Minutes

Meeting Title:	Demand Side Response Review Working Group (DSRRWG)
Date:	5 July 2023
Time:	9:33 AM to 11:31 AM
Location:	Microsoft TEAMS

Attendees	Company	Comment
Dora Guzeleva	(Chair) EPWA	
Toby Price	AEMO	
Alicia Volvricht	AEMO	
Devika Bhatia	Economic Regulation Authority	
Claire Richards	Enel X	Joined 10:13 AM
Thomas Marcinkowski	EPWA	
Mitch O'Neill	Grids	
Bobby Ditric	Lantau Group, Consultant	
Dave Carlson	Lantau Group, Consultant	
Tom Higgins	Perth Energy	
Erin Stone	Point Global, observer for EPWA	
Tessa Liddelow	Shell Energy	Joined 10:01 AM
Graeme Ross	Simcoa Operations	
Chris Alexander	Small-Use Consumer Representative	Joined 9:44 AM
Noel Schubert	Small-Use Consumer Representative	
Justin Ashley	Synergy	
Peter Huxtable	Water Corporation	
Valentina Kogon	Western Power	
Apologies	**From**	**Comment**
Oscar Carlberg	Alinta Energy	
Dimitri Lorenzo	Bluewaters Power	
Jake Flynn	Collgar Wind Farm	
Michael Zammit	Integrated Management Services	
Wayne Trumble	Newmont Mining	
George Martin	Starling Energy	Apology

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1	**Welcome** The Chair opened the meeting at 9:33 AM with an Acknowledgement of Country.
2	**Meeting Apologies/Attendance** Noted as per the attendance record above.
3	**Consumer Law Statement** The Chair drew members' attention to the *Competition and Consumer Law Obligations* document circulated prior to the meeting. The Chair encouraged members to read the document carefully, and to raise any issues with the Chair immediately should they arise during the course of the working group deliberations.
4	**Agenda** The Chair outlined the four broad issues for discussion by the working group at this meeting: • Constrained access for loads – Consideration of the future role of runback schemes and the required level of transparency in their integration in various market components. • Hybrid facilities – Consideration of potential current and future configurations of hybrids, whether each scenario is possible and how any barriers to those configurations can be removed where appropriate. There will also be discussion on how to provide the opportunity for value-stacking but not allow double-dipping. • Minimum demand support – Consideration of what services could address minimum demand issues, and whether we need to do more to incentivise load shifting and/or increasing load during low demand. • Demand Side Programme (DSP) obligations – Consideration of how we should design an efficient dynamic baseline and address the potential for gaming.
5	**Constrained access** The Chair invited Mr Ditric to provide an overview of the issue to the working group. Mr Ditric stated that: • Western Power has been connecting customers (generators and loads) in congested areas of the network under runback schemes for some time. These customers are connected and curtailed on a pre-contingent basis (i.e. curtailed before a network constraint occurs). • Constrained connections are likely to occur more in the future as loads seek connection in more congested parts of the network, and connecting a customer to a runback scheme is quicker and cheaper than reinforcing the network. Mr Ditric asked Ms Kogon whether connection constraints for electric storage resources (ESR) would affect a customer's ability to inject and/or withdraw. • Ms Kogon answered that constraints for customers with ESR would affect both withdrawal and injection depending on the mode of operation (i.e. whether they are operating as a load or generator at the time would determine the requirements that apply under the Technical Rules). She noted that Western Power is currently considering certain concessions when it comes to hybrid facilities. The Chair asked Ms Kogon to elaborate on situations in which ESR would be constrained in future for withdrawal rather than injection.

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- Ms Kogon answered that withdrawal could be constrained if a load was to withdraw/consume during the peak when there is a risk of the network being overloaded.

The Chair asked whether, in the unlikely event an ESR's withdrawal is constrained during peak, when prices are at the highest, whether Western Power would connect the customer under a runback scheme that both constrains injection at certain points and their withdrawal during the peak period.

- Ms Kogon took the question on notice on behalf of Western Power.

ACTION: Western Power to advise how constrained access schemes would work for ESR if it is required to constrain both their injection at certain times and their withdrawal during the peak period

Mr Ditric stated that, as the volume of constrained access schemes increases, the transparency around these schemes needs to increase so AEMO can have more visibility and more information can be made available to the broader energy sector.

