AEMC

Australian Energy Market Commission

DRAFT RULE DETERMINATION

NATIONAL ELECTRICITY AMENDMENT (INTEGRATING ENERGY STORAGE SYSTEMS INTO THE NEM) RULE 2021

Proponent: AEMO

15 JULY 2021

DETERMINATION

INQUIRIES

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ABOUT THE AEMC

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

SUMMARY

1 As the electricity system transitions, energy storage is playing an increasingly important role and the regulatory framework needs to accommodate this shift. This draft determination explains the changes we are proposing to enable the integration of storage into the NEM.

2 On 23 August 2019, the Australian Energy Market Operator (AEMO or proponent) submitted a rule change request to the Australian Energy Market Commission (AEMC or Commission) seeking to amend the National Electricity Rules (NER) to define storage and introduce a new participant category, the bi-directional Resource Provider (BDRP), and apply storage-specific obligations. AEMO's proposal was intended to remove barriers and better facilitate the integration of storage and hybrid facilities into the national electricity market (NEM).

3 In response to the rule change proposal, the Commission has made a more preferable draft rule that introduces a new participant category, the Integrated Resource Provider (IRP), that will accommodate storage and hybrid facilities in a flexible and technology-neutral way. The more preferable draft rule also makes changes to the recovery of the non-energy costs framework that recognise many participants now have two-way energy flows, and will better reflect how participants use and benefit from the non-energy services AEMO procures to operate the power system in a safe, secure and reliable manner. A range of other changes are also proposed throughout the NER to remove barriers and better integrate storage and hybrid facilities into the NEM, and to update and streamline the NER.

4 The more preferable draft rule has been considered alongside the Energy Security Board's two-sided market work which is looking at simplifying the participation framework more holistically, with a move towards a services-based model and a single trader participant category in the future. The changes proposed in this draft rule solve the immediate issues relating to integrating storage that were raised by AEMO, and takes important steps towards the two-sided market future being developed by the ESB.

A future-focused framework for a changing market

5 The market is moving towards a future that will be increasingly reliant on storage to firm up the expanding volume of renewable energy as well as deliver the growing need for critical system security services as the ageing fleet of thermal generators retire. While the existing storage capacity in the NEM today is relatively small, it is forecast to increase significantly over the coming years (see Figure 1). It is therefore critical that this rule change not only resolves the immediately identified issues but that it creates a framework that facilitates innovation to supply energy reliably at the lowest cost to meet the long term needs of energy consumers.

6 In the short-term, the draft decision will remove barriers to storage and hybrid systems participating in the market and create a level playing field for all participants. This will primarily be achieved by introducing a new technology neutral participant category to accommodate participants with bi-directional energy flows. This new category will allow aggregators to classify small storage units and provide energy and ancillary services. The reforms will also level the playing field for all participants in relation to the recovery of non-

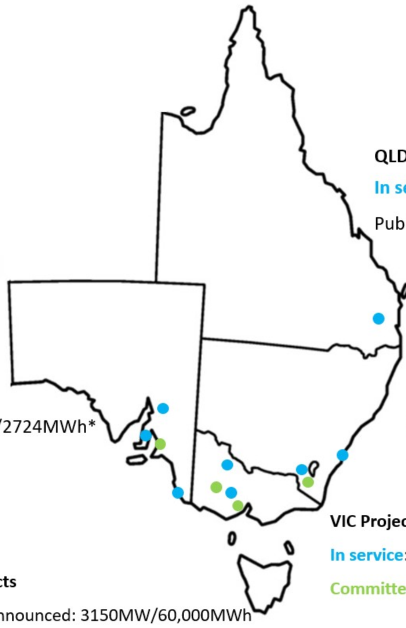
energy costs. This will remove distortions in the market that would otherwise become greater and increasingly drive inefficient behaviour and outcomes. These changes would open the market up to greater participation by both small and large batteries. Greater participation will likely lead to lower costs being passed onto end consumers through increased competition to supply energy and ancillary services. It will allow customers with generators or storage units (e.g. home batteries) to access a greater range of services and value.

7 In the longer term, these changes:

- are the first steps along the path towards a two-sided market in the NEM in which both demand and generation participants respond to price based on their cost preferences and technical obligations are placed on services not participant categories
- will facilitate innovative business models that deliver efficient market solutions to address reliability and security needs of the transitioning system
- will remove barriers to entry for more flexible resources and services in the future power system, including providing flexibility to accommodate new forms of participants such as small and large storage units embedded into hybrid systems as well as standalone
- provide a market signal to investors that the new category is being set up as the future universal category as outlined through the ESB's two-sided market work.

Figure 1: Existing and planned energy storage capacity in the NEM

Unit Status	MW	MWh
In Service	2,570.3	15,707
Committed	2,372	350,496
Publicly Announced	9,577	73,754



*AGL VPP, Armidale Pumped Hydro, Highbury Pumped Hydro Energy Storage, Kidston Pumped Storage Hydro Project, Snowtown North Solar Farm (BESS) and Tumut 3 do not disclose MWh and have been excluded

Source: AEMO's Generation Information Page. It can be accessed here.

Key issues raised in the rule change process

8 The Commission has engaged stakeholders through two rounds of consultation to date. After considering stakeholder feedback, the Commission considers that there are material issues to

be addressed to better integrate storage into the NEM. These issues are important to address, not only for current participants, but also to accommodate the greater amounts of storage and hybrid facilities that are expected to enter the market in the future. The Commission considers a number of key issues need to be resolved:

- The requirement under the NER for storage and hybrids to register in two registration categories. This is not only an issue in the registration process, but also for participation in dispatch, where storage units have to provide two separate bids (one from each registration category).
- The NER requirements for DC coupled hybrid facilities are unclear. In particular, it is important to clarify the scheduling requirements for hybrids that are DC coupled to facilitate the entry and participation of those configurations which can also deliver benefits to the system.
- How exempt batteries participate should be clarified and made more flexible. Specifically, it should be clear in the NER that exempt batteries can be included in the portfolios of aggregators and they should be able to provide ancillary services.
- The framework for the recovery of non-energy costs needs to be changed to ensure there is a consistent approach across participation categories and technology types in light of increasing bi-directional flows.

We are changing the rules to remove barriers to storage participation and facilitate future innovation

Registration and participation

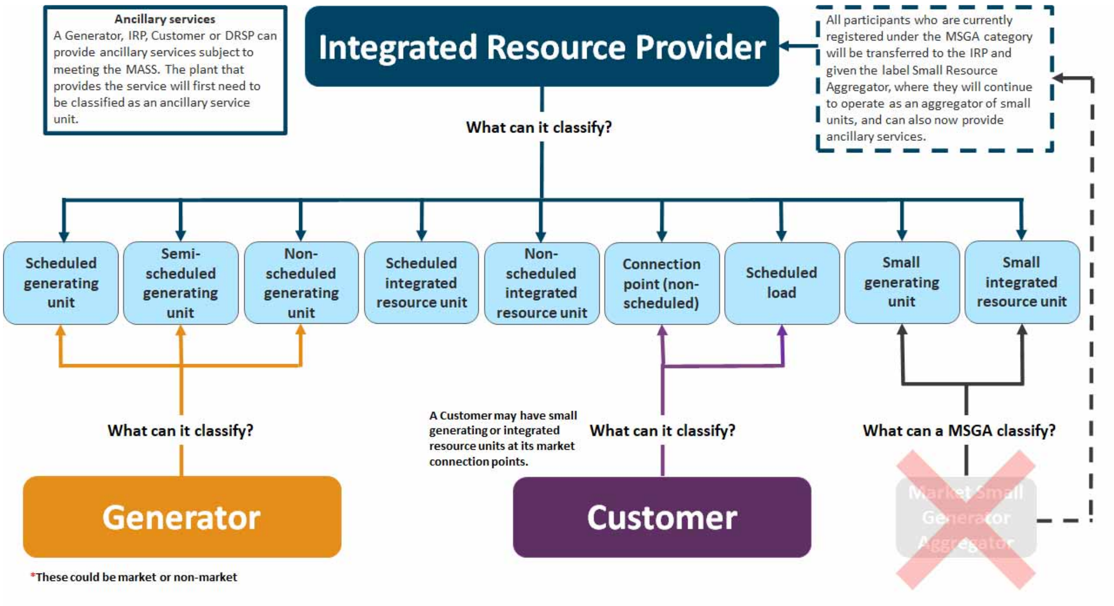
9 The Commission's draft determination includes the creation of a new technology neutral participant category, the IRP. It accommodates a variety of participants with bi-directional energy flows that may offer (and consume) energy and ancillary services. This includes grid-scale storage, hybrids and aggregators of small generation and storage units.

10 Introducing the IRP registration category also addresses issues raised by AEMO and stakeholders by:

- enabling storage and hybrids to register and participate in a single registration category rather than under two different categories. Figure 1 provides an overview of the classifications and services that can be provided by the new IRP category.
- providing clarity for scheduling obligations that apply to different configurations of hybrid systems, including DC coupled systems (with have different technologies behind a single inverter) who will have flexibility to choose whether those technologies are scheduled or semi-scheduled
- providing in aggregate dispatch conformance for hybrid systems, subject to system security limitations
- enabling batteries to participate in dispatch using a single dispatch bid, facilitated by the proposed new term in the Rules — the integrated resource unit (IRU)

- clarifying that the current approach to performance standards that are set and measured at the connection point will apply for grid-scale storage units, including where part of a hybrid
- transferring existing small generation aggregators to the new category
- enabling new aggregators of small generating units and/or storage units to register in this new category or as Market Customers
- enabling aggregators registered in the new category to provide market ancillary services from generation and load.

Figure 2: Classifications and services that can be provided by Market Participants



Recovery of non-energy costs

11 The Commission's draft determination amends the framework to recover non-energy costs based on a participant's consumed and sent out energy over relevant intervals, irrespective of the participant category in which it is registered. Consumed and sent out energy will be measured separately for all market participants and not netted at the connection point, or among a market participant's connection points. It would not include the energy produced and consumed behind the connection point, for example, rooftop solar production that is consumed on site.

12 This change provides a number of benefits. It:

- **Aligns cost recovery with the principle of beneficiary and causer pays** — The Commission considers the cost of services to support the power system should be funded by those who benefit from or cause the need for them. Under the current framework the increase in connection points and participants who have two-way energy flows has resulted in these participants being able to reduce their liability (without reducing the need for the services), while others pay more. The draft decision removes this outdated approach. It provides a forward-looking framework that incentivises participants to manage their demand for these services by recovering non-energy costs proportionally from those who benefit from or cause the need for them.

- **Stops inappropriate payments** — Non-energy cost calculations were not designed for Market Customers to be net generators, which can happen during some trading intervals when there is significant behind-the-meter generation. This results in unintended payments made to Market Customers rather than recovery of costs from them. The draft decision removes this unintended outcome.
- **Provides incentives for more efficient behaviour** — By charging participants based on an accurate accounting of their share of gross load (or generation, where relevant), some participants will be exposed to greater non-energy costs – reflecting the benefit they receive from, or their contribution to the need for, these non-energy services. This may provide stronger incentives for these participants, or their customers, to mitigate this cost by providing the service themselves, where possible. Other participants will see reduced costs, lowering their costs of participating in the market.
- **Aligns with a service-based approach**— assigns costs to participants based on the service they receive from the market and is an important step towards a (more efficient) two-sided market.

13 In addition, the draft rule provides a permanent solution to the settlement and equity issues raised by both AEMO and Infigen in separate rule change processes.

A summary of key parts of the draft determination

Table 1: **A guide to key parts of the draft determination**

TOPIC	DRAFT CHANGE	RATIONALE
Registration and participation	The changes to registration and participation include: • introducing a new participant category, the IRP • moving to a single Dispatchable Unit Identifier (DUID) for storage units and increasing the number of bid bands to 20 (10 bid bands for both load and generation) • allowing flexibility for DC coupled systems to register and participate as scheduled, semi-scheduled or both •	The draft decision combines a number of reforms that simplify the registration process for storage participants and allows hybrid facilities a clear avenue to join the NEM. In particular it: • enhances system reliability and security as it would encourage and promote the entry of new storage capacity that would help to firm up the growing amount of renewable energy in the market • allows greater flexibility in how small storage units can be used in the market

TOPIC	DRAFT CHANGE	RATIONALE
	• moving aggregators of small units (including existing small generator aggregators) into the IRP and allowing them to participate in the ancillary services market.	• aligns with the possible future direction foreshadowed by the ESB towards a trader-services model.
Recovery of non-energy costs	Two main changes: • The use of two new data streams in non-energy cost recovery – adjusted sent out energy (ASOE) and adjusted consumed energy (ACE). • Non-energy cost recovery would be based on a participant's gross energy flows, i.e. gross consumed energy (ACE) or exported energy (ASOE) during relevant intervals, rather than the category a participant is registered in.	The draft decision removes this outdated approach and provides a forward-looking framework that incentivises participants to manage their demand for these services by recovering non-energy costs proportionally from those who benefit from or cause the need for them.
Addressing inconsistencies in ramp rates	Set a minimum ramp rate at the lower of 3 MW or 3% of scheduled load capacity and remove the 6 MW threshold for aggregating semi-scheduled units. This would see a consistent minimum ramp rate set for: • storage and non-storage participants • load and generation units • scheduled and semi scheduled units, that have the same number of units and MW capacity.	This change would set minimum ramp rates in a way that would: • be more equitable for scheduled generation and load • make storage participation less complex • allow semi-scheduled participants to aggregate units above 6 MW • better align with the longer-term two-sided market vision (more consistent treatment of load and generation). The Commission considers a more equitable approach, where units of all sizes are treated proportionally, should be explored in a dedicated rule change on ramp rates in the future when more of the less flexible 'old fleet' of generators have retired.

TOPIC	DRAFT CHANGE	RATIONALE
The application of Transmission Use of System (TUOS) and Distribution Use of System (DUOS) charges	The draft rule makes minor amendments to provide additional clarity on three issues: • in the event of a dispute, the tariffs that a Distribution Network Service Provider charges for the provision of common distribution services for customers who are not retail customers should reflect its efficient costs of providing those services to the customer. • Transmission Network Service Providers must provide shared transmission services as prescribed transmission services if the prescribed service is sought by the connection applicant • the new market participant category, the IRP, will be treated as a Network Customer for the purposes of Chapter 6A in relation to electricity taken from the grid and so will pay TUOS for prescribed transmission services.	The rationale for providing only minor amendments is due to the Commission's view that the NER contain appropriate provisions on the treatment of TUOS and DUOS for generation and load: • For generation: The rules are clear that generators do not incur TUOS or DUOS charges. Changes to the rules for charging DUOS for exports are being considered in a separate process. • For load: While the rules are reasonably prescriptive both in form and process for load, they are designed to provide flexibility to negotiate different outcomes in certain circumstances.
Intervention compensation framework	The draft rule does not develop any unique arrangements for storage and hybrids in the intervention compensation frameworks, but does integrate the IRP market participant category into these frameworks.	The benefits of the draft rule are that it will: • provide that the intervention compensation framework is consistently applied across storage, hybrids, other generation and loads • allow for the Commission to consider how this framework applies to storage and hybrids through a parallel rule change process, which is specifically focusing on the intervention

TOPIC	DRAFT CHANGE	RATIONALE
		compensation framework.
Retailer Reliability Obligation (RRO)	The draft rule makes IRPs liable entities under the RRO, in respect of their load, if aggregate annual load exceeds 10GWh in a particular NEM region.	The draft rule will treat load of IRPs consistently with how load of Market Customers is treated. That is, any liable entity will be assessed to have a liable load where their aggregate load is greater than 10 GWh per annum.
Updating the language in the Rules	Changing definitions for load and generation, replacing all mentions of offer with bid in Chapter 3 of the NER and providing generic references to scheduled plants and market participants where possible.	The benefits of the draft rule are that it will: • improve the drafting of the rules by reducing the extent of technology specific, direction-specific and participant category-specific language • address the ambiguity of how certain terms and concepts apply to energy storage and hybrids • avoid implementing new definitions in the rules which are unnecessarily prescriptive on the direction of the flow of electricity.
Consolidating clauses in Chapter 2 that relate to ancillary services	This approach involves: • defining an umbrella term ('ancillary service unit') to replace the separate treatment of existing FCAS providers • allowing the relevant types of Market Participants to provide FCAS from this umbrella term in accordance with the Market Ancillary Service Specification.	The draft rule is more consistent with the ESB P2025 policy direction for a more developed two-sided market. This is because it creates frameworks that are more adaptable to change and better able to facilitate innovation.
Streamlining the Rules	Improving the drafting throughout the Rules, where necessary, in clauses that are being amended for the changes above.	The Commission agrees with AEMO that given the draft rule involves extensive drafting changes, it is also an opportunity to do a 'spring-clean' and fix drafting errors or improve the clarity of provisions that are also being amended for the reasons above. These changes will contribute to the overall coherence of the Rules.

Implementation and costs

14 The Commission notes the scope of this draft rule is extensive and, if implemented as final, would result in a number of changes for participants, especially those that currently have or intend to include storage or hybrid systems in their portfolios. However, the Commission considers this is a necessary change, as it would:

- reduce barriers and provide the right framework and incentives to encourage innovation in using storage and other technologies to provide consumers with reliable energy at the lowest cost
- help transition the market towards one that will be predominantly supplied by renewables as the ageing thermal fleet of generators continues to exit the market.

15 The draft rule, if implemented as final, would come into effect 18 months after the final determination is published on 28 April 2023. The Commission will continue to engage with AEMO and stakeholders to understand the work required to implement these changes and whether it would be appropriate for implementation to be staggered. The draft decision will also require all existing grid-scale storage participants who are currently registered as both Market Customers and Market Generators to transition across to the IRP participant category.

16 The Commission understands the draft decision will require changes to a number of AEMO systems, procedures and processes. AEMO has provided an estimated range of upfront costs for these changes of $19 million to $28.7 million. This is more than the $8 to $10 million estimated for AEMO's proposed solution, due to:

- AEMO's cost estimate in its rule change request for the BDRP did not include changes to the recovery of non-energy costs framework (which has been estimated at $5 million to $7 million)
- the number of additional changes made in the draft rule which affect AEMO's systems, procedures and processes.

17 The Commission considers the benefits of the draft decision are likely to outweigh the costs of the reforms and therefore the draft determination promotes the National Electricity Objective. The likely costs and benefits of the draft rule are discussed in further detail in Chapter 2.

18 The Commission will continue to engage with AEMO and stakeholders on the implementation timeline, benefits and costs prior to making a final decision in October 2021.

Next steps

19 The Commission invites submissions on this draft rule determination, including the draft rule, by **16 September 2021**. The consultation period is nine weeks. The Commission will provide a briefing on the draft determination prior to 16 September 2021.

CONTENTS

TABLES

FIGURES

1 AEMO'S RULE CHANGE REQUEST

1.1 The rule change request

On 23 August 2019, the Australian Energy Market Operator (AEMO) submitted a rule change request to the Australian Energy Market Commission (Commission) seeking to amend the National Electricity Rules (NER or Rules) to support the participation of energy storage systems as both standalone units and within hybrid facilities in the national electricity market (NEM). This included defining storage systems in the NER.

The Commission has completed two rounds of consultation on the issues arising in relation to this rule change request. The consultation paper and options paper stages are described below.

This chapter (**chapter 1**):

- outlines the rule change request
- explains its context and in particular, the relationship between the rule change request and the Energy Security Board's Post 2025 strategic policy direction
- gives an overview of the rule making process so far
- describes the process for providing feedback on this draft determination, including the draft rule.

Chapter 2 provides an overview of the Commission's analysis supporting the draft rules for the integration of storage into the NEM.

Chapter 3 sets out the Commission's draft determination, including how the rule change request was assessed against the assessment framework and the reasons for the Commission's draft determination.

The appendices provide more background information and a detailed overview of stakeholder feedback and the Commission's analysis. The appendices are arranged as follows:

- The trend towards a greater role for storage (**Appendix A**)
- Registration and participation framework (**Appendix B**)
- Recovery of non-energy costs (**Appendix C**)
- Network use of system charges (**Appendix D**)
- Drafting and other integration issues (**Appendix E**)
- Network service provider connections (**Appendix F**)
- DC coupled systems (**Appendix G**)
- Chapter 2 ancillary service provisions (**Appendix H**)
- Summary of other issues raised in submissions (**Appendix I**)
- The legal requirements under the NEL for the draft determination (**Appendix J**)
- Summary of the draft rule (**Appendix K**).

