regarding constrained access connections should be provided for and, to the extent practicable, constrained access loads should be integrated into the processes in the WEM rules. The WEM Rules should set out: • the requirements for Western Power to share information on constrained access loads with AEMO; • the manner in which AEMO integrates curtailable loads in determining the Reserve Capacity Target and Network Access Quantities; • how curtailment of constrained access loads is considered in the real time market and constraint equations / optimization processes.	Constrained access connections for loads are becoming more commonplace. The disconnect between the constrained access connections and the WEM may have an impact on the overall efficiency of both the RCM and the real time market. It is important to consider these matters now, before constrained access connections increase, while striking the right level of transparency and integration.

Design Proposal	Rationale
Proposal 2: The WEM Rules should be amended to clarify the circumstances in which a hybrid facility comprising a load and an ESR component will be required by AEMO to register as a Scheduled Facility. The WEM Rules should also be clear whether there is any flexibility for the relevant market participant to register such a facility as a DSP and receive capacity credits accordingly.	A hybrid facility comprising a load and an ESR component cannot register as both a DSP and as another facility type (e.g. a Scheduled Facility). Further, this hybrid facility may not have a choice whether to registers as a DSP or a Scheduled Facility i.e. AEMO may require it to register as a Scheduled Facility. As a result, this hybrid facility can only receive capacity credits for its ESR component and not for its DSR. EPWA considers that the WEM Rules should be clear about the circumstances in which a hybrid facility comprising a load and an ESR component will be required by AEMO to register as a Scheduled Facility. The WEM Rules should also be clear whether there is any flexibility for the relevant market participant to register such a facility as a DSP and receive capacity credits accordingly.
Proposal 3: Currently, participants with hybrid facilities are restricted in the way they operate their facilities in the energy and the ESS markets due to metering and settlement limitations. More flexibility should be provided to hybrid facilities by enabling them to use Western Power installed sub-metering for the purpose of settlement in the STEM and the real time market, including the ESS markets.	Providing hybrid facilities (capable of providing DSR) with the choice of what services they provide and with access to a variety of possible revenue streams has the potential to provide market wide benefits. With Western Power revenue quality metering on each component, it would be possible to use the same DSR in a hybrid facility to participate across the different markets (real time energy market, ESS, RCM) to provide different services. However, revenue quality metering comes at a cost, so it should not be something all hybrid facilities are required to install.

Design Proposal	Rationale
Proposal 4: The dynamic baseline for DSR participation will be based on an ex-ante 'X of Y' methodology incorporating a 'day of adjustment'. A cap will be placed on upward adjustment but uncapped for downward adjustment. Ex-post mitigation through examination of data could still be followed to detect any undesirable behavior that is not being mitigated through ex-ante measures.	One of the Review Outcomes of the RCM Review was that the performance of DSPs should be measured against a dynamic baseline, rather than the static baseline in the status quo[1]. The rationale for this move can be found in the Reserve Capacity Mechanism Review Information Papers (Stage 1) and (Stage 2). During the RCM Review, it was noted that the introduction of a dynamic baseline increases the potential for gaming. This proposal will assist to prevent gaming of the baseline.
Proposal 5: No change to the SRC mechanism is proposed, as the SRC framework already provides for the effective participation of DSR.	A recent procurement of SRC and subsequent review of this mechanism by EPWA indicates that the SRC framework already provides for the effective participation of DSR.
Proposal 6: Amend the Metering Code so Western Power must share energy data on request to AEMO, to the extent necessary for market purposes, and with AEMO keeping that information confidential.	One of the issues raised in DSRRWG discussions discussion was that Western Power is currently limited in the energy information it can provide to AEMO because of the confidentiality obligations in the *Electricity Industry (Metering) Code 2012* ("The Metering Code"). This issue has also been raised in the recent SRC Review. During the SRC Review, EPWA identified that AEMO's ability to measure the performance of some of the services provided by DSR, for example in relation to demand response aggregations, was impeded.

[1] Review Outcome 4, Reserve Capacity Mechanism Review Information Paper (Stage 1) and Consultation Paper (Stage 2), 3 May 2023.

Design Proposal	Rationale
Proposal 7: Take steps to remove impediments from the WEM Rules to allow direct participation by DSR in the STEM.	DSR participation in the STEM could increase activity and provide more opportunities for flexible loads. STEM participation is not mandatory thus, only willing DSR would participate. Additionally, the STEM is a 'simple' market so facilitating DSR participation is not expected require large implementation changes.
Proposal 8: No changes are proposed to DSP participation in the real time energy market.	Following discussions with the DSRRWG, EPWA considers that flexible loads are already provided with the opportunity to participate in the real time energy market, and DSPs are required to be available during the day time hours. Further changes to the real time energy market to allow bidding by DSPs are likely to be complex and costly without significant benefits to justify such changes.
Proposal 9: No change is proposed to DSR participation in the real time energy market as the participation of flexible loads is already provided for.	DSRRWG members acknowledged the ability for scheduled loads to participate but were also of the view that direct participation by DSR in the real time energy market is likely to have low uptake due to the costs and effort outweighing the benefits. It was also notes that the willingness to patriciate in the real time energy market may change over time or could appeal to hybrid facilities (such as a large load with on-site generation).
Proposal 10: No changes are proposed to be made for a specific service to address the minimum demand issues in the SWIS at this time.	DSRRWG members discussed the idea of developing a standard service to address minimum demand in the context of AEMO having already triggered NCESS twice to procure minimum demand services. While there was some support for this, it was ultimately concluded that it's best to see if the increasing penetration of ESR, the new flexible capacity product and the real time energy market pricing will address this issue in the medium term.

Design Proposal	Rationale
Proposal 11: The size and potential technical limitations (such as the telemetry requirements) for providing ESS services should be reviewed to ensure that there no unnecessary barriers for the provision of ESS services by technically capable DSR.	Based on discussions by DSRRWG, EPWA considers that the size and potential technical limitations (such as the telemetry requirements) for providing ESS services, currently detailed in the relevant AEMO WEM Procedure, need to be reviewed. The focus of this review should be to ensure that there no unnecessary barriers for the provision of ESS services by technically capable DSR. The review should also consider, amongst other things, whether some of these limitations should be moved from the relevant WEM Procedures to the WEM Rules.
Proposal 12: No changes are proposed to be made to the ability of DSR to register as both an Interruptible Load and a DSP, and provide Contingency Reserve Raise services at the same time it receives capacity credits.	On the basis of the DSRRWG discussion, EPWA considers that DSR, capable of providing the relevant services, should be able to stack value by receiving capacity credits as a DSP as well as being paid for providing Contingency Reserve Raise services.

Government of Western Australia
Department of Mines, Industry Regulation and Safety
Energy Policy WA

Review of the Participation of DSR in the Wholesale Electricity Market

Consultation Paper

xx September 2023

Working together for a brighter energy future.

An appropriate citation for this paper is: Review of the Participation of DSR in the Wholesale Electricity Market

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Contents

Tables

Figures

Abbreviations

Term	Definition
AEMO	Australian Energy Market Operator
AMI	Advanced Metering Infrastructure
BTM	Behind-the-meter
DER	Distributed Energy Resources
DSP	Demand Side Programme
DSR	DSR
DSRWG	DSR Review Working Group
EPWA	Energy Policy WA
ESR	Electricity Storage Resource
ESS	Essential System Services
IRCR	Individual Reserve Capacity Requirement
MAC	Market Advisory Committee
MDT	Minimum Demand Threshold
MW	Megawatt
NCESS	Non-co-optimised Essential System Services
RCM	Reserve Capacity Mechanism
RCOQ	Reserve Capacity Obligation Quantity
RoCoF	Rate of Change of Frequency
RTM	Real-time market
SRC	Supplementary Reserve Capacity
STEM	Short Term Energy Market
SWIS	Southwest Interconnected System
WEM	Wholesale Electricity Market

Executive Summary

The DSR Review

The Coordinator of Energy (Coordinator), in consultation with the Market Advisory Committee (MAC), is reviewing the rules for participation of Demand Side Response (DSR) in the Wholesale Electricity Market (WEM) in Western Australia under clause 2.2D.1 of the WEM Rules (the DSR Review).

DSR will play an important role in the WEM in the future, because of:

- the changes to the nature of the demand profile and generation in the South West Interconnected System (SWIS) since the commencement of the WEM in 2006;
- the transition to a low emissions energy system characterised by increasing levels of intermittent and distributed generation; and
- the important flexibility / firming service DSR can provide in a market with ever increasing levels of intermittent and distributed generation.

Therefore, it is important to ensure that there are no barriers to the participation of DSR in the different WEM components.

The purpose of this review is to ensure that DSR has adequate incentives to participate in the WEM and is compensated appropriately for the provision of its services. The importance of DSR as a flexibility/firming resource in the WEM has also been highlighted during the Reserve Capacity Mechanism (RCM) Review modelling work.

The MAC has constituted the DSR Review Working Group (DSRRWG) to support the DSR Review. More information on the DSR Review is available from the Energy Policy WA (EPWA) website[1], including the Scope of Works for the review, the Terms of Reference for the DSRRWG, papers for DSRRWG and relevant MAC meetings and detailed minutes for each meeting.

1 DSRRWG: https://www.wa.gov.au/government/document-collections/demand-side-response-review-working-group

MAC: https://www.wa.gov.au/government/document-collections/market-advisory-committee

Proposals and Rationale

Table 1 lists the proposals outlined in this consultation paper and provides a high-level summary of the rationale for each proposal.

Table 1: Proposals from the first stages of the DSR Review

Design Proposal	Rationale
Proposal 1: Transparency regarding constrained access connections should be provided for and, to the extent practicable, constrained access loads should be integrated into the processes in the WEM rules. The WEM Rules should set out: • the requirements for Western Power to share information on constrained access loads with AEMO; • the manner in which AEMO integrates curtailable loads in determining the Reserve Capacity Target and Network Access Quantities; • how curtailment of constrained access loads is considered in the real time market and constraint equations / optimization processes.	Constrained access connections for loads are becoming more commonplace. The disconnect between the constrained access connections and the WEM may have an impact on the overall efficiency of both the RCM and the real time market. It is important to consider these matters now, before constrained access connections increase, while striking the right level of transparency and integration.
Proposal 2: The WEM Rules should be amended to clarify the circumstances in which a hybrid facility comprising a load and an ESR component will be required by AEMO to register as a Scheduled Facility. The WEM Rules should also be clear whether there is any flexibility for the relevant market participant to register such a facility as a DSP and receive capacity credits accordingly.	A hybrid facility comprising a load and an ESR component cannot register as both a DSP and as another facility type (e.g. a Scheduled Facility). Further, this hybrid facility may not have a choice whether to registers as a DSP or a Scheduled Facility i.e. AEMO may require it to register as a Scheduled Facility. As a result, this hybrid facility can only receive capacity credits for its ESR component and not for its DSR. EPWA considers that the WEM Rules should be clear about the circumstances in which a hybrid facility comprising a load and an ESR component will be required by AEMO to register as a Scheduled Facility. The WEM Rules should also be clear whether there is any flexibility for the relevant market participant to register such a facility as a DSP and receive capacity credits accordingly.

Design Proposal	Rationale
Proposal 3: Currently, participants with hybrid facilities are restricted in the way they operate their facilities in the energy and the ESS markets due to metering and settlement limitations. More flexibility should be provided to hybrid facilities by enabling them to use Western Power installed sub-metering for the purpose of settlement in the STEM and the real time market, including the ESS markets.	Providing hybrid facilities (capable of providing DSR) with the choice of what services they provide and with access to a variety of possible revenue streams has the potential to provide market wide benefits. With Western Power revenue quality metering on each component, it would be possible to use the same DSR in a hybrid facility to participate across the different markets (real time energy market, ESS, RCM) to provide different services. However, revenue quality metering comes at a cost, so it should not be something all hybrid facilities are required to install.
Proposal 4: The dynamic baseline for DSR participation will be based on an ex-ante 'X of Y' methodology incorporating a 'day of adjustment'. A cap will be placed on upward adjustment but uncapped for downward adjustment. Ex-post mitigation through examination of data could still be followed to detect any undesirable behavior that is not being mitigated through ex-ante measures.	One of the Review Outcomes of the RCM Review was that the performance of DSPs should be measured against a dynamic baseline, rather than the static baseline in the status quo[2]. The rationale for this move can be found in the Reserve Capacity Mechanism Review Information Papers (Stage 1) and (Stage 2). During the RCM Review, it was noted that the introduction of a dynamic baseline increases the potential for gaming. This proposal will assist to prevent gaming of the baseline.
Proposal 5: No change to the SRC mechanism is proposed, as the SRC framework already provides for the effective participation of DSR.	A recent procurement of SRC and subsequent review of this mechanism by EPWA indicates that the SRC framework already provides for the effective participation of DSR.

[2] Review Outcome 4, Reserve Capacity Mechanism Review Information Paper (Stage 1) and Consultation Paper (Stage 2), 3 May 2023.

Design Proposal	Rationale
Proposal 6: Amend the Metering Code so Western Power must share energy data on request to AEMO, to the extent necessary for market purposes, and with AEMO keeping that information confidential.	One of the issues raised in DSRRWG discussions discussion was that Western Power is currently limited in the energy information it can provide to AEMO because of the confidentiality obligations in the *Electricity Industry (Metering) Code 2012* ("The Metering Code"). This issue has also been raised in the recent SRC Review. During the SRC Review, EPWA identified that AEMO's ability to measure the performance of some of the services provided by DSR, for example in relation to demand response aggregations, was impeded.
Proposal 7: Take steps to remove impediments from the WEM Rules to allow direct participation by DSR in the STEM.	DSR participation in the STEM could increase activity and provide more opportunities for flexible loads. STEM participation is not mandatory thus, only willing DSR would participate. Additionally, the STEM is a 'simple' market so facilitating DSR participation is not expected require large implementation changes.
Proposal 8: No changes are proposed to DSP participation in the real time energy market.	Following discussions with the DSRRWG, EPWA considers that flexible loads are already provided with the opportunity to participate in the real time energy market, and DSPs are required to be available during the day time hours. Further changes to the real time energy market to allow bidding by DSPs are likely to be complex and costly without significant benefits to justify such changes.
Proposal 9: No change is proposed to DSR participation in the real time energy market as the participation of flexible loads is already provided for.	DSRRWG members acknowledged the ability for scheduled loads to participate but were also of the view that direct participation by DSR in the real time energy market is likely to have low uptake due to the costs and effort outweighing the benefits. It was also notes that the willingness to patriciate in the real time energy market may change over time or could appeal to hybrid facilities (such as a large load with on-site generation).

Design Proposal	Rationale
Proposal 10: No changes are proposed to be made for a specific service to address the minimum demand issues in the SWIS at this time.	DSRRWG members discussed the idea of developing a standard service to address minimum demand in the context of AEMO having already triggered NCESS twice to procure minimum demand services. While there was some support for this, it was ultimately concluded that it's best to see if the increasing penetration of ESR, the new flexible capacity product and the real time energy market pricing will address this issue in the medium term.
Proposal 11: The size and potential technical limitations (such as the telemetry requirements) for providing ESS services should be reviewed to ensure that there no unnecessary barriers for the provision of ESS services by technically capable DSR.	Based on discussions by DSRRWG, EPWA considers that the size and potential technical limitations (such as the telemetry requirements) for providing ESS services, currently detailed in the relevant AEMO WEM Procedure, need to be reviewed. The focus of this review should be to ensure that there no unnecessary barriers for the provision of ESS services by technically capable DSR. The review should also consider, amongst other things, whether some of these limitations should be moved from the relevant WEM Procedures to the WEM Rules.
Proposal 12: No changes are proposed to be made to the ability of DSR to register as both an Interruptible Load and a DSP, and provide Contingency Reserve Raise services at the same time it receives capacity credits.	On the basis of the DSRRWG discussion, EPWA considers that DSR, capable of providing the relevant services, should be able to stack value by receiving capacity credits as a DSP as well as being paid for providing Contingency Reserve Raise services.

1. Introduction

Under Clause 2.2D.1(h) of the WEM Rules, the Coordinator of Energy (Coordinator) has the function to consider and, in consultation with the Market Advisory Committee (MAC), progress the evolution and development of the Wholesale Electricity Market (WEM) and the WEM Rules.

The Coordinator, in consultation with the MAC, is reviewing the rules for participation of Demand Side Response (DSR) in the Wholesale Electricity Market (WEM) under clause 2.2D.1 of the WEM Rules (the DSR Review).

1.1 Background

1.1.1 Current Participation of DSR in the WEM

Currently, the direct participation of DSR in the WEM is limited to participation as a:

- Demand Side Programme (DSP) or part of a DSP in the RCM; and
- Interruptible Load.

Loads also participate indirectly in the WEM as they:

- pay for the consumption of energy either through retail contracts or the Balancing Market; and
- pay for Reserve Capacity based on their Individual Reserve Capacity Requirement (IRCR).

While loads will be able to register as Scheduled Facilities in the New WEM to provide other market services, analysis of the WEM Rules must be undertaken to ensure that they can provide services and extract value in the different WEM components, in the same way as other facilities.

1.1.2 The Need for the DSR Review

DSR will play an increasingly important role in the WEM in the future because of:

- the changes to the nature of the demand profile and generation in the SWIS since the market start; and
- the transition to a low emissions energy system characterised by increasing levels of intermittent and distributed generation; and
- the important flexibility / firming service DSR can provide in a market with ever increasing levels of intermittent and distributed generation.

Therefore, it is important to ensure that there are no barriers to the participation of DSR in the different WEM components.

The purpose of this review is to ensure that DSR has adequate incentives to participate in the WEM and is compensated appropriately for the provision of its services. The importance of DSR as a flexibility/firming resource in the WEM has also been highlighted during the Reserve Capacity Mechanism (RCM) Review modelling work and relevant key observations made from this review with respect to DSR have been summarised in Appendix C.