The Chair asked whether thermal limits used in constraint equations for the purposes of the Reserve Capacity Mechanism (RCM) and the real time market (RTM) both take into account the presence of these schemes.

- Mr Price stated that real time constraint equations reflect a facility's contribution to network constraints given the operational condition. These may result in the constrained operation of the facility for both injection and withdrawal.

The Chair asked how this is taken into account in the Long Term (LT) PASA.

- Mr Price responded that the LT PASA reliability assessment applies for any facility, in that it considers the impact of network constraints on a facility's ability to supply demand.

The Chair asked whether, when projecting demand in the LT PASA, it may be necessary to consider that ESR may be constrained to serve that demand under certain scenarios at peak times.

- Mr Price confirmed that this was the case.

The Chair asked how this is done.

- Mr Price took the question on notice highlighting that the assessment for the 2023 LT PASA was still being finalised, and that it is the first cycle in which storage was participating.

ACTION: AEMO to advise how an ESR with constrained consumption is, or will be, taken into account in the reliability modelling as part of the LT PASA

- Mr Schubert asked whether there was a situation in which a constraint may bind where an ESR is withdrawing from the network but the local load is not, and how that would be accounted for in constraint equations.

The Chair responded that constraint equations account for withdrawals or load on the left side of the constraint equation and injections or supply on the right.

- Mr Price added that:
  - Constraint equations are capable of managing withdrawal and injection of ESR.
  - RTM constraint equations include line flows and relative changes for facilities participating in dispatch, and make sure any thermal and non-thermal limits are respected based on the change in dispatch.
  - Load is reflected in the line flow meaning the operation of a facility would be limited by the demand at the time.

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	The Chair noted that Mr Alexander had asked: “How widely used are runback arrangements now?” in the meeting chat. The Chair answered that the network is constrained in many of the sub-regions and, therefore, it is likely that until the network is reinforced constrained operation may become more prominent.
	
	• Ms Kogon noted she has an outstanding action to provide statistics on curtailable loads under runback schemes, but there have been unforeseen delays in obtaining such information. Ms Kogon addressed Mr Alexander’s question, stating her understanding was that:
	   ○ runback arrangements are not particularly prevalent and are done as an exception rather than the rule;
	   ○ Western Power offers runback arrangements to customers if the choice is whether to connect or not, however, the customer decides whether this is acceptable; and
	   ○ ultimately, runback arrangements only apply in parts of a network where there is a need to handle a specified network event.
	
	ACTION: Western Power to provide information on the prevalence of curtailable load arrangements
	
	Mr Ditric suggested that curtailable loads should be integrated all the way from the beginning to the end of their life cycle.
	
	Mr Ditric asked the group to consider whether there is a need to:
	   ○ standardise the treatment of curtailable loads in the LT PASA, system adequacy planning or capacity targets, and provide direction for AEMO in the WEM Rules;
	   ○ investigate how curtailable loads work in network access quantity (NAQ) calculations to ensure there is neither allocation of more capacity credits than is possible nor inaccurate reduction of the capacity credits or NAQs; and
	   ○ provide more clarity, direction, standardisation and transparency in relation to how curtailable loads are factored into the RTM optimisation and dispatch.
	
	• In relation to information provision, Ms Kogon provided a summary of how this information is currently communicated:
	   ○ For transmission connected customers under a runback scheme, operational information such as the size of the constraint, the size of the load and the constraint triggers is provided to AEMO by email.
	   ○ In respect of distribution connected customers or non-market loads, Western Power is limited by confidentiality obligations in the Metering Code, and the information able to be captured by the type of meter (e.g. accumulation or deemed accumulation meters).
	
	The Chair highlighted the need to change the Metering Code so that confidentiality is not applicable to exchanges between Western Power and AEMO, as the system cannot be secure and reliable without full transparency. The Chair noted this issue had also been raised in relation to Supplementary Reserve Capacity.
	
	The Chair asked for any objections to her suggestion, but there were none.
	
	• Mr Schubert reiterated that curtailable load arrangements, particularly those affecting peak and low demand periods, must necessarily be considered in all aspects of planning and forecasting from the RTM to the LT PASA. Mr Schubert stated his view that there is a deficiency when such arrangements affect important loads such as peak load and minimum load, yet are not taken into account in planning for more capacity.
	