1.2 Key terms used in the draft determination

The following terms are used in this draft determination:[1]

- **Storage:** encompasses different electricity storage technologies such as pumped hydro, batteries (grid-scale and exempt) or flywheels. It is an alternative term to Energy Storage Systems (ESS) which AEMO uses in its rule change request. The Commission is no longer using Energy Storage Systems (ESS) to refer to storage because the acronym is used by the Energy Security Board's (ESBs) post-2025 market design in its work on Essential System Services.
- **Grid scale batteries:** batteries that are 5 MW and above, the owners, operators or controllers of which are currently required under AEMO's policy to register in the NEM as a Market Generator (the battery being classified as a scheduled generating unit) and as a Market Customer (the battery being classified as a scheduled load).[2]
- **Exempt batteries:** batteries less than 5 MW, the owners, operators or controllers of which AEMO exempts from registering in the NEM.[3]
- **Hybrid facilities:** a grid-scale facility that has a group of assets that are co-located behind a single connection point that allow a registered participant to both consume and export significant amounts of electricity from or to the grid. This does not refer to aggregators of small customers with solar panels and batteries.

1.3 Current arrangements

When the NER were first drafted there was little storage in the system and the concept of single connection points with the potential for significant energy flows in both directions was not anticipated. As a result the NER do not define storage technologies or the ability to have bi-directional energy flows. As a consequence there are no specific registration categories and classifications for storage units and hybrid facilities. This means that storage and hybrids must register in two separate categories. To clarify how storage units register and participate in the NEM, AEMO has developed the:

- *Registering a battery system in the NEM — fact sheet*, for grid-scale batteries (greater than 5MW).[4]
- *Registering a Hybrid Generating System in the NEM — fact sheet*, for hybrids that combine grid-scale generation and large batteries (greater than 5MW) behind a connection point.[5]

In addition to being required to register and participate under two different categories, non-energy costs are currently recovered from storage differently compared to other market participants. Non-energy costs are those associated with AEMO's role in operating the power

1 Additional defined terms can be found in the Abbreviations in Appendix I.

2 AEMO's policy is set out in its 2017 paper *Interim Arrangements for Utility Scale Battery Technology*, available on its website www.aemo.com.au.

3 AEMO, Integrating energy storage systems into the NEM - rule change request, August 2019, p. 9.

4 The *Registering a Battery System in the NEM* fact sheet can be accessed here.

5 Hybrid systems that contain large batteries are required to register as both a Market Generator and Market Customer. The *Registering a Hybrid Generating System in the NEM — fact sheet* can be found here.

system in a safe, secure and reliable manner. They are costs involved in managing the technical characteristics of the system through various market and non-market ancillary services and regulatory mechanisms. AEMO generally recovers the cost of these services and mechanisms from participants in proportion to the energy consumed or sent out in relevant trading intervals (currently 30 minutes).[6] Grid-scale batteries are charged based on the two participant categories in which they are registered (market generator and market customer). This results in charges incurred for both consumed and sent out energy (based on gross meter data with two data streams). Other registered participants including market generators, market customers and Market Small Generator Aggregators (MGSAs) are charged based on being registered in a single participant category, where the consumed and sent out energy is netted within an interval (net meter data with one data stream).[7] [8]

Other relevant arrangements for grid scale batteries and hybrids are set out below:

- Battery proponents are currently negotiating the application of "use of system charges" with network services providers at the distribution and transmission levels, on a case-by-case basis.
- Batteries are currently liable as Market Customers under the Retailer Reliability Obligation (RRO) (where their annual load exceeds the 10GWh threshold).
- Batteries are treated as both load and generation under the intervention compensation framework and so are compensated as though they are two separate participants.
- The treatment of storage as both load and generation also means that they are currently subject to two different marginal loss factors (MLFs), one MLF on the load side and another for the generation side.
- Batteries are required by AEMO to be scheduled for their load and generation, if above the 5MW threshold.
- Batteries must bid in separately for load and generation; they cannot combine this into a single bid.
- For hybrids, the scheduling and dispatch obligations depend on the individual technologies and hybrids are required to issue separate bids for each different technology within the hybrid facility. If for example, a hybrid facility contains a battery and a wind farm, it must bid the wind farm in separately to the battery's load and generation.
- The technical performance standards treat batteries as scheduled generation and load.
- Storage and hybrids are not explicitly represented on the Reliability Panel as they do not have a participation category that is represented on the Panel.

Smaller batteries that are less than 5MW are treated as generation and are currently included in the portfolios of MGSAs as though they were small generators. This treatment does not

6 A full list of the NEM non-energy costs and the parties from whom these costs are currently recovered can be found in Appendix C.

7 This net meter data provides an energy value for market settlement, fees and non-energy cost recovery calculations. This arrangement has been in place since the commencement of the NEM and is reflected in the NER settlement formula as adjusted gross energy (AGE).

8 AEMO, *Integrating energy storage systems into the NEM - rule change request*, p. 15.

recognise that batteries also have a load side and can also offer these services in addition to generation.

1.4 Rationale for the rule change request

In the rule change request AEMO sought to provide greater clarity for how new technologies and business models, such as batteries and hybrid systems, register and participate in the NEM. AEMO considered this to be important in the context of:[9]

- growing grid scale battery storage connections[10]
- increasing numbers of applications and interest in registering storage systems and hybrid facilities[11]
- an expectation that there will be a growing role for storage into the future.[12]

While AEMO has made changes to its processes to accommodate batteries and hybrids, AEMO says that issues remain because the NER create problems. In its rule change request, AEMO noted that categorising storage systems and hybrid facilities as both load and generation is having unintended consequences. The consequent impacts will be discussed in greater detail in subsequent chapters. However, in summary AEMO is concerned the current rules cause:[13]

- a lack of clarity in the NER for proponents regarding how to register and participate in the NEM
- increased operational complexity and inefficiency involved in treating a single asset as two components because the unit is treated as load and generation (in particular the need for storage to participate in dispatch with separate and simultaneous bids)
- possible issues where the technical requirements applicable at the grid connection point are not symmetrical for the same asset (for example ramp rates differ for the generation category compared to the load category)
- complicated IT arrangements for registered participants and AEMO
- difficulty for AEMO and other parties understanding and analysing market data, because it is necessary to reference two dispatchable unit identifiers (DUID) (one DUID for the generation category and one DUID for the load category) to understand the operation of the single storage asset
- uncertainty regarding the application of "use of system" fees at the transmission and distribution levels
- the recovery of non-energy costs not taking a technology neutral approach
- insufficient information provided on the limited energy capacity reserves of a storage system.

9 AEMO, *Integrating energy storage systems into the NEM* - rule change request, p. 4.

10 See Appendix A for information about the numbers of grid scale batteries.

11 See Appendix A for information about upcoming storage and hybrid projects.

12 See Appendix A for information about AEMO's recent reports regarding the expected role of storage into the future, including the *2020 Renewable Integration Study* and the *2020 Integrated System Plan*.

13 AEMO, *Integrating Energy Storage Systems into the NEM* - rule change request, p. 17.

AEMO argued that the above combine to make the registration process slower, more expensive, complex and uncertain for batteries and hybrids, and increase AEMO's administrative costs and could impact on its role as market operator.[14] In addition, AEMO suggested that the existing NER contain barriers to entry for storage and hybrid facilities. Given the importance of storage and hybrids in supporting variable renewable energy (VRE), this is an issue that needs to be resolved to help facilitate the current transition in the NEM.[15]

AEMO also considered that the NER need to be changed to better recognise bi-directional flows. AEMO noted that the NER were written for an industry that was structured around one way energy flows from large generators to customers. However, the NEM is increasingly characterised by two-way energy flows where participants are both buying and selling electricity.[16]

1.5 Solution proposed in the rule change request

AEMO sought to resolve the issues discussed above by proposing a rule (proposed rule) to define storage and hybrid facilities, so that the NER can better recognise storage and connection points with bi-directional flows. To do this AEMO proposed that the NER should establish a new registration category called a "bi-directional resource provider" that could accommodate storage and hybrids with bi-directional flows and enable:

- storage and hybrids to register in one participation category instead of two
- batteries to be treated as a single scheduled asset and able to submit both load and generation tranches in the same bid
- storage to be treated equitably compared to other participants in the recovery of non-energy costs
- batteries to be exempt from being charged transmission use of system fees (TUOS) and for it be clarified that they will continue to be charged distribution use of system fees (DUOS)
- any necessary updates to be made to the performance standards for the connection of batteries and hybrids to the grid
- batteries to be exempt for being liable entities under the RRO
- the intervention compensation framework to specifically take into account batteries and hybrids
- the representation of storage and hybrid facilities on the Reliability Panel, if considered appropriate.

In addition, the proposed rule specified that with the definition of storage units in the NER, it would be possible to clarify that smaller batteries (less than 5 MW) can be included in the portfolios of MSGAs.

14 AEMO, *Integrating energy storage systems into the NEM* rule change request, pp. 17, 18.

15 AEMO, *Integrating Energy Storage Systems into the NEM* - Rule Change Request, p. 54.

16 AEMO, *Integrating energy storage systems into the NEM* - rule change request, pp. 4-5.

More broadly, the proposed rule also sought to update the language in the NER, which has become outdated as a range of market participants have significant bi-directional flows. AEMO noted that the NER were written in the context of generators that primarily sent out electricity and customers that primarily consumed electricity. Now, generation can be part of a battery or hybrid system that also draws from the grid and customers have installed growing amounts of behind the meter generation, and so they also export in increasing quantities. The proposed rule seeks to update certain definitions, such as for "load" and "generation" to reflect bi-directional flows and help the NER to better reflect the evolving NEM.

AEMO's proposed solutions are discussed in the following chapter and in the relevant appendices in greater detail.

1.6 Relevant background

The question of integrating storage into the NEM is also a critical part of the ESB's Post 2025 market design work.[17] The policy question, which is being considered under the Post 2025 *Demand side participation and distributed energy resource (DER) integration* work stream, relates to how well the NER are able to accommodate new business models, bi-directional flows and the increasing importance of DER on the customer-side of the market. Encouraging greater participation of the customer side of the market can help to contribute to a more fully developed two-sided market.[18] A two-sided market delivers benefits such as improved efficiency and innovation, and customer benefits including better prices and more choice.

This section covers:

- the Commission's previous consideration of how best to integrate storage
- AEMO's earlier consideration of the issues
- the relationship with the ESB's Post 2025 market design initiative.

1.6.1 Commission's previous consideration of integrating storage

In 2015, the Commission recognised the increasing interest in, and application of, storage in the NEM and began a review titled *Integration of Storage: Regulatory Implications*. This review considered possible issues with the regulatory framework that may be acting as a barrier to the integration of storage.[19] Following consultation with stakeholders, the Commission found that the regulatory framework in the NEM was largely robust to this technology change and could accommodate the installation of storage across the electricity sector.[20] However, the Commission recommended that an interested party submit a rule change request to ensure the definitions of 'Generator' and 'generating unit' included storage. Subsequently, AEMO submitted this rule change request and in 2016, the Commission made this Rule.[21]

17 On 22 March 2019, the then COAG Energy Council tasked the ESB with developing advice for a long-term, fit-for-purpose market framework to support reliability which could apply from the mid 2020s. The tasking letter can be found here.

18 A two-sided market utilises quantity and price information from the demand and supply sides.

19 AEMC, *Integrating Storage: regulatory implications*, final report, 3 December 2015. Available here.

20 Ibid, p. iii.

The Commission again considered the issue of whether NER changes were required to better recognise and facilitate storage participation in the NEM in its 2018 *Coordination of Generation and Transmission Investment* (COGATI) review. The final 2018 report made some recommendations relating to storage, including that:[22]

- The appropriate NEM registration category that should apply to storage systems, and consequently how they should be treated within the regulatory framework, are issues that require long-term solutions.
- Greater clarity should be provided for storage system proponents and to remove operational inefficiencies for registered participants and AEMO.
- AEMO should submit a rule change request to create a new NEM registration category to accommodate storage systems.
- The rule change regarding a new participant category should also consider whether or not it is appropriate for storage systems to pay TUOS and the rule change request should consider what other regulatory obligations should be placed on participants registered under the new category for energy storage systems.

AEMO subsequently responded to the Commission's recommendation that it submit a rule change request to create a new NEM registration category and submitted its proposed rule, which is the subject of this draft determination.

It is also important to note that, while the Commission considered in its 2018 COGATI final report that there was a need to create clarity for storage proponents, in its earlier options paper for that review, the Commission expressed the view that a more holistic look at the registration categories in the NEM may be needed in order to:

- make sure that the existing participant categories in the NER sufficiently accommodate and support the participation of existing and emerging technologies and business models into the future
- reduce operational complexity and administrative burden for AEMO and participants.[23]

1.6.2 AEMO's Emerging Generation and Energy Storage initiative

AEMO's rule change request was informed by its *Emerging Generation and Energy Storage* (EGES) initiative. As part of this initiative AEMO discussed the challenges and issues for storage and hybrids registering and participating in the NEM. This consultation process included stakeholder workshops in December 2017 and March 2018, and a stakeholder paper published in November 2018.[24]

This engagement process asked stakeholders their views on AEMO's proposed solution including a definition for storage in the NER. The majority of stakeholder feedback supported AEMO's proposed model. Stakeholder feedback summarised in AEMO's rule change request

21 AEMC, *Registration of proponents of new types of generation,* final determination, 26 May 2016.

22 AEMC, *COGATI review final report*, 21 December 2018, p. 105.

23 Ibid p. 109.

24 These materials are available on AEMO's website here.

also shows there was support for including a definition for storage in the NER. Reasons provided by stakeholders included that such a definition would:[25]

- enable streamlining of the registration process
- reduce complexity for participation in the NEM
- reflect the changing technologies being connected to the grid.

1.6.3 Relationship with the Energy Security Board's Post 2025 market design

AEMO's proposed rule predates the current work of the ESB post-2025 market design, which is considering a move away from defining specific technologies and assets in the rules towards a technology-neutral approach that attaches obligations to services and activities. One of the objectives of the ESB's work is to promote a two-sided market design, which includes better valuing the latent demand flexibility already existing within the system and increasing the quantity of flexible demand that is emerging with the growth in DER. When the demand side can better respond to price signals, it behaves in ways that benefit the system, reducing load when prices are high and increasing when prices are low. This reduces the need for investments in peaking generation and unnecessary network infrastructure upgrades.

There are many issues that need to be addressed on the path to a two-sided market. One of the key challenges is removing barriers to entry for more active participation on both sides of the market. The ESB's policy approach is to create a participation framework that supports the development of a two-sided market that focuses on addressing the costs and complexity of market entry. This includes addressing the costs which are particularly burdensome for smaller participants. It also includes considering how to facilitate new business models and technologies, such as energy storage systems and those that involve aggregating customers' capability to provide demand response and other services, e.g. virtual power plants.

This is a similar objective to AEMO's proposed rule which seeks to remove barriers to entry for storage and business models that incorporate a mix of technology types, such as storage and different renewable generation, behind a connection point. Therefore, addressing the issues that AEMO has identified in its proposed rule can be considered as an important milestone on the path to a two-sided market.

However, the solution proposed in AEMO's rule change request, which was developed prior to the ESB post-2025 project, may not be consistent with the ESB's approach. The proposed design for a two-sided market promotes a "trader-service model", which could:

- Simplify the existing registration process in the NEM by accommodating existing categories (other than network service providers) in a single 'trader' category. This would be one universal registration category covering all commercial parties participating in the NEM (e.g. retailers, aggregators, generators, scheduled loads, ancillary service providers). This would enable 'traders' to deliver a range of services to customers without having to register in multiple categories.

25 AEMO, *Integrating Energy Storage Systems into the NEM* - rule change request, p 58.

- Provide for greater regulatory flexibility that supports innovation by seeking to attach obligations to services at connection points as opposed to attaching them to registration categories and assets.
- Enable new participation models that allow customers to obtain services from more than one trader at a site. For example, a customer may have a contract with a trader providing standard retail services for the end user’s uncontrolled load, and a separate arrangement with another trader that trades the end user’s DER output or controlled load and buys and sells services on their behalf in the wholesale market.

The NER have been amended in recent years to add new categories of registered participant, resulting in one entity potentially needing to register in different categories in order to provide a range of services. This generally adds complexity and potential ambiguity for market participants and new entrants. There is also increasing overlap of formerly distinct categories (e.g. Market Customers representing 'load' connection points can be net exporters of energy at some intervals due to solar and other DER uptake). The trader-services model is an alternative to *ad hoc* changes to accommodate new business models and technologies. It is a framework that reflects the broader changes occurring in the NEM, where market participants are increasingly both consumers and generators of electricity. The intention is to make the arrangements in the rules keep pace and facilitate the changes in participation in the market so they continue to be cost effective and meet the needs of market participants.

Additionally, the NEM arrangements, particularly for wholesale market participation, use ‘asset focused’ regulation. That is, participant categories (and the associated regulatory obligations) are based on the assets present, as opposed to the services bought or sold, at the connection point. This approach will become more complex as the number of services and service providers increase and new asset combinations emerge (e.g. hybrid facilities with load, generation and storage all behind a single connection point). The trader-services model allows innovations in services, without rigid market designs linking services back to physical types of generators, loads or storage devices. Technical capabilities and the set of services offered could then evolve without requiring incremental rule change processes.

The Commission has considered AEMO's proposed rule in the context of this broader reform. This has involved assessing additional solutions to AEMO's proposal to ensure that the NER are amended in line with the overarching policy direction. It is noted that implementing the trader-services model in full is a long-term reform that needs to be well sequenced and phased in over time. The draft rule is a step towards the trader-services model that is within the scope of, and addresses, the issues AEMO raised in its rule change request.

1.7 The rule making process

1.7.1 The Consultation Paper

On 20 August 2020, the Commission published a notice advising of its commencement of the rule making process and consultation in respect of the rule change request.[26] A consultation

26 This notice was published under s.95 of the National Electricity Law (NEL).

paper identifying specific issues for consultation was also published. Submissions closed on 15 October 2020.

The Commission received 38 submissions as part of the first round of consultation.[27] Stakeholders had mixed views on the best solution to deal with the issues AEMO identified and a number raised the link between the proposed rule and the ESB's post-2025 market design initiative. AEMO also raised further issues relating to storage in its submission, on which other stakeholders had not yet had an opportunity to comment.

1.7.2 The Options Paper

In light of the feedback and the link with the ESB's work, the Commission granted an extension of time for this rule change to allow further engagement on alternative solutions that better align with the two-sided market design.[28] The Commission also sought to consult further on several issues through an options paper. This paper was released on 17 December 2020 and submissions closed eight weeks later on 11 February 2021.[29]

Through the options paper, the Commission consulted further on the issues below:

- *Registration and participation*: The Commission sought feedback on four options for how storage and hybrid facilities could register and participate in the NEM. These covered a spectrum of options ranging from no change to more significant changes that attempt to move the market towards the trader-services model proposed in the two-sided market project.
- *Scheduling, dispatch, and performance standards*: The Commission sought feedback on how generation and load from storage and hybrid facilities should be scheduled and dispatched, and where performance standards should be set for hybrid facilities, i.e. at the connection point or the asset level.
- *Non-energy cost recovery*: The Commission asked how non-energy costs should be recovered from all market participants, including storage and hybrid facilities.
- *Additional storage-related issues raised by AEMO in its submission to the consultation paper:*
  - connection issues arising where the owner of a storage system is also the local network service provider
  - suggestions for simplifying the ancillary services provisions in the NER
  - opportunities to clarify how DC-coupled systems should register and participate in the NEM.

The Commission held a briefing and Q&A session for the options paper on 4 February 20201.[30] The Commission received 31 submissions in response to the options paper.

27 You can find the consultation paper and submissions to it on the project page here, under Initiation.

28 The date to publish the draft determination was extended to 29 April 2021. You can find the Notice of extension on the project page here.

29 The options paper and submissions on the options paper are on the project page here.

30 The briefing session slides on the options paper are on the project page here.

The Commission has considered feedback provided by stakeholders in submissions. Issues raised in submissions are discussed and responded to throughout this draft rule determination.

1.7.3 Further consideration of implementation

On April 29 2021 the Commission extended the time to publish this draft determination as AEMO requested more time to consider potential impacts from issues which it had previously not incorporated into its considerations, particularly on its operating systems and procedures.[31] AEMO has subsequently provided input on the cost breakdown of the key design features and this information has been included in Chapter 2.

1.8 Consultation on draft rule determination

The Commission invites submissions on this draft rule determination, including the draft rule, by **16 September 2021**. The consultation period is for nine weeks, longer than the standard consultation period of six weeks, due to the length and significance of the draft rule. The Commission will provide a briefing session on the draft determination prior to 16 September 2021.

Any person or body may request that the Commission hold a hearing in relation to the draft rule determination. Any request for a hearing must be made in writing and must be received by the Commission no later than 22 July 2021.

Submissions and requests for a hearing should quote project number **ERC0280** and may be lodged online at www.aemc.gov.au. You can access the 'lodge a submission' webpage here: https://www.aemc.gov.au/contact-us/lodge-submission

The Commission's guide for making submissions is at: https://www.aemc.gov.au/our-work/changing-energy-rules-unique-process/making-rule-change-request/our-work-3.