1.1.3 Guiding Principles

The guiding principles for the review of the participation of DSR in the WEM are that any recommendations should:

1. meet the Wholesale Market Objectives;
2. enable the orderly transition to a low greenhouse gas emissions energy system;
3. be cost-effective, simple, flexible and sustainable;
4. allocate risks to those who can best manage them;
5. provide investment signals and technical capability signals that support the reliable and secure operation of the power system;
6. ensure that the value of DSR can be maximised for the benefit of those who provide it and the WEM as a whole; and
7. ensure that DSR is not under- or over-compensated for its participation and treatment in any of the WEM components.

1.1.4 Scope of Review

The Coordinator, in consultation with the MAC, set the following objectives for the DSR Review:

- identify the different ways DSR can participate across the different WEM components;
- identify and remove any disincentives or barriers to DSR participating across the different WEM components; and
- identify any potential for over- or under-compensation of DSR (including as part of "hybrid" facilities") as a result of its participation in the various market mechanisms and provision of Network Services.

The following aspects related to the participation of DSR are out of scope for this review:

- certification of DSPs; and
- treatment of IRCR.

DER (Distributed Energy Resources), also known as 'behind the meter' devices, also fall outside of the scope of this review. DER has been separately addressed under the WA Government's 'Distributed Energy Resources (DER) Roadmap' of April 2020.

1.2 Key observations from the RCM Review

DSR participation in the RCM is mostly out of scope of this review. However, the RCM Review flagged three areas of consideration for the DSR review:

1. AEMO's ongoing procurement of Non Co-optimised Essential System Services (NCESS) for minimum demand services highlights that minimum demand remains an ongoing concern (refer to Section **Error! Reference source not found.**).
2. Rules will be needed to ensure that a Capability Class 2 facility with co-located load and storage cannot self-discharge its storage so as to reduce its IRCR exposure while also receiving capacity credits for that capability (refer to Section **Error! Reference source not found.**).
3. The implementation of the dynamic baseline as an important element relevant to DSP participation (refer to Section **Error! Reference source not found.**).

1.2.1 Staged Approach

The review of the participation of DSR in the WEM is being conducted in three stages:

Stage	Description	Refer Section
Stage 1	High level assessment of the participation of DSR across all WEM components based on:	
	• A review of the participation of DSR in other markets in the context of what problems their electricity systems are facing or are expected to face in the future, and whether/how these arrangements relate to the WEM. Jurisdictions to be investigated include: - NEM; - UK; - PJM; and any other jurisdictions identified by the MAC or Energy Policy WA.	Appendix A
	• The outcome of the system stress analysis from stage 1 of the RCM Review.	**Error! Reference source not found.** and 3.7.3
	• Identification of typical flexible loads (e.g. large cold stores) that exist in the WEM and don't participate	3.7.3
	• Assessment of possibilities for over- or under compensation for different scenarios of DSR participating in the various market mechanisms and Network Services provision.	3.2.1, 3.3, 3.4, 3.5, **Error! Reference source not found.** and 3.7.3
Stage 2	A gap analysis identifying any barriers and disincentives for DSR to participate across the different components of the WEM and provide the services identified under Stage 1, including in: • the registration framework; • the RCM; • the Short Term Energy Market (STEM); and • the Real Time Market (RTM), including the ESS market and Non-Co-Optimised ESS. This includes assessment on why the flexible loads identified under Stage 1 don't currently participate.	3.2.1, 3.3, 3.4, 3.5, **Error! Reference source not found.** and 3.7.3
Stage 3	Formulations of recommendations for further action, if any, and development of Rule changes, if necessary.	To be completed during Stage 3

The MAC has constituted the DSR Review Working Group (DSRRWG) to support this review. More information on the review is available from the EPWA website[3], including the Scope of Works for the review, the Terms of Reference for the DSRRWG, papers for the DSRRWG and relevant MAC meetings and detailed minutes for each meeting. A timetable for the review stages is included in **Error! Reference source not found.**.

1.3 Purpose of this paper

This consultation paper sets out the findings and proposals arising from Stage 1 and Stage 2 of the DSR Review and presents proposals to enable the participation of DER in the various components.

This paper is structured as follows:

- Chapter 2 describes the role that DSR can play in liberalised energy markets;
- Chapter 3 discusses the areas of the new market (post 1 October 2023) that DSR is able to participate in based on the new WEM Rules[4] and makes proposals for change.
- Appendix A provides information on international jurisdictions investigated.

1.4 Stakeholder Consultation

Stakeholder feedback is invited on the proposed changes to DSR participation in the WEM, as outlined in this consultation paper. Submissions can be emailed to energymarkets@dmirs.wa.gov.au.

Any submissions received will be made publicly available on www.energy.wa.gov.au, unless requested otherwise.

The consultation period closes at 5:00pm (WST) on x, x September 2023. Late submissions may not be considered.

[3] DSRRWG: https://www.wa.gov.au/government/document-collections/demand-side-response-review-working-group

[4] Based on the 29 April 2023 version of the new WEM Rules

2. The Role of DSR

2.1 Traditional roles of DSR

Demand response in energy markets takes many traditional forms:

- ***Curtailable/Interruptible load*** - demand competing for varying reserve products with other resources and avoiding investment in other types of reserve capacity (e.g. generation facilities);
- ***Demand side bidding and forecasting*** - requirement for the demand side of the market to forecast and bid in its requirements in order to improve system demand accuracy;
- ***Dispatchable demand*** - incentive to use less electricity when prices are higher and more when prices are lower (subject to elasticity), sometimes called Energy Arbitrage;
- ***Demand reduction*** - call option given to the network operator in order to manage outages and maintenance or to defer investment. It can also be provided to retailers to mitigate high price periods when under hedged;
- ***Ripple Control*** - relinquishing some control over consumption to the retailer and/or the network operator (direct load control). The rollout of Advanced Metring Infrastructure (AMI) is expanding these opportunities;
- ***Real time response*** - giving control to the retailer, the network operator or, in some cases, aggregator to use demand response for frequency (regulation) control. A discounted tariff will typically be provided for this.
- ***Load shedding*** - when system supply is insufficient to meet demand.

2.2 Realising the potential of DSR

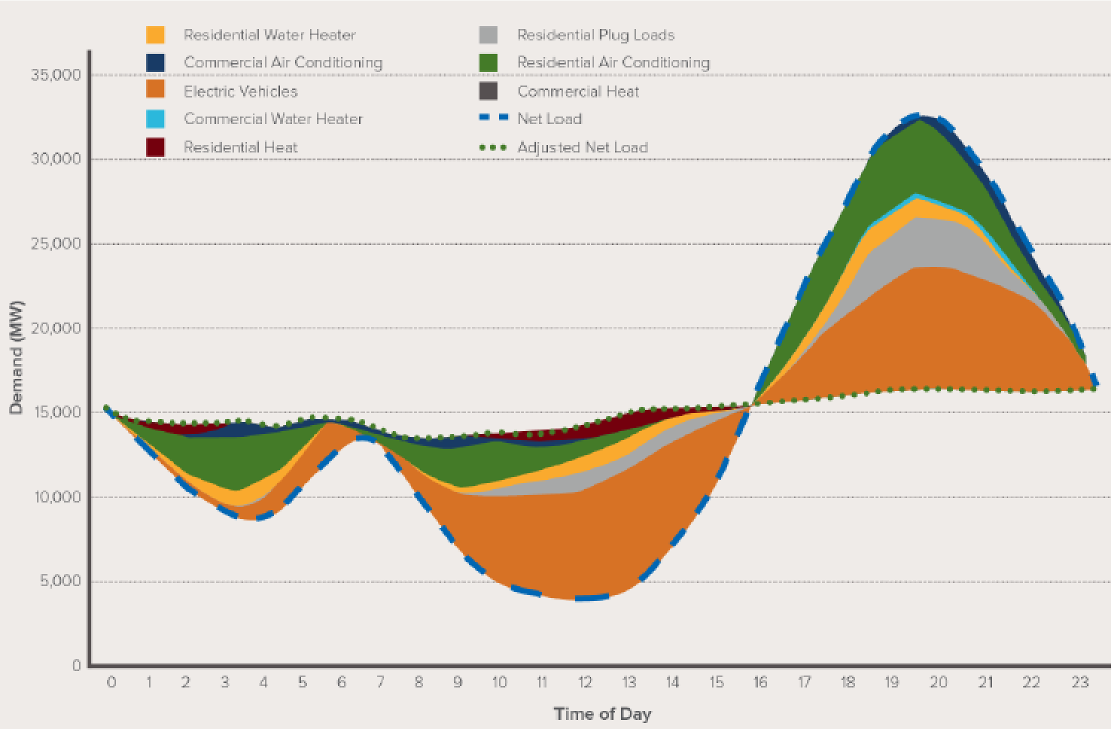
Demand response has the potential to add value in two broad areas:

- system security & reliability (contributing to ancillary/essential system services); and
- enhanced efficiency, through:
  - deferring investment in network and reserve capacity;
  - shifting usage away from peak periods (improve capital resource utilisation) and to minimum demand periods; and
  - reducing system and market costs through increased competition (demand and supply sides competing among and with each other).

DSR has the potential to provide a wide range of flexibility and load shifting services. This can be in response to a price signal or a direction, due to a technical requirement or a constraint.

The potential for demand shifting is illustrated in the following diagram, which projects the potential net load and changes due to demand flexibility for an average day:

Figure 1: Value of Demand Flexibility (load shifting)



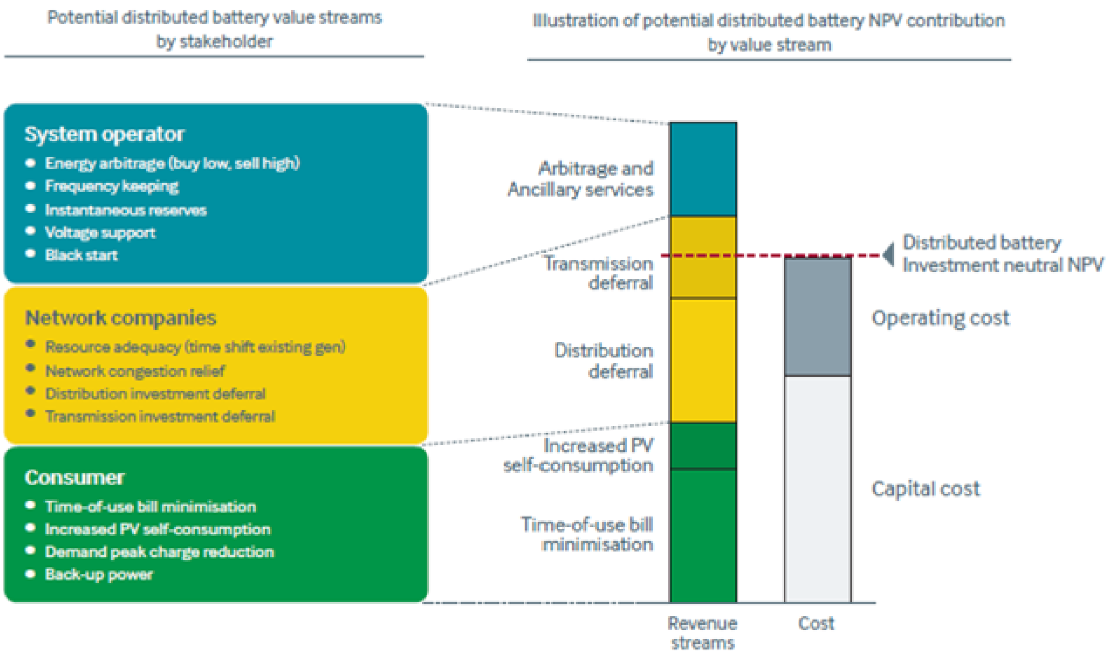
Source: Using a hypothetical 2050 generation mix in ERCOT. Demand Flexibility - The key to enabling a low cost, low carbon grid. Rocky Mountain Institute, February 2018

Greater participation of DSR is anticipated in many electricity markets around the world. This is made possible through:

- The roll out of advanced metering infrastructure (AMI), "smart" appliances and batteries;
- Improved control systems;
- The emergence of aggregators;
- Electric vehicles that can both withdraw and inject into the distribution network (combining a "smart" load and a battery).

New technologies are presenting a more diverse range of potential solutions to energy sector challenges. The value propositions that these technologies bring will vary depending on how they are deployed, and the perspective of the stakeholder being involved. For example, the utilisation of energy storage presents differing value propositions depending on the perspective of the System Operator, Network Operator or the Consumer as illustrated in Figure 2.

Figure 2: Potential distributed battery value streams by stakeholder.

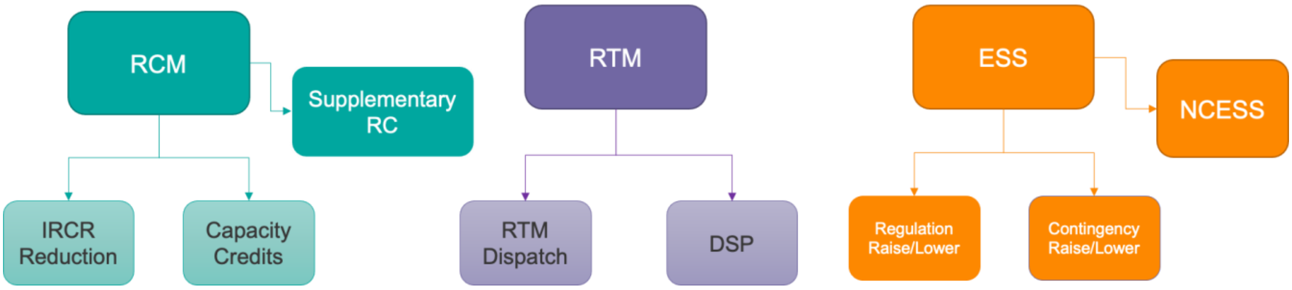


Source: Based on The Economics of Battery Energy Storage, Rocky Mountain Institute

3. DSR Participation in the new WEM

The following sections explore all the opportunities for DSR participation, based on the WEM Rules[5] for the new market. The paper steps through the various WEM components and considers the barriers and incentives to DSR participating in each component. It also discusses how matters such as network connection and metering arrangements may affect DSR participation.

Figure 3: DSR Participation in the WEM



3.1 Network connection

While the DSR Review is concerned with the participation of DSR in the WEM, it is also necessary to consider how the network connection arrangements influence WEM participation. One matter that has been identified through the DSRWG discussions is the framework for managing constrained access loads, and the transparency regarding these arrangements.

3.1.1 Constrained Access for Loads

As a general principal, customers have unconstrained network access. They can consume electricity as desired. Some new customers connecting in congested parts of the network are being placed on 'runback schemes' by Western Power. These customers' consumption can be limited when the network is congested. These customers are referred to as 'constrained access loads'.

Connecting constrained access loads is cheaper if it avoids or delays reinforcing the network. These customers can also be connected earlier. The number of new constrained access loads is expected to increase over time, as more regions are expected to become congested in the transition to a lower emissions system and as more customers pursue electrification.

The ability to elect to connect on a constrained basis is desirable. However, there are some issues with the operations of these schemes as they currently stand, including:

- Runback scheme connections currently lack transparency and are not fully integrated in the market. For example, the number, the demand and location of these constrained access loads is not transparent to the market.
- Effective integration into the market is also not currently provided for. For example:
  - the triggers for curtailment are not transparent to AEMO and the WEM; and
  - whether and how the effect of this curtailment is considered in system planning or in the RCM processes more generally isn't clear.

5 Based on the 29 April 2023 version of the new WEM Rules

The disconnect between the constrained access connections and the WEM may have an impact on the overall efficiency of both the RCM and the real time market.

It is important to consider these matters now, before constrained access connections increase, while striking the right level of transparency and integration.

Proposal 1:

Transparency regarding constrained access connections should be provided for and, to the extent practicable, constrained access loads should be integrated into the processes in the WEM rules. The WEM Rules should set out:

- the requirements for Western Power to share information on constrained access loads with AEMO;
- the manner in which AEMO integrates curtailable loads in determining the Reserve Capacity Target and Network Access Quantities;
- how curtailment of constrained access loads is considered in the real time market and constraint equations / optimization processes.

Consultation Questions:

1. Do stakeholders support integrating constrained access loads in the WEM and the WEM Rules?
2. Are there any circumstances in which it would not be efficient or practical to integrate constrained access loads into the WEM Rules?

3.2 Registration

The new WEM registration taxonomy defines a facility by its technology type and then by its class. The technology types in the new WEM are:

- a distribution system;
- a transmission system;
- an Intermittent Generating System;
- a Non-Intermittent Generating System;
- an Electric Storage Resource; and
- a Load.

Technology types must be registered into a facility class. The facility classes in the new WEM are:

- a Network;
- a Scheduled Facility;
- a Semi-Scheduled Facility;
- a Non-Scheduled Facility;
- an Interruptible Load; and
- a Demand Side Programme.

Loads (which are not part of a hybrid facility) can register as one of the following:

- a Scheduled Facility consisting of a Load[6];
- a Semi-Scheduled Facility consisting of a Load;
- a Non-Scheduled Facility consisting of a Load;
- an Interruptible Load consisting of a Load;
- a Demand Side Programme consisting of a Load; and
- a Demand Side Programme consisting of Non-Dispatchable Load(s)[7].

For clarity, a DSR cannot be regisistered as a Load. It can either apply to be be registered in one of the facility classes or left unregistered. AEMO will consider the 'controllabliity' of a facility when determining its facility class.

Overall, the registration framework in the new market provides appropriate flexibility for DSR which wishes to participate in the WEM. However, the DSRWG has identified that the metering arrangements that apply to hybrid facilities may pose a barrier to flexibility in registration, and therefore participation in other WEM components. This is discussed further below.