	Action: EPWA to propose changes to the Metering Code to allow confidential information to be shared between Western Power and AEMO for market purposes and for these to be consulted on in the DSR Review consultation paper

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6	**Hybrid Facilities**

Mr Ditric asked the working group to consider:

- Whether the rules currently allow hybrids with DSR to provide multiple services and give participants a number of options in choosing how to participate across markets and maximise value.
- Issues of double-dipping and inefficiencies in respect of hybrids.

Mr Ditric noted he would take the group through a number of examples to facilitate the discussion.

Example 1.1: ESR and on-site load (ESR no CCs, load reducing IRCR)

Mr Ditric stated that this scenario consists of an ESR and load. The ESR chooses not to receive capacity credits and the load seeks to reduce IRCR. Mr Ditric noted his view that this scenario is currently possible and should continue, and invited the group to provide views. The following points were raised:

- Mr Alexander asked if this scenario was hypothetical, given there are currently no registered hybrid facilities.

The Chair confirmed that there were currently no hybrids commissioned but they may exist in the future.

- Mr Alexander stated that while rules may allow certain things to be done, there are not many instances of anybody making use of them.
- Mr Schubert stated that this scenario should be encouraged because locating storage behind the meter provides demand leveling benefits for the whole system.
- Mr Schubert stated that locating storage only at strong transmission nodes does not help loads downstream in terms of evening out demand.

Mr Ditric asked how this should be encouraged.

- Mr Schubert responded that investors and retailers need to be incentivised by the right price signals, highlighting that the rules currently allow this and yet nothing is being done.

The Chair stated that there are questions as to how expensive it is to locate storage behind the meter vs how high the cost is of covering one's IRCR. If the equation is right, participants will invest. However, it is first necessary to check for barriers in the WEM Rules.

Example 1.2: ESR and on-site load ESR with CCs, load reducing IRCR

Mr Ditric explained this scenario as follows:

- The ESR has capacity credits but the load does not.
- The load switches off during intervals to reduce its IRCR and the ESR does not supply the load behind the meter.
- The ESR is available to the market and achieving all its capacity credit obligations and expectations.

Mr Ditric asked the working group to consider whether the rules allow for this scenario, and whether anything else needs to be done in respect of it.

The Chair referred to the discussion on this scenario at the previous working group meeting when it was agreed that a facility should not be able to receive capacity credits for the ESR as well as the ESR supplying the load to reduce IRCR. The Chair posed the question of what needs to be added in the WEM Rules and procedures so this particular behavior is identified in advance when the ESR is provided capacity credits.

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The Chair posed a related question of what information AEMO would need to in the certification process to assure itself that the storage facility is not going to double-dip in this way.

- Mr Price suggested two options:
  1. That load already exists and there would be information about the ability of that load to curtail.
  2. There is information provided to demonstrate the curtailability of that load. Perhaps there needs to be more explicit data provision to support that in the WEM Rules.
- Mr Price added that when a hybrid facility is operating in the market, the ability to meet the Reserve Capacity Obligation Quantity (RCOQ) means it will need to offer into the market to inject. This is net of any behind the meter consumption.

The Chair stated that there is a need to provide clarity in the WEM Rules and procedures what is expected of hybrid facilities.

- Mr Schubert stated that one way AEMO can know storage is meeting its obligations is to ensure AEMO can see its state of charge.

The Chair responded that the problem is that AEMO only looks at the next interval, rather than over the duration of the storage obligation.

- Mr Huxtable stated that loads currently have no obligation to reduce consumption for the purpose of IRCR, noting that sometimes a load may try this and fail.
- Mr Huxtable reiterated his concern that the WEM Rules should be amended to allow load and ESR to be measured and treated separately.

The Chair said that if upfront visibility is needed then proper measurements must be in place to ensure a storage facility is not used to reduce IRCR for load and at the same time receive capacity credits under the linear de-rating methodology.

- Mr Price stated that the current sub-metering arrangement do not capture load behind the meter because the facility is dispatched as a whole, net of that load.
- Mr Price stated that his understanding was that if there is more than one technology type behind the meter each becomes a separately certified component.

The Chair summarised the discussion as follows:

- There is a need to examine the procedure, subject to making sure participants have the choice to avoid the cost of a second revenue meter behind the connection point meter if that would be cost prohibitive.
- If participants are given a choice, metering and settlement calculations must change.
- Alternatively, provide a choice but ensure the facility does not benefit both from capacity credits and IRCR reduction if the storage facility is supplying the behind the meter load during IRCR intervals.