Please note, the Commission publishes all submissions on its website, subject to confidentiality requirements and certain other exceptions as noted on our submissions webpage. Please clearly mark any sections of your submission which you consider contain confidential material.

If you have any questions about this project, please contact either:

- Project leader: Joel Aulbury on (02) 8296 0648 or joel.aulbury@aemc.gov.au
- Project sponsor: Kate Wild on (02) 8296 0622 or kate.wild@aemc.gov.au.

31 AEMO's letter requesting the extension of time is on the project page here.

2 CHANGING THE NER TO ACCOMMODATE STORAGE

This chapter covers *why* the Commission considers the rules need to change and then sets out *how* the Commission considers they should be amended.[32]

2.1 Why the rules need to change to better integrate storage into the NEM

As outlined in chapter 1, AEMO considered that the Rules need to be changed to:

- remove barriers to the registration and participation of storage and hybrid facilities in the NEM
- provide clear obligations for storage and hybrid facilities
- create a level playing field between different technologies and participants in the NEM.

Stakeholder feedback on the issues AEMO has identified are summarised below, along with a summary of the Commission's analysis of why the rules need to change to better integrate storage and hybrid facilities into the NEM.

2.1.1 Stakeholder views on barriers to the participation of storage and hybrids

Stakeholder submissions in response to the consultation paper were generally supportive of the main objectives of the proposed rule. Most stakeholders agreed with AEMO that the existing registration process for grid scale storage is complex, duplicative and costly, and welcomed the opportunity to clarify and streamline the process.[33] Some stakeholders acknowledged the issues AEMO identified regarding grid scale battery participation in dispatch and the requirement for providing two separate bids, one from the market customer side and another from the market generator side. These stakeholders noted the possibility of dispatch conflicts and the difficulties this creates for interpreting market data.[34] Others did not consider these issues to be significant at present or considered that they could be managed through system and process changes, outside of the NER.[35]

Most stakeholders also saw benefits in making the registration process clear for hybrid facilities. Stakeholders suggested that hybrid facilities should be supported because they allow a greater flexibility for market participants as well as for the system as a whole.[36] In particular, most stakeholders support hybrids on the basis that they allow for a better use of excess energy where, instead of energy from VRE generators being curtailed, it can be stored and released into the network when it is needed.[37]

32 This chapter provides an overview, and further details on the draft rule can be found in the appendices.

33 Submissions to the consultation paper: AGL, p. 3; ARENA, p. 4; Citipower, Powercor, United Energy, p. 7; ENGIE, p.3; Essential Energy, p. 3; GE Hydro, p.15; Maoneng, p. 6; Enel X, p. 5; Fluence, p. 11; Tilt Renewables, p.1; Grids Energy, p.1; CEC, p.2; Tesla, p.2.

34 Submissions to the consultation paper: Infigen, p.1 and Monash Energy Institute, p.11.

35 Submissions to the consultation paper: Neoen, p.2; AGL, p.4; Origin, p.2; Tesla, p.4 and ERM Power, p.1.

36 CEC, submission to consultation paper, p. 2

37 Consultation paper submissions: Maeoneng, p. 5; Monash Energy Institute, p. 8; BECA p. 4, Tilt Renewables, pp. 1-2; UPC\AC Renewables, p. 4; Fluence, p. 10; Transgrid, p. 1.

AEMO also suggested in its rule change request that a lack of certainty relating to the application of TUOS and DUOS was also a possible barrier to entry for storage and hybrid facilities. Stakeholders generally agreed that uncertainty relating to the application of TUOS and DUOS was a barrier to entry although some Distribution Network Service Providers (DNSPs) did not agree.[38]

AEMO's submission in response to the consultation paper also raised two new issues relating to barriers for storage and hybrid facilities.[39] The Commission sought stakeholder feedback on these through the options paper. Stakeholder views are set out below:

- The first issue related to a lack of clarity regarding the scheduling requirements for a DC coupled system which, if not clarified, could be considered to be a barrier to entry for these types of hybrids. The stakeholders who responded on this issue considered that the scheduling arrangements for DC coupled systems warrants further consideration.[40]
- A second issue, which AEMO considered could be a barrier to the connection of grid scale batteries if not resolved, relates to issues with the approval process for connections of NSP owned batteries. Some stakeholders considered that there were issues that should be addressed regarding NSPs approving connections for their own batteries or else suggested changes to the proposed solution.[41] Other stakeholders did not consider this to be an issue.[42]

In relation to small storage units, most stakeholders who commented on the issue in the consultation paper generally agreed that the NER should clarify if MSGAs can classify exempt batteries in their portfolios.[43] Some stakeholders suggested that another barrier is that MSGAs are currently prevented from providing market ancillary services and that this should be addressed as part of the rule change.[44]

2.1.2 Stakeholder views on the need for clear obligations for storage and hybrids

Stakeholders supported the objective to clarify obligations for storage and hybrid facilities' participation in the NEM and responded as follows:

- Stakeholders generally agreed that it is important for AEMO to understand the state of charge of a battery but were mixed on whether there are issues with the current framework and whether the NER needs to include technology specific requirements.[45]

38 Submissions to the consultation paper: AGL, p. 6; AER, p. 2; Beca, p. 9; CEC, p. 4; CEIG, p. 3; Enel X, pp. 13-14; ERM Power, p. 3; Firm Power, p. 1; Fluence, pp. 19- 20; Maoneng. pp. 7-11; Monash Energy Institute, pp. 15-18; Origin, p. 2; Telsa, p. 6; Tilt Renewables, p. 2; UPC/AC Renewables, p. 5.

39 Note: there was also a third issue relating to a proposed drafting approach for Chapter 2 ancillary services. This is discussed in sectionsection 2.1.3below.

40 Submissions to the options paper: YES Energy, p. 4; Australian Energy Council, p. 3; EnergyAustralia, p. 2; Tesla, p. 10; Stanwell, p. 9; Energy Queensland, p. 10; Fluence, pp. 11-12; Clean Energy Council, p. 3; Acciona, p. 2; Damien Vermeer, p. 6; Carisbrooke Consulting, p. 9; ERM Power, p. 8; Maoneng, p. 2; AusNet, p. 2; Energy Queensland, p. 10.

41 Submissions to the options paper: Energy Australia, p. Alinta, p.5; AEMO, p. 16-17, ERM, p.5-6; Carisbrooke consulting p.8; Acciona, p.2; PIAC p. 1-2; Energy Queensland, p.7; Stanwell, p.8; Tesla, p. 9-10; GE Hydro p.4; Redearth Energy Storage, p.4.

42 Submissions to the options paper: AusNet p.2; Essential Energy, p.2; ENA, p. 5; Ausgrid p. 4-5.

43 Submissions to consultation paper: AGL, p.4; ARENA, p.5; Yes Energy, p.7; Monash Energy Institute, p. 8; Citipower, Powercor and Unite Energy, p. 9; Reposit, p.8; Enel X, p.8; Tesla, p.8.

44 Submissions to consultation paper: Yes Energy, p.7; Enel X, p.8; Tesla, p.8.

45 Submissions to the consultation paper: Fluence, p.18-20; AusNet, p.1; Reposit, p.3; Monash Energy Institute, p.6; Neoen, p.2-3.

Further, AEMO and other stakeholders identified that there are broader issues with forecasting and unit availability that may need to be addressed separately to this rule change.[46]

- The stakeholders that addressed the issue of minimum ramp rates provided feedback that the current framework for calculating the rates is unclear, inequitable and asymmetrical.[47] [48] This was consistent with AEMO's rule change request that highlighted that the existing minimum ramp rate framework creates an inconsistency between:
  - different categories of units (where unlike scheduled units, semi-scheduled units above 6 MW cannot be aggregated under NER chapter 2)
  - generation and load within a battery (where the minimum ramp rate for a scheduled load is 3 MW per unit and for scheduled generation is the lower of 3 MW or 3 per cent of maximum generation capacity).
- The majority of stakeholders agreed that there are issues regarding the performance standards framework for storage and hybrids.[49]
- Only a small proportion of submissions commented on AEMO's concern about the treatment of storage and hybrid facilities under the RRO compared to other loads. These stakeholders agreed that storage should not be treated as though it was the same as other types of load. They argued that storage that is scheduled does not contribute to reliability issues because it is dispatchable and able to be directed by AEMO.[50]
- Most stakeholders who commented on whether storage should continue to be subject to two MLFs considered that there was not an issue that required solving.[51] However, other stakeholders considered the MLF framework should be updated to reflect the unique operational characteristics of storage.[52]

2.1.3 Stakeholder views on the need to create a level playing field

AEMO raised several issues relating to an uneven playing field for storage. The main issue AEMO identified related to the inconsistent approach to recovering non-energy costs from storage, compared with other technologies and participants. Several stakeholders supported changes or were neutral about this issue, with several noting that cost recovery should be technology-neutral.[53] Those stakeholders who did not support any changes focused their comments on the solution rather than the materiality of issue, except for ERM who noted that the materiality of the issue was small.[54] In the options paper the majority of stakeholders

46 Submissions to the consultation paper: Fluence, p.18-20; Infigen, p.3; AEMO, p.6-7 Monash Energy Institute, p.11-12

47 Submissions to the consultation paper: GE Hydro, p.15-16 Fluence, p.18; AGL, p.4-5 and Infigen, p.2; ERM, p.6-7.

48 In response to the consultation paper Neoen stated that it was not aware that ramp rates are an issue on p.2.

49 Submissions to the consultation paper: CitiPower, Powercor, United Energy, p.12; Infigen, p.3; BECA, p.5-7; Monash Energy Institute, p.12; Maoneng, p.5; Fluence, p.12-13; Tesla, p.5; Transgrid, p.2.

50 Submissions to the consultation paper: Infigen, p. 4; Tesla, p. 7; Clean Energy Council, p. 4; Engie, p. 5; Monash Energy Institute, p.20; GE Hydro, p.16.

51 Submissions to the consultation paper: Neoen, p. 3; Energy Queensland, p. 31; ERM Power, p. 6; EnergyAustralia, p. 2; Energy Networks Australia, p. 17.

52 Submissions to the consultation paper, Fluence p. 28; Tilt Renewables, p.3; Monash Energy Institute, p. 21.

53 Submissions to the consultation paper that:Yes Energy, p.12; Monash Energy Institute, p.13-14; AEC, p.2-3; Neoen, p.3; Tesla, p.7; Arena, p.5; CEC, p.4-5; Infigen, p.2-4; essential Energy, p.2-3; Energy Queensland, p.23-24; Grids Energy, p.1-2; Ausgrid, p.3-4.

supported a consistent approach to the recovery of non-energy costs across participant categories.[55]

Stakeholders also provided feedback in relation to the other issues that AEMO raised regarding consistent treatment of storage and hybrids under the Rules, compared with other technologies and participant types. These are summarised below:

- Of those stakeholders who responded to the issue of storage proponents not being explicitly represented on the Reliability Panel, some felt that the issue was not yet material[56] while others considered that the matter should be addressed.[57]
- Stakeholders were split on whether the language and definitions in the Rules do not adequately reflect the increasing levels of bi-directional flows in the NEM. Some stakeholders agreed that current definitions of load and generation were problematic.[58] Others disagreed that the language in the NER was causing material issues.[59]
- Only a small proportion of submissions addressed AEMO's identified issue with the intervention compensation framework and the way it applies to storage compared to other participants. Some of these stakeholders considered that the unique operating characteristics of storage and hybrids prevented them from being correctly compensated.[60]

In its submission to the consultation paper AEMO suggested additional changes to simplify the drafting in NER Chapter 2 in relation to ancillary service provision.[61]

2.1.4 Commission's analysis

After considering stakeholder feedback, the Commission considers that there are material issues to be addressed relating to the integration of storage into the NEM. These issues are important to address, not only for current participants, but also to accommodate the greater amounts of storage and hybrid facilities that are expected to enter the market in the future. As highlighted in Appendix A, AEMO's 2020 ISP central scenario forecasts over 16,000MW of storage installed in the NEM by 2042, which is an eight fold increase on the current amount.[62] Facilitating greater participation of storage and hybrids helps to increase the proportion of dispatchable generation in the market, which in turn improves security and reliability, and supports the efficient participation of more renewable generation. This is crucial in the transitioning energy system.

Addressing these issues also helps to streamline and update the NER so that it is ready to accommodate and support new technologies, business models and innovative services into the future. Removing barriers to the participation of grid scale storage and smaller customer-

54 Submission to the consultation paper: ERM, p.4-5.

55 A more detailed summary of stakeholder comments to the options paper is in Appendix C.

56 Submissions to the consultation paper: AEC, p.3; Energy Networks Australia, p. 18; Reposit Power, p.20.

57 Submissions to the consultation paper: Monash Energy Institute, p. 22; GE Hydro, p. 17.

58 Submissions to the consultation paper: Monash Energy Institute, p.5-7; Maoneng, p.10-12; Fluence, p.25-26.

59 Submissions to the consultation paper: Reposit power, p.2; Origin, p.1; Essential energy, p.1.

60 Submissions to the consultation paper: Monash Energy Institute, p.19; Neoen, p.3; Tesla, pp. 5-6.

61 AEMO submission to the consultation paper, page 18.

62 See Appendix A for AEMO's forecasts of the growing importance of storage in the NEM.

owned storage, improving transparency, as well as levelling the playing field between different types of participants and different technologies, also makes progress towards the longer term objective of achieving a fully developed two-sided market.

Barriers to entry that need to be removed

The Commission considers the following barriers to entry should be addressed:

- The requirement under the NER for storage and hybrids to register in two registration categories should be removed because it creates duplication, complexity and additional costs. This is not only an issue in the registration process, but also for participation in dispatch, where storage units have to provide two separate bids (one from each registration category). The Commission acknowledges that this risks dispatch conflicts and causes difficulties interpreting market data and considers that this is an issue that is caused by the current arrangements under the Rules.[63]
- The rules should provide more flexibility for hybrid facilities to manage electricity flows behind the connection point. In particular, they should allow use of excess energy that would otherwise be curtailed to be stored and released into the network later, when it is needed. The Commission notes that facilitating hybrids to efficiently manage flows between units not only has benefits for participants but also has benefits for the market and power system.[64]
- The NER requirements for DC-coupled hybrid facilities are unclear. In particular, it is important to clarify the scheduling requirements for hybrids that are DC-coupled to facilitate the entry and participation of those configurations which can also deliver benefits to the system.[65]
- The use of exempt batteries by MSGAs should be clarified and made more flexible. Specifically, it should be clear in the NER that exempt batteries can be included in the portfolios of MSGAs. Further, the NER prevents an MSGA from using its portfolio of batteries to provide ancillary services, and this restriction should be removed to enable aggregators to use batteries to their full potential.[66]
- It is important to establish a policy position on the application of TUOS and DUOS to storage to provide greater certainty for participants.[67]
- The current approach of setting performance standards at the connection point is clear for stand-alone grid scale batteries. However, the approach for setting performance standards at the connection point for hybrids, with a mix of synchronous and non synchronous technologies, require clarification to provide greater certainty for proponents.[68]

63 More information on registration and participation can be found in Appendix B.

64 More information on the recovery of non-energy costs can be found in Appendix C.

65 More information on DC coupled systems can be found in Appendix G.

66 More information on exempt batteries can be found in Appendix B.

67 More information on TUOS and DUOS can be found in Appendix D.

68 More information on setting performance standards can be found in Appendix B.

Creating a level playing field

The Commission considers that a range of issues in the NER, particularly on the recovery of non-energy costs and the use of technology-specific or direction-specific (import or export of energy) language, need to be addressed to create a level playing field between technologies and participants.

Non-energy cost recovery

The framework for the recovery of non-energy costs needs to be changed to ensure there is a consistent approach across participation categories and technology types in light of increasing bi-directional flows, and that it provides a forward-looking framework that incentivises participants to manage their demand for these services by recovering non-energy costs proportionally from those who benefit from or cause the need for them. The Commission agrees there is an issue where grid scale batteries are charged non-energy costs on the basis of two separate gross meter flows while other participant categories have these costs recovered based on net meter flows.[69]

The current arrangements that enable participants other than grid-scale batteries to net meter flows for the calculation of causer-pays costs are no longer fit for purpose in the context of more bi-directional flows, especially where market customers have increasing amounts of generation behind the meter. These arrangements can result in participants, who were contributing to a reliability or security issue, being able to reduce their liability through subtracting flows that occurred in the opposite direction, even where such flows do not reduce the need for the relevant non-energy service. It can also result in perverse outcomes, where a market customer with significant generation behind a connection point is paid when the amount of generation exceeds the consumption in an interval, instead of making a payment. This can happen even where the market customer's consumption during the interval was contributing to the issue that required AEMO's intervention. The Commission considers that this issue requires a resolution as bi-directional flows continue to increase.[70]

If this issue is not addressed, the increasing amounts of bi-directional flows will continue to weaken signals intended to be causer-pays signals, that aim to incentivise participants to change their behaviour to help address reliability and security issues. This will not only have implications for the security and reliability of the power system but could also contribute to more interventions in the market by AEMO that will place upward pressure on customer bills.

Intervention compensation framework

While the Commission does not consider that the existing intervention compensation framework is causing problems for the way storage and hybrids are compensated following interventions, it proposes a draft rule confirming the framework will apply to storage and hybrids (using the new participant category) in the same way that it applies to other generators and loads to promote a level playing field.[71]

69 More information on the recovery of non-energy costs can be found in Appendix C.

70 See Appendix A for more information about the forecast increase in bi-directional flows.

71 More information on the interventions compensation framework can be found in Appendix E.

Technology-specific and uni-directional language in the Rules

The technology-specific language, and language specific to certain types of participants or specific to a single direction of energy flow, used in the NER is an issue because it reflects the older technologies and the original concept of having flow in only one direction, from large generators to end-use customers. This language does not appropriately accommodate new technologies and the large (and increasing) number of participants of all sizes with significant bi-directional flows of electricity. In many cases this language is unnecessarily restrictive, creates unintended outcomes or merely makes it harder to interpret and apply the NER in the current circumstances, where bi-directional flow is increasingly common and a participant may wish to provide a range of services from a single site. This language should be addressed throughout the NER to reduce the regulatory burden and make the NER more fit-for-purpose.[72]

Minimum ramp rates

The different aggregation methods can result in different minimum ramp rates calculated for semi-scheduled generating units and bi-directional units. The Commission considers this inconsistency in the minimum ramp rate framework needs to be addressed to create a level playing field for storage participants and semi-scheduled generating units.[73]

Issues that are not material or better addressed through other rule change processes

The Commission considers that it is important for AEMO to have visibility of a battery's state of charge. However, this is a matter that is best reviewed in the context of broader issues relating to forecasting and unit availability. This should be considered for future rule change requests dealing with these issues.

The Commission does not consider the following are material issues that require rule changes or clarification at this time, beyond confirming that the existing treatment of storage and hybrids will continue to apply, using the new participant category.

- **Retailer reliability obligation**: The Commission does not share the view that it is problematic that proponents of batteries and hybrids are liable entities under the RRO in respect of the loads of those facilities. While sympathetic to the view that batteries are different to non-scheduled loads and contribute to reliability, in practice the Commission does not consider that being liable loads under the RRO would materially affect the way these facilities operate in the market. This is because they are able to choose whether to draw from the grid during a reliability event, and if they choose not to due to the likely high prices at that time, they would have no effective load hedging requirement under the RRO. Further, the Commission considers it desirable that these facilities are treated consistently with other forms of load (noting that scheduled load is not currently exempted from the RRO). Participants with significant amounts of load at their connection points should be subject to the same requirements whether they are

72 More information on this issue can be found in Appendix E.

73 More information on minimum ramp rates can be found in Appendix B.

registered as Market Customers or Integrated Resource Providers, to avoid perverse incentives to register in one category rather than another.[74]

- **Reliability Panel representation**: The Commission does not agree that there is a need at this time to establish a specific place on the Reliability Panel for storage/ hybrid proponents. This is because the Commission already has the discretion to appoint up to three other persons (in addition to the five specified categories) to broaden the perspective of the Panel.[75]
- **Marginal loss factors**: The Commission sees no issue with storage and hybrids continuing to be subject to two different MLFs, one for load and the other for generation.[76]
- **Connection of NSP-owned batteries:** The Commission does not consider that a new regulatory regime should be included in NER chapter 5 to allow performance standards to be established for batteries owned by, and connected by, network service providers. It is appropriate for the existing arrangements to apply, under which an NSP-owned battery can be connected by another party such as a separate commercial entity or a ring-fenced subsidiary of an NSP, where performance standards are established under the usual connection agreement process.[77]

2.2 How the Rules need to change to integrate storage into the NEM

The solutions that the Commission sets out in this draft determination seek to address the issues identified above, and be consistent with overarching policy direction for a two-sided market envisaged by the ESB's P2025 initiative.

This section provides an overview of the draft determination and the Commission's rationale, and includes AEMO's estimated costs to implement the changes. More detail can be found on how the Commission reached its draft decisions in the relevant appendices.