3.2.1 Registration of hybrid facilities

The presence of hybrid facilities in energy markets is increasing to support renewable energy resources in the energy transition. The SWIS is no different in this regard and is equally expected to see an increase in hybrid facilities, many of which may include a load.

A hybrid facility is a facility compromising two or more different technology types. Often it is a combination of a generating system and an Electric Storage Resource. However, the WEM Rules allow for a hybrid facility to include a load, to form:

- A load and an Electric Storage Resource hybrid facility; or
- A load and on-site generating system (intermittent or non- intermittent) hybrid facility; or
- A load, on-site generating system (intermittent or non- intermittent) and an Electric Storage Resource hybrid facility.

Registering a hybrid facility in the WEM is based on injection and withdrawal capacity and direction of energy flows. A load can be collocated with another technology type provided they share a common connection point (i.e. a single Western Power meter) and then register as a Scheduled Facility, Semi-Scheduled Facility or a Non-scheduled Facility, depending on the size of the technology type(s).

As part of this review, EPWA analysed the range of hybrid configurations to test their value proposition. The hybrid configurations considered were:

- ESR and on-site load;
- ESR and on-site load (on-site load turning off or reducing to reduce IRCR);
- ESR and on-site load (on-site load supplied by ESR to reduce IRCR);

6 In the WEM, loads are defined as one or more electricity consuming resources or devices, other than Electric Storage Resources, located behind a single network connection point or electrically connected behind two or more shared network connection points.

7 A non-registered load by default is a Non-Dispatchable Load.

- ESR and DSP;
- ESR and DSP (on-site load turning off or reducing to reduce IRCR);
- ESR and DSP (on-site load supplied by ESR to reduce IRCR); and
- ESR, Intermittent Generation and DSP.

Through the above analysis four likely viable operational models emerged:

- ESR and load not participating in the RCM, and using the ESR to reduce IRCR costs;
- only ESR participating in the RCM and load reduced to reduce its IRCR;
- load operating as a DSP and ESR not particiapting in the RCM; and
- both components participating in the RCM.

Hybrid facilities are most viable when there is opportunity to 'value stack'. Value stacking is when multiple services are provided by the same facility. This is different from the potential for 'double dipping' in which multiple payments are received for the same action. Double dipping needs to be considered carefully and prevented if it does not add value to the market.

The ability to value stack depends on the level of flexibility available to facilities to choose how to engage the different facility components with the different market components at any given time. Hybrid facilities are treated differently in the energy markets and the RCM, as discussed below.

Hybrid facilities in the RCM

Hybrid facilities are eligible to apply for certified capacity. Each technology type in hybrid Scheduled or Semi-scheduled Facilities is assessed separately. Hybrid Non-scheduled Facilities are assessed under the relevant level methodology.

Capacity credits assigned to a hybrid facility are the sum of each component's certified capacity, capped by the facility's NAQ. If the NAQ value is less than the total certified capacity, the Market Participant will advise AEMO of the number of capacity credits for each component it receives.

A hybrid facility with a DSP component is certified based on its relevant demand. All of a DSP's associated loads must be associated with a common TNI.

The RCOQ for a hybrid facility reflects all technology types of the separately certified components. A hybrid facility must meet the RCOQ for each certified component. For example:

- a hybrid facility with a DSP and an ESR will have an 8am to 8pm RCOQ requirement for the DSP and a 4 hour RCOQ requirement for the ESR; and
- a hybrid facility with an intermittent generating system and a DSP will have no RCOQ requirement for the intermittent generation and will have an 8am to 8pm RCOQ requirement for the DSP.

However, the hybrid facility reserve capacity refunds are not separately calculated. This means that one of the components (e.g. an intermittent generator) can meet the RCOQ of another component (e.g. the ESR). An under-performing component may also affect the facility total capacity revenue.

Hybrid facilities (apart from intermittent generator components) are subject to capacity testing, with each component tested independently. A testing failure resulting in capacity credit reduction will only lower the capacity credits of the failing component.

Overall, hybrid facilities are offered sufficient flexibility for their participation in the RCM.

The DSRRWG identified one potential issue with the registration of hybrid facilities. Currently, a DSP cannot also register in another facility class. The only exception is an Interruptible Load, which can also register as a DSP.

As a consequence, a hybrid facility comprising a load and an ESR component cannot register as both a DSP and as another facility type (e.g. a Scheduled Facility). Further, this hybrid facility may not have a choice whether to registers as a DSP or a Scheduled Facility i.e. AEMO may require it to register as a Scheduled Facility. As a result, this hybrid facility can only receive capacity credits for its ESR component and not for its DSR.

EPWA considers that the WEM Rules should be clear about the circumstances in which a hybrid facility comprising a load and an ESR component will be required by AEMO to register as a Scheduled Facility. The WEM Rules should also be clear whether there is any flexibility for the relevant market participant to register such a facility as a DSP and receive capacity credits accordingly.

Proposal 2:

The WEM Rules should be amended to clarify the circumstances in which a hybrid facility comprising a load and an ESR component will be required by AEMO to register as a Scheduled Facility. The WEM Rules should also be clear whether there is any flexibility for the relevant market participant to register such a facility as a DSP and receive capacity credits accordingly.

Consultation Questions:

3. Do stakeholders support providing clarity in the WEM Rules regarding the registration requirements applying to a hybrid facility comprising a load and an ESR component?

Hybrid facilities in the energy market

Currently, the WEM considers a hybrid facility as a single Facility for dispatch. This is because the Metering Code, standard metering practices and national legislation require the meters used for settlement to be installed, owned, and operated by Western Power. However, in practice, under the WEM Rules a facility currently can only elect to have a Western Power meter installed at its connection point. This may be limiting the opportunity for hybrid facility participation in the energy markets.

Currently, participants are restricted in the way they operate their facilities in the energy, including ESS, markets due to the metering limitations placed on them. More flexibility could be provided to hybrid facilities if they were able to use Western Power installed sub-metering for the purpose of settlement in the STEM and the real time market.

With Western Power revenue quality metering on each component, it would be possible to use the same DSR in a hybrid facility to participate across the different markets (real time market/ESS, RCM) to provide different services.

Providing hybrid facilities (capable of providing DSR) with the choice of what services they provide and with access to a variety of possible revenue streams has the potential to provide market wide benefits. However, revenue quality metering comes at a cost, so it should not be something all hybrid facilities are required to install.

Proposal 3:

Currently, participants with hybrid facilities are restricted in the way they operate their facilities in the energy and the ESS markets due to metering and settlement limitations. More flexibility should be provided to hybrid facilities by enabling them to use Western Power installed sub-metering for the purpose of settlement in the STEM and the real time market, including the ESS markets.

Consultation Questions:

4. Do stakeholders support providing the option for hybrid facilities to install settlement grade sub-meters?

3.3 RCM

Loads can participate in the RCM in two different ways.

The first, is indirectly through reducing demand during expected peak demand periods to reduce their Individual Reserve Capacity Requirement (IRCR). If the load can successfully match its demand reduction to the peak demand IRCR intervals, it will be allocated a smaller IRCR cost.

The second, is through direct participation in the RCM and receiving capacity payments. A load must be part of a Demand Side Programme (DSP) to be eligible for capacity payments. Most commonly DSR receives capacity payments as a DSP.

The DSR Review examined the potential for a DSR to 'double dip' by seeking to reduce its IRCR cost while receiving capacity payments for the same flexible load. It concluded that for a load that is not collocated with another technology type, the WEM Rules prevent this from occurring by reducing its capacity payments in subsequent years.

A recipient of capacity payments must make its capacity available for dispatch by AEMO. The availability requirements vary depending on the facility class. For example, DSPs must be available from 8am to 8pm, whereas scheduled facilities must be available all of the time.

3.3.1 Measuring the performance of DSPs

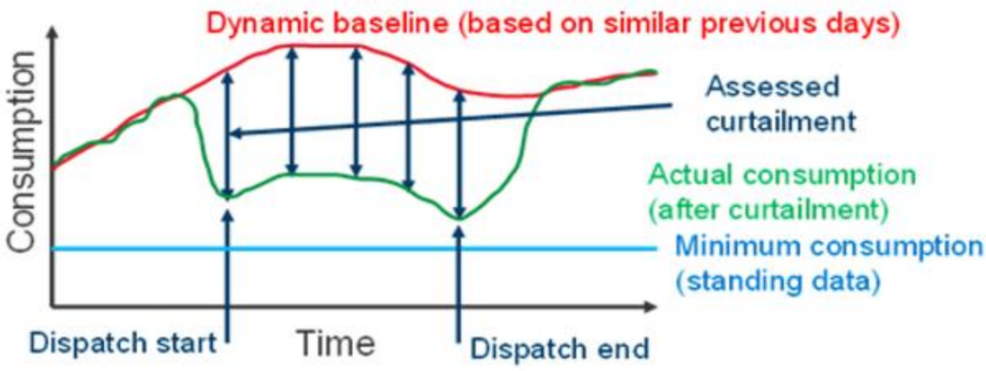
One of the Review Outcomes of the RCM Review was that the performance of DSPs should be measured against a dynamic baseline, rather than the static baseline in the status quo[8]. The rationale for this move can be found in the Reserve Capacity Mechanism Review Information Papers (Stage 1) and (Stage 2)[9].

A dynamic baseline would assist flexible loads participation in the WEM.

[8] Review Outcome 4, Reserve Capacity Mechanism Review Information Paper (Stage 2), 2 August 2023.

[9] https://www.wa.gov.au/system/files/2023-08/reserve_capacity_mechanism_review_-_information_paper_stage_2.pdf

Figure 4: Dynamic Baseline



Source: RCM Review, Consultation Paper (Stage 2)

During the RCM Review, it was noted that the introduction of a dynamic baseline increases the potential for gaming. For example, if the baseline were set by interpolating between consumption immediately before and after the dispatch period, a DSP could artificially increase its consumption in the preceding periods to increase its baseline.

The DSR Review is considering the detailed design of a dynamic baseline that mitigates this risk. This can be achieved in two ways:

- ex ante (before the fact) measures such as stricter calculation guidelines; or
- ex post (after the fact) measures such as regulatory monitoring and penalties.

Some examples of ex-ante measures to reduce opportunities for baseline manipulation by participants include[10]:

- using a baseline calculation method that's fair on average on likely event days, absent any gaming;
- ensuring that baseline calculation data include recent "similar" days, and are limited in how far back the "look-back" period can be so that data from another season cannot be used to overstate the baseline;
- using rules that have the effect of limiting participants' ability to control or predict what days they will be called on to reduce withdrawal;
- investigating load and bidding patterns that seem perverse based on customer characteristics; and
- requiring advance notice of scheduled shut-downs.

In the DSRWG deliberations on the potential for gaming, a member noted that:

> *"In the WEM, most energy users that participate or would participate in a demand side programme are commercial or industrial businesses with production targets and/or service levels to meet. While it is feasible that such a business would chase an opportunity to game its baseline, it would not do this if it posed any risk or distraction to the achievement of its primary business objective".*

10 Measurement and Verification for Demand Response - Prepared for the [USA] National Forum on the National Action Plan on Demand Response: Measurement and Verification Working Group , KEMA, February 2013

It was further noted that there are technical limitations to running equipment harder and contractual demand limits in participant's connection agreements that would limit any opportunity for gaming.

However, if provided with a sufficient incentive, some participants may look to push the boundaries of what is deemed as acceptable behaviour by DSPs. An example of this is how participants in the UK 'gamed' the way Transmission Use of System (TUoS) charges were allocated during peak times. Known as 'triad avoidance schemes' (refer Appendix A.2.3), participants tried to predict which three periods each Winter would be used by the Transmission Operator as the basis to allocate peak system charges and to reduce their usage during these three periods. This created a significant cost transfer to those participants who did not, or could not, play this 'game'.

There are four general types of possible baseline designs:

- the "X of Y" baselines,
- the weighted average (or current and preceding day),
- regression; and
- matching day-pair[11].

The most common type of baseline is the "X of Y". This methodology loosely translates as looking at 'X' of the last 'Y' days. In practice, an adjustment is often made if there were atypical load days in the preceding 'Y' period, such as a public holiday or facility outage. Such atypical days can be removed from both the 'X' and the 'Y'. Five of the USA markets use this methodology, as shown in Table 5 below.

Table 2: 'X' of 'Y' baselines adopted in the US Markets

Market	Baseline Name	Average of	Out of
CAISO, MISO	10-in-10	10 most recent weekdays	10 most recent weekdays
ERCOT	Mid 8-of-10	10 most recent weekdays, dropping highest and lowest kWh days	10 most recent weekdays
NYISO	5-of-10	5 highest kWh days	10 most recent weekdays
PJM	4-of-5	4 highest kWh days	5 most recent weekdays

Given that DSPs are most often called to respond when demand is at its highest, it is common practice to apply 'day-of adjustments' to the raw baseline. Day-of adjustments apply so that the baseline more accurately reflects the load conditions of the event day.

Such an adjustment is also used in the NEM. The NEM, both in its emergency reserve (RERT) mechanism, and its Wholesale Demand Response Mechanism, has adopted the "10-in-10" baseline methodology.

To further mitigate any concerns of gaming, a cap can be placed on positive adjustments for the day-of-adjustment (suggesting 20%), but uncapped for negative adjustments to reflect, for example, a load being out on maintenance during the response day.

Ex-post examination of data could still be used to assess whether gaming is taking place.

[11] Development of DR Mechanism, Baseline Consumption Methodology – Phase 1 Results, AEMO/KEMA, July 2013

Proposal 4:

The dynamic baseline for DSR participation will be based on an ex-ante ‘X of Y’ methodology incorporating a ‘day of adjustment’. A cap will be placed on upward adjustment but uncapped for downward adjustment.

Ex-post mitigation through examination of data could still be followed to detect any undesirable behavior that is not being mitigated through ex-ante measures.

Consultation Questions:

5. Do stakeholders agree that an ex-ante ‘X of Y’ methodology incorporating a ‘day of adjustment’ is an appropriate baseline design for DSP participation?

3.4 Supplementary Reserve Capacity (SRC)

Six months before the start of a capacity year AEMO can seek SRC if AEMO considers there will be inadequate reserve capacity. All facilities including DSRs are eligible to participate if they:

1. do not hold Capacity Credits in the current Capacity Year; and
2. have not held Capacity Credits in the current Capacity Year or a previous Capacity Year; and
3. hold Capacity Credits in a subsequent Capacity Year, or
4. provide evidence satisfactory to AEMO, prior to a Supplementary Capacity Contract taking effect, that:
   a) costs have been incurred to enable the provision of the capacity through the installation of physical equipment; and
   b) the capacity is in addition to the sent-out capacity of the Energy Producing Systems, or the maximum amount of load that can be curtailed, that existed prior to the installation of the physical equipment.

AEMO dispatches any procured SRC in line with the agreed contractual terms.

Proposal 5:

No change to the SRC mechanism is proposed, as the SRC framework already provides for the effective participation of DSR.

Consultation Questions:

6. Do stakeholders agree that the existing framework of the SRC mechanism already provides effective incentives for DSR participation?

3.5 Metering Code – Amending Confidentiality Obligations

During the DSRRWG meeting of 5 July 2023, there was discussion on the prospect of DSR to integrated from the beginning to the end of its life cycle.

One of the issues raised in that discussion was that Western Power is currently limited in the energy information it can provide to AEMO because of the confidentiality obligations in the *Electricity Industry (Metering) Code 2012* (“The Metering Code”).

This issue has also been raised in the recent Supplementary Reserve Capacity (SRC) Review[12]. During the SRC Review, EPWA identified that AEMO's ability to measure the performance of some of the services provided by distributed energy resources, such as demand response aggregations, was impeded due to the following issues with meter data availability.

- Confidentiality prevented Western Power from providing AEMO with meter readings for some of the relevant NMIs.
- Some of the relevant meters were either not capable of providing, or were not set up to provide, interval meter data.

Energy Policy WA proposed to make amendments to the WEM Rules to require and enable Western Power to provide AEMO with the information necessary for the performance measurement of SRC services, including the interval meter data needed to measure the performance of SRC services.

Stakeholder feedback in the SRC Review was supportive of the intent of the proposed changes, with suggestions that an additional clause is required in the Metering Code to overcome issues and challenges with confidentiality.

Following the similar discussion in the DSRRWG, EPWA agreed to propose changes addressing these issues.

Proposal 6:

Amend the Metering Code so Western Power must share energy data on request to AEMO, to the extent necessary for market purposes, and with AEMO keeping that information confidential.

Consultation Question:

7. Do stakeholders support amending the Metering Code so Western Power must share data (which AEMO shall keep confidential) with AEMO upon request?

3.6 Short Term Energy Market (STEM)

DSR is not currently able to participate in the STEM. While participation is not explicitly prohibited, DSR is not able to comply with STEM bidding requirements. The STEM is a small market with few participants, some of which quite active. STEM participation could be extended to DSR allowing it to purchase energy and optimise its contract position.

Members of the DSRRWG were asked for their views on the benefits of extending STEM participation to DSR. One member noted that historically a retailer had purchased energy from STEM on the behalf of a customer. This arrangement was possible because the retailer had a bilateral contract with the customer which allowed this. Members suggested that STEM participation should be allowed for customers without a bilateral contract.

DSR participation in the STEM could increase activity and provide more opportunities for flexible loads. STEM participation is not mandatory thus, only willing DSR would participate. Additionally, the STEM is a 'simple' market so facilitating DSR participation is not expected require large implementation changes.

[12] More information can be found at: https://www.wa.gov.au/government/document-collections/supplementary-reserve-capacity-review

Proposal 7:

Take steps to remove impediments from the WEM Rules to allow direct participation by DSR in the STEM.