Action: EPWA to propose changes to allow a load and storage connected at the same NMI to be measured and treated separately, to be consulted on in the DSR Review consultation paper

<u>Example 1.3: ESR and on-site load (on-site load supplied by ESR)</u>

Mr Ditric explained that under this scenario an ESR with capacity credits is supplying the co-located load to reduce its IRCR. Mr Ditric noted that this scenario clearly fits within the definition of double dipping, and that it has been discussed by the working group before and clearly should not be allowed.

The Chair stated that the working group needs to ensure the rules and procedure properly treat this arrangement.

<u>Example 1.4: ESR and on-site load (ESR and load dispatched independently)</u>

Mr Ditric introduced this scenario stating that it is using submetering to dispatch and settle individual components separately. Mr Ditric asked for views on whether that option should be allowed. The following points were made:

- Mr Price identified three options of metering and settlement for separate components:
    1. A single meter with multiple components behind that meter, all collectively settled and all having combined obligations. Everything is netted through that meter.
    2. A single settlement point but multiple components being allowed to participate in the market as separate dispatchable units (the model used in the NEM), with settlement determined for each component. For example, a battery offers its injection and withdrawal into the market separately from a non-dispatchable load.
    3. Separate sub-metering owned and operated by Western Power, which allows registration of multiple facilities behind a single connection point.
- Mr Price asked which option the scenario was trying to address.

Mr Ditric answered that it was number 2.

The Chair stated in respect of Mr Price's three options:

1. A hybrid that has a storage facility and a load may still register as a scheduled facility, and the storage facility is able to offer and be settled in the market. However, it needs to be measured at the interface because this is an actual measurement of energy injection or withdrawal.
2. Two components separately metered behind the same connection point by sub-metering not owned by Western Power are not allowed to be settled separately as they are not measured by revenue-grade metering.
3. Option 3 is currently not provided for but would be allowed because the sub-metering is Western Power metering, so it would be suitable for settlement.

<u>Example 2.1: ESR and DSP (ESR – no CCs, smaller than registration threshold):</u>

Mr Ditric introduced this scenario stating that:

- it is a hybrid facility not receiving capacity credits for the ESR but having a DSP component which is receiving capacity credits; and
- the ESR therefore has no obligations but the DSP has capacity credits and associated obligations.

Mr Ditric noted his view that this is possible under the WEM Rules and should continue as there are no obvious problems.

The Chair compared this scenario with diesel generators behind the connection point in that the ESR can supply the load so the load receives capacity credits and its response is measured at the connection point.

The Chair asked for views on this scenario continuing to be allowed. There were no objections.

<u>Example 2.2: ESR and DSP (ESR – no CCs, larger than registration threshold):</u>

Mr Ditric introduced this scenario as the same as the previous scenario.

- Mr Price said that the only situation that could pose problems for this scenario is if the ESR is larger than the mandatory registration threshold. The facility would need to

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	- register as a scheduled facility and once it does that, it cannot have a DSP associated with it. The Chair asked if there is a DSP at the connection point, whether the participant should be given a choice as to whether to register as a scheduled facility or DSP. - Mr Price said that he would need to take the question on notice, highlighting that for a very large facility there is a question as to whether a DSP would be appropriate. Mr Price highlighted that the obligations around DSPs and scheduled facilities are dramatically different. The Chair noted that a DSP has the more stringent obligation as it has to be available for 12 hours versus 4 hours for an ESR. - Mr Schubert suggested that the obligation period should be based on what the system needs, rather than simply being a strict 12 hour time period. The Chair stated that this had already been consulted on and there was support for keeping the 12-hour obligation period. There was presently no proposal to change that period. The Chair asked AEMO to consider whether participants can be given the choice of registering a DSP with capacity credits instead of a scheduled facility if they have an ESR and a load behind the meter, and whether that poses any threat to system security. - Mr Price stated that while having flexibility for proponents to structure their facilities and their business cases to suit them is important, there is a need to establish whether there is industry appetite for those arrangements. The Chair asked how this is different to having a diesel generator in a building that is registered as a DSP, if the diesel generator capacity is higher than the maximum demand of that building. - Mr Price stated that in that scenario, it is only ever the diesel that delivers the DSP response. Here, there is controllable load that can reduce at any time but might prefer to use a battery, yet cannot deliver response solely from the battery because of the 12 hour obligations. **Action: AEMO to provide views on whether participants can be given the choice of registering a DSP with capacity credits instead of a scheduled facility if they have an ESR and a load behind the meter, and whether that poses any threat to system security.** <u>Example 2.3: ESR and DSP(ESR – no CCs, load also reducing IRCR:</u> Mr Ditric stated that in this scenario the ESR is not certified, and there is a DSP with capacity credits that is also trying to reduce its IRCR. Mr Ditric asked whether this scenario should be allowed, particularly whether it is double-dipping for the same load to receive capacity credits and IRCR reduction if the IRCR reduction period is outside the DSP 12-hour obligation. There was discussion between the Chair, Mr Ditric and Mr Schubert as to when 12 hour intervals would occur and whether the IRCR intervals could ever feasibly occur outside the DSP obligation intervals. Mr Ditric concluded the discussion by stating that it is not worth allowing this as it may never occur. No further views were provided. <u>Example 2.5: ESR and DSP (ESR – no CCs, supplies on-site load):</u> Mr Ditric described this scenario as a facility using ESR to assist in DSP dispatch outside the ESR's 4 hour obligation periods. - Mr Schubert said that this should be allowed.