2.2.1 How the registration and participation framework should change

Through the consultation and options papers, the Commission investigated alternative solutions to AEMO's proposed BDRP, that were more aligned to the trader-services model under the ESB's Post 2025 initiative.[78]

One of the reasons why AEMO's BDRP was not considered to be aligned with the trader-services model was due to it being underpinned by a technology specific definition of storage. While the Commission acknowledges that there is already technology specificity in the Rules in places where it is necessary, the Commission is not in favour of introducing more technology specificity where it is not. In this case, the Commission consider that the issues identified in AEMO's rule change request can be accommodated without defining storage as such.

74 More information on this issue can be found in Appendix E.
75 More information on this issue can be found in Appendix E.
76 More information on this issue can be found in Appendix E.
77 More information on NSP connections can be found in Appendix F.
78 AEMO developed its rule change proposal prior to the publication of the ESB's policy direction.

In addition, AEMO's proposal to create a new registration category for specific business models and assets is inconsistent with the trader-services model, which features a single universal category through which participants (or traders) can provide the full range of energy and non-energy services.

Stakeholders supported changes that aligned with the direction of the ESB's Post 2025 initiative and wanted changes to be incremental allowing the market to adjust.

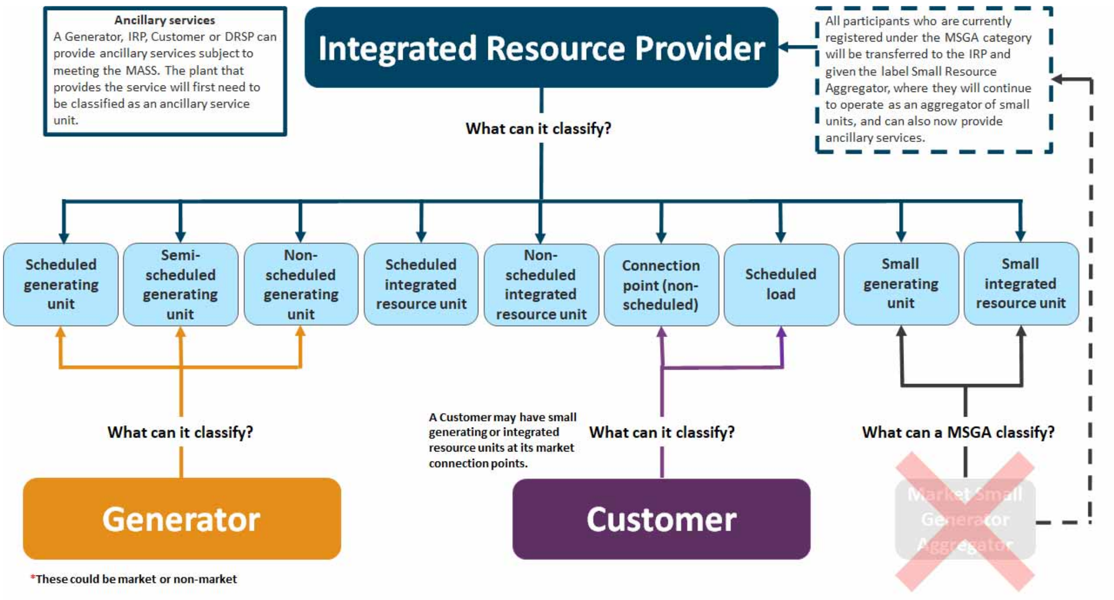
Consequently, taking account of stakeholder feedback and discussions with AEMO, the Commission has selected a participation model it considers to be an incremental step towards the trader-services model and addresses the issues identified by AEMO and confirmed by stakeholders. These issues and the Commission's approach are discussed below and in more detail in Appendix B.

Commission's draft determination

The Commission's draft determination includes the creation of a new technology neutral participant category called the Integrated Resource Provider (IRP). It accommodates a variety of participants with bi-directional energy flows that may offer (and consume) energy and ancillary services. This includes grid-scale storage, hybrids and aggregators of small generation and storage units. Figure 2.1 outlines the range of classifications and services that can be provided by the IRP. It would be optional for Market Customers and Generators to join the IRP category.

The IRP category is consistent with the ESB's trader-services model as it provides for a technology neutral approach and a vehicle for an eventual universal category into which other participants can transition over time. It also provides greater certainty for flexible trading arrangements for aggregators of customer-owned DER, enabling them access to multiple markets on behalf of customers. This provides customers with greater choice of services and a means for them to obtain greater value from their investment in DER, such as a household battery.

Figure 2.1: Classifications and services that can be provided by Market Participants.



In addition, the IRP registration category would also address the issues that AEMO and stakeholders identified by:

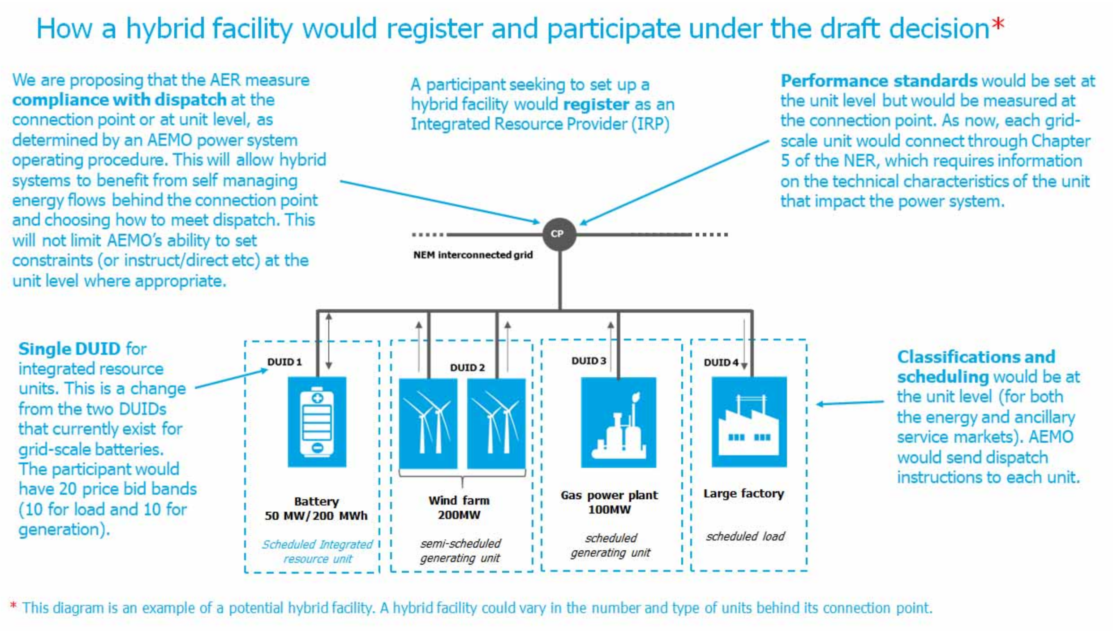
- Preventing storage and hybrids from needing to register and participate under two different registration categories. It will be mandatory for any participant to register as an IRP if it has (behind a single connection point) both generation capability that would on its own see it register as a Market Generator and consumption that is not auxiliary load for the generating unit. It would also be voluntary for a participant who did not meet these requirements to register as an IRP.
- Providing clarity about the scheduling obligations that apply to different configurations. Under the IRP category, standalone grid-scale storage would be classified and scheduled (for both load and generation) at the unit level. Each unit within a hybrid system would be classified and scheduled at the unit level, with the following exceptions for flexibility. It may be possible to aggregate similar technologies together. Hybrids that are DC coupled systems and have different technologies behind a single inverter will be able to chose to be scheduled with one DUID, semi-scheduled with one DUID (subject to the existing bidding limits on semi-scheduled generating units), or to have two DUIDs - one scheduled and the other semi-scheduled.
- Providing flexibility for hybrids to manage their own energy behind the connection point (i.e. under or over deliver on unit level dispatch instructions) to comply with dispatch on aggregate at the connection point. For example, exceeding dispatch from a battery to firm up under-delivery from a solar farm. This will improve these facilities' dispatchability and efficiency, reduce causer pays liabilities and deliver benefits to the greater system. The draft rule will enable this through setting scheduling and dispatch obligations at the

unit level, with compliance with dispatch for hybrids able to be assessed in aggregate (subject to an AEMO procedure which will specify when dispatch instructions must instead be complied with at the unit level).[79]

- Enabling batteries to participate in dispatch using a single dispatch bid, facilitated by the proposed new term in the Rules: the "integrated resource unit" (IRU). Rather than a battery having two DUIDs, one for load and one for generation, the new term in the Rules covering units that have both load and generation (as part of a single unit) will enable the battery to participate using one DUID. This will enable it to issue a single bid that will have 20 bands, 10 positive (for export) and 10 negative (for import).
- Clarifying that the current approach to performance standards that are set and measured at the connection point will apply for grid-scale storage units, including where part of a hybrid.
- Enabling aggregators of small generating units and/or storage units to register in the new category (although this will not be mandatory, and they will still be able to utilise the Market Customer category) and enable aggregators registered in this category to provide market ancillary services from generation and load.[80]

Figure 2.2 outlines a number of key design features for hybrid facilities, and Figure 2.3 outlines the flexibility a DC-coupled connection would have in connecting to the power system.

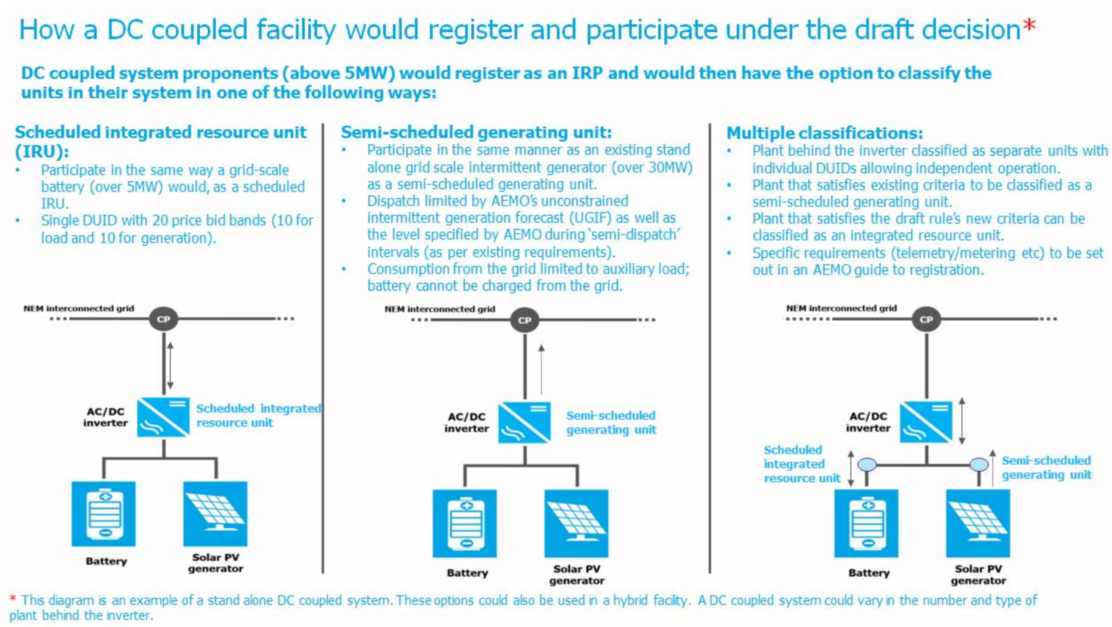
Figure 2.2: An example of a hybrid facility registered as an IRP



79 See NER clause 4.9.2A in the draft rule.

80 All existing SGAs will automatically be transferred across to the new IRP category.

Figure 2.3: The options for a DC coupled connection to connect to the power system



Implementation and cost considerations

These changes, if the draft implementation decision is made final, would come into effect 18 months after the final determination is published - that is, 28 April 2023. The Commission will continue to engage with AEMO and stakeholders to understand the work required to implement these changes and whether it would be appropriate for implementation to be staggered. AEMO has informed the Commission that the draft decision will require changes to a number of AEMO systems, procedures and processes.

- Systems that will require changes include registration, portfolio management, Market Settlement and Transfer Solution (MSATS), Consumer Administration and Transfer Solution (CATS), medium, short and pre-dispatch Projected Assessment of Systems Adequacy (PASA), Electricity Management Market (EMM), National Electricity Market Dispatch Engine (NEMDE), and causer pays.
- AEMO will need to update existing procedures and guidelines to reflect changes in terminology in the draft rule, eg in relation to load.
- Processes, guides and forms that will need to be developed include those for IRP registration and IRU classification, single DUID bidding and dispatch conformance on aggregate for hybrid systems, and the settlement process.

The Commission's draft decision will also require all existing grid-scale storage participants who are currently registered as both Market Customers and Market Generators to transition across to the IRP participant category.

AEMO provided a cost estimate for the draft decision to introduce the IRP and make changes to the registration and participation framework, of $14 million to $21.7 million. The Commission considers the benefits of these reforms (in relation to the long-term interests of consumers) are likely to outweigh the costs and will therefore promote the NEO. In the current circumstances, they are the best combination of reforms to integrate storage and hybrid facilities into the market. Table 2.1 shows a breakdown of the costs and estimated benefits associated with each design feature.

The Commission notes there are a large number of changes to the rules in this draft decision, some of which may result in cost impacts for market participants. The Commission will continue to work with stakeholders over the extended engagement period to understand how these changes would impact on the market, and the costs and benefits this draft rule would create for existing and future market participants. The engagement and feedback on the costs and benefits of the draft decision will inform and be reflected in the Commission's final decision.

Table 2.1: **Estimated cost of implementing the draft decision for registration and participation**

DESIGN FEATURE	AEMO'S ESTIMATED COST RANGE	ESTIMATED BENEFIT
New participant category	$8 to $10 million	This is the original and lowest cost estimate from AEMO to introduce a new bi-directional market participant category. This cost is necessary to set up a new category that specifically caters for participants with bi-directional energy flows, minimises the administrative burden that currently exists for storage participants and allows hybrid facilities to register and participate. This change would also: • enhance system reliability and security as it would encourage and promote the entry of new storage capacity that would help to firm up the growing amount of renewable energy in the market • allow greater flexibility in how small storage units can be used in the market • align with the possible future direction foreshadowed by the ESB towards a trader-services model.
Increasing number of bid bands for IRPs to 20	$1.5 to $2 million	Moving to 20 bid bands for IRPs would allow a level playing field for storage participants as they will have 10 bid bands for each of

DESIGN FEATURE	AEMO'S ESTIMATED COST RANGE	ESTIMATED BENEFIT
		their load and generation, the same as other scheduled load and scheduled or semi-scheduled generators. A single bi-directional DUID for storage also complements a simplified registration and classification process through the IRP.
Allowing flexibility for DC coupled systems to register and participate	$1 to $2.5 million	Participants have noted that, by allowing DC connected systems (rather than registering and connecting a renewable generator and battery separately), there are savings in the order of 10 to 20 per cent for setup and connection costs. Setting up a clear framework for hybrid systems to register and participate in the market is important as it is anticipated hybrid systems will become increasingly common.
Moving SGAs into the IRP and allowing them to participate in the ancillary services market	$1 to $2 million	This change would send clearer investment signals in allowing aggregators of small generating and storage units to provide more services, including the ability to provide ancillary services. It is a relatively low cost change that will allow more participants access to more revenue streams, and deliver services the market needs. This change aligns with an important element of the ESB's two-sided market work on developing a universal participant category (trader-services model) and establishing flexible trading arrangements.
Amending Generator Performance Standards for integrated resource units	$0.5 to $1 million	This is a relatively low cost that is necessary to integrate and allow storage and hybrid systems to connect to the system and participate in the market
Review of AEMO's procedures and guidelines	$0.5 to $1 million	This is a relatively low cost that is necessary to review and update AEMO's procedures and processes to implement the Integrated Resource Provider participant category and Integrated Resource Unit classification.

DESIGN FEATURE	AEMO'S ESTIMATED COST RANGE	ESTIMATED BENEFIT
Other system changes needed for this rule change that also set up flexibility to implement post-2025 reforms	$1.5 to $3.2 million Note: Some of these costs could be attributed to other design features, but it is not always possible to break out costs that are incurred because of a number of changes.	Incurring these costs now, as part of this reform, sets up some systems more efficiently for the flexibility needed to implement further post-2025 reforms. Future changes that fall out of the ESB work would be simpler and cheaper to implement.

Source: The costs have been provided by AEMO. The benefits have been developed through AEMC analysis, including stakeholder feedback.

An alternative registration approach

During the extension of time for AEMO to consider cost and implementation issues, it raised an alternative registration approach that would see all participants, existing and new, moved into a single participant category. That is, all participants would move into the IRP category. AEMO noted that this alternative option, while only an early view and not explored in detail, would likely be around $2 million cheaper to implement, compared to implementing the draft rule and then implementing a later rule change to combine all participants into one category (flagged as a potential part of the ESB's post-2025 reform project).

In its view it would be a simpler approach as AEMO would not need to maintain multiple registration processes and procedures. AEMO did note that it had not considered cost and implementation impacts on participants of this alternative approach. It did not express a preference for either the alternative approach or the draft decision, but did highlight that this alternative approach was a bigger move towards the universal category and trader-services approach being explored by the ESB's post-2025 work.

The Commission notes that the alternative approach may reduce implementation complexity and present some cost efficiencies for AEMO, but considers it is not the right approach for this draft determination for the following reasons:

- In submissions to the options paper, and to the ESB's post-2025 work, stakeholders generally agreed that any changes, including if there is a move towards a universal category and trader-services model, should be incremental over time to allow the market and participants to adjust, not implemented all at once.
- The rule change and engagement to date on registration and participation has been focused on changes for small and large storage and hybrid facility participants. A decision to consider a registration approach that impacts on all participants, in this rule change, would be inconsistent with the identified scope and engagement to date. It would therefore be more appropriate for a new rule change request to be submitted by AEMO and formally consolidated with this rule change.

- The alternative approach has not been tested with stakeholders. If the Commission were to consider this new approach it would need to further delay this rule change to consult on the alternative approach, including putting on hold the draft decision on all other issues this rule change addresses. This would not align with stakeholder feedback that highlighted the need to better integrate storage and hybrid facilities as a matter of priority.

Consumer protections for an evolving participation framework

The facilitation of aggregators under the IRP category would help ensure there is sufficient flexibility in the Rules for innovative products and services. Encouraging more competition through enabling consumers to take up contracts with multiple service providers at their home or business brings benefits for consumers. However, the Commission is also mindful that there could be risks associated with these new services.

As more service providers emerge there is a need to consider the types of protections that may be needed for each of the new products and services. The "consumer experience" under a two-sided market is being considered by the ESB and it has proposed a risk assessment tool to help assess where risks or opportunities to customers may be emerging and ensure the protections in place remain fit for purpose. For example, what are the right-sized obligations for third parties that are delivering the services, and how and where do these obligations differ from the service of essential energy supply? An example of an obligation that might be appropriate to apply to third party aggregators includes their coverage by jurisdictional ombudsman schemes (the Commission has previously made recommendations on the role of energy ombudsman schemes in relation to new energy products and services).[81]

This rule change is specifically dealing with integrating storage into the wholesale market. The application of consumer protections to new products and services that may, over time, evolve from these changes is being actively considered by the ESB.[82] The protections framework will continue to evolve under the move to a two-sided market design and this will be informed by ongoing risk assessments of new products and services and various trials undertaken by the market bodies and ARENA.[83]

2.2.2 How the framework for the recovery of non-energy costs should be changed

The Commission engaged with stakeholders through the consultation and options papers to explore a resolution to the non-energy cost issues described above in section 2.1. While AEMO's proposed solution in its rule change request was focused on addressing the inconsistencies between the recovery of non-energy costs between grid-scale batteries versus exempt batteries controlled by MSGA, it also suggested that the Commission may want to address the inconsistencies with the recovery of costs from other market

81 In its 2020 retail energy competition review, the Commission recommended that that energy ombudsman schemes consider extending their jurisdiction to handle consumer complaints regarding new energy products and services that relate to the sale or supply of energy. This may need support from jurisdictional governments. More information can be found here.

82 The ESB's January 2021 Directions paper can be found here - see section 5.4.3.

83 Links to the relevant studies here: Project Edge, Virtual Power Plant (VPP)

participants. AEMO noted that there was the opportunity to address the issue more broadly due to AEMO soon having access to more metering information through the implementation of global settlements in May 2022.[84]

Through the options paper, the Commission sought feedback on a proposed approach that would address inconsistencies in the way non-energy costs are recovered between participants. Most stakeholders who commented on the non-energy costs framework in the options paper (20 of 31 submissions) supported the alternative option, where all participants would pay for non-energy services based on a beneficiary/causer pays approach. That is, not based on the participant category in which they are registered.[85]

Commission's draft determination

The Commission's draft determination involves recovering non-energy costs based on a participant's consumed and sent out energy over relevant intervals, irrespective of their participant category. Consumed and sent out energy would be measured separately for all market participants i.e. consumed and sent out energy data in an interval would be measured separately and not netted at the connection point, or among a market participant's connection points. It would not include the energy produced and consumed behind the connection point, for example, rooftop solar production that is consumed on site.