Consultation questions:

8. Do stakeholders agree that DSR should be allowed to directly participate in the STEM?

3.7 The real time energy market

DSPs and Loads are treated differently from Energy Producing Systems (i.e. generating systems and ESR) in the real time energy market.

3.7.1 DSP participation

The WEM Rules set out specific requirements for DSP dispatch and these do not provide for real time energy market participation. For example, DSPs do not submit bids in the real time energy market.

A DSP is required to be available for dispatch between 8am – 8pm on each day. AEMO would issue Dispatch Instructions to a DSP if it reasonably considers that the dispatch of that DSP is required to restore or maintain Power System Security or Power System Reliability (clause 7.6.5A of the Market Rules). As DSP providers do not submit bids, AEMO does not factor prices when selecting DSP for dispatch.

Dispatch Instructions to DSPs are different from those issued to other facilities. For example, Dispatch Instructions for DSPs are issued in accordance with the required notice period for the facility (two hours) while Dispatch Instructions are issued to other facilities every five minutes.

The meaning of a Dispatch Instruction is also different for DSPs:

- a non-zero MW quantity means that the consumption of the DSP must be curtailed to less than or equal to the specified level by the start time shown in the Dispatch Instruction;
- the market participant is expected to maintain at least this level of curtailment until the start time of the next dispatch instruction;
- a zero MW quantity dispatch instruction means that the consumption of the DSP no longer needs to be curtailed from the start time shown in that dispatch instruction; and
- DSP when dispatched must be at or below the required level by the start time of the dispatch instruction, and must remain at or below that required level until the start time of the next dispatch instruction. This may either be to increase or decrease curtailment, or return to uncurtailed levels.

Following discussions with the DSRRWG, EPWA considers that flexible loads are already provided with the opportunity to participate in the real time energy market, and DSPs are required to be available during the day time hours. Further changes to the real time energy market to allow bidding by DSPs are likely to be complex and costly without significant benefits to justify such changes.

Proposal 8:

No changes are proposed to DSP participation in the real time energy market.

Consultation questions:

9. Do stakeholders agree that there is no need or benefit that would justify changes to DSP participation in the real lime energy market?

3.7.2 DSR participation

Loads that are not part of a DSP[13] have the option to participate in the real time energy market by registering as a scheduled facility or semi-scheduled facility (if part of a hybrid facility). Scheduled facilities and semi–scheduled facilities can bid withdrawal quantities/prices into the real time energy market. They are then included in the real time energy market dispatch algorithm.

AEMO centrally dispatches facilities using the Wholesale Energy Market Dispatch Engine (WEMDE), based on bids and offers submitted by facilities. Scheduled facilities are given a dispatch target, while semi-scheduled facilities are given a dispatch cap.

From a market perspective dispatchable DSR can be valuable in two scenarios:

1. Dispatched 'on' during low load periods to increase demand; and
2. Dispatched 'off' during high load periods to reduce demand.

When demand is low, DSR can be valuable by increasing demand to avoid the risks associated with insufficient system demand. Further, when prices are negative DSR can benefit by effectively being paid to consume.

Alternatively, when demand is high DSR can be valuable by reducing demand. This could help reduce prices or avoid load shedding if generation is insufficient.

DSRRWG members acknowledged the ability for flexible loads to participate in the real time energy market but were also of the view that direct participation by DSR in the real time energy market is likely to have low uptake due to the costs and effort outweighing the benefits. It was also notes that the willingness to patriciate in the real time energy market may change over time or could appeal to hybrid facilities (such as a large load with on-site generation).

Proposal 9:

No change is proposed to DSR participation in the real time energy market as the participation of flexible loads is already provided for.

Consultation questions:

10. Do stakeholders agree that the real time energy market has sufficient opportunity for DSR participation?

[13] A load cannot be registered concurrently as both a DSP and as another Facility, apart from an Intermittent Load.

3.7.3 Minimum demand services

An increasing challenge in the SWIS is that minimum operational demand is falling as inverter-based generation (e.g. roof top PV generation) increases. With less synchronous generation available, alternative response is required to counter:

- low levels of inertia;
- lower operational flexibility; and
- reduced system strength.

The lowest SWIS demands typically occur in the following circumstances:

- mild weather periods when there is little demand from heating or cooling;
- weekends when there is less commercial/industrial demand - less businesses are open or operating; and
- the middle of clear, sunny days (say from 10am to 2pm) when behind-the-meter solar PV installations are generating most and reducing consumer demand.

In response EPWA is already coordinating and leading the Low Load Project[14]. This project is to ensure appropriate responses, frameworks and mechanisms are in place to manage low demand when it occurs.

This Review has identified that DSR can contribute in two ways:

1. help to keep demand above the minimum demand threshold; and
2. provide alternative response to maintain system stability.

DSR can contribute to keeping demand above the minimum demand threshold in the following ways:

- load shifting from peaks to troughs (both reducing exposure to high prices during the evening peak and taking advantage of low prices in the middle of the day); and
- increasing demand in low load periods / high PV output periods.

If discretionary demand exists, the real time energy price during low demand periods should provide a signal for load to increase. However, this may happen only if discretionary loads are not fully hedged (e.g., through fixed tariffs or their bilateral contracts) and are thus exposed to the pricing signals.

Retail and network electricity price signals have already moved some demand to low demand periods overnight.

Some large customers are on energy supply contracts with peak and off-peak pricing, with higher peak prices applied during the day. Over many years some of these customers, adapted and shifted some of their consumption to the overnight 'off-peak' period.

Customers which have flexibility around the time of their consumption may be able to shift consumption to the emerging off-peak times, now in the middle of the day. While the STEM or real

[14] https://www.wa.gov.au/system/files/2022-08/EPWA-SWIS%20Low%20Demand%20Project%20Stage%201.pdf

time energy market prices are low or negative during the low demand periods, just a few of these customers may currently receive direct price signals to encourage them to do so.[15]

The types of loads that could increase their demand during the SWIS minimum demand periods typically:

- do not need to operate 24/7;
- do not currently operate in the middle of the day or weekends; and
- can do some type of “batch” process resulting in storage of their “product”.

Examples of this include:

- conveyors carrying material to a stockpile;
- milling or grinding of ore or other material to a stockpile or storage;
- production of chilled water (stored in a specially designed chilled-water storage system) for later use;
- ice storage for shifting air-conditioning load is also used in other jurisdictions;
- pumping of water to storage or for irrigation, and similarly for other pumped products;
- desalination of water;
- cooling of large cold stores (warehouses) which can be over-cooled during off-peak periods and then the cooling can be turned off during peak periods and still maintain the required temperatures due to the large thermal mass of cooled product and good cold store insulation;
- electric-heat-pump-heated aquatic centres;
- ice production – although demand for ice will be lower in mild weather; and
- on-site load that is supplied by on-site generation.

Retailers and wholesale market customers that are benefiting from the low or negative prices during the minimum demand periods, however, may not want to encourage increased demand. Increasing demand during these times may increase market prices.

Barriers and Incentives

DSR participation in the real time energy market can help to support the system stay above minimum operational demand by increasing consumption during low load periods.

The real time energy market provides price signals to the demand side to incentivise the desired response. The price floor of the real time energy market is negative $1,000 which means that load would be paid to consume during times of over-supply.

However, only some demand will be sufficiently flexible to respond in this way, and a portion of this flexible load will not be exposed to real time energy prices due to the protection of its contractual arrangements against volatile spot prices. Further, if flexible load responds to this price signal demand will increase and result in higher market prices.

Given this ‘dampened’ effect on the market price signal it may be necessary to provide some other form of incentive, for example compensation for the provision of a minimum demand service.

15 It is only recently that some new network tariffs have been introduced by Western Power – from 1 July 2023 - to focus price signals specifically to encourage more consumption in the middle of the day – the new super-off-peak tariffs. Some retailers are starting to offer retail tariffs to a few customers on this basis.

However, such a measure may be premature with more ESRs likely to enter the market which may help to resolve the problem.

DSRRWG members discussed the idea of developing a standard service to address minimum demand in the context of AEMO having already triggered NCESS twice to procure minimum demand services. While there was some support for this, it was ultimately concluded that it's best to see if the increasing penetration of ESR, the new flexible capacity product and the real time energy market pricing will address this issue in the medium term.

EPWA, therefore, proposes that no specific changes to introduce a minimum demand service be made at this time.

Proposal 10:

No changes are proposed to be made for a specific service to address the minimum demand issues in the SWIS at this time.

Consultation questions

11. Do stakeholders agree that no changes should be made to introduce a minimum demand service at this time?

3.8 DSR participation in the Essential System Services (ESS) markets

There are two types of ESS services:

- Frequency Co-Optimised ESS (FCESS); and
- Non-Co-Optimised ESS (NCESS).

3.8.1 FCESS

DSR can provide a variety of FCESS. When the system is short on synchronised generation DSR can assist in maintaining system stability. Table 3 shows the possible ways DSR can support system stability.

Table 3: Potential DSR roles to maintain system stability

Required response	Potential synchronous generation response	Potential DSR role
Frequency control	• Greater volume creates higher inertia ⇨lower frequency disturbance from events. • 6 second pulsing. • Governor response. • Out-of-merit dispatch.	• Direct load control • RoCoF (rate of change of frequency)
Raise frequency nadir	• System inertia, both actual and synthetic.	• RoCoF
Ramp management (from min. demand to peak demand)	• Multi-period dispatch planning. • Out-of-merit dispatch.	• Dispatchable demand.
Voltage stability	• Reactive power	• Pre-contingent load management.

Required response	Potential synchronous generation response	Potential DSR role
		• Post-contingent load management (immediate response).

The new co-optimised energy and ESS market includes five FCESS services:

- Regulation Raise and Regulation Lower;
- Contingency Reserve Raise and Contingency Reserve Lower; and
- Rate of Change of Frequency (RoCoF).

The WEM Rules do not provide for a DSP to provide FCESS, unless also registered as an Intermittent Load.

For DSR to be accredited for providing FCESS, the DSR must be registered as either a scheduled or semi-scheduled facility or an interruptible load. Subject to meeting the technical requirements, DSR registered as a Scheduled or Semi-Scheduled Facility can provide any of the of the FCESS services.

However, there are technical and size limitations to the DSR ability to provide some or all of the services. For example, in other to provide Regulation Raise or Regulation Lower, the DSR must have Automatic Generation Control System (AGC) installed, which enables it to automatically receive and respond to signals from AEMO. AGC is the system into which Dispatch Targets or Dispatch Caps are entered and processed by AEMO for facilities operating on automatic generation control.

Interruptible Loads, on the other hand, already provide Contingency Reserve Raise services in the WEM. However, there are size limitations to the DSR ability to provide these services, which are enshrined in the relevant AEMO WEM Procedure.

Members of the DSRRWG discussed telemetry requirements as a possible barrier to participating in the Contingency Reserve Raise services WEM. One member noted that:

> *"In other interruptible load markets, there are no telemetry obligations, only compliance with dispatch instructions. Offers reflect what loads can actually provide in a frequency event, with local response to locally measured frequency deviation."*

International experience supports the DSRRWG's view. Observations from the NEM demonstrate that the RERT with lower telemetry and more notice lead time had higher uptake than the Wholesale Demand Response Mechanism (WDRM) which has stricter requirements. In the UK, a survey by the energy regulator OFGEM raised telemetry as one of the higher obstacles to DSR participation.

A DSRRWG member representing AEMO acknowledged the views regarding telemetry and noted that:

> *"AEMO plans to consult on this as part of updating the FCESS Accreditation WEM Procedure"* and *"that the real time SCADA is not necessary to provide those services but some level of visibility of the service availability should be required."*

Based on the above, EPWA considers that the size and potential technical limitations (such as the telemetry requirements) for providing ESS services, currently detailed in the relevant AEMO WEM Procedure, need to be reviewed.[16]

The focus of this review should be to ensure that there no unnecessary barriers for the provision of ESS services by technically capable DSR. The review should also consider, amongst other things, whether some of these limitations should be moved from the relevant WEM Procedures to the WEM Rules.

Proposal 11:

The size and potential technical limitations (such as the telemetry requirements) for providing ESS services should be reviewed to ensure that there no unnecessary barriers for the provision of ESS services by technically capable DSR.

Consultation questions:

12. Do stakeholders agree that there may be potential barriers to the participation of DSR in the ESS markets?
13. Do stakeholders agree that the size and potential technical limitations (such as the telemetry requirements) for providing ESS services should be re-examined?

3.8.2 Intermittent Loads

Currently, a DSP can also register as an Interruptible Load and be accredited to provide Contingency Reserve Raise services. Members of the DSRRWG queried whether a DSR should be allowed to register as both a DSP and an Intermittent Load given that, historically, Intermittent Loads have provided Contingency Raise services only and have not been dispatched as a DSP.

In the new WEM:

- Interruptible Loads would be bidding in the Contingency Reserve Raise market;
- If they are not dispatched because they are not in merit, they would be treated as any other DSP and dispatched when necessary (noting that a DSP providing capacity would not be providing Contingency Reserve Raise service at the same time).
- the WEM Rules will require a participant to reduce its Interruptible Load offers to zero if dispatched as a DSP, and if it is registered as both an Interruptible Load and a DSP at same connection point; and
- AEMO would need to know how to rotate loads in such circumstances.

Members of the DSRRWG considered that Interruptible Loads offering Contingency Reserve Raise are valuable to the market because their response is fast and do not need to have ACG. They also noted that, if an Interruptible Load is interrupted at peak times, it is no longer providing Contingency Reserve Raise but demand reduction and, therefore, the remaining generator output is reduced by the same amount thus maintaining the level of spinning reserve.

[16] The WEM Rules do not prescribe the requirements for telemetry instead the WEM Rules give AEMO authority to detail the requirements (clause 2.35.4 of the WEM Rules)

On the basis of the DSRRWG discussion, EPWA considers that DSR, capable of providing the relevant services, should be able to stack value by receiving capacity credits as a DSP as well as being paid for providing Contingency Reserve Raise services.

Proposal 12:

No changes are proposed to be made to the ability of DSR to register as both an Interruptible Load and a DSP, and provide Contingency Reserve Raise services at the same time it receives capacity credits.

Consultation questions

14. Do stakeholders agree that no changes are required to the ability of DSR to simultaneously participate as a DSP and as an Interruptible Load providing ESS?

Appendix A. Investigation of International Jurisdictions

Stage 1 of the DSR Review calls for a review of the participation of Loads/DSR in other markets in the context of what problems their electricity systems are facing or are expected to face in the future, and whether/how these arrangements relate to the WEM.

The following jurisdictions have been investigated and are detailed within this Appendix:

- NEM, Australia;
- United Kingdom;
- PJM, USA; and
- New Zealand.

Many jurisdictions have, or are in the process of, looking at the role that DSR can play in helping to transform their energy systems. For example, Transpower's (New Zealand) energy outlook plan "Empowering our Energy Future" postulates the potential benefits of demand response as:

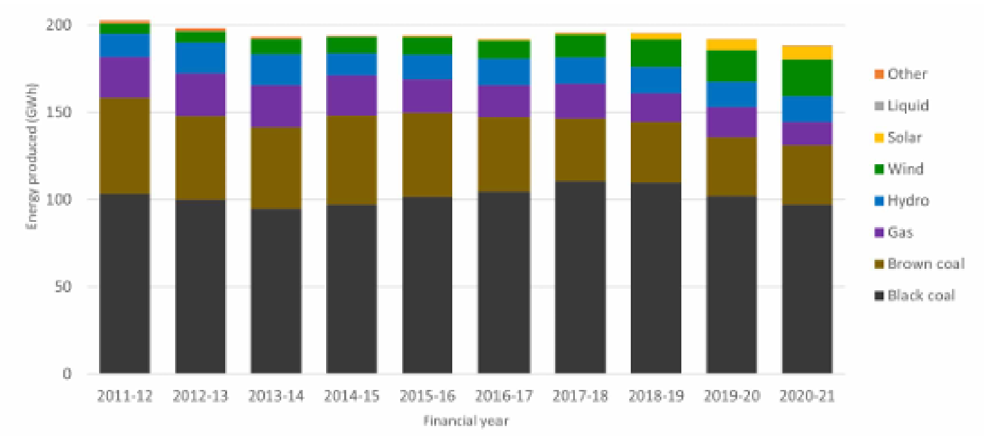
- avoiding unnecessary investment in peaking generation (typically gas-fired);
- deferral of transmission and distribution investments;
- enabling congestion management on electricity networks;
- encouraging renewable generation through providing the demand-side flexibility required to;
- firming intermittent energy (wind and solar);
- encouraging consumer investment in renewable solar and battery systems;
- encouraging electrification through enabling the full demand-side value of assets such as process heaters and batteries (including those in EVs) to be realised; and
- enabling efficient integration of DER into the electricity system.

A.1 NEM Australia

A.1.1 Jurisdiction Overview

The National Electricity Market (NEM) is comprised of five physically connected regions on the east coast of Australia: Queensland, New South Wales (which includes the ACT), Victoria, Tasmania and South Australia.