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	The Chair noted the need to confirm whether or not this scenario is currently allowed. No further views were provided. <u>Example 2.6: ESR and DSP (dispatched and settled independently):</u> Mr Ditric explained that this scenario as using revenue grade metering to allow separate settlement of the ESR and the DSP for the facility. The Chair said that the ESR and DSP in this scenario need to be considered as two separate facilities. The Chair noted that the calculations WEM Rules need to be changed to allow settlement for the two meter values to be subtracted from each other. No further views were provided. <u>Example 3.1: ESR, Intermittent Generation and DSP (all have CCs):</u> Mr Ditric introduced this scenario as a hybrid facility with capacity credits but which is using intermittent generation to provide some self-supply while the DSP is dispatched. The Chair said that, for the purposes of the discussion on dispatch, there was nothing stopping this in the WEM Rules. • Mr Price asked whether the DSP is the right construct in this circumstance. The Chair noted that an ESR and a DSP cannot both have capacity credits if they are behind the same meter, as they cannot register two facilities. Participants may have a choice if AEMO agrees system security allows them to, either to register the DSP or ESR but they can't both be registered. The Chair stated, in respect of dispatch, that it is not relevant which component meets the obligation. • Mr Price confirmed that the obligation is injecting energy and unless there is an outage for a component, there is no stipulation which component needs to deliver this. The Chair stated that there is no recourse if the intermittent generator happens to fulfil part of that obligation and the ESR does not fully meet the obligation. The Chair added that the obligation can be met by either of those components. • Mr Schubert stated that, if there was Western Power metering on each component and that was used for settlement, capacity credits could be allocated for each component. The Chair clarified that, in that situation, there would be separate facilities that happen to be behind same connection point. • Mr Schubert stated that the intermittent generator does not have obligations but because it has been allocated capacity credits there is an unwritten expectation that it will be providing megawatts to the extent of these credits. If the intermittent generator happens to be generating at the time, the expectation is that it might be producing extra megawatts it could do what it likes with, for example charging its battery or helping the DSP to meet its obligations. The Chair asked whether Mr Schubert was saying that for hybrids that do not have metering on each component, the intermittent generator can fulfil the DSP obligations because it does not have obligations itself. • Mr Schubert confirmed this was what he was saying, but it does not seem fair unless the intermittent generator uses output above its capacity credit allocation to do so.
7	**Minimum demand support** Mr Carlson provided a summary of the issue, highlighting that the working group needed to look at the role DSR can play to minimise the impact of low load of the system, including to: 1. avoid or reduce the impact of minimum load; and

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2. provide an alternative response to maintain system stability.

Mr Carlson said that minimum demand can be avoided through load shifting, but highlighted that there must be the right incentives on the demand side. He noted that during low load times prices usually fall, so hopefully that will create a price incentive.

Mr Carlson asked whether, in the south west interconnected system it is normal for large loads to respond to price signals or fixed tariffs are more common.