This would require two main changes:

- The use of two new data streams in non-energy cost recovery – adjusted sent out energy (ASOE) and adjusted consumed energy (ACE).
- Non-energy cost recovery would be based on a participant’s gross energy flows, i.e. gross consumed energy (ACE) or exported energy (ASOE) during relevant intervals, rather than the category a participant is registered in.

The benefits of this approach are that it:

- **Aligns cost recovery with the principles of beneficiary and causer pays** - The Commission considers that the cost of services to support the power system should be funded by those who benefit from or cause the need for them. Under the current framework the increase in participants who have two-way energy flows at their connection points has resulted in these participants being able to reduce their liability (without reducing the need for the services), while others pay more. The draft decision removes this outdated approach and provides a forward-looking framework that incentivises participants to manage their demand for these services by recovering non-energy costs proportionally from those who benefit from or cause the need for them.
- **Stops inappropriate payments** - Removes inappropriate payments made to Market Customers rather than recovery from them. In some recovery calculations, if the sent-out energy exceeds consumed energy, payments would be made to the Market Customer

84 AEMO, Integrating energy storage systems into the NEM - rule change request, August 2019, p. 39. Note - the implementation of Global Settlement & Market Reconciliation Rule has been extended to May 2022 since AEMO submitted its rule change request.

85 Submissions to the options paper: Redearth Energy Storage, p. 3; Engie, p. 2; Origin, p. 2; Enel X, p. 6; AustNet Services, p. 2; Tesla, p. 9; Alinta, p. 4; ERM, p. 7; AEC, p. 3; Carisbrooke Consulting, p. 8; Flow Power, p. 5; Stanwell. p. 8; Energy Queensland, p. 9.

based on the net export, even though the Market Customer still had some consumption during this period that contributed to the need for the non-energy service.

- **Provides incentives for more efficient behaviour** – By charging participants based on an accurate accounting of their share of gross load (or generation, where relevant), some participants will be exposed to greater non-energy costs – reflecting the benefit they receive from, or their contribution to the need for, these non-energy services. This may provide stronger incentives for these participants, or their customers, to mitigate this cost by providing the service themselves, where possible – e.g. FCAS from Virtual Power Plants (VPPs) - thereby better allocating risks and improving the overall efficiency of the market. It will also reduce the share of these costs currently paid by participants (and retail customers) that are not benefiting from, or contributing to the need for, these non-energy services.
- **Aligns with a service-based approach** – The draft rule assigns costs to participants based on the service they receive from the market and is an important step towards a (more efficient) two-sided market.

In addition, the draft rule rectifies the distortion being created by greater levels of bi-directional flows and provides a permanent resolution for the settlement and equity issues raised by AEMO and Infigen in separate rule changes.[86]

The Commission notes that Market Customers who produce energy and Market Generators who consume energy in relevant trading intervals may pay more, while other Market Participants without significant energy counter flows may pay less. In practice, the total amount of money that AEMO is recovering for these non-energy services is not changing, but the costs are being distributed differently so that participants pay their fair share of the costs, in accordance with causer pays principles established at NEM start. This change is more likely to impact Market Customers with large amounts of small 'exempt' generating units in their portfolios as they will no longer be able to reduce their consumption flows through netting and will now be liable for non-energy costs attributed to produced energy.[87]

Implementation and cost considerations

These changes, if the draft implementation decision is made final, would come into effect 18 months after the final determination is published, ie 21 April 2023. This will be after Global settlements in May 2022, which will provide AEMO access to new data streams that identify a participant's consumed and sent out energy in each interval, separately.

There are still a significant number of Type 6 accumulation metering installations, AEMO estimates up to 8.5 million across the NEM, which cannot separately measure bi-directional energy flows. Under the draft rule these sites would continue to have non-energy cost recovery calculated on a net energy flow amount, until these meters are replaced with smart meters.

86 This is explained further in Appendix C.

87 Historically, non-energy costs have varied between $0.30 to $1.60 per MWh, so an amendment to the redistribution of this cost is unlikely to materially impact on end-use customers.

AEMO has provided a cost estimate for the draft decision, regarding changes to the recovery of non-energy costs framework, of $5 million to $7 million. The Commission considers the benefits of removing inefficient cross subsidies among participants and providing a permanent solution to the settlement and equity issues raised by AEMO and Infigen in separate rule changes, as discussed in further detail in Appendix C, are likely to outweigh the cost to implement these changes to the framework for the recovery of non-energy costs.

2.2.3 Other changes in the draft determination to integrate storage

The table below sets out the Commission's analysis and draft decisions on other aspects of the rule change request.

Table 2.2: **Other changes to integrate storage, and consequential changes**

TOPIC	DRAFT CHANGE	RATIONALE
Addressing inconsistencies in ramp rates	Set a minimum ramp rate at the lower of 3 MW or 3% of scheduled load capacity and remove the 6 MW threshold for aggregating semi-scheduled units. This would see a consistent minimum ramp rate set for: • storage and non-storage participants • load and generation units • scheduled and semi scheduled units, that have the same number of units and MW capacity.	This change would set minimum ramp rates in a way that would: • be more equitable for scheduled generation and load • make storage participation less complex • allow semi-scheduled participants to aggregate units above 6 MW • better align with the longer-term two-sided market vision (more consistent treatment of load and generation). The Commission considers a more equitable approach, where units of all sizes are treated proportionally the same, should be explored in a dedicated rule change on ramp rates in the future when more of the less flexible 'old fleet' of generators have retired.
The application of TUOS and DUOS	The draft rule makes minor amendments to provide additional clarity on three issues: • in the event of a dispute, the tariffs that a DNSP charges for the provision of common distribution services for customers who are not retail customers	The rationale for providing only minor amendments is due to the Commission's view that the NER contain appropriate provisions on the treatment of TUOS and DUOS for generation and load: • For generation: The rules are clear that generators do not incur TUOS or DUOS charges. Changes to the rules for charging DUOS for exports are being considered in a separate

TOPIC	DRAFT CHANGE	RATIONALE
	should reflect its efficient costs of providing those services to the customer. • TNSPs must provide shared transmission services as prescribed transmission services if the prescribed service is sought by the connection applicant • the new market participant category, the IRP, will be treated as a Network Customer for the purposes of Chapter 6A in relation to electricity taken from the grid and so will pay TUOS for prescribed transmission services.	process. • For load: While the rules are reasonably prescriptive both in form and process for load, they are designed to provide flexibility to negotiate different outcomes in certain circumstances.
Intervention compensation framework	The draft rule does not develop any unique arrangements for storage and hybrids in the intervention compensation frameworks, but does integrate the IRP market participant category into these frameworks.	The benefits of the draft rule are that it will: • provide that the intervention compensation framework is consistently applied across storage, hybrids, other generation and loads • allow the Commission to give closer consideration to how this framework applies to storage and hybrids through a parallel rule change process, which is specifically focusing on the intervention compensation framework.
Retailer Reliability Obligation	The draft rule makes IRPs liable entities under the RRO, in respect of their load, if aggregate annual load exceeds 10GWh in a particular NEM region.	The draft rule will treat load of IRPs consistently with how load of Market Customers is treated. That is, any liable entity will be assessed to have a liable load where its aggregate load is greater than 10 GWh per annum.
Updating the language in the Rules	Changing definitions for load and generation, replacing all mentions of offer with bid in	The benefits of the draft rule are that it will: •

TOPIC	DRAFT CHANGE	RATIONALE
	Chapter 3 of the NER and providing generic references to scheduled plants and market participants where possible.	• improve the drafting of the rules by reducing the extent of technology specific, direction-specific and participant category-specific language in them • address the ambiguity of how certain terms and concepts apply to energy storage and hybrids • avoid implementing new definitions in the rules which are unnecessarily prescriptive on the direction of the flow of electricity.
Consolidating clauses in Chapter 2 that relate to ancillary services	This approach involves: • defining an umbrella term ('ancillary service unit') to replace the separate treatment of existing FCAS providers • allowing the relevant types of Market Participants to provide FCAS from this umbrella term in accordance with the Market Ancillary Service Specification (MASS).	The draft rule is more consistent with the ESB P2025 policy direction for a more developed two-sided market. This is because it creates frameworks that are more adaptable to change and better able to facilitate innovation.
Streamlining the Rules	Improving the drafting throughout the Rules, where necessary, in clauses that are being amended for the changes above.	The Commission agrees with AEMO's view in the rule change request that given the draft rule involves extensive drafting changes, it is also an opportunity to undertake a "spring-clean" and fix drafting errors or improve the clarity of provisions that are also being amended for the reasons above. These changes will contribute to the overall coherence of the Rules.

Note: Further detail about the proposed changes can be found in the relevant appendices. A summary of the draft rule is set out in Appendix K.

3 DRAFT RULE DETERMINATION

3.1 The Commission's draft rule determination

The Commission's draft rule determination is to make a more preferable draft rule, which is attached to and published with this draft determination. The more preferable draft rule includes the creation of a new technology neutral participant category called the IRP. This accommodates a variety of participants with bi-directional flows that provide and consume energy and may also offer ancillary services. It includes new grid scale storage, hybrids and aggregators of small generators and storage units. Further details of the draft rule are set out in Appendix K, and the differences between the proposed rule and the more preferable draft rule are explained in chapter 2 and in more detail in the appendices.

The Commission's reasons for making this draft determination are set out in section 3.4 below, as well as being discussed at a high level in Chapter 2 and in more detail in the relevant appendices.

This chapter outlines the:

- rule making test for changes to the NER
- more preferable rule test
- assessment framework for considering the rule change request
- Commission's consideration of the more preferable draft rule against the national electricity objective
- Commission's consideration in deciding whether to make a uniform or differential rule in accordance with the Northern Territory legislation adopting the NEL.[88]

Further information on the legal requirements for making this draft rule determination is set out in Appendix J.

3.2 Rule making test

3.2.1 Achieving the NEO

Under the NEL the Commission may only make a rule if it is satisfied that the rule will, or is likely to, contribute to the achievement of the national electricity objective (NEO).[89] This is the decision-making framework that the Commission must apply.

The NEO is:[90]

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

88 National Electricity (Northern Territory)(National Uniform Legislation) Act2015.

89 Section 88 of the NEL.

90 Section 7 of the NEL.

3.2.2 Making a more preferable rule

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

In this instance, the Commission has made a more preferable draft rule. The reasons are summarised below. More detailed reasons for making this more preferable draft rule, including analysis of the issues raised and responses to them, are set out in Chapter 2 and in the appendices.

3.2.3 Rule making in the Northern Territory

The NER, as amended from time to time, apply in the Northern Territory, subject to modifications set out in regulations made under the Northern Territory legislation adopting the NEL.[91]

Under the NT Act, the Commission must regard the reference in the NEO to the "national electricity system" as a reference to whichever of the following the Commission considers appropriate in the circumstances having regard to the nature, scope or operation of the proposed rule:[92]

(a) the national electricity system

(b) one or more, or all, of the local electricity systems[93]

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

For the rule change request considered in this draft determination, the Commission has determined that the reference to the national electricity system in the NEO is a reference to (c), all of the above (noting that the draft rule, if made as a final rule, would have only limited effect in relation to the NT's local electricity systems).

Under the NT Act and its regulations, only certain parts of the NER have been adopted in the Northern Territory.[94]

As the draft rule relates to parts of the NER that apply in the Northern Territory, the Commission has assessed whether to make a uniform or differential rule (defined below) under Northern Territory legislation.

Under the NT Act, the Commission may make a differential rule if, having regard to any relevant MCE statement of policy principles, a differential rule will, or is likely to, better contribute to the achievement of the NEO than a uniform rule.[95] A differential rule is a rule that:

91 *National Electricity (Northern Territory) (National Uniform Legislation) Act 2015* (NT Act). The regulations under the NT Act are the *National Electricity (Northern Territory) (National Uniform Legislation) (Modification) Regulations 2016*.

92 Clause 14A of Schedule 1 to the NT Act, inserting section 88(2a) into the NEL as it applies in the Northern Territory.

93 These are specified Northern Territory systems, listed in schedule 2 of the NT Act.

94 The version of the NER that applies in the Northern Territory is available on the AEMC website at www.aemc.gov.au/regulation/energy-rules/northern-territory-electricity-market-rules/current.

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

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

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

A uniform rule is a rule that does not vary in its terms between the national electricity system and one or more, or all, of the local electricity systems, and has effect with respect to all of those systems.[96]

The Commission has determined to make a uniform draft rule as it does not consider that a differential rule will, or is likely to, better contribute to the achievement of the NEO than a uniform rule, for the reasons set out in section 3.4 below.

3.3 Assessment framework

In assessing the rule change request against the NEO, the Commission has considered the following principles, in light of the current and future interests of consumers in a transitioning electricity system:

- ***Promotes competition:*** Would the changes proposed remove barriers to entry and reduce operating costs?
- ***Promotes transparency:*** Would the proposed clarifications to the obligations and charges in the rules reduce information asymmetry and improve the decision-making of participants?
- ***Creates a level playing field:*** Are the proposed obligations proportional, technology-neutral and even-handed?
- ***Appropriately allocates risks:*** Would the appropriate parties be assigned responsibility for costs under the approaches proposed for cost recovery?
- ***Minimises administrative and regulatory burden:*** Would the proposed changes reduce the administrative burden on AEMO and participants?
- ***Enhances system reliability and security:*** Would the proposed obligations on storage improve reliability and security?

Promoting competition, including through enhanced transparency and enabling a level playing field, is in the long-term interests of consumers. This is because it increases choice for consumers, improves the service they receive and puts downward pressure on prices. In addition, ensuring appropriate allocation of risks and minimising administrative and regulatory burden contribute towards the efficiency of the market that benefits consumers through fewer inefficient costs being passed onto them.

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

More broadly, the Commission considered how the rule change would benefit the reliability and security of the system (albeit indirectly) in light of the potential for new technologies and business models to assist in balancing the power system as the NEM continues its transition.

The assessment framework is consistent with that set out in the consultation paper for this rule change process.

3.3.1 Commission response to feedback on the assessment framework

Most stakeholders who commented on the assessment framework agreed with the criteria.[97] While no stakeholders disagreed with the assessment criteria, some noted the following criteria should be considered:

- changes should be aligned with other major reforms such as Transmission Access Reform and the ESB's post-2025 work[98]
- it would be good to clarify what cost-reductions the AEMC will evaluate as part of its assessment framework[99]
- if not implementing AEMO's proposed solution, the cost implications of different approaches to registration and participation need to be assessed[100]
- it is important that changes allow flexibility for storage proponents[101]
- overall cost to implement does not include cost to participants[102]
- changes should promote technology and commercial flexibility and innovation in behind-the-meter arrangements over time.[103]

The Commission considers the assessment criteria includes consideration of the issues raised by stakeholders, in particular:

- consideration of other major reforms through 'creating a level playing field'
- assessing the cost implications for participants and of different implementation options against the short and long term benefits through 'promoting competition' and 'creating a level playing field'
- providing a flexible framework for storage which 'promotes competition'.

3.4 Summary of reasons

Having regard to the issues raised in the rule change request and during consultation, the Commission is satisfied that the more preferable draft rule will, or is likely to, better contribute to the achievement of the NEO than the rule proposed by AEMO. The draft rule is made for the following reasons:

97 Submissions to the consultation paper: Reposit, p. 1; Fluence, p. 6; Enel Green Power, p. 3; Engie, p. 2; YES Energy, p. 3;Energy Queensland, p. 7; AusNet Service, p. 3.

98 Submissions to the consultation paper: Energy Queensland, p. 7; ENA, p. 7.

99 BECA, submission to the consultation paper, p. 2

100 AEMO, submission to the consultation paper, p. 5.

101 Engie, submission to the consultation paper, p. 2.

102 Energy Queensland, submission to the consultation paper, p. 7.

103 ARENA, submission to the consultation paper, p. 3.

Promoting competition:

- By removing barriers to entry for proponents of storage, hybrid facilities, and aggregators of small generating units and batteries. The more preferable rule promotes competition and removes barriers more effectively than AEMO's proposal because it:
    - accommodates aggregators as well as storage and hybrids in the proposed new participant category
    - enables hybrids more flexibility to manage electricity flows behind the connection point
    - accommodates DC coupled hybrids through clarifying the choices these configurations have in regards to scheduling
    - enables aggregators of small units to provide ancillary services from those units
    - confirms the policy position on the application of TUOS and DUOS for storage and hybrids.
- By providing a signal to the industry that the NER are being streamlined for the purpose of accommodating new technologies, business models and services that offer greater choice for consumers. The more preferable rule provides a stronger more enduring signal because it is technology-neutral and is consistent with the ESB's long term goal of a two-sided market.

Promoting transparency:

- By clarifying the obligations that apply to storage and hybrids, including:
    - that batteries can participate in dispatch through a single bid (making it easier to interpret market data)
    - how performance standards will be set for hybrids that have a mix of synchronous and non-synchronous technologies
    - how the minimum ramp rates apply.
- By updating the language and streamlining the NER so that it more appropriately accommodates new technologies and participants with significant bi-directional flows and makes the NER easier to read and understand.

Creating a level playing field:

- By introducing a new participant category. The more preferable rule more effectively contributes to a level playing field by avoiding the inclusion of additional technology-specific terms in the NER (such as a definition for storage) and taking a substantial step towards the trader-services model (part of the P2025 reforms) that aims to achieve a technology-neutral services-based approach to applying obligations.
- By amending the non-energy cost framework to ensure a consistent and equitable approach across participant categories and technology types in light of increasing bi-directional flows. The more preferable rule achieves a more even playing field as it applies a consistent approach to all participant categories, rather than only levelling the field between grid-sized and smaller (exempt) batteries that are operated by MSGAs.

- By confirming that existing mechanisms in the NER, including the intervention and compensation framework and the RRO, will apply to storage and hybrids in the same way that they apply to other generators and loads.

Appropriately allocating risks:

- By amending the non-energy cost recovery framework so that participants have costs recovered from them when they contribute to a security or reliability event. The non-energy cost changes strengthen the causer pays signals to participants to encourage them to behave in ways that help promote the reliability and security of the system.

Minimising administrative and regulatory burden:

- By clarifying the registration and classification process for storage and hybrid facilities.
- By consolidating and streamlining the registration and classification provisions for market participants.
- By making it easier for AEMO's systems to receive bids from batteries and interpret market data (through the introduction of a single dispatch bid).
- By clarifying the meaning of key terms such as “load”, and ensuring these terms are used in a consistent way throughout the NER and are not used in such a way as to be unnecessarily restrictive given the prevalence of two-way electricity flows.

Enhancing system reliability and security:

- By facilitating storage to participate in the NEM and help increase the proportion of dispatchable resources which are needed to support increasing amounts of renewable generation.

This draft rule relates to parts of the NER that apply in the Northern Territory. In making the draft rule, the Commission has also considered whether a uniform or differential rule should apply to the Northern Territory. The draft rule determination is to make a uniform rule because some of the provisions in the NER which are amended by the draft rule are the same in the Northern Territory version of the NER, and the different physical characteristics of the Northern Territory’s network would not affect the operation of the draft rule in such a way that a differential rule would better achieve the NEO in this instance.

ABBREVIATIONS

AC	Alternating current
ACE	Adjusted consumed energy
AEC	Australian Energy Council
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGE	Adjusted gross energy
AGC	Automatic Governor Control
ARENA	Australian Renewable Energy Agency
ASOE	Adjusted sent out energy
BDRP	Bi-Directional Resource Provider
BNEF	Bloomberg New Energy Finance
CEC	Clean Energy Council
CEFC	Clean Energy Finance Corporation
Commission	See AEMC
DC	Direct current
DER	Distributed Energy Resources
DNSP	Distribution network service provider
DUID	Dispatchable Unit Identifier
DUOS	Distribution use of system
EAAP	Energy Adequacy Assessment Projection
EGES	Emerging Generation and Energy Storage
EMM	Energy Ministers Meeting
ENA	Energy Networks Australia
ESB	Energy Security Board
ESD	Energy storage device
ESCRI	Energy Storage for Commercial Renewable Integration
ESS	Essential System Services
ESS	Energy Storage Systems
FCAS	Frequency Control Ancillary Services
FRMP	Financially Responsible Market Participant
IRP	Integrated Resource Provider
IRU	Integrated Resource Unit
ISP	Integrated System Plan
MASS	Market Ancillary Service Specifications
MLF	Marginal loss factor
MSATS	Market Settlement and Transfer Solution

MSGA	Market Small Generation Aggregator
MW	Megawatt
MWh	Megawatt-hour
NEL	National Electricity Law
NEM	National electricity market
NEMDE	NEM Dispatch Engine
NEO	National electricity objective
NER	National electricity rules
NSCAS	Network Support Control Ancillary Services
NSP	Network service provider
PASA	Projected assessment of system adequacy
RAB	Regulatory asset base
REZ	Renewable Energy Zone
RERT	Reliability and Emergency Reserve Trader
RRO	Retailer Reliability Obligation
SAPS	Stand-alone Power Systems
SGA	Small Generator Aggregator
SRAS	System Restart Ancillary Services
SSMR	System Strength Mitigation Requirement
TNSP	Transmission network service provider
TSS	Tariff structure statement
TUOS	Transmission use of system
UGIF	Unconstrained intermittent generation forecast
VPP	Virtual Power Plant
VRE	Variable renewable energy

A INCREASING STORAGE IN THE MARKET

A.1 Storage in the current market

In its rule change request, AEMO explains that the market now consists of greater numbers of participants who are both purchasing and selling electricity rather than predominately just doing one of these activities. AEMO notes that proponents are now more frequently including storage (mainly batteries) in their facilities and portfolios and it expects the role of inverter-connector storage[104] in the power system, which provide energy and system support service, will continue to grow.[105]

In addition, AEMO is observing:[106]

- growing grid scale battery storage connections
- increasing numbers of applications and interest in registering storage systems and hybrid facilities
- significant growth in battery storage and bi-directional flows at the distribution level.