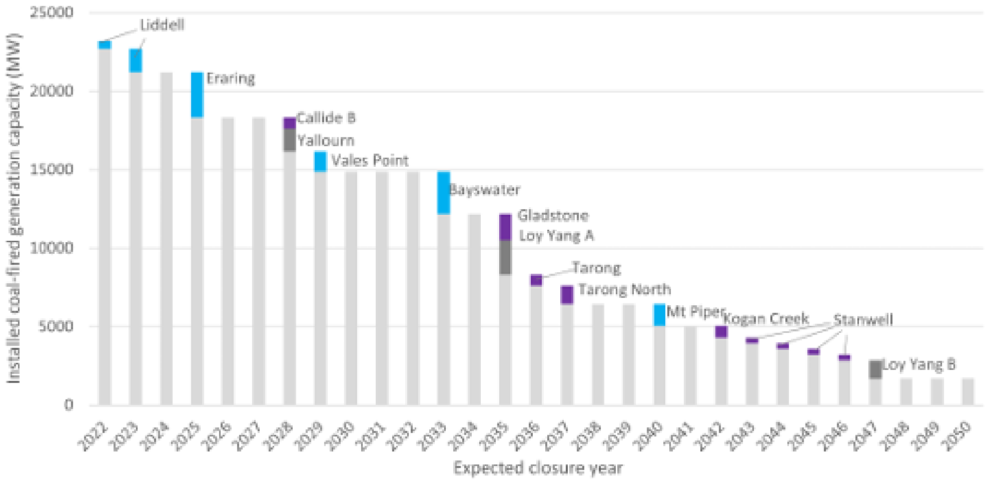
Figure 5: Energy produced by grid-scale generation technology



Source: AEMC Reliability Panel, 2021 Annual Market Performance Review, April 2022

Annual electricity consumption has declined from a peak of 210.5TWh in 2008/09 to 188.4TWh in 2002/23[17]. The system remains predominately thermal (especially coal) driven (refer Figure 5), but the trend towards renewables is expected to hasten with the planned retirement of much of the coal generation in the next 25 years (refer Figure 6).

Figure 6: Announced Coal Closures



Source: AEMC Reliability Panel, 2022 Annual Market Performance Review, March 2023

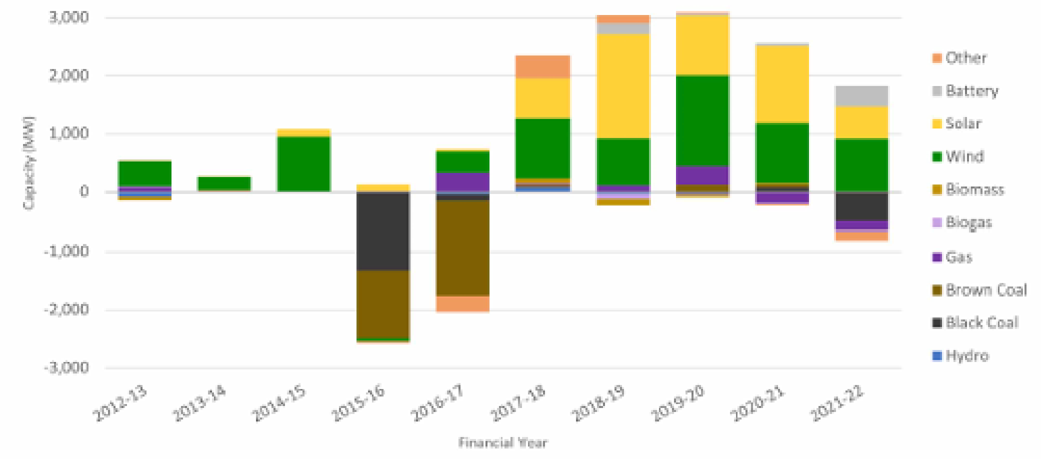
The NEM is an energy only market design with a capacity backstop – the Reliability and Emergency Reserve Trader (RERT) mechanism. To better support the expected hole left behind by the retirement of coal generation (refer Figure 6), and in response to the power outages suffered by South Australia in 2016, the RERT was augmented with the Retailer Reliability Obligation (RRO) from July 2019.

A.1.2 Problems being faced or expected to be faced in the future

The increasing penetration of intermittent renewable generation in the NEM (refer Figure 5) has led to a change in the shape of electricity demand, in particular, intra-day demand has become more volatile.

[17] Annual electricity consumption – NEM, AER website

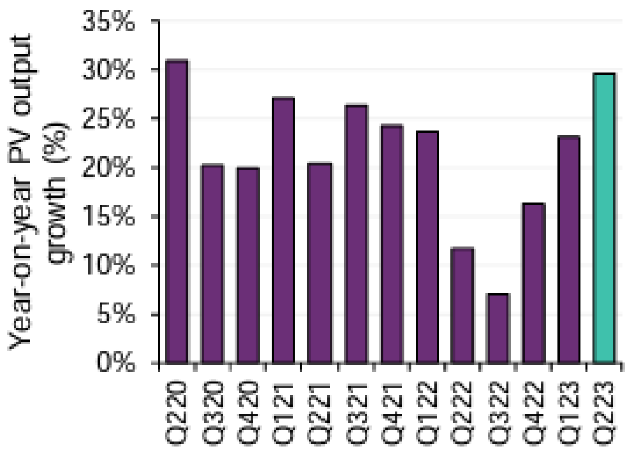
Figure 7: NEM utility-scale Generator Entry & Exit



Source: AEMC Reliability Panel, 2022 Annual Market Performance Review, March 2023

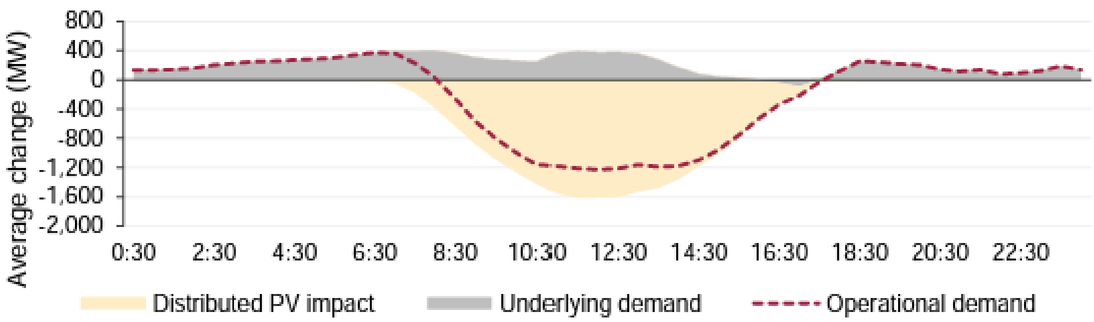
Distributed PV has seen strong year-on-year growth (refer Figure 8) which has resulted in a reduction in daytime operational demand on the system (refer Figure 9 below).

Figure 8: Year-on-year growth in distributed PV output



Source: Quarterly Energy dynamics, Q2 2023, AEMO

Figure 9: Distributed PV reduced daytime operational demand (Q2 2023 vs Q2 2022)



Source: Quarterly Energy dynamics, Q2 2023, AEMO

A.1.3 Use or planned use of Loads and DSR

Demand Response Mechanism (DRM)

In 2012, the AEMC undertook a review with the aim to give consumers more choice in how they used electricity. Part of this review looked at the potential for DR in the NEM, noting that the then current (as at 2012) level of DR in the NEM was limited[18]:

Under the current arrangements consumers are limited in their ability to respond to changes in the wholesale electricity spot price. While they are able to physically reduce their consumption in response to the spot price under specific contractual arrangements such as interruptible tariffs, spot pass-through and scheduled demand, these involve a degree of risk and transaction costs that for most commercial and industrial users cannot be efficiently managed. For various reasons, these arrangements have only been partially effective in exploiting the many opportunities for efficient demand response to spot.

The review went on to recommend a demand response mechanism be established:

A demand response mechanism is introduced that pays demand resources via the wholesale electricity market (rewards changes in demand). Under this mechanism demand resources would be treated in a manner analogous to generation and be paid the wholesale electricity spot price for reducing demand. We recommend that AEMO develops the details for a rule change proposal and required procedures, including the baseline consumption methodology.

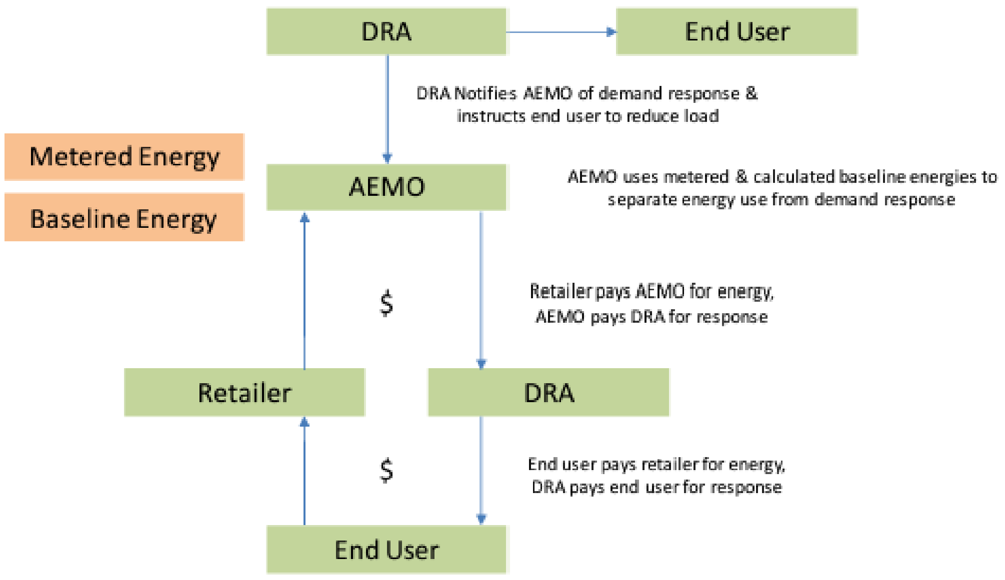
AEMO, in consultation with industry, went on to design such a mechanism, called the Demand Response Mechanism (DRM) in 2013. However, such a mechanism was not implemented until much later in 2021.

The mechanism was intended to be initially available for use by large C&I customers with a contestable energy supply contract and annual consumption over 100MWh and a revenue grade meter that could be remotely read. Such consumers would participate through a Demand Response Aggregator (DRA) or register as a DRA themselves. The DR mechanism was intended to work as follows[19]:

[18] Power of choice review - giving consumers options in the way they use electricity, Final Report, AEMC, November 2012

[19] Demand Response Mechanism and Ancillary Services Unbundling – High Level Market Design, AEMO, 30 July 2013.

Figure 10: The workings of the DRM for a demand response interval:



Source: DRM and Ancillary Services Unbundling - High Level Design, AEMO, 30 July 2013

In summary (taken form the high-level design):

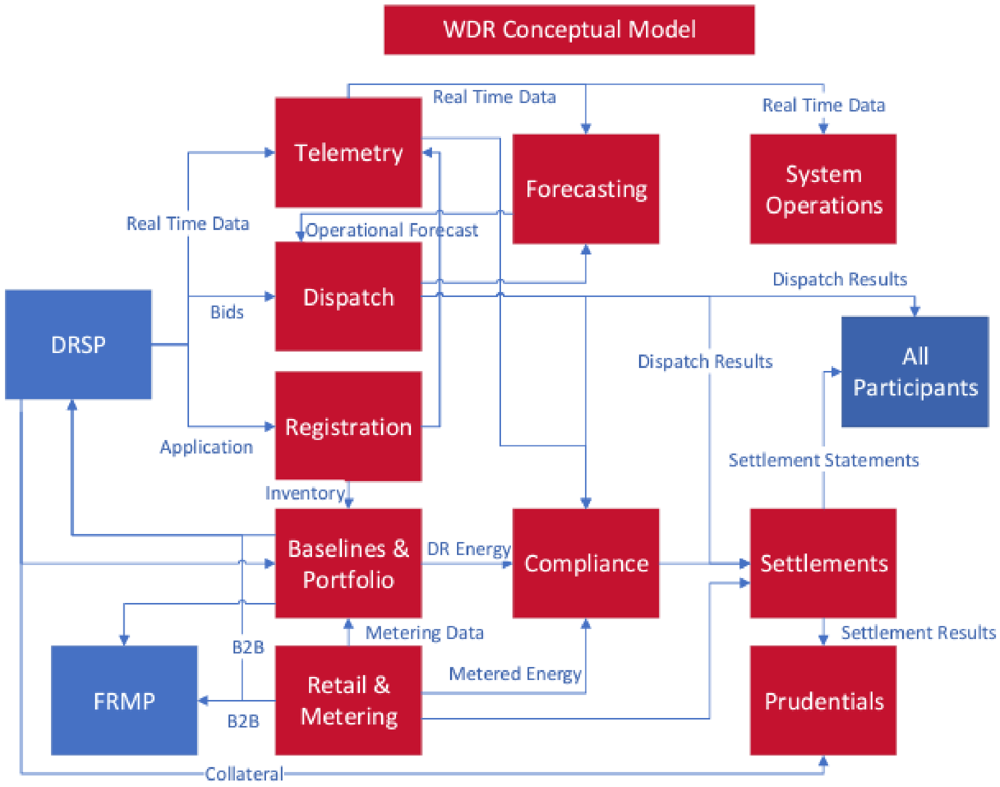
- A DRA notifies AEMO of an imminent or commenced load reduction forming what is termed a Demand Response Interval.
- After the event, AEMO calculates a baseline consumption for this interval, reflecting what demand is expected to have been had there been no demand response. The baseline is based both on historic data and data from the day the demand reduction occurred.
- In settlement, the calculated "baseline" consumption is compared with actual energy used to unbundle the amount of demand response 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 consumption and actual consumption. For symmetry, DRA will be charged if actual consumption exceeds baseline consumption.
    - 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 consumption.
    - End users would be charged by their retailer (at their retail rate) based on the baseline consumption.

The DRM never actually launched and was succeeded by the WDRM.

Wholesale Demand Response Mechanism (WDRM)

In June 2020, AEMO, in collaboration with AEMC, released a plan to implement the WDRM. The new scheme commenced in October 2021.

Figure 11: WDRM functional model



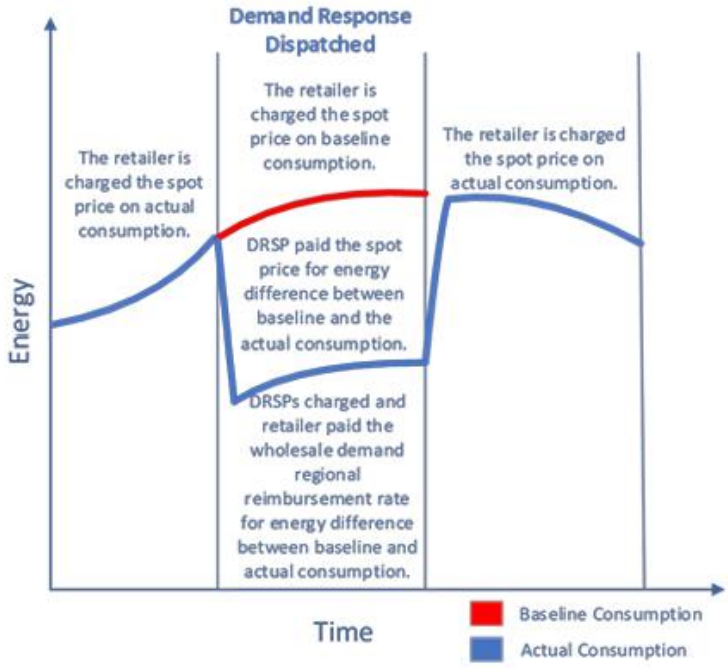
Source: Wholesale Demand Response: High-level Design, AEMO 2020

To qualify as a DR load in the new mechanism, a load needs to meet the following requirements:

- retail customer consent;
- type 1 to 4 metering installation;
- not a scheduled load;
- at a market load connection point;
- not a small customer load; and
- the load can provide a wholesale demand response.

Compensation paid to the load is illustrated below:

Figure 12: Illustration of demand response financial flows relative to baseline and actual consumption



Source: Wholesale Demand Response: High-level Design, AEMO 2020

DR Utilisation within the NEM

AEMO released their 2nd Annual Report on the new WDRM in June 2023, noting that "there has been a slow build of WDR capacity registered since the start of the mechanism. Most of the WDR events to date have been in the NSW and VIC regions, concentrated in the May to October periods, with very little WDR over summer seasons".

Total DR registered was a modest 65.3 MW, with 222MWh dispatched during the year.

Table 4: WDRM operation – key statistics as of 13 June 2023

Key statistic	Value
Baseline methodologies available	4
Baseline methodologies used by participants	3
Total DRSP registered	1
Total WDRUs registered	13
Total NMIs registered	34
Regions in which NMIs are registered	NSW, VIC, SA, QLD
Total capacity registered (MW)	65.3 MW
Number of NMIs not passing compliance testing – July 2022 to June 2023	4 (Summer 2022-23), 3 (Winter 2023)
WDR event days – July 2022 to June 2023	26 days
Region of WDR events	NSW, QLD, SA, VIC
Total WDR dispatched - July 2022 to June 2023 (MWh)	222 MWh
Average Volume Weighted Price for WDR - July 2022 to June 2023 ($/MWh)	284 $/MWh to 2,193 $/MWh
Non-conformance frequency - July 2022 to June 2023	None
Non-conformance extent - July 2022 to June 2023	9 MW

Source: Wholesale Demand response, Annual Report, June 2023;

Bypassing the Market

DR loads can choose not to participate in the WDRM and instead bypass by participating in the RERT (Reliability and Emergency Reserve Trader) or contractually via a retailer or network service provider.