- Mr Schubert answered that a lot of the large flexible loads do not currently receive a price signal to increase demand on minimum demand days.
- Mr Carlson posed further questions to the working group:
  - What kinds of loads exist in WA that can take advantage of lower prices?
  - How prevalent are high elasticity demand users, and what types of loads are they typically?
- Mr Schubert stated the following:
  - There are quite a few loads that could assist in increasing minimum demand, but this requires an aggregator or retailer to arrange this with customers and provide them with sufficient incentives. This would require tariffs and/or contracts to change to reflect minimum demand times.
  - AEMO should provide more information to the market closer to real time to indicate when there is likely to be an issue to incentivise response.

The Chair summarised the issues:

1. Whether the price is sufficient to incentivise the necessary behavior.
2. Whether a subset of the loads are capable of delivering what is required.

The Chair highlighted that the working group needed to know how many loads can actually reduce their own internal generation to expose the load to the system, and questioned whether:

  - these loads should be provided with additional incentives to do so and how much of an incentive would change the behavior; and
  - there are loads that can either reduce internal generation or increase their load to provide these services, and if so, what type of loads they are.

- Mr Schubert stated that there is already a retail tariff being offered to disadvantaged customers for free electricity at midday. That could be done by a number of aggregators and retailers.

The Chair asked if there were any obstacles to this that could be addressed by a change to the WEM Rules, noting it was not possible to interfere with commercial contracts.

- Mr Schubert stated that he was not aware of any barriers in the WEM Rules.
- Mr Graeme Ross stated that prices he has seen are in the RTM and most contracts are bilateral, so signals may not be reaching users except for large users. He, therefore, highlighted that aggregators and retailers needed to be incentivised to pass the signals through to users.

The Chair noted that AEMO has triggered Non-Cooptimised Essential System Services (NCESS) twice to provide these types of services, highlighting that if the price signal was sufficient they would not need to trigger an NCESS to get a response.

- Mr Price noted that the increase in intermittent generation in the future needs to be supported by a similar increase in discretionary demand, particularly when there is an over-supply situation. Mr Price asked whether such an imbalance is expected to be transitional, or a longer-term problem.

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The Chair asked whether storage charging during the day to fulfil its evening obligations would negate the need for other loads to increase their demand during low load periods.

- Mr Schubert responded that this would depend on whether the amount of storage exceeded the reduction in the minimum demand. He highlighted that there is not enough storage to keep up with the rate of solar PV growth but that, if the messaging to solar PV owners was right to encourage them to own the low demand problem, some would be prepared to respond to requests to reduce solar PV output.

The Chair asked whether we need an incentive, or just effective communication.

- Mr Schubert responded that we need communication and an incentive may also be needed providing that the cost of the incentive is less than the cost of procuring minimum demand services (through NCESS).

The Chair noted that, in the chat, Mr Huxtable had asked what AEMO is paying for NCESS. The Chair noted that AEMO would publish the costs of NCESS when the process was complete.

The Chair noted that the group wanted to understand what flexibility existed in the contestable customer space to manage minimum demand, including the types of load and its size, to better understand whether the market needs services that are more regular in this space.

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8 DSP obligations

Mr Carlson noted that the issue of dynamic baselines was already familiar to the group, highlighting that there had been significant discussion at the Market Advisory Committee (MAC) and other forums. He highlighted that the general consensus was that a dynamic baseline was more efficient and effective than a static baseline.

The Chair reiterated that a dynamic baseline was strongly supported, but asked the group what would be required in the WEM Rules to avoid gaming.

Mr Carlson stated that there were two ways to achieve this:

1. limit the loopholes to limit the possibility for gaming; or
2. rely on the regulator of deal with non-compliance after the fact.

The Chair highlighted that the primary goal of the new market arrangements is to prevent behaviour like this by design, i.e. to not rely on enforcement actions by the Regulator.

- Ms Richards considered that the potential for gaming is overstated, noting that with the long activation window there is no guarantee of dispatch, so it is unlikely the load will artificially increase consumption for such a sustained period of time. Ms Richards suggested referring to the NEM and making sure there is a rigorous baseline methodology.

The Chair asked Ms Richards to provide examples of how this works in other markets.

Action: EnelX to provide examples of how dynamic baselines work in other markets in which there are proactive rules and incentives as opposed to reactive compliance-based regimes.

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9 Next Steps

- Prepare slides for 2 August 2023 meeting and issue a week prior

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The meeting closed at 11:33 AM