AEMO notes that the recent increases in connecting storage systems in the NEM, at both the transmission and distribution level, are due to the:[107]

- support energy storage systems can provide to variable renewable energy (VRE)
- ability for energy storage systems to provide important grid support services
- opportunities for energy storage systems to leverage energy arbitrage.

A.1.1 Current levels of storage and bi-directional flows in the NEM

Grid-scale storage

Storage systems, including batteries and pumped hydro units, are not new technologies in the NEM. Storage systems have been connected to the Australian electricity grid since 1973, when the 1,500 MW Tumut 3 pumped hydro unit was first built as part of the Snowy Hydro complex. Over the past two decades, a number of small battery systems have also connected to the grid in a range of demonstration projects and trials, but these systems were too small to require registration.

In December 2017, the Hornsdale Power Reserve became the first utility-scale battery in the NEM when it connected to the grid. Since then, four more lithium-iron batteries have connected across the network. Of these five projects, two connected adjacent to wind and solar power plants, one behind the same connection point, and two were deployed at network substations. These projects have storage capacities that range from 15 minutes to 2 hours.

A list of grid-scale battery systems that currently connected in the NEM is below in Table A.1.

104 encompasses different electricity storage technologies such as pumped hydro, batteries (grid-scale and exempt) or flywheels.

105 AEMO, *Integrating energy storage systems into the NEM* - rule change request, p. 4.

106 AEMO, *Integrating energy storage systems into the NEM* - rule change request, p. 4.

107 AEMO, *Integrating energy storage systems into the NEM* - rule change request, p. 2

Table A.1: **Grid-scale battery systems connected to the NEM since 2017**

PROJECT	LOCATION & CONFIGURATION	COMMISSIONED
Hornsdale Power Reserve* (100MW/129MWh)	Co-located with the Hornsdale Wind Farm (but with its own connection point) 15 km north of Jamestown in South Australia.	December 2017
Dalrymple ESCRI battery (30MW/8MWh)	Installed at the Dalrymple substation near the Wattle Point wind farm on the Yorke Peninsula, South Australia.	September 2018
Ballarat Energy Storage System (30MW/30MWh)	A stand-alone system located at the Ballarat Area Terminal Station in Warrenheip, Victoria	November 2018
Gannawarra Energy Storage System (30MW/25MWh)	Co-located with the Ganawarra Solar Farm in Ganawarra, Victoria.	March 2019
Lake Bonney (25MW/52MWh)	Co-located with Lake Bonney Wind Farm and shares connection point at the Mayurra substation in Mount Gambier, South Australia.	October 2019

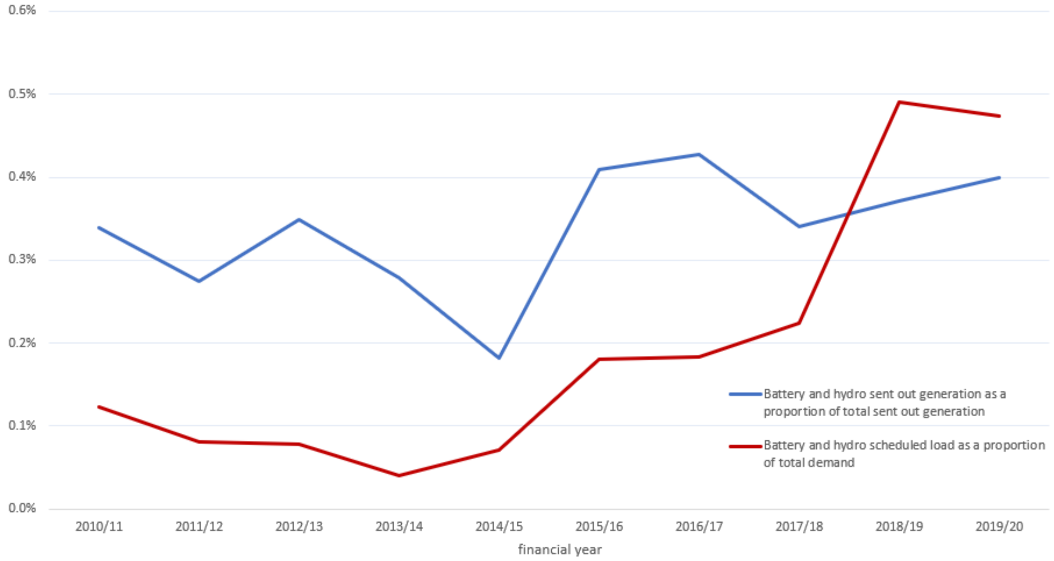
Source: Hornsdale: Barker, Stephanie, 2019, *Showcase Project: Hornsdale Power Reserve Project, Australia*, Global Infrastructure Hub: Sydney. Accessed here; Darlrymple, Ganawarra, Ballarat and Lake Bonney: Aurecon, 2019, *Large -Scale Battery Storage Knowledge Sharing Report,* September 2019, updated November 2019, ARENA: Sydney. Accessed here; Lake Bonney: ESCOSA, *Application form for the issue of an Electricity Generation Licence (Lake Bonney Wind Farm)*, licence variation request for Lake Bonney Wind Power Pty Ltd, August 2019. Accessed here.

* The Hornsdale Power Reserve has recently commenced testing for a 50MW/64.5MWh expansion of the facility[108]

The proportion of sent out electricity and demand that is attributable to hydro facilities and grid-scale batteries has increased over the past 10 years, as shown in Figure A.1. While this still only represents about half a percent of sent out energy and demand, the amount of storage capacity in the NEM is expected to increase more than eight fold over the next 20 years, see appendix A.2.3 below, which highlights the need for change now to meet the direction of the future market.

108 https://hornsdalepowerreserve.com.au/testing-on-the-expansion-has-commenced/

Figure A.1: Battery and hydro activity as a proportion of total sent out generation and total demand (TWh)



Source: AEMC analysis of AEMO's Market Management System (MMS) database.

Current interest in connecting large hybrid facilities

Hybrid facilities have, in some ways, always been part of the NEM. All power plants have auxiliary loads, and many of these could consume electricity from the grid. However, these auxiliary loads generally consume a far smaller amount of electricity than the electricity exported. For most of the NEM's operation, there were only a few facilities that had significant exports and imports of electricity behind a single connection point, and few assets that could both import and export electricity.

While the Commission understands that there is currently only one grid-scale hybrid facilities in operation, in its rule change request, AEMO notes that it is continuing to receive registration and connection enquiries in relation to storage systems as part of a hybrid facility (i.e storage system coupled with a generating system and/or industrial loads).[109]

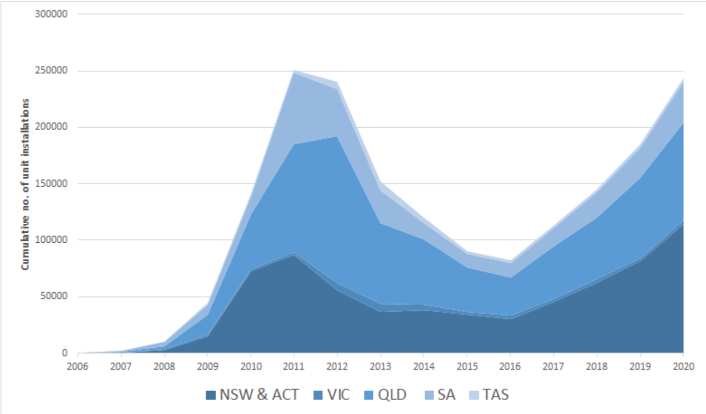
Current levels of storage and bi-directional flows in distribution networks

AEMO notes in its rule change request that the current market includes greater numbers of connection points with two-way electricity flows including, at the distribution level, "residential customers with installed devices, e.g. rooftop photovoltaic (PV) and batteries".[110] The figures below demonstrate these trends by jurisdictions by illustrating the number of rooftop PV units installed (Figure A.2), as well as annual installation of rooftop PV and battery systems (Figure A.3) annually across the NEM.

109 AEMO, *Integrating energy storage systems into the NEM* - rule change request, p.4.

110 AEMO, *Integrating energy storage systems into the NEM* - rule change request, p.2

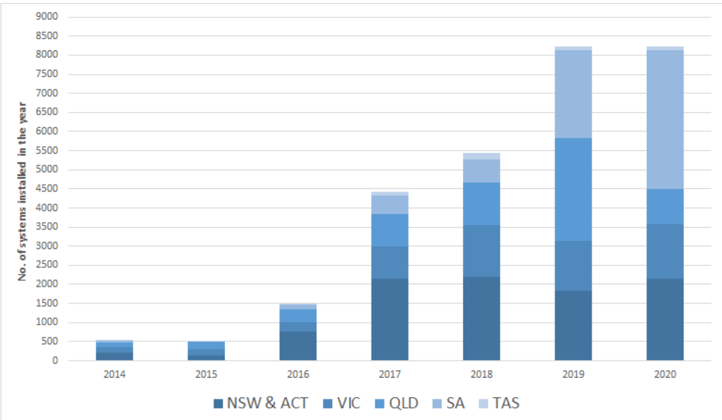
Figure A.2: Number of small-scale solar PV unit installations, per year, in the NEM (31 December 2020)



Clean Energy Regulator postcode data for small-scale installations: [available here]

Note: The data includes new installations, upgrades to existing systems and stand-alone (off-grid) systems. A 12-month creation period for registered persons to create small-scale technology certificates applies under the *Renewable Energy (Electricity) Act 2000*. Therefore, the 2019 and 2020 figures will continue to rise due to the 12-month creation period.

Figure A.3: Residential battery storage and PV system installations in, per year, the NEM (31 December 2020)



Clean Energy Regulator postcode data for small-scale installations: [available here]

Note: The data includes new installations, upgrades to existing systems and stand-alone (off-grid) systems. A 12-month creation period for registered persons to create small-scale technology certificates applies under the *Renewable Energy (Electricity) Act 2000*. Therefore, the 2019 and 2020 figures will continue to rise due to the 12-month creation period. Also note that this data is based on the calendar year and not the financial year and so the above graph has excluded 2021.

A.2 The role of storage and bi-directional flows into the future

In its rule change request, AEMO explains that, in addition to the current issues noted above, there is a need to address the issues it has identified for storage and hybrids now given the expected strong uptake of battery storage and increasingly complex arrangements of assets behind connection points.[111]

The following sections summarise:

- drivers for increased investment in storage technologies in the future
- upcoming projects
- AEMO's recent reports that show an increasingly important role for storage in the future.

A.2.1 Drivers for increased storage technologies

The drivers for increased uptake include:

- technology costs reducing
- government programs that subsidise investment in batteries
- reforms to the market design that will provide stronger signals for investing in storage technologies.

Technology costs reducing

The cost of utility-scale storage technologies has significantly decreased over the past decade. For example, Bloomberg New Energy Finance (BNEF) identifies that between 2010 and 2019, the cost of lithium ion batteries fell by 87%. [112]

Government programs

A range of government programs are driving uptake of both small and grid-scale storage, whether as stand-alone units, combined with PV behind-the-meter, or aggregated into virtual power plants (VPPs).

- In 2019 Hydro Tasmania highlighted future hydro capacity to provide more energy into the NEM. In December 2020, the Tasmanian and Australian Governments announced a commitment to identify and refine support mechanisms for the project. A $650 million redevelopment of Tarraleah could increase the scheme's responsiveness, flexibility and double its generation capacity. The announcement came alongside the signing of a bilateral Memorandum of Understanding (MOU) between the Tasmanian and Australian Governments to progress this Battery of the Nation project.[113]
- The NSW Government has introduced a $75 million Emerging Energy Program that provides grants for pre-investment studies and capital investment for dispatchable generation technologies. So far, it has awarded grants to 5 capital projects and 9

111 AEMO, *Integrating energy storage systems into the NEM* - rule change request, pp. 2, 3, 26, 28, 54. See also AEMO's rule change request cover letter.

112 (BNEF, *Battery Pack Prices Fall As Market Ramps Up With Market Average at $156/kWh In 2019*, 3 December 2019. Accessed here.

113 Hydro Tasmania's *Battery of the Nation* webpage can be accessed here.

investigative projects under the Pre-Investment Studies stream. These projects include pumped hydro, battery, VPPs, and solar thermal storage technologies.[114]

- In 2020 the NSW government announced its Electricity Infrastructure Roadmap,built upon the 2018 Transmission Infrastructure Strategy and the 2019 Electricity Strategy [115]. This roadmap commits the government to establishing 5 Renewable Energy Zones (REZ), an Electricity Investment Safeguard and a Transmission Development scheme to reduce REZ investment risks. The roadmap is designed to meet the NSW Energy Security Target and will deliver 12GW of new capacity into the system over the coming decade - 2GW of which has been specifically allocated for storage.
- The Queensland Government's Renewables 400 reverse auction program is providing financial support to renewable energy and energy storage projects. In July 2019, it shortlisted 10 projects for potential support: eight of these were combined VRE and battery projects, and one was a standalone battery project. The Queensland Energy Security Taskforce is also tasked with developing options to increase pumped storage generation capacity in the state.[116]
- As well as providing grant funding for the Gannawarra and Ballarat storage systems, the Victorian Government has committed to providing rebates for Victorian households with existing solar PV systems to install batteries.[117] Following a successful pilot of 10,000 homes, the Solar Homes Program has been expanded and is providing a rebate of up to $4,174 for eligible households until 30 June 2021. The battery program is designed to target postcodes with high PV penetration and population growth.[118]
- The South Australian Government has committed $100 million to the Home Battery Scheme, which will provide 40,000 household subsidies to install battery storage systems. Households can access low finance through the program to cover the balance of the subsidised battery system, as well as purchase new or additional solar panels, if required.[119] The South Australian Government has also committed to support Tesla to install up to 50,000 Powerwall batteries and operate it as a VPP with a capacity of 250MW/650MWh.[120]
- The ACT Government started the Next Generation Energy Storage Program, one of the world's largest roll out of household batteries, in early 2016. The $25 million program is supporting the roll out of 36MW of distributed battery storage to 5,000 ACT homes and businesses, and is currently seeking proposals from interested battery providers to participate in Round Five, Submission Period 2 of the program.[121]

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114 Department of Planning, Infrastructure and Energy, *Emerging Energy Program*, webpage, NSW Government. Accessed here.

115 Energy NSW, *Electricity Infrastructure Roadmap*, webpage, NSW Government. Accessed https://energy.nsw.gov.au/government-and-regulation/electricity-infrastructure-roadmaphere

116 Department of Energy and Public Works, *Achieving our renewable energy targets*, webpage, Queensland Government, 23 October 2019. Accessed at: https://www.epw.qld.gov.au/about/initiatives/renewable-energy-targets

117 The Hon Daniel Andrews MP, 2018, *Cheaper Electricity with Solar Batteries for 10,000 homes*, media release, Victorian Government, 11 September 2018. Accessed here.

118 Solar Victoria, *Solar battery rebate*, webpage, Victorian Government. Accessed here.

119 Government of South Australia, *South Australia's Home Battery Scheme*, webpage. Accessed here.

120 Government of South Australia, *South Australia's Virtual Power Plant,* webpage. Accessed here.

121 ACT Government, *Next Generation Energy Storage (Next Gen) Program*, webpage. Accessed here.

Current reforms that will provide efficient incentives to enhance the case for storage to enter the NEM

There are a number of market reforms underway or being considered that, once implemented, are expected to provide clearer price signals to the market resulting in stronger incentives for storage to enter the NEM. For example, the five-minute settlement (5MS) reforms, commencing in 2021, will increase the opportunity for price arbitrage in the NEM's energy and FCAS markets. Increasing the granularity of the settlement period should also lead to an increase in profitability for batteries as they will become better compensated for their ability to quickly charge and discharge their full capacity in just a few trading intervals.

The system strength rule change (ERC0300) proposes to introduce the *System strength mitigation requirement* that imposes a proportional charge for the service to those connections, including some storage, that require it. This charge is designed to align the incentives of market participants to locate in the areas of the NEM where system strength is provided, thus better utilising the service across the grid.

The ESB's medium term solutions in the transmission and access market design initiative seek to provide storage with more granular price signals than the current market design. More granular locational pricing incentives are likely to enhance the business case for batteries in the NEM because they can be more rapidly and flexibly deployed than traditional firming capacity. International experience, and research undertaken by the AEMC suggests that these changes are likely to have a material impact on the deployment of battery storage.[122]

A.2.2 Upcoming Projects

AEMO has identified a number of upcoming storage projects. In its *April 2020 NEM Generation Information* dataset, AEMO identifies over 13GW of publicly announced, maturing and committed future storage projects for the NEM, as shown in the table below.[123]

122 AEMC research and analysis can be found here.

123 AEMO, *April 2020 Generation information* dataset. Accessed here.

Table A.2: **Total MW capacity of announced, committed and maturing storage projects in the NEM as at July 2020**

	PUBLICLY ANNOUNCED	COMMITTED	MATURING	TOTALS (BY TECHNOLOGY)
Batteries	7410	333	20	**7763**
Pumped hydro	6254	2040	0	**8294**
VPP	7	8	0	**15**
TOTAL (by status)	13671	*2381*	*20*	16072

Source: AEMO, *July 2020 NEM Generation Information* dataset. Accessed here.

Note: Publicly announced projects are those that "have been announced publicly, but do not yet have any finance arrangements in place. Costs and capabilities of these projects are developed using recently-completed projects and projections of cost components such as raw material supply and labour." In this table, Committed projects are those where construction and has commenced; project finance is in place; the projects have either completed contracts for major equipment components (or are at an advanced stage); and planning and registrations are completed or are at an advanced stage. . Maturing projects "have progressed with site, planning applications, and finance arrangements, but not to the point that they can be classified as advanced. Maturing projects may be explicitly included in scenario analysis to assess future reliability or market impacts and are tested for economic efficiency in capacity outlook modelling."

This data indicates that storage projects are already starting to incorporate larger storage capacities: around 4 hours for battery projects and several days for the larger pumped hydro projects.[124] Projects are also now being developed without direct support from government grants and subsidies. For example, Nexif's 10 MW/10MWh[125] Lincoln Gap battery was deployed using only low-cost finance from the Clean Energy Finance Corporation (CEFC).[126]

Another notable upcoming project is the Kennedy Energy Park. This facility is seeking to co-locate 15MW of solar resources, 43.2MW of wind resources and a 2MW/4MWh battery storage facility in the one facility.[127] This project has reportedly experienced difficulties connecting to the NEM[128] and would be the first hybrid facility in operation in Australia.

A.2.3 AEMO's recent reports about the role of storage in the future

AEMO states in its rule change request that it expects the number of battery units and hybrid facilities in the NEM to significantly increase, and this expected growth is one of the reasons why it has submitted its rule change request.[129] AEMO has separately articulated possible future roles for storage in its *Renewable Integration Study* and *Engineering Framework March 2021 Report,* as well as forecasting expected growth in storage in its *Integrated System Plan*. These are detailed below.

Renewable Integration Study

124 Ibid.

125 This means the battery can operate at a maximum output of 10MW and has storage capacity of 10MWh i.e. if it had one hundred per cent state of charge, it could discharge at maximum output for one hour before it would be empty.

126 "Nexif's Port Augusta battery at Lincoln Gap ready to turn on and pay its way commercially", *Adelaide Now,* 21 June 2019. Accessed at: https://www.adelaidenow.com.au/business/sa-business-journal/marketbased-big-battery-at-port-augusta-ready-to-switch-on-and-pay-its-way-commercially/news-story/f5842818169aa47b8e4f4d08cf5d5fd4

127 ARENA, Kennedy Energy Park. Project site available here.

128 "After more than a year, Kennedy renewable energy farm still not fully connected to grid", *ABC*, 4 March 2020. Accessed here.