AEMO note the following differences in participating in the RERT vs participating in the WDRM:

Table 5: How does WDRM compare to other DR options

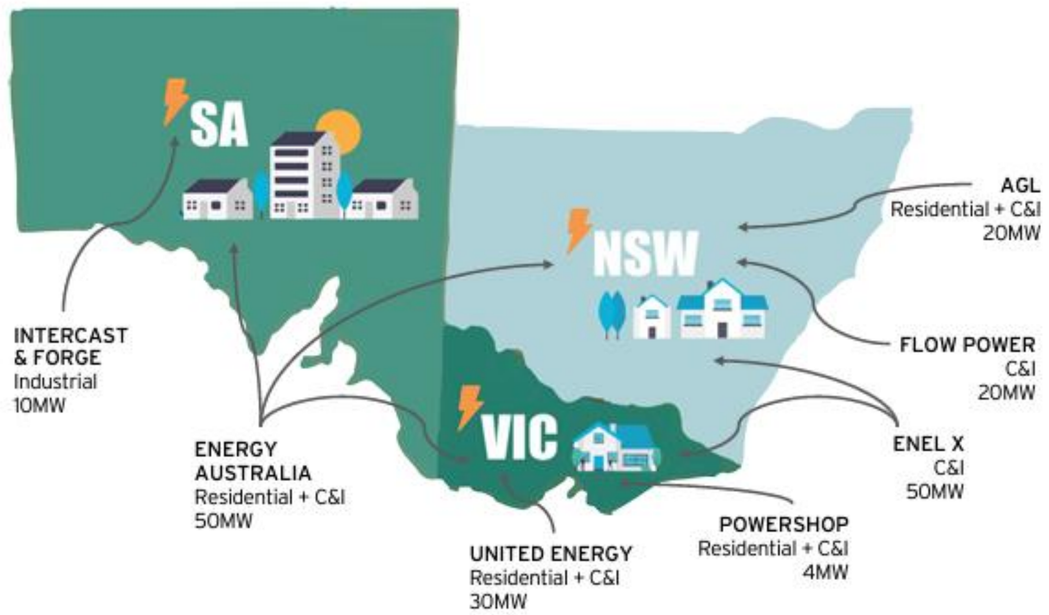
	WDRM	RERT
Type of mechanism	Market	Out of market
Dispatch timeframes and communication	Scheduled in 5 min dispatch timeframe through standard bidding and dispatch process.	Planned ahead (several hour lead time) through verbal communications and agreement
Dispatch trigger	Bid is at or below market price	AEMO operational decision
Technical requirements	Standardised capability assessment through registration to meet obligations of NER and ensure no system security issues	Procurement-based service provision to meet reliability need
Market interactions	Bid information included in PASA and pre-dispatch	PASA outputs feed into decisions on the need for RERT to protect market
Settlement & Baselines	Baselines calculated at NMI level for settlement	Baselines calculated at aggregated level for settlement
Dispatch compliance	Baselines aggregated to DUID level for dispatch compliance assessment	Aggregated baselines used to assess demand response provided against contractual commitment
Who pays for response?	Retailer pays for demand response at its NMI	All Market Customers pay for RERT service
Telemetry	Established based on size and location	Large loads typically have telemetry, no additional requirements for RERT

Source: AEMO website, WDR Frequently Asked Questions

DR participation in the RERT

AEMO and the Australian Renewable Energy Agency (ARENA) jointly developed a series of 'proof of concept' projects to support DR participation in the RERT. A three year trial took place from 2017 to 2020 with participation spread over NSW, Victoria and South Australia (refer Figure 13).

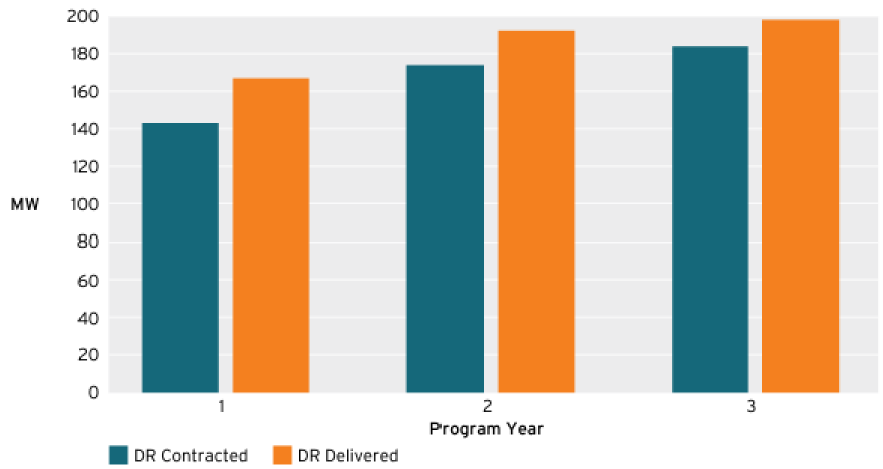
Figure 13: DR contracted resources



Source: Demand Response Short Notice RERT Trial Year 3 Report, ARENA

Over the tree year pilot DR delivered exceeded that contracted (see Figure 14).

Figure 14: DR capacity contracted vs delivered in each program year (MW)



Source: Demand Response Short Notice RERT Trial Year 3 Report, ARENA

A.1.4 How these arrangements relate to the WEM

The three year RERT pilot provided some useful lessons for further deployment of DR in the NEM that are equally as relevant to the WEM. Key outcomes from the three year trial highlighted[20]:

- more DR delivered than contracted;
- residential customers – behavioural demand response (BDR) highly popular;

[20] Demand Response Short Notice RERT Trial Year 3 Report, ARENA

- residential customers – direct load control less popular: Despite high incentives very few customers expressed interest in participating in these programs. Customers were not particularly willing to cede control of their end-use equipment;
- C&I customers – automated technologies yielded better DR delivery - Where automated technologies have been accepted by C&I customers (as compared to the use of manual curtailment), there has been a significant improvement in the delivery of contracted DR and a high level of customer satisfaction;
- C&I customers – potential for DR to contribute to NEM operations - Participants indicated that the trial had given them and their end-customers valuable experience with DR, and provided the opportunity for the participants to improve their processes and to identify more fit-for-purpose DR technology solutions; and
- C&I customers – from peripheral activity to business as usual: Lessons learned in the trial have influenced participants to move DR from a peripheral activity to business as usual. For instance, interest has been expressed in exploring the potential for DR to shift loads and encourage new loads that address minimum operational demand conditions in the generation market, as well a localised over-voltage conditions in the distribution network.

It is also useful to note that the market mased WDRM mechanism has yet to enjoy the same level of participation as the off-market RERT mechanism. The WDRM is only coming up 2 year old, so this newness may be a factor, although in looking at the differences between the two schemes (refer Table 5) the less stringent telemetry requirement and greater lead time for dispatch appear to favour the RERT mechanism (albeit may not be sufficient for moving to real-time market services).

A.2 United Kingdom

A.2.1 Jurisdiction Overview

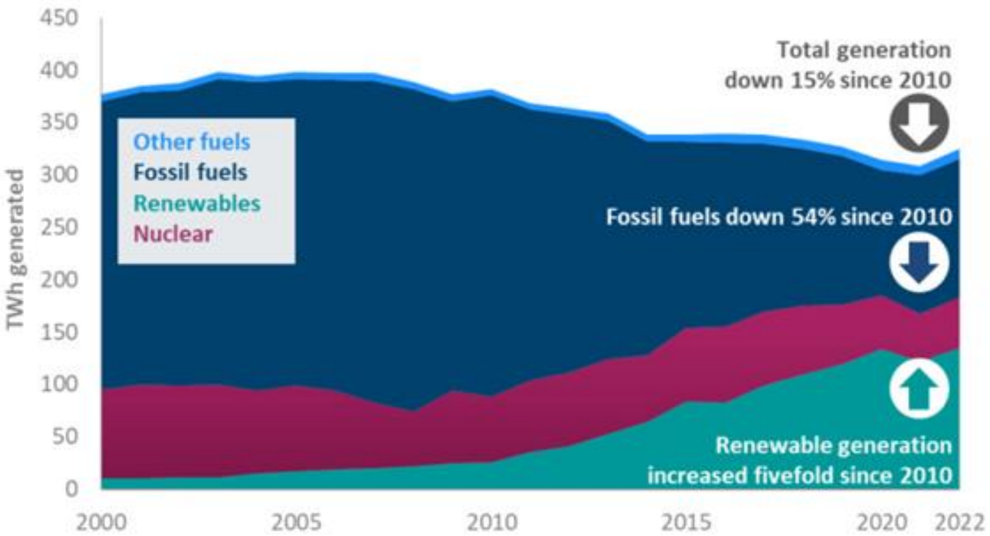
The UK is a thermally dominated system in transition towards renewables as seen in Table 6 and Figure 15. It has recently moved from an energy only market to an energy and capacity market with first capacity contracts commencing delivery in 2018.

Table 6: Generation Mix, June 2023

Fuel Source	(%)
Gas	38.5%
Wind	26.8%
Nuclear	15.5%
Biomass	5.2%
Coal	1.5%
Solar	4.4%
Imports	5.5%
Hydro	1.8%
Storage	0.9%

Source: Britain’s Electricity Explained: 2022 Review, National Grid ESO

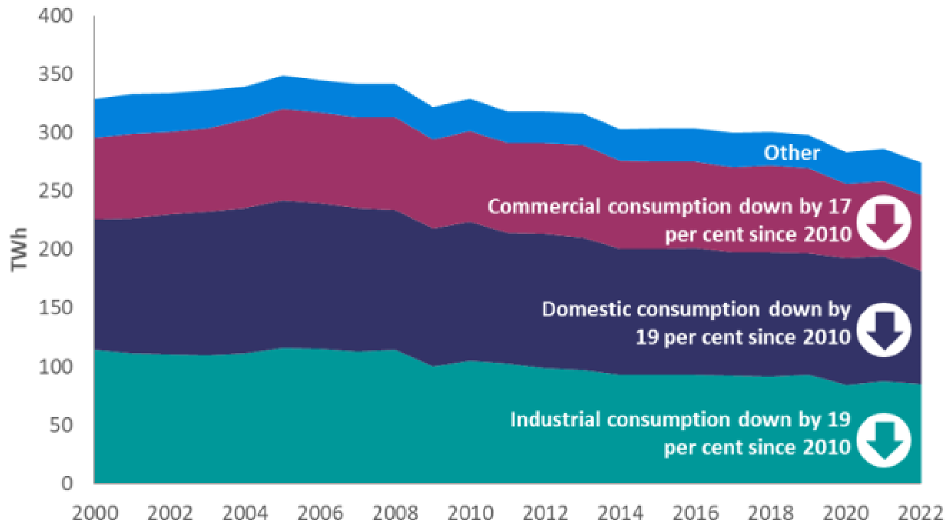
Figure 15: Electricity generated by fuel 2000 to 2022



Source: Electricity Statistics, energysecurity.gov.uk

Electricity demand has been declining since 2005

Figure 16: Electricity consumption by sector, 2000 to 2022[21]



Source: Electricity Statistics, energysecurity.gov.uk

A.2.2 Problems being faced or expected to be faced in the future

Like many jurisdictions, the UK electricity system is in a period of transition with the shift towards large volumes of distribution connected generation, flexible demand and storage. In conjunction with this has been the significant shift from fossil fuels to renewables (as shown in Figure 15).

Despite falling demand (refer Figure 16) UK is also seeing recurring concerns in how they will manage their system through high demand periods (winters). For example, in 2022 Bloomberg reported[22] that the National Grid ESO sent a request to some firms, asking how much electricity

[21] Electricity consumption (Figure 16) is lower than Electricity generated (Figure 15) due to station load and system losses.

[22] UK Grid Prepares to Pay Firms Cash to Cut Power Use Next Winter, Bloomberg, 30 June 2022

demand they will be able to cut next winter (2022/23) to help keep the lights on and how much they would need to be paid to reduce operations. National Grid floated a price range for potential payments, ranging from £100 a megawatt-hour to as high as £6,000, according to the document.

A.2.3 Use or planned use of Loads and DSR

History of DR

In the pre to mid-2000's there was limited DR usage in the UK. From the mid 2000's an increase in DR began due to coping with climate change targets, security of supply and efficiency concerns[23].

The Short Term Operating Reserve (STOR) operated by the UK National Grid SO has comprised the primary market for DR, with STOR capacity awarded by tenders.

The other market mechanism for DR participation has been through Frequency Response, either by:

- Firm Frequency Response (FFR) - provides firm provision of Dynamic (continually matching) or Non-Dynamic Response (set points) to changes in Frequency; or
- Frequency Control by Demand Management (FCDM) - provides frequency response through interruption of demand customers. The electricity demand is automatically interrupted when the system frequency transgresses the low frequency relay setting on site.

Table 7: Market programme participation parameters

Programme	Response time	Duration (max)	Minimum MWs	Trigger
FFR - Primary	2 to 10 seconds	1 to 2 minutes	10	
FFR - Secondary	Up to 30 Seconds	30 minutes	10	
FCDM	2 to 10 seconds	30 minutes	3	
STOR	Up to 20 minutes	2 hours	3	National Grid Request

Source: M Curtis, Overview of Demand Response Market, EPFL Workshop, 11 September 2015

DR payments from these mechanisms are as follows:

- FFR and FCDM run 24/7; returns are based on an hourly availability payment;
- STOR has two daily operational windows (~07:00-14:00 & ~16:00-22:00); returns are based on an availability payment and a utilisation payment; and
- STOR DR capacity is provided via 150-250MW of Load Reduction and 300-500MW from Load Replacement (using backup generators, CHP etc.).

The following deployment examples[24] highlight issues faced by DR participation.

[23] M Curtis, Overview of Demand Response Market, EPFL Workshop, 11 September 2015

[24] Taken from M Curtis, Overview of Demand Response Market, EPFL Workshop, 11 September 2015

Table 8: Example 1 - STOR using Generator Load Replacement

Overview: Uses client's backup generator to replace grid demand. Effectively appears as grid 'Demand Reduction' and is how the majority (>80%) of DR in the UK was being provided	
Benefits: • Creates revenue from an expensive non-revenue generating asset • Can replace the need for monthly testing -and cover costs of testing • Can meet the 2 hour duration requirement and 20 minute response time • Easy to install control and monitoring equipment	Issues: • Reliability of the generator: backup generators are often not maintained (or not fuelled) • Client trust: the building manager is often not happy with allowing external control of a building's generator • Running costs: no revenue from the STOR utilisation payment given assumed 'no load' running costs • Meeting DR expectations: the STOR programme requires committed reduction, 7 days a week in operating windows (~07:00-14:00 & ~16:00-22:00), reducing site's potential to the lowest demand level at these times

Table 9: Example 2 - STOR - turndown

Overview: **Temporarily turndown / off assets to reduce demand on the grid. This can be through turning off large HVAC systems, manufacturing lines, refrigeration etc.**	
Benefits: • Often can be implemented with no noticeable user impact -e.g. HVAC can be turned off for an hour without users knowing • Creates a new revenue stream and also savings from a reduced electricity bill • Promotes 'green' business credentials	Issues: • Hard to meet programme conditions: event durations can last up to 2 hours (normally less than an hour in practice) therefore risking non-delivery penalties or user impacts • Installation costs: installation can often be expensive due to individual asset control and each asset will only provide a small amount of turndown • Client trust and meeting DR expectations issues, as per Example 1

Table 10: Example 3 - FFR –Battery or Turndown

Overview: **Frequency response based programmes use an onsite frequency relay which triggers mains disconnection within seconds of meeting the trigger conditions –normally 49.7 Hz. Batteries are an obvious choice if available -or any asset that can respond within 30 seconds. Sometimes a combination is used, with short term response being handled by a battery while larger assets are turned down (e.g. as an HVAC system might take 5 minutes to meet reduction levels, a battery system is used for those first 5 minutes)**

Benefits:	Issues:
• Greater flexibility for participation through allowing for variable DR targets, set a week ahead • Fast response requires direct controls therefore drives fully automated solutions • Short event duration minimises any potential impact	• Meeting response times: fast response times (within 30 seconds) can make it difficult to find suitable assets • Client trust: can be hard to build trust in client's base given concerns about losing control of their assets • Monitoring requirements: frequency DR requires second by second monitoring - hard to achieve, without specialised monitoring hardware

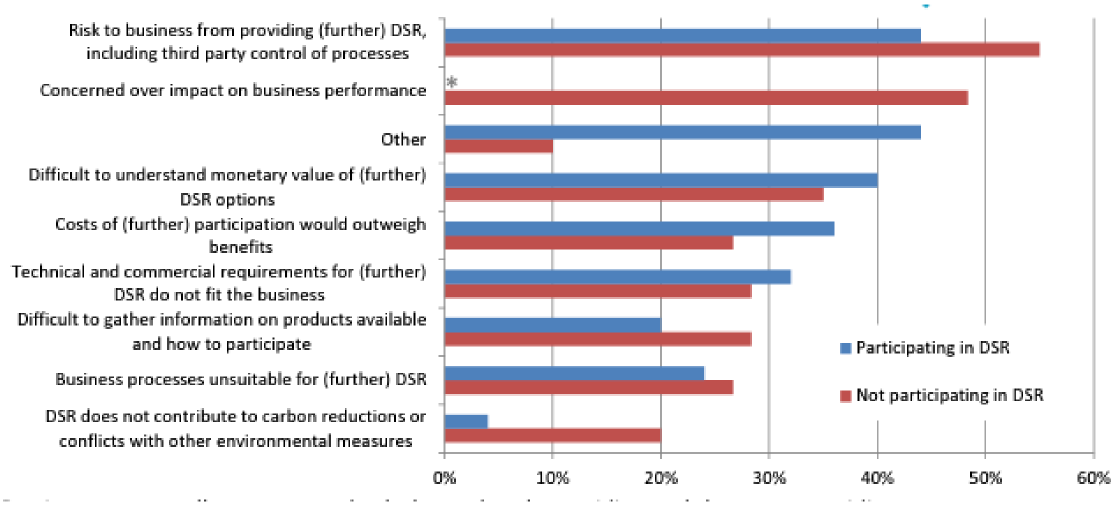
DR Potential and Barriers

In 2016, Ofgem surveyed large industrial and commercial consumers to assess the potential for DR in Great Britain and to identify barriers preventing greater flexibility. The conclusion of this survey were[25]:

- most of the C&I consumers currently providing DSR are industrial customers and have relatively high electricity consumption and peak demand;
- respondents cited a wide variety of sources for flexibility provision within their processes;
- respondents currently provide around 350 MW of demand reduction with over 400 MW of technically and commercially viable additional demand reduction potentially available;
- translated to a GB scale, the survey responses suggest a far greater untapped flexibility potential (c.3 GW for reducing demand and c.2 GW for increasing demand as a rough estimate);
- however, several barriers (refer Figure 17) are preventing a greater provision of flexibility, principally;
    - a perceived risk to primary business,
    - difficulty in understanding the monetary value of DSR options, and
    - commercial and technical DSR requirements not fitting the business.
- from a financial point of view, the majority of DSR providers value availability payments over utilisation payments, while for nearly half of non-providers there currently seems to be no financial incentive that would lead them to offering DSR services, possibly owing to concerns about potential disruption to business; and
- I&C customers generally have multiple routes to market for DSR services (refer Figure 18).