129 AEMO, *Integrating energy storage systems into the NEM* rule change request p. 2, 4, 56.

AEMO's 2020 *Renewable Integration Study* considers potential roles for storage in the future grid. AEMO identifies that the system will need to operate more flexibly to accommodate increased variability and uncertainty.[130] It identifies storage, particularly batteries and pumped hydro, as a possible source of flexibility.[131]

> Storage can participate by increasing demand (load) or increasing supply (generation). It can decrease production or increase its load during periods of surplus generation, such as in high VRE periods. It can then increase production in periods where VRE is lower. Having a diverse range of technical characteristics across the storage fleet allows management of variability over different timescales, for example pumped hydro and battery storage.
>
> - Pumped hydro has the capability to quickly produce or demand large amounts of energy over a longer duration, although there are limitations to how quickly it can switch between these modes. New variable speed drive pumped hydro projects, such as three of Snowy 2's six units, are able to provide this flexibility almost instantaneously.
> - Batteries have fast response times and can cycle from charge to discharge much quicker than pumped hydro, however, the units currently installed in the NEM have a much shorter duration for which they can run. This is important, as having a diverse range of technical characteristics across the storage fleet allows management of variability over different timescales. Battery storage is also a scalable technology that can be readily co-located with VRE resources in a hybrid facility to firm VRE output or as a stand-alone installation.

2020 Integrated System Plan

AEMO's Integrated System Plan (ISP) models the optimal development path for the NEM.[132]

The *2020* ISP, released on 30 July 2020, identifies that storage, combined with strategically placed interconnectors and renewable energy zones, "will be the most cost-effective way to add capacity and balance variable resources across the whole NEM".[133] The ISP identifies that, to support an expected 26 to 50GW of new grid-scale renewable generation, the grid requires 6 to 19GW of new dispatchable resources by 2040. Dispatchable resources include flexible gas generators, demand-side participation, hydrogen generation, and storage technologies like pumped hydro, grid-scale battery storage, and distributed batteries participating as VPPs.[134]

The 2020 ISP forecasts that most initial investment in dispatchable generation will be in "utility-scale pumped hydro (such as Snowy 2.0, already committed) or battery storage

130 AEMO, *Renewable Integration Study Stage 1 Appendix C: Managing variability and uncertainty*, April 2020, p. 45. Accessed here.

131 Ibid, p. 46.

132 AEMO, *2020 Integrated System Plan*, webpage. Accessed here.

133 AEMO, *2020 Integrated System Plan: for the National Energy Market*, 30 July 2020, p. 13. Accessed here.

134 Ibid, p. 50.

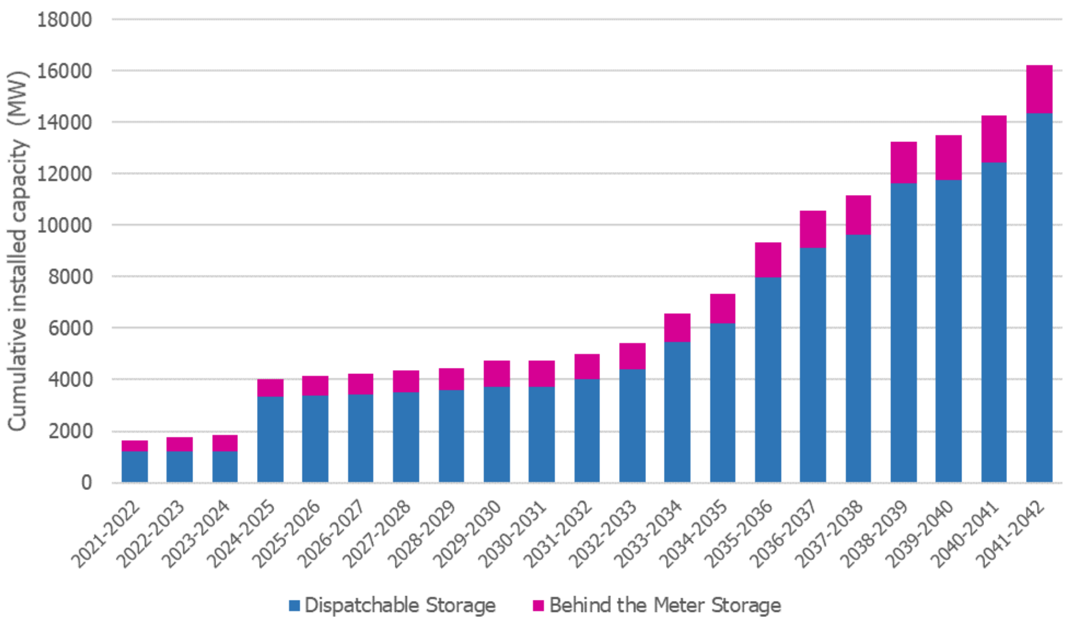
(assuming technology costs continue to fall, and the market arrangements sufficiently incentivise this development)."[135]

The ISP identifies that:

- Utility-scale energy storage can shift the timing of renewable energy production, reduce the magnitude of new intra-regional transmission required, and provide firming support during peak loads or when renewable production is low.[136]
- The growth in storage is expected to be broadly aligned with timing of coal-fired generation retirements.[137]
- The type and depth of storage required will depend on the mix and location of renewable generation, and the ability of existing generators to smooth out short-term and seasonal renewable variability.[138]

As shown in the figure below, AEMO's 2020 ISP central scenario forecasts over 16,000MW of storage installed in the NEM by 2042.

Figure A.4: Cumulative installed storage capacity (MW) by year (ISP central scenario)



AEMO, *2020 ISP NEM Generation Outlook*, dataset extracted from online visualisation, central scenario, filtered for storage technologies. Note that dispatchable storage includes all sizes of dispatchable storage, including grid-scale batteries, pumped hydro and virtual power

135 Ibid, p. 50.

136 Ibid.

137 Ibid p. 51.

138 Ibid

plants. Behind the meter storage includes all storage that is not dispatchable, such as residential batteries that are not part of a virtual power plant. Chart completed in Excel using AEMC formatting. Accessed here.

AEMO notes that its 2020 ISP analysis "assumes optimal operation of the installed storage with perfect foresight. However, even minor inefficiencies in real world operations lead to the need for more storage or other forms of dispatchable generation, to ensure reliable supply for consumers."[139]

The Commission notes that the ISP did not take into account the NSW 2020 Infrastructure Roadmap in its modelling, requiring further analysis.

Engineering Framework March 2021 Report

In the NEM Engineering Framework March 2021 Report, AEMO outlines its proposed approach to preparing for the future system and operational conditions of the NEM[140]Among the example conditions AEMO is considering is the operation of the system with a high amount of price-responsive energy storage and increasing demand response. The report notes that as a key distributed asset enabling power system operation, storage will form an important aspect of physical power system infrastructure and the associated performance standards in the future of the NEM. As such, storage and its future role are being actively considered under several AEMO work streams, including:

- Within AEMO's DER operations work stream, focused on identifying and addressing power system operational impacts of increasing DER penetration within which storage will continue to play an important role
- AEMO's analysis of future system restoration highlights the potential for large and strategically located storage with grid-forming capabilities to be utilised for black start and other security services
- AEMO's review and development of 'fit for purpose' performance standards to meet the needs of an increasingly complex system that will involve growing amounts of storage and demand response.

Given the rapidly changing technological landscape of the energy sector, AEMO is actively seeking to facilitate stakeholder feedback and discussion on these matters.

139 Ibid p. 50

140 AEMO, *NEM Engineering Framework March 2021 Report*. Accessed here

B REGISTRATION AND PARTICIPATION FRAMEWORK

B.1 Overview

In its rule change request, AEMO outlined a number of issues that, in its view, exist with the current registration, classification and participation framework for storage and hybrid facilities. To address these issues, AEMO proposed a change to introduce a definition of storage in the NER and a new participant category, the BDRP, as well as additional technical and operational changes.

The Commission's draft decision is to introduce a new participant category, the Integrated Resource Provider or IRP, with a technology-neutral approach for any new definitions in the NER to accommodate storage and hybrid facilities. All new grid-scale storage and hybrid systems would be required to register in this category. Aggregators of small units, and entities that would otherwise register as Generators or Market Customers, would also be allowed to register under the IRP category and provide energy and ancillary services into the market.

The draft decision lowers barriers to entry for new storage participants, small and large, by creating a clear and simple regulatory framework for participation in the NEM. It also increases operational efficiency through providing flexibility for hybrid facilities to manage energy flows between units behind the connection point. This draft decision also aligns with the ESB’s longer term view to move to a trader-services based model for participation in the NEM with a universal participant category. Establishing the IRP is a no-regrets first step toward that longer-term outcome.

This chapter outlines:

- how registration, classification and participation currently occurs in the NEM
- the issues raised by AEMO
- AEMO's proposed solution
- stakeholder feedback
- the Commission's draft decision and analysis.

B.2 How registration, classification and participation occurs in the NEM

B.2.1 Registration and classification under the NER currently

Broadly, the NEL and NER require all legal entities that own, operate or control a generating system connected to the NEM, or that intend to buy or sell electricity from the spot market, to register with AEMO.[141] Chapter 2 of the NER sets out the categories under which entities can register to become participants in the market. Some of these categories include classifications that the relevant registered entity must apply to its units depending on the technical characteristics of that unit and how the entity chooses to participate in the market. There are also eligibility requirements that entities must meet to register in a category. Once registered, an entity becomes bound by the obligations in the NER that are specific to that

141 *National Electricity Law (South Australia) Act 1996*, sections 11 and 12; National Electricity Rules Chapter 2.

category and must provide services from its units under the obligations in the NER specific to the classification of those units. The relationship between registered participant categories and classifications is explained in Box 1 below.

BOX 1: THE RELATIONSHIP BETWEEN REGISTRATION AND CLASSIFICATION IN THE NEM

To participate in the NEM, people must become registered participants unless eligible for an exemption. The generating equipment or load that is owned, operated or controlled by registered participants, and used to provide services in the NEM, must then be classified based on its size, technical capacity and the services it provides.

Any person engaged in the activity of owning, controlling or operating a generating system in the NEM must be **registered** as a *Generator*. Similarly, any person involved with purchasing electricity through a wholesale market must be **registered** as a *Customer.* This is the case unless the person is eligible for an exemption.

Before officially becoming a registered participant in the NEM, a *Generator* must also **classify** each of its *generating units*. Generally, the **classification** of a *generating unit* is determined by its size and technical capacity. All **classifications** are subject to AEMO's approval, which is in turn subject to the satisfaction of various technical and operational requirements. A *Generator* will also be **classified** as either a *Market* or *Non-Market Generator* depending on whether the electricity it produces will be sold through the *spot market* or used in other commercial processes respectively. There are three primary types of generator **classifications**:

- scheduled – the *generating unit* participates in *central dispatch*
- non-scheduled – the *generating unit* does not participate in *central dispatch*
- semi-scheduled – the *generating unit* will participate in central dispatch, though with a lower set of obligations to meet dispatch targets than scheduled generating units.

A *Market Customer* may request to have any of its *market loads* **classified** as a *scheduled load* and participate in central dispatch.

Source: AEMO, *Guide to generator exemptions and classifications of generating units,* Available here. Section 11(1)(a) of the NEL. Clauses 2.2.1(c), 2.2.2, 2.2.3, 2.2.7 and 2.3.4(d) of the NER.

Current registration and classification approach for storage units and hybrid facilities

As no forms of storage facilities are currently defined in the NER, storage assets are treated as both "load" and "generation" due to the fact that a storage asset can 'consume' electricity from the grid and send electricity out to the grid. To clarify how storage units register and participate in the NEM, AEMO has developed the Interim arrangements guidelines.[142] Based on the requirements of the NER and AEMO's guidelines, storage units and hybrid facilities currently register and participate in multiple ways:

142 AEMO, 2018, *Interim arrangements for utility scale battery technology.*

- A participant with a grid-scale storage unit, above 5MW, would typically register as both a Market Generator and a Market Customer. The storage unit would be classified separately as a scheduled generating unit and a scheduled load.
- A participant with a hybrid facility would typically:
  - register as both a Market Generator and Market Customer[143]
  - classify their units and participate according to their technical capabilities.[144]
- A participant with a storage unit below 5MW would be automatically exempt from registration as a Generator. However, that participant could choose to register as a Small Generation Aggregator (SGA) and classify the unit as a small generating unit.[145] The Market Participant category of an SGA is the Market Small Generation Aggregator (MSGA).

B.2.2 Participation under the NER currently

Central dispatch

Under the current arrangements, scheduled participants are required to participate in the central dispatch process operated by AEMO. Generators submit 'offers' and scheduled loads submit 'bids' to AEMO linked to unique dispatchable unit identifiers (DUIDs). These offers and bids specify the quantities at which each participant is willing to supply or consume electricity at nominated prices. AEMO runs central dispatch through the NEM Dispatch Engine (NEMDE), which dispatches scheduled participants every five minutes to balance supply and demand of the electricity market in real time. NEMDE optimises the bids and offers provided to determine a 'least-cost' dispatch for energy and ancillary services accounting for technical constraints.[146]

The operator of a storage facility currently participates in central dispatch by providing both an offer to generate electricity, from the scheduled generating unit, and a bid to consume electricity, from the scheduled load, and may offer FCAS services from both. For each bid and offer, it can submit up to 10 price-quantity pairs. The operator of a storage facility receives two dispatch targets and is required to comply with these targets.

A hybrid facility would participate in central dispatch by submitting separate offers for each of its generating units and separate bids for each of its scheduled loads. A hybrid facility operator would receive dispatch targets for each individual unit and be required to meet those targets at each individual unit.[147] However, AEMO has indicated it would consider dispatch compliance at the connection point level for hybrids in some circumstances, in the form of an aggregated conformance cap.[148]

143 Ibid, pp. 11-12.

144 Ibid, p. 12.

145 Ibid, p. 13. Storage units below 5MW could also be included in a Market Customer's retail portfolio.

146 Clause 3.8.1 of the NER.

147 AEMO, Integrating energy storage systems into the NEM rule change request, p. 12. Semi-scheduled generators are taken to be compliant with dispatch targets if variance is only as a result of energy source availability and in the case of a semi-dispatch interval, does not exceed the dispatch level, regardless of energy source availability.

148 See AEMO's 'Registering a Hybrid Generating System in the NEM' fact sheet here.

Small storage units, below 5MW and classified by an MSGA, do not participate in central dispatch. Instead, they participate similarly to non-scheduled generators with AEMO paying the MSGA the spot price for any electricity generated.[149] The NER do not currently allow MSGAs to provide ancillary services to the NEM.

Ramp rates and aggregation

Ramp rate limits maintain the dispatch targets issued to generators within their technical limits so the operation of the power system stays within its secure operating limits. Generators are limited in how quickly they can change the level of output. These limitations need to be reflected in the security constrained optimisation run by NEMDE to make sure generators are not set dispatch targets beyond their technical capability.

The NER also set out minimum ramp rate requirements.[150] Minimum ramp rates seek to reduce the risk of scheduled participants changing their ramp rates to take advantage of market conditions. For example, minimum ramp rates limit the ability of a generator to reduce output during periods when prices are high. Minimum ramp rates are currently set differently for different scheduled resources:

- scheduled generating units: the lower of three per cent of maximum capacity or 3 MW per minute
- scheduled generating units that are aggregated: the lower of three per cent of maximum capacity or 3 MW per minute applied to individual physical units, then summed
- scheduled network services and scheduled loads: 3 MW per minute
- scheduled network services and scheduled loads that are aggregated: 3MW per minute applied to individual network services and individual loads, then summed.

Forecasting and energy availability

AEMO has multiple forecasting responsibilities as market operator, including managing:

- the projected assessment of system adequacy (PASA) processes, which collect information on, analyse and disclose medium term and short term power system security and reliability of supply prospects up to two years in advance[151]
- the Energy Adequacy Assessment Projection (EAAP), which analyses and quantifies the impact of energy constraints on energy availability under a range of scenarios over a two year period[152]
- the pre-dispatch process, which is a daily forecast of electricity demand for scheduled and semi-scheduled generation, scheduled load and projected demand.[153]

AEMO is responsible for collecting the necessary information from participants, and determining and publishing the results. The NER require this information to be submitted by

149 For more information on SGAs see AEMO's fact sheet [here, and rule 2.3A of the NER].

150 Clause 3.8.3A of the NER.

151 Clause 3.7.1 of the NER.

152 Rule 3.7C of the NER.

153 Clause 3.8.20 of the NER.

market participants on behalf of scheduled generators, scheduled loads, ancillary service generating units and ancillary service loads. This includes the export and import sides to utility scale scheduled storage. The information that needs to be provided includes:

- dispatch bids, dispatch offers, and market ancillary service offers[154]
- intention to self-commit and synchronise scheduled generating units (via PASA and pre-dispatch)[155]
- self-decommitment and de-synchronisation (via PASA and pre-dispatch).[156]
- ahead of real time, market participants must also provide AEMO their daily energy availability for any energy constrained scheduled generating units or scheduled loads.[157]

Performance standards

Equipment that connects to the power system needs to be able to perform in a manner that enables the power system to operate securely and reliably. For connecting generating systems, this means:

- having certain technical capabilities available while in normal operating conditions
- the need to be able to withstand certain disturbances (including those caused by faults and generation tripping) and provide support to the power system throughout the disturbances
- the ability to quickly recover after disturbances to help bring the power system back to normal operating conditions.

Loads generally have less onerous performance standards applied when connecting. When scheduled storage facilities (stand-alone batteries or hybrid facilities) connect to the NEM, they are required to meet a single set of performance standards agreed at the connection point.

B.3 Issues raised

B.3.1 Defining storage in the NER

AEMO's rule change request suggested it is problematic for the NER to treat a single energy storage asset as both generation and load. While AEMO has been able to accommodate storage to date, it notes there still remain problems for storage registering and participating in the NEM under the existing regulatory framework. AEMO also suggested that this is an issue for hybrid facilities (that have a combination of load and generation behind the connection point, which may or may not include storage) because a hybrid facility would also be defined as being both load and generation, as the facility both consumes and sends out electricity.

154 Clauses 3.8.2(a), (c), (c1) and (e); 3.8.6; 3.8.7; 3.8.7A of the NER.
155 Clauses 3.8.17(e) and (f) of the NER; applies to scheduled generating units 30MW and above.
156 Clauses 3.8.18(c) and (d) of the NER; applies to scheduled generating units 30MW and above.
157 Clauses 3.8.4(c)(3) and (d)(2) of the NER.

B.3.2 Registration and classification

In AEMO's view the current arrangements for registering and classifying storage units and hybrid facilities:

- Increase administrative costs for AEMO and make the registration process slower, more expensive, complex and uncertain. For example, AEMO highlighted that it must still work extensively with applicants "almost on a case-by-case basis" to determine how the NER should apply to hybrid facilities.[158]
- Increase registration costs (fees and time spent registering) for intending participants with storage units and hybrid facilities. For example a storage proponent would pay $34,000 to register as both a Market Customer and Market Generator compared to the $11,000 or $23,000 to register as a Market Customer to classify a scheduled load or as a Market Generator to classify a generating unit, respectively.[159]
- Include no explicit NER provisions that prohibit an MSGA from classifying storage that is treated as a small generating unit.[160] AEMO also noted in its rule change request that it has no oversight of these small storage units and they would effectively act as 'non-scheduled' generators. This could involve a very large set of small storage units over which AEMO would have no oversight in scheduling and dispatch.

B.3.3 Participation

Central dispatch

In its rule change request, AEMO noted it considers the current approach to accommodating scheduled storage facilities in dispatch is problematic. It considers there is increased operational complexity and inefficiency involved in treating a single asset as two components. In particular, AEMO considered it is problematic to require a Registered Participant with a scheduled storage facility (which has two DUIDs, one for load and one for generation) to submit separate:[161]

- energy bids and offers for the scheduled load and scheduled generating unit, which could result in simultaneous dispatch of the load and generation
- FCAS offers for the ancillary service load and ancillary service generating unit (the combined offers need to reflect the overall capacity to move from load to generation and vice versa).

AEMO argued that this makes participation more complex, expensive and risky for scheduled storage units (compared to other asset types), which could create barriers to entry and impact on efficient investment and operation.[162]

158 AEMO, *Integrating energy storage systems into the NEM* rule change request, pp. 17, 18.

159 AEMO, *Electricity market revenue requirement and fees: 2019-20*, 21 February 2020, Table 2: "AEMO Schedule of Registration Fees 2019-20", p. 2.