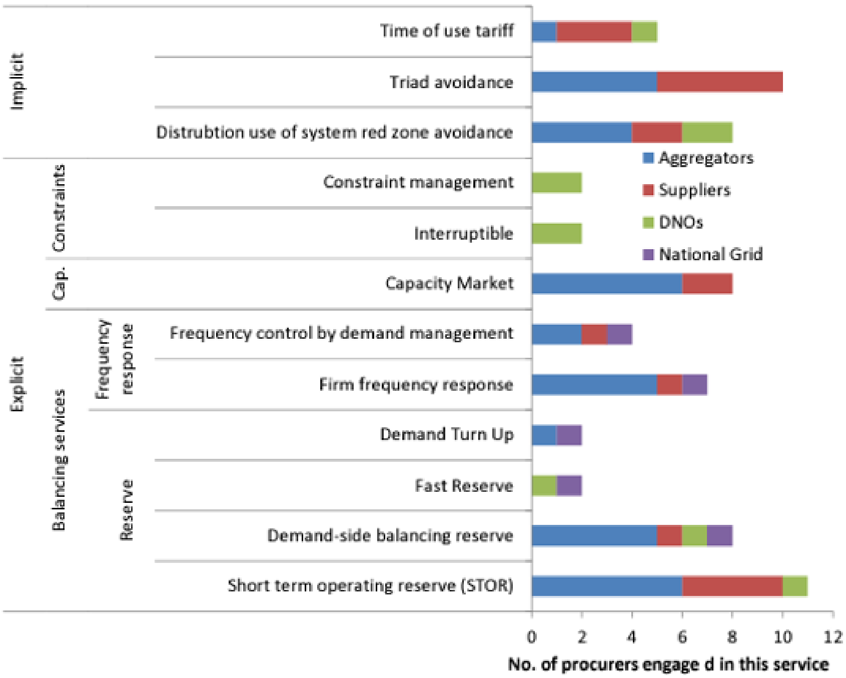
[25] Industrial & Commercial demand-side response in GB: barriers and potential, Ofgem, October 2016

Figure 17: Barriers to (further) DSR provision tend to be common to providers and non-providers (survey results)



Source: Industrial & Commercial demand-side response in GB: barriers and potential, Ofgem, October 2016

Figure 18: DSR services provided by procurers (survey results)



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Source: Industrial & Commercial demand-side response in GB: barriers and potential, Ofgem, October 2016

Promoting Awareness

“Power Responsive” is a stakeholder-led programme, facilitated by the National Grid Operator (ESO), to stimulate increased participation in DR and storage.

The stated role of Power Responsive is to:

- Raise awareness of DR.
- Shape the growth of the market in a joined-up way and ensure demand has equal opportunity with the supply side when it comes to balancing the system

More recent changes to DR participation have not been favourable

From 2018 (delivery) the new UK capacity market included provisions for DR. Initially this saw little DR success. In 2014 (for 2018 delivery) 49,258 MWs of capacity was awarded of which only 174MW was for DR. In addition, contract terms disadvantaged DR, with 15 year contracts granted for generation but DR contracts limited to 1 year. Recent awards for the Winter 2022/23 period paint an even worse picture for DR participation in the capacity market (see below).

The Major Energy Users Council presented the following 'scoresheet' on DSF[26] usage in the UK at the Power Responsive Summer Event, 13 July 2022. This is a salient reminder of the need to look beneath the headline figures.

Table 11: DSF Scorecard

Product	DSF results
Dynamic Containment	980MW of batteries
Firm Frequency Response (FFR)[27]	coming to the end of its life
STOR day-ahead	1.7GW, mainly gas fired generation (onsite CHP or backup generation to cover own load)
Balancing Mechanism	Very small amount of DSF
DSO schemes	Growing but through batteries and non-renewable generation
Capacity Market	Winter 2022/23: T-3; zero DSR; T-1; 154MW DSR but mostly batteries (25MW true DSR)
Triad Avoidance	1.3GW of reduction 2021/22 1.7GW of reduction 2020/22 Will end in April 2023

Source: Major Energy Users Council, 13 July 2022

The most successful DSF product, Triad Avoidance (based on trying to bring down energy usage during the three highest demand points in each winter period[28]) ended in April 2023 due to the introduction of the Targeted Charging Review which saw a significant shift towards fixed TNUoS charging, and the reduced variable component no longer being based on winter peak usage.

While DSF involvement in the balancing mechanism was "very small" it is interesting to note that since 2016 Demand Turn-up has been available as a non-BM balancing Service to encourage large energy users and generators to either increase demand (through shifting) or reduce generation when there is excess energy on the system – typically overnight and weekend afternoons.

At the DSO level there have been a number of recent initiatives such as the Interoperable DSR Programme but these are aimed more at small consumers to take advantage of an expected increase of EVs and smart appliances.

[26] DSF = Demand Flexibility Services. Effectively DSR (DSR) + battery storage.

[27] FFR is being phased out over 2023/24 and being replaced with New Dynamic Services.

[28] The triad periods are used to determine the allocation of peak Transmissions Network Use of System (TNUoS) charges. To mitigate against these charges companies and supplies tried to predict when the triads would occur and turn down their energy usage during these periods. DR was a key part of these Triad avoidance schemes.

New round of changes

The UK are currently in the process of launching new reserve and frequency response markets to provide the system flexibility required with the shift towards net zero emissions. It is too early to see if these changes will be effective in attracting a greater amount of DR.

A.2.4 How these arrangements relate to the WEM

The 2016 OFGEM survey which highlighted the perceived barriers to greater DR participation echoes similar comments that we heard from DSRWG members. The tree highest rated barriers that need to be overcome are:

- a perceived risk to primary business,
- difficulty in understanding the monetary value of DSR options, and
- commercial and technical DSR requirements not fitting the business.

THE UK also highlights the need for greater customer awareness of the potential for DR. The stakeholder-led programme “Power Responsive” is a useful illustration of how such an awareness campaign might work in the SWIS.

Also noteworthy, is how changes to one part of the market design (the TNUoS charging methodology in the case of the UK) can have large consequential impact on DR participation (although the underlying concept of triad avoidance schemes, while highly inventive, is not something we would suggest be replicated any where else).

A.3 PJM (USA)

A.3.1 Jurisdiction Overview

PJM is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia. It is one of the largest interconnected systems in the world (refer Table 12 below).

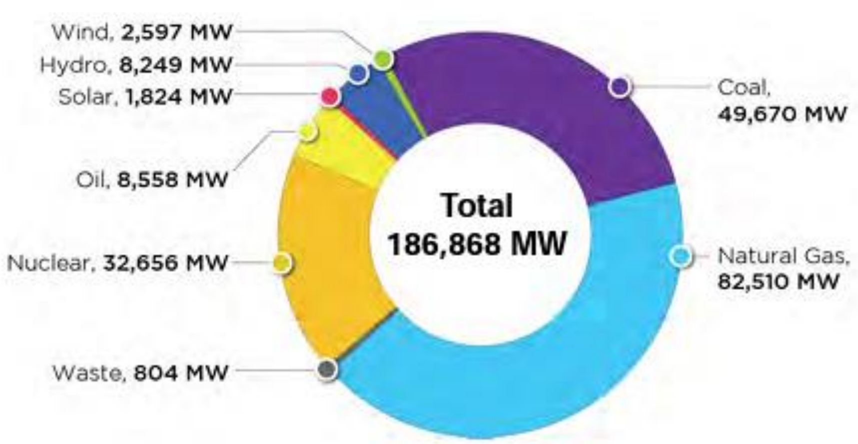
Table 12: Key statistics for PJM

Key Statistics	
Millions of people served	65
Miles of transmission lines	88,115
Generation of capacity in MW	183,254
Square miles of territory	368,906
Area served	13 states + D.C.

Source: PJM Factsheet

PJM operates a primarily thermal (coal, gas and nuclear) system with a small proportion (7%) of renewables (refer Figure 19 below).

Figure 19: Generation Mix – Installed Capacity

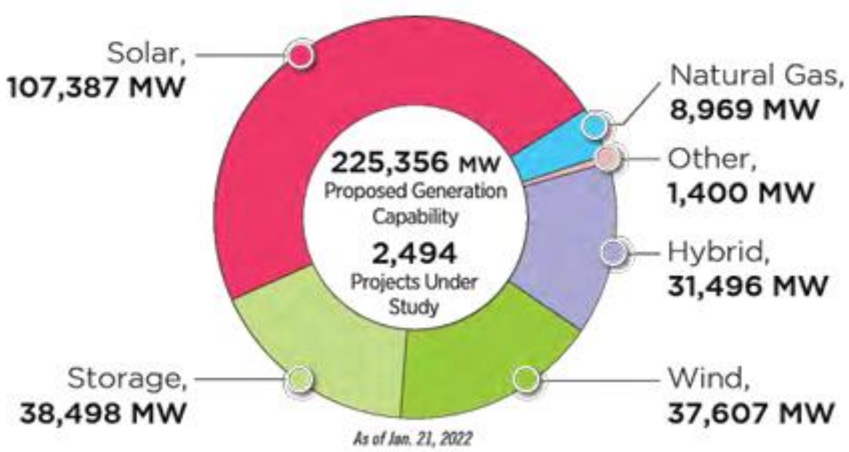


Source: Importance of Flexibility in a Changing Resource Environment, PJM, October 2022

A.3.2 Problems being faced or expected to be faced in the future

PJM is expecting a significant shift to cleaner resources in the PJM Region.

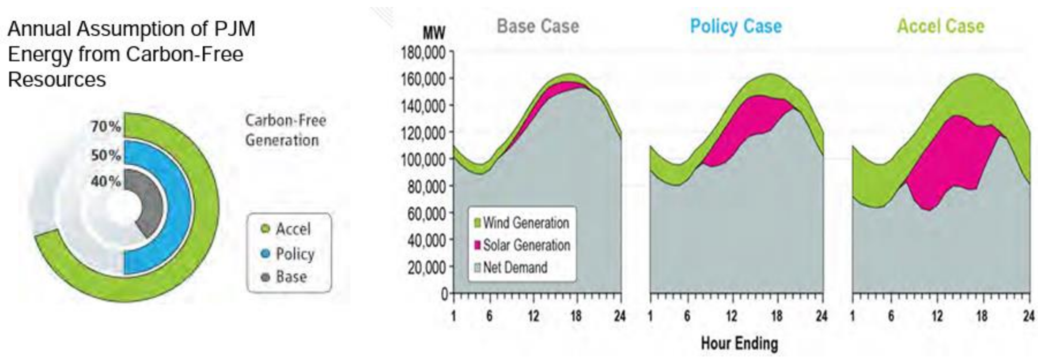
Figure 20: Current Interconnection Queue



Source: Importance of Flexibility in a Changing Resource Environment, PJM, October 2022

It has identified that peak load levels and ramping needs will shift with an increase in renewables (refer Figure 21 below).

Figure 21: PJM Study – Importance of Flexibility



Source: Importance of Flexibility in a Changing Resource Environment, PJM, October 2022

To cope with these challenges PJM has noted the role that DR can play, among many other solutions being considered. The potential solutions to enhance flexibility include:

- up and down regulation signals (minimises min gen impacts);
- sloped Reserve Demand Curves;
- demand response;
- regulation for wind/solar;
- enhance interaction of wind and solar forecast/bids/curtailment with constraint management;
- enhance forecasting;
- optimization of storage schedules;
- derate renewables with higher deployment;
- intraday unit commitment - more frequent updates, more granular;
- resource flexibility requirements; and
- research and new technologies.

A.3.3 Use or planned use of Loads and DSR

Beginning with customer trials in the early 2000's, PJM has been an early proponent of DR. DR is now offered by numerous Curtailment Service Providers (CSP) who pool smaller customers into a monitored demand response system and bid capacity on their behalf. These service providers were initially large energy service companies, but many have emerged which are specific to demand response services.

Significant review of DR in 2017[29]

The 2010's brought significant change to the PJM markets, including:

- those markets had evolved;
- grid operational needs had changed;
- the focus on resilience was increasing; and
- behind-the-meter technology had the potential to change the dynamics of markets and grid operations.

Therefore, in 2017 PJM undertook a review to consider the future direction of how DR was integrated into PJM operations, markets and planning.

The review findings were split across short-term goals (one to two years), medium-term focus (three to five years) and longer-term direction (five-plus years). PJM's strategic objectives for DR were to:

- ensure that DR was a predictable, reliable and transparent resource with which to manage the grid;
- enable more efficient market outcomes through price-sensitive demand; and

[29] Demand Response Strategy, PJM Interconnection, 28 June 2017

- increase alignment of wholesale and retail market incentives through coordination with state retail regulatory authorities.

CSP Model

The conclusion from the review was that the CSP model of DR participation in PJM wholesale markets had been successful, and this approach should be preserved for the foreseeable future.

Capacity and Ancillary Services Markets

It was recommended that DR should remain as a supply-side resource in the capacity and ancillary service markets. This approach was seen as a more effective way for customers to manage these costs and for the wholesale market to incorporate these load-reduction actions.

Energy Market

It was determined that the long-term view should be for DR capability to participate on the demand side of the energy market (i.e. they would not be compensated by the market but instead by the load-serving entity). PJM would look for opportunities to evolve in this direction through collaboration with load-serving entities and the state retail regulatory authorities.

It was reasoned that if retail customers received payments through the wholesale market then this would result in a subsidy when customers were already on a dynamic retail rate (i.e. they had already received the benefit of a lower energy price through their DR activity).

Short-Term Goals: Transition to Capacity Performance and Annual Capability through Aggregation

The implementation of capacity performance would be a major change in the DR capacity market availability requirements. Capacity performance requires DR resources to be available on an annual basis with the potential to dispatch for several hours during a day. PJM's short-term focus was on:

- transitioning DR to Capacity Performance (CP) requirements
- developing a DR dispatch model to optimize dispatch and release of DR
- reviewing DR and Price Responsive Demand (PRD) rules and consider integrating into one approach
- continuing to increase PJM operational visibility of DR
- implementing broader energy market changes (e.g., five-minute settlements, hourly offers, price caps)
- identifying any needed enhancement for Distributed Energy Resources that operate as DR; and
- Implementing mandatory training to ensure all CSPs are ready when DR is dispatched.

Medium-Term Focus: Ensure DR Capabilities Align with Commitments

As PJM transitioned away from customer-specific capabilities to portfolio capabilities (based on the new annual CP requirements), PJM would review existing rules and procedures and make changes where necessary to ensure PJM fully understood the DR capability. In the medium term, PJM would:

- ensure DR commitments reflect DR capabilities by developing and implementing:
    - more robust and comprehensive capacity testing requirements; and
    - synchronized reserve testing with enhanced performance measurement using the Customer Baseline Load approach;

- work with states and other stakeholders on other options to recognize the value of seasonal resource flexibility; and
- refine PJM's ability to dispatch DR by quantity and location.

Long-Term Direction: Explore Opportunities to Move DR in the Energy Market to the Demand Side

PJM would work with Load Serving Entities (LSEs) to determine how to enable more dynamic retail contracts to help align wholesale market prices with retail market prices or incentives and to help transition from wholesale energy market revenue on the supply side to retail energy cost savings on the demand side. In the long term, PJM planned to:

- collaborate with LSEs to support contracts/pricing that foster demand elasticity;
- explore and develop opportunities to move DR in the energy market to demand side (cost savings) by modifying or eliminating energy compensation;
- expand participation in ancillary services markets where performance is comparable to generation;
- foster or support investment and implementation of DR automation; and
- evaluate transitioning energy efficiency to the demand side (retail electricity cost savings) by eliminating capacity compensation.

How DR works in PJM

Following the 2017 review, there are two broad categories for customers to participate in PJM markets as DR, with the ability to participate as both:

Load management (Pre-Emergency and Emergency DR) providers make a commitment in the capacity market to reduce load when required by the system or receive a financial penalty.

Economic DR providers participate in the energy and ancillary services markets when it is economic for them. If the Economic DR offer price is less than the marginal price, they will be deployed similar to a generator.

The choice to participate in DR programs is voluntary. Participants must meet certain requirements in order to qualify for payments for reducing their demand for electricity. DR does not include reductions in electricity use that follow normal operating patterns or behaviour.

Qualified PJM Market Participants who act as agents, called Curtailment Service Providers (CSPs), help eligible customers identify opportunities and determine the equipment and systems required to benefit financially from DR participation in PJM markets.

CSPs aggregate customers' curtailment capability, register that capability with PJM, offer it in the appropriate market, submit load data to verify the reductions and receive payment from PJM. Subsequent allocation of PJM payment between the CSP and the retail customer is a matter of private agreement.

Demand Response in the Capacity Market

Most demand response activity in PJM takes place in the capacity market, called the Reliability Pricing Model. Both DR resources and Energy Efficiency (EE) Resources participate in PJM's capacity market. These resources can receive payments for committing to reduce electricity demand or for implementing energy-efficiency measures, such as more efficient lighting, heating and other building systems, up to three years in the future.

The ability to dispatch DR gives PJM greater flexibility to manage the grid during summer heat waves and other challenging conditions. In the capacity market, DR participants must reduce load when requested by PJM or receive a significant financial penalty.

Economic Demand Response in PJM's Energy and Ancillary Services Markets

Customers may participate as Economic Demand Response in the energy and ancillary services markets through a Curtailment Service Provider. Curtailment Service Providers will offer the load-reduction capability into the PJM Day Ahead or Real-Time energy markets. They may also offer into the ancillary services markets for shorter periods of curtailment flexibility – such as minutes or seconds.

Economic DR participants in the Energy Market will only be compensated for load reductions that are not part of normal operations. In other words, if the customer already manages their electricity usage to help lower their retail electricity bill, these reductions would not be eligible for compensation through PJM's energy markets.

PJM clears the energy and ancillary services markets on a least-cost basis based on the resources that are available. If a DR resource is competitive, it will clear in the market in the same way as a generator. Ancillary services participation includes Synchronized Reserve, Regulation and Secondary Reserves markets.

Level of DR utilised by PJM

DR participation is spread over many locations with a contribution over 10GW (refer Table 13 below).

Table 13: PJM Demand Response Report, May 2023

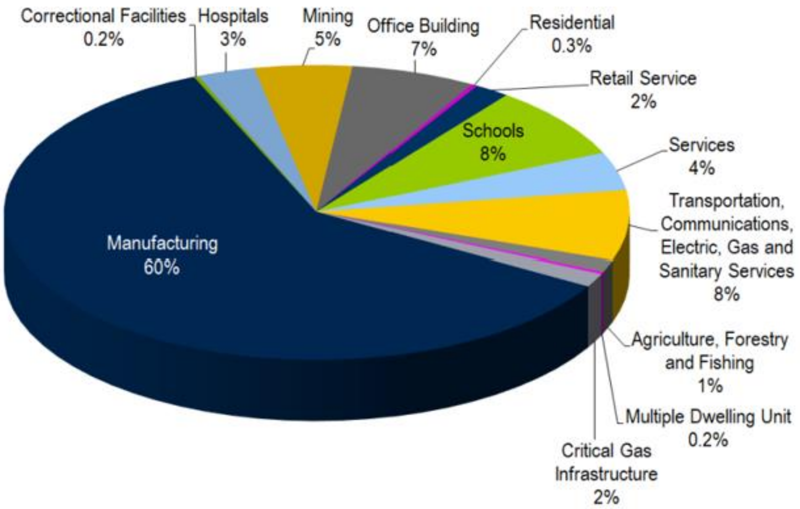
Type of demand response	# of locations	Capacity in MW
Economic	511	2,489
Load management	14,532	9,074
Price responsive	2,680	443
Total (unique[30])	17,425	10,595

Source: Load Response Activity Report, May 2023, PJM

PJM has seen its demand response program expand and diversify into many sectors and customer segments (refer Figure 22 below). On a megawatt basis, Manufacturing accounts for the highest demand response capacity in PJM's area, 60% of the total. Other important sectors for providing demand response services are Transportation, Communications and other public services (8%), Office Buildings (7%) and Mining (5%).

30 Locations may participate in more than one type of demand response.

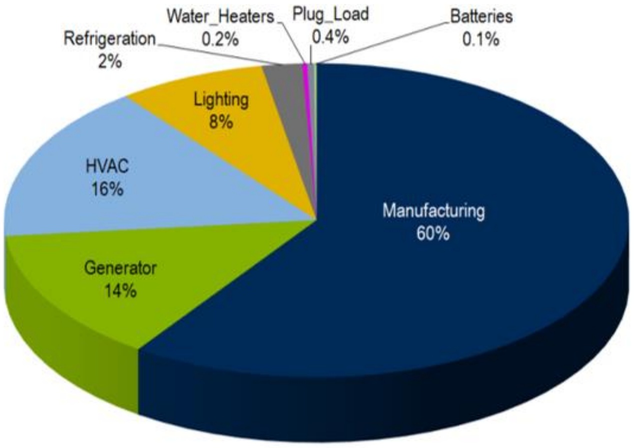
Figure 22: DY 22/23 Confirmed Load Management DR Registrations Business Segments



Source: Load Response Activity Report, May 2023, PJM

Participants also employ a range of sources to carry out demand response, although again Manufacturing (specifically adjustment of timing of manufacturing activities) is the most prominent method at 60%. Other sources and methods employed are: HVAC (16%), Generator (14%), Lighting (8%).

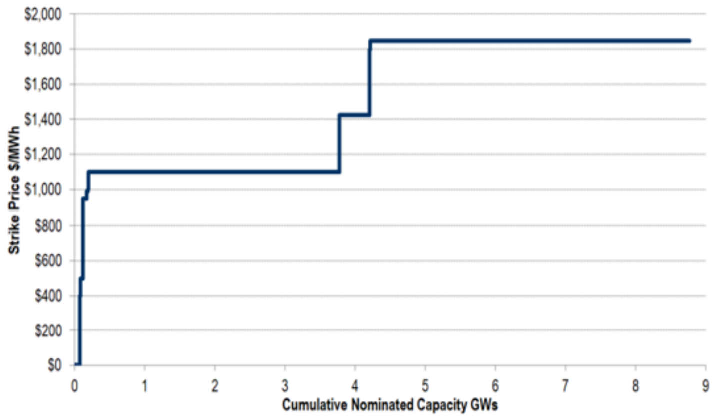
Figure 23: DY 22/23 Confirmed Load Management DR Registrations Customer Load Reduction Methods



Source: Load Response Activity Report, May 2023, PJM

The energy supply curve for demand response registrations (Figure 24 below) shows the range of strike prices for cumulative nominated capacity, with a majority bidding at either $1,100/MWh or $1,850/MWh.

Figure 24: DY 22/23 Confirmed Load Management Full DR Registrations Energy Supply Curve



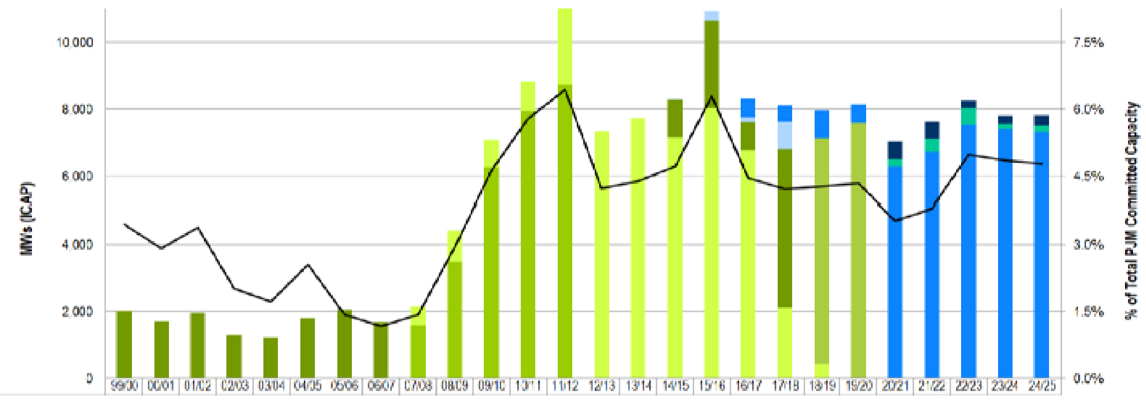
Source: Load Response Activity Report, May 2023, PJM

A.3.4 How these arrangements relate to the WEM

It is important to note that while PJM tried to distinguish between how DR is compensated in Capacity and Ancillary Service markets vs Real-time markets (as part of its 2017 review), it has not significantly advanced this. DR is still compensated by PJM (via the CSP) for the day-ahead and real-time markets, but a distinction is made for 'normal operations' as one would expect.

Following the 2017 review the performance obligations on DR were strengthened (to provide greater visibility and control to the RTO) but this does not appear to have significantly affected the level of DR participation as seen in Figure 25.

Figure 25: PJM DR committed MWs by delivery year



Source: 2022 DR Operations Markets Activity Report, PJM, 11 July 2023

A.4 New Zealand

A.4.1 Jurisdiction Overview

New Zealand is a small contained (no regional connectors) system. It operates an energy and reserve co-optimised market with 30-minute trading intervals. It has very recently moved from ex-post pricing to real-time pricing (ex ante).

The system is primarily renewable energy powered with a high dependency on hydro (refer Table 14 below). Demand growth is virtually non-existent with electricity consumption of 43.5GWh in 2022 being almost identical to that of 2010 (43.6GWh)[31].

NZ does not have a capacity market.

Table 14: Energy Mix

Fuel	Mar 23 Quarter	
	(GWh)	(%)
Net Generation (GWh)	10,134	
Hydro	6,018	59.4%
Geothermal	1,932	19.1%
Biogas	62	0.6%
Wood	109	1.1%
Wind	641	6.3%
Solar3	102	1.0%
Oil	1	0.0%
Coal	172	1.7%
Gas	1,086	10.7%
Waste Heat	11	0.1%
Renewable Share (%)		87.5%
Renewable Share (%) – Four-Quarter Moving Average		88.2%

Source: MBIE Electricity Statistics

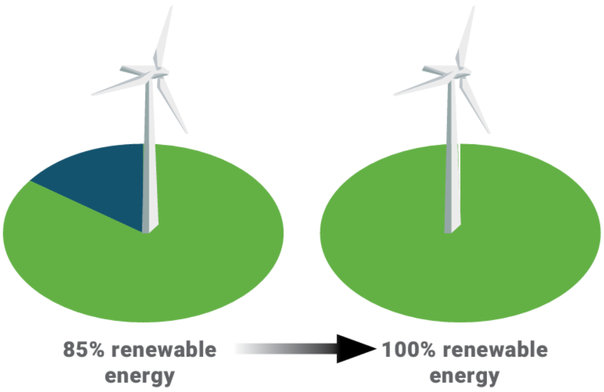
A.4.2 Problems being faced or expected to be faced in the future

Transition to a low emissions economy

Similar to many jurisdictions, NZ has ambitions towards greater low emission sources of electricity production.

[31] MBIE Electricity Statistics

Figure 26: Aspirational Renewables' Target



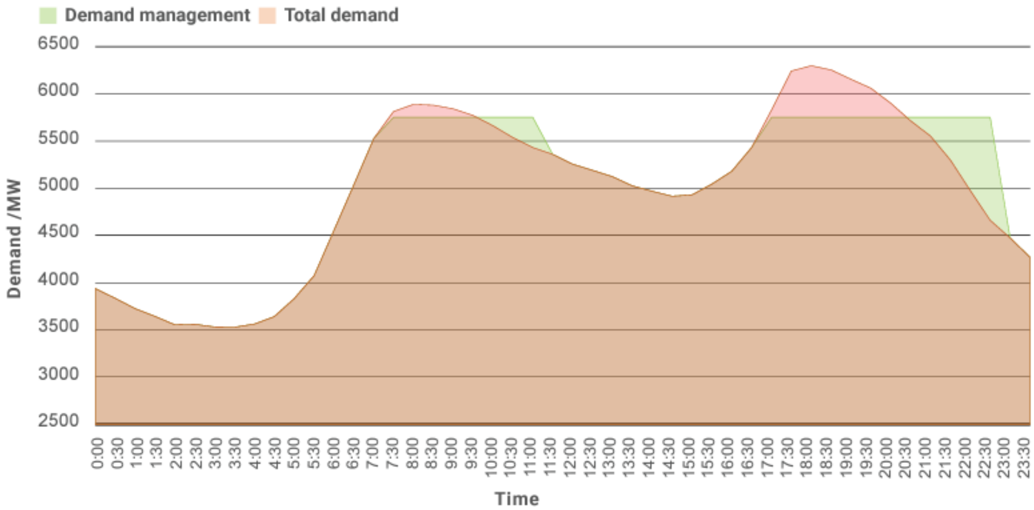
Source: Real Time Pricing, Electricity Authority, 2022

NZ already has very high levels of renewable energy but during times of peak demand requires energy powered by gas and coal to meet demand. NZ has aspirations (some- what ideological) to move to 100% renewable. However, with approximately 65% of generation hydrologically sourced, NZ's energy mix is prone to El Niño weather patterns. And, with increased solar and wind energy comes the problems of intermittency, including more volatile spot market pricing.

DR has been identified as a cost-effective way to manage volatility. By enabling demand response and Distributed Energy Resources to signal their price sensitivity in the wholesale market, spot market prices will be more stable and, on average, lower than they would otherwise have been[32].

Potential

Figure 27: Potential for demand management in New Zealand



Source: Real Time Pricing, Electricity Authority, 2022

A.4.3 Use or planned use of Loads and DSR

[32] Real Time Pricing, Electricity Authority, 2022

Current Usage of DR

At the smaller consumer level, NZ deploys ripple control of hot water cylinders (operating since the 1950s). This presents 987 MW of connected load for centralised control. At peak times, this is estimated to be 644 MW of controllable load.

At the large industrial end of the scale, DR takes the form of bidding Interruptible Load into the market and contracting with gen-tailers for reduced rates in power supply agreements in return for relinquishing some demand flexibility.

An example of this is the DR agreement between generator-retailer Meridian Energy and manufacturer New Zealand Aluminium Smelters Ltd (NZAS). This smelter is the largest single load on the New Zealand electricity grid, accounting for approximately 11-13% of national demand. This was negotiated as part of the overall preferential supply agreement and allows for Meridian Energy to give notice to NZAS to reduce consumption according to specified terms.

Voluntary demand reduction

NZ also operates a voluntary demand reduction scheme through Official Conservation Campaigns (OCC). An official conservation campaign is a period during which the system operator calls on New Zealanders to voluntarily reduce their electricity usage. An OCC is required when the risk of electricity supply shortage) exceeds 10% and is forecast to continue to do so for at least one week.

Running in conjunction with official conservation campaigns is the Customer Compensation Scheme (CCS). This is enforced through the Electricity Industry Participation Code which requires electricity retailers to have CCS. The CCS requires retailers to pay their qualifying customers financial compensation for their reduction in electricity usage if the system operator has commenced an OCC. Passing the obligation for compensation to the retailer is intended to:

- incentivise retailers to manage their spot price risk appropriately – through appropriate hedges – to avoid an OCC (and therefore avoid paying compensation); and
- incentivising generators to invest in last-resort dry-year generation (to fulfil their hedge obligations).

Proposed Enhancements to DR

As part of moving to real-time pricing in 2022-23 more DR and DER participation were seen as a key value contributor.

Table 15: Staged rollout of Real-Time Pricing

Date	Introduces
1 November 2022	From 1 November 2022 wholesale market pricing is calculated in real time. The settlement price for each trading period will be calculated at the end of the trading period and published immediately. Retailers are able to reliably develop new products and **consumers who are on plans where they buy from the spot market, will for the first time be able to make decisions on prices that they will actually pay.**
27 April 2023	From April 2023 the dispatch notification product will enable the inclusion of Distributed Energy Resources and aggregated demand management in the wholesale market, subject to approval by the system operator. Enhancements to dispatchable demand will allow large industrial consumers to bid in demand management in a way that better suits the physical constraints of their plant and processes.

Source: Real Time Pricing, Electricity Authority, 2022

Some of the benefits expected of the new DR participation in the market include:

Area/Consumer Group	Benefit
Residential and light industrial customers–	Can reduce their electricity bill, by the use of smart technology that will give retailers or a third party the ability to adjust their consumption according to cost.
Large industrial customers	Can manage their exposure by having part of their load based on fixed price and the other part on demand response and bidding that demand response into the wholesale market.
Improve price forecasting	Actively participating in the market, as opposed to passively responding to published prices, will lead to more stable and certain pricing outcomes.

Source: Real Time Pricing, Electricity Authority, 2022

It is too early to assess what level of DR these market changes will attract (if any).

A.4.4 How these arrangements relate to the WEM

It is useful to see that NZ has identified DR as a cost-effective way to manage the increased system volatility caused by the transition to increased levels of intermittent renewables. However, much of the ability for DR to play this role was only introduced very recently with the April 2023 shift to real-time pricing in the wholesale market. Much of NZ's plans in this area are exactly that – plans.

The voluntary demand reductions through the Official Conservation Campaigns (OCC) are useful to note as a potential way for incentivising DR participation in the WEM. Also, interesting to note is the way the obligation is placed on retailers to compensate customers during these campaigns. However, anecdotal evidence would suggest that the level of response is more due to a willingness to make a social contribution rather than any incentive paid.

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Agenda Item 10: Meeting Schedule for 2024

Market Advisory Committee (**MAC**) Meeting 2023_08_31

1. Purpose

MAC members to approve the schedule for the MAC's 2024 meetings.

2. Recommendation

That the MAC considers and approves the proposed MAC meeting dates for 2024.

3. Process

The MAC usually meets every six weeks, commencing in February of each year. The MAC Secretariat has developed, in consultation with the Independent Chair, the proposed schedule for MAC meetings for 2024, where practicable timing these meetings to avoid public holidays and school holidays.

The MAC is asked to consider and approve the proposed schedule for the 2024 MAC meetings.

Month	Proposed MAC Meetings
January 2024	
February 2024	9:30am on Thursday, 8 February 2024
March 2024	9:30am on Thursday, 21 March 2024
April 2024	
May 2024	9:30am on Thursday, 2 May 2024
June 2024	9:30am on Thursday, 13 June 2024
July 2024	9:30am on Thursday, 25 July 2024
August 2024	
September 2024	9:30am on Thursday, 5 September 2024
October 2024	9:30am on Thursday, 17 October 2024
November 2024	9:30am on Thursday, 28 November 2024
December 2024	