160 AEMO, *Integrating energy storage systems into the NEM* - rule change request, p. 13.

161 AEMO, *Integrating energy storage systems into the NEM - rule change request*, p. 17.

162 Ibid, pp. 17, 18, 27.

Ramp rates and aggregation

In its rule change request, AEMO highlighted some issues relating to minimum ramp rates. AEMO notes that different aggregation methods can result in different minimum ramp rates calculated for semi-scheduled generating units and bi-directional units.[163] AEMO also considered there is no longer a rationale to apply a 6 MW maximum threshold to the aggregation of semi-scheduled generating units (this threshold exists in Chapter 2 of the NER).

Forecasting and energy availability

AEMO considered that, under the current arrangements, insufficient information is provided on the energy limited capacity reserves of scheduled storage. AEMO also noted that it considers battery systems to be of particular concern because they can charge and discharge quickly and cycle a number of times a day and typically rebid regularly. AEMO also considered these resources are not optimised in pre-dispatch and PASA because the NER do not recognise or specify any requirements for these assets.

AEMO stated this lack of information might result in less informed decision-making for:[164]

- registered participants, as pre-dispatch information is less accurate
- AEMO when managing power system security and reliability. For example, if scheduled storage capacity is not known in a certain timeframe, it cannot be relied on when assessing system reserves and may result in AEMO underestimating available reserves and intervening, potentially inefficiently. Alternatively, relying on scheduled storage capacity when energy limits are not accurate could lead to AEMO overestimating available reserves and not taking action early enough.

Performance standards

In its rule change request, AEMO noted that technical requirements are not currently symmetrical for two sides of the same asset, i.e. there are different technical requirements on the export and consumption sides of a scheduled storage facility.[165] AEMO argued that it is necessary to have greater visibility of all assets in a hybrid facility so that AEMO can understand the impact these facilities are likely to have on the power system. AEMO considered that it is no longer appropriate to base performance standards on the registered participant category as greater numbers of storage and hybrid facilities connect to the NEM. Instead, AEMO considered that a registered participant's performance standard should be based on its physical assets.[166]

163 AEMO provided an example of how the aggregation methods could lead to different minimum ramp rates under the current arrangements on p. 22 of its rule change request. AEMO, *Integrating energy storage systems into the NEM - rule change request,* p. 22.

164 AEMO, *Integrating energy storage systems into the NEM - rule change request*, p. 17.

165 AEMO, *Integrating energy storage systems into the NEM - rule change request*, p. 17.

166 Ibid, p. 18.

B.4 AEMO's proposed solution

B.4.1 Defining storage in the NER

AEMO's rule change request proposed to define storage and hybrid facilities, so that the rules better recognise storage and connection points with bi-directional flows. This proposal can be considered as the cornerstone of AEMO's rule change request because these definitions underpin AEMO's proposed solutions for how storage registers in the NEM and participates in dispatch. It is also the mechanism for AEMO's proposal to clarify fees and charges and other relevant NER requirements that apply to storage. AEMO notes in its rule change request that defining and recognising storage increases clarity and transparency for all stakeholders.[167]

B.4.2 Registration and classification

AEMO proposed to amend the NER to create the BDRP participant category and bi-directional unit type which would be classified as scheduled. Under this proposal, a proponent intending to connect a standalone storage unit would register as a scheduled BDRP and classify the unit as a scheduled bi-directional unit. A hybrid facility proponent would also register as a scheduled BDRP, and classify:

- each storage unit as a scheduled bi-directional unit.
- each generating unit that meets the criteria to be scheduled as a scheduled generating unit
- each generating unit that meets the criteria to be semi-scheduled as a semi-scheduled generating unit
- any loads that it wishes to be scheduled as a scheduled load.[168]

AEMO also proposed:

- that a storage unit without the ability to transition linearly from production to consumption (meaning it cannot submit a single dispatch bid), such as some types of pumped hydro, would classify as both a scheduled load and scheduled generating unit.[169]
- to clarify that MSGAs can classify small exempt storage as small bi-directional units.

B.4.3 Participation

Central dispatch

AEMO's rule change request proposed that scheduled storage assets would participate in central dispatch as a single asset, a scheduled bi-directional unit, with one DUID with 10 price bands. AEMO considered that a single dispatch model and bidding for scheduled storage would reduce the set-up and ongoing operational costs of participating in central dispatch. Scheduled storage operators would set up and operate a less complicated bidding and dispatch system when compared to managing two dispatch bids, two dispatch instructions and incurring costs associated with managing any conflicts. Under AEMO's

167 AEMO, *Integrating Energy Storage Systems into the NEM* - Rule Change Request, p. 54.

168 Ibid, pp. 30, 49, 63.

169 Ibid, p. 26.

proposed rule, a BDRP operating a hybrid facility would separately dispatch each scheduled bi-directional unit, scheduled generating unit, semi-scheduled generating unit and scheduled load.[170]

Ramp rates and aggregation

AEMO considered there should be one aggregation approach for semi-scheduled generating units and storage systems, reflecting the process in NER clause 3.8.3, and that the chapter 2 aggregation provisions including the 6 MW threshold should be removed. Clause 3.8.3 of the NER also requires AEMO to approve aggregation of generating units if certain conditions are met. AEMO noted that participation in dispatch as an aggregated generating unit (i.e. with one DUID) may not always be possible for different technology types.[171]

However, AEMO considered it is appropriate for the NER to allow AEMO the discretion to consider whether different technology types can be aggregated. In its view, AEMO's proposal would be to give greater flexibility for it to consider different technology types and classifications to be aggregated within a 'hybrid' facility, which it could do if there is no adverse impact on central dispatch.[172]

AEMO's proposal set out ramp rate requirements that would be applicable to a scheduled bi-directional unit, including requiring the ramp rate for each unit to be the lower of 3MW/minute or 3 per cent of the maximum produced electricity or consumed electricity (for a bi-directional unit).

Forecasting and energy availability

AEMO's proposed rule would require registered participants with a scheduled storage facility to submit a dispatch bid that reflects their available capacity for each trading interval. This would need to reflect the 'energy limits' of a scheduled storage unit, effectively the remaining stored energy capacity. AEMO considered an accurate availability profile is needed for pre-dispatch and is an input to other forecasting tools. [173]

Currently, a dispatch bid for an energy constrained scheduled generating unit or scheduled load may (or must) specify a daily energy limit.[174] While the proposed rule does not seek to change this approach for scheduled generation and load, AEMO noted that it is currently reviewing whether the PASA tools and processes are fit for purpose and this may result in subsequent rule changes.[175]

170 Ibid, p. 63.
171 Ibid, p. 23.
172 Ibid.
173 Ibid, p. 27.
174 Scheduled generating units *must* specify a daily energy limit and scheduled loads *may* specify a daily energy limit. Clauses 3.8.4(c)(3), 3.8.6(b) and 3.8.7(m) of the NER.
175 AEMO, *Integrating energy storage systems into the NEM - rule change request*, p. 28.

Performance standards

AEMO's proposed rule would require a single performance standard to apply to a "bi-directional facility" and this be reflected in Chapter 5, recognising that a bi-directional facility may include more than one asset (e.g. generating units, bi-directional units or loads).[176]

B.5 Stakeholder feedback

The Commission engaged with stakeholders on registration and participation issues twice, through the consultation paper and the options paper. Appendix B.5.1 to appendix B.5.3 cover feedback from the consultation paper, and appendix B.5.4 covers feedback to the options paper.

B.5.1 Defining storage in the NER

In response to the consultation paper, stakeholders were generally mixed on whether storage should be defined in the NER as proposed by AEMO. Some stakeholders argued storage is fundamentally different from generation and load, and should be treated as such, while others did not see the need for a storage-specific definition and any changes should align with the ESB's post-2025 reforms.

More specifically, stakeholders who supported AEMO's proposed definitions for storage either:

- agreed in principle with the need to define storage and hybrid facilities[177]
- argued that storage is fundamentally different from load or generation, because it can time-shift energy (store at times of surplus and generate during deficits). Therefore, it should be defined in the NER as this would allow AEMO to set specific obligations.[178]

Stakeholders who opposed AEMO's proposed definitions argued:

- The NER should remain technology agnostic whereby, whenever possible, generators and loads are treated equally when accessing the network[179]
- Storage participation in the NEM has worked to date, the framework works well, and there is no reason to change it[180]
- It is questionable if the benefits outweigh the costs, given the benefits have not been clearly articulated by AEMO, and there is an estimated cost of $8-10 million for AEMO to implement and additional implementation costs for market participants[181]
- It is not clear how defining storage will reduce entry barriers faced by storage[182]

176 AEMO, submission to the consultation paper, p. 9.

177 Submissions to the consultation paper: Firm Power, p. 1; Grids Energy, p. 2; Transgrid, p. 2; Infigen, p. 2; YES Energy, p. 1; Fluence, p.6; Maoneng, p. 2, BECA, p.3.

178 Submissions to the consultation paper: Monash Energy Institute, p. 5; Citipower Powercor United Energy, pp. 3-4; GE Renewables, p. 15; AusNet Services, p. 1-2; ERM, p.1; Enel Green Power, p. 3.

179 Submissions to the consultation paper: Essential Energy, p.2; Energy Queensland, p.7; Reposit Power, p.3.

180 Submissions to the consultation paper: Neon, p.2.

181 Submissions to the consultation paper: Snowy Hydro, p.2-3; Origin, p.1-2.

182 Submissions to the consultation paper: Origin, p.1-2.

- Defining storage may restrict the flexibility of other market participant categories [183], or it may limit the way in which grid-scale batteries operate and participate in the NEM. This may create barriers to entry and it may inadvertently reduce a level playing field, favouring one technology approach over another.[184]

Some stakeholders considered that in light of the ESB's market reforms, in particular moving towards a two-sided market, the Commission should:

- only consider urgent or incremental 'do now' solutions without extensive amendments to the NER[185]
- define any new participant category more broadly and not limit it to storage[186]
- not define storage as it does not align with the reforms raised in two-sided market work including moving towards obligations being based on services rather than assets.[187]

B.5.2 Registration

In response to the consultation paper most stakeholders agreed the existing registration process was complex, duplicative, and costly, although most did not agree with AEMO's proposed participant category (the BDRP) as the right solution. Some stakeholders considered incremental changes could be made to improve the registration process for storage and hybrid facilities without making significant amendments to the NER. Some stakeholders considered any changes made need to align with large market reforms, in particular moving towards a services based market as flagged in the two-sided markets project.

Stakeholders who supported AEMO's proposal to introduce a storage-specific registration category considered:

- It would make the registration process more transparent[188]
- It would reduce costs and make the process less complex[189]
- Supported the introduction of a storage specific participation category.[190]

Stakeholders who did not support AEMO's proposed solution considered:

- It may not align with the simplified and more flexible participation framework discussed in the ESB's post-2025 NEM design work, and noted:
  - concern that if short term changes were made, these may become irrelevant over time[191]

183 Enel X, submission to the consultation paper, p.3.
184 AGL, submission to the consultation paper, p.3.
185 Submissions to the consultation paper: Endeavour Energy, p.1; Energy Australia, p.3.
186 Submissions to the consultation paper: Energy Queensland, p.7-8; AEC, p.1-2; Tesla, p.2-3.
187 ARENA, submission to the consultation paper, p.2-3.
188 Monash Energy Institute, submission to the consultation paper, p.9.
189 GE Hydro, submission to the consultation paper, p.15.
190 Submissions to the consultation paper: Yes Energy, p.13; Maoneng, p.6.
191 Submissions to the consultation paper: Endeavour Energy, P.1; AEC, p.2-3.

    - a preference for a single participant category that aligns with longer term market reforms, i.e. an approach where obligations instead fall to services delivered as identified in the two-sided market work[192]
    - a preference for streamlining the registration process, with one fee, and one set of performance standards.[193]
- It is too much detail for the NER to accommodate efficiently, and noted:
    - the addition of a technology specific category would result in a net increase in complexity[194]
    - AEMO can reform its registration processes without any formalised rule process.[195]
- The benefits of reducing uncertainty and complexity might not outweigh the $8-10 million AEMO estimated for the BDRP[196]
- The proposed BDRP category is more focused on the control provided from a smaller battery and does not allow for the operational behaviour of a large hydro unit.[197]

Stakeholders who commented on the proposed approach for transitional arrangements considered:

- that existing participants should be migrated rather than grandfathered, highlighting that costs and side effects of legacy regulation will not be cost effective. [198] Infigen highlighted that transitioning would provide a consistent platform for AEMO to manage energy storage.[199]
- should not be forced to re-register if it would require renegotiation of performance standards.[200]
- grandfathering should be considered carefully given the potential for confusion and costs[201]
- that existing participants should be given the opportunity to grandfather their rights to avoid unnecessary time or costs associated with re-registering.[202] Neoen stated that it would want to keep dual DUIDs.[203]

192 Submissions to the consultation paper: AER, p. 3; Energy Queensland, p.3; Essential Energy, p.6.
193 EnergyAustralia, submission to the consultation paper, p.2.
194 Submissions to the consultation paper: Reposit power, p.8; Energy Queensland, p.11-13.
195 Submissions to the consultation paper: Essential Energy, p.3; Citipower-powercor-United Energy, p.7.
196 AEC, submission to the consultation paper, p.2-3.
197 Snowy Hydro, submission to the consultation paper, p.1 & 3.
198 Submissions to the consultation paper: Reposit Power, p.7-8 and UPC/AC Renewables, p,5.
199 Infigen, submission to the consultation paper, p.2-3.
200 Submissions to the consultation paper: BECA, p.5; Enel Green Power, p.8 and Infigen p.2-3.
201 Energy Queensland, submission to the consultation paper, p.13-14.
202 Submissions to the consultation paper: Snowy Hydro, p. 3-4 and CEC, p. 5.
203 Neoen, submission to the consultation paper, p.2.

B.5.3 Participation

Central dispatch

Stakeholders identified that, while dispatch conflicts are possible, they are rare and insignificant. Stakeholders suggested that dispatch conflicts and market data issues can be resolved through participant software and changes to AEMO's systems, rather than changing the current approach to bidding.[204]

While stakeholders generally did not hold strong views over a single DUID or two DUIDs:

- Infigen did consider moving to a single bi-directional DUID would greatly simplify operations.[205]
- Fluence identified that any storage facility that uses automatic governor control (AGC) for dispatch would receive a single energy target from AGC, and this would mitigate any operational impact of receiving two targets due to a dispatch conflict.[206]

Many stakeholders strongly opposed the move from 20 bands to 10 for storage.[207] These stakeholders argued that doing so:

- would make storage less competitive than other participants
- would not make bidding less complex.

Ramp rates

While few stakeholders discussed minimum ramp rates, those that did generally supported AEMO's proposed solution to create symmetry in setting minimum ramp rates for the generation and load sides of storage units,[208] and to remove the 6MW limit on aggregating semi-scheduled units.[209] Engie considered that the rounding requirement for individual aggregated units is the key issue, which should be addressed by relaxing this requirement (which would be necessary for the participation of VPPs).[210]

AGL did not agree with the AEMO interpretation of the NER minimum ramp rate requirement of 1MW per minute as it considered that the 1MW should be applied to the summed total of individual aggregated units. AGL viewed that a semi-scheduled generating unit is the aggregation of all of the physical DUIDs since the available capacity of the total aggregation DUID is submitted to AEMO for the dispatch process.[211]

204 Submissions to the consultation paper: AGL, p. 4; Fluence, p. 17; Origin, p. 2; ERM Power, p. 4-5; Neoen, p. 2; Tesla, p. 3; Engie, p. 4.

205 Infigen, submission to consultation paper, p. 3.

206 Fluence, submission to consultation paper, p. 17.

207 Submissions to the consultation paper: AGL, p. 4-5; GE Hydro, p. p.15-16; FLuence, p. 16-17; ERM Power, p. 5; Maoneng, p.3&6; Infigen, p. 3; Tilt, p. 2; , Neoen, p. 2; Tesla, p. 3; CEC, p.4.

208 Submissions to the consultation paper: Fluence, p. 18; Energy Queensland, p. 17; Tesla, p. 1.

209 Star of the South, submission to the consultation paper, p. 1-2.

210 Engie, submission to the consultation paper, p. 4.

211 AGL, submission to the consultation paper, p. 4-5.

Snowy Hydro and GE Hydro were concerned the proposed rule may require pumped hydro units to ramp linearly.[212] However, AEMO is aware that pumped hydro units cannot ramp linearly and the proposed rule does not require them to do so.[213]

Forecasting and energy availability

AEMO proposed that a change should be made to the NER to explicitly require grid-scale storage resources to reflect the state of charge of their storage units in their bids.

Stakeholders generally agreed it is important for AEMO to understand state of charge but were mixed on whether there are issues with the current framework. Most stakeholders did not support AEMO's proposed solution[214] and some considered it:

- is unlikely to address these issues[215]
- may produce more volatility in bidding.[216]

Additionally, AEMO and other stakeholders identified that there are broader issues with forecasting and unit availability that may need to be addressed separately to this rule change.[217] AEMO noted that its proposed ST PASA rule change request will "require more information" from storage units, with Infigen suggesting any changes to PASA should be progressed in conjunction with AEMO's current ST PASA review.[218]

Performance standards

Stakeholders confirmed that the issues with performance standards are material. Many stakeholders supported changing the current framework to address these issues. No stakeholders completely supported AEMO's approach, but some supported it with caveats, said it could provide benefits, or supported aspects of AEMO's approach. Stakeholder views included:

- setting asset-specific performance standards that apply at the asset level would be beneficial[219]
- greater visibility of storage assets would be beneficial[220]
- support for AEMO's approach unless this requires renegotiating connection agreements, or if it increases requirements for other assets in hybrid facilities[221]
- AEMO's approach to performance standards could be simpler than the current approach[222]

212 Submissions to the consultation paper: Snowy Hydro, p. 3; GE Hydro, p. 17.

213 AEMO, *Integrating energy storage systems into the NEM - rule change request,* p. 22.

214 Submissions to the consultation paper: Fluence, p.18-19; Infigen, p 3; AEMO, p. 5-6; Monash Energy Institute, p. 11-12; Origin, p. 2; Neoen, p. 2; ARENA, p.6-7.

215 Submissions to the consultation paper: Fluence, p.18-19; Monash Energy Institute, p.11-12

216 Neoen, submission to the consultation paper, p.2

217 Submissions to the consultation paper: Fluence, p. 18-20; Infigen, p 3; AEMO, p. 6; Monash Energy Institute, p.11-12.

218 Submissions to the consultation paper: Infigen, p. 3; AEMO, p. 6.

219 Submissions to the consultation paper: Transgrid, p.2-3; Neoen, p.3; Tesla, p.5; CEC, p.4-5 and BECA, p.6-7

220 Submissions to the consultation paper: CitiPower, Powercor, United Energy, p.1-2 and Transgrid, p.3.

221 Tilt Submission to the consultation paper, p.2-3

222 Monash Energy Institute submission to the consultation paper, p.12

- support for only requiring compliance with GPS (S5.2) so long as this does not extend to loads[223]
- support for AEMO's proposed approach, but see no evidence that AEMO requires more visibility of assets behind a connection point.[224]

B.5.4 Further engagement through the options paper

The Commission considered, based on the feedback in response to the consultation paper, that stakeholders generally agreed with the intent of AEMO's rule change, but that further engagement was needed to develop a solution that solved the existing issues raised by AEMO in a way that aligned with the direction of the ESB's two-sided market work. Through the second round of consultation (the options paper) the Commission explored two alternative options that tested stakeholders' appetite for a solution that moved towards the long-term vision of a technology neutral trader-services model.[225]

The main difference between the two options was that one proposed to modify existing participant categories to accommodate storage and hybrid facility participants, while the other proposed a new participant category, the IRP, that would be designed for participants with bi-directional energy flows. The IRP was described as a more progressive option as it could eventually become the universal registration category envisaged through the ESB's two-sided market work. The options paper did not set out detailed design features for each option, but sought feedback on:

- modifying existing categories or introducing a new participant category
- scheduling of hybrid facilities
- participation in dispatch
- MSGAs providing ancillary services
- setting performance standards for hybrid facilities.

Registration

A majority of stakeholders supported one of the two alternative options, rather than the proposal in the rule change request.

Stakeholders who preferred a new category considered:

- a single category for storage and hybrids is preferred with the ability to consume and generate energy behind the connection point without being dispatched[226]
- it builds a tangible path towards the future[227]
- while likely to cost more it would be more amenable to incorporating a growing range of resources and technology types[228]

223 Infigen submission to the consultation paper, p.3-4
224 UPC/AC submission to the consultation paper, p.5
225 These options are described in chapter 2 of the options paper. It can be accessed here.
226 Submissions to the options paper: Acciona, p.1; Carisbrooke Consulting, p.1-2.
227 Submissions to the options paper: GE Hydro, p.1; Carisbrooke Consulting, p.2.
228 Flow Power, submission to the options paper, p.2.

- it is most likely to facilitate simple and streamlined integration of storage into the NEM[229]
- a 'lighter-touch' move from current market arrangements was preferable, option 4 is the better option if we move towards a 2SM, and could continue even if we don't.[230]

Stakeholders who preferred modifying existing participant categories considered:

- it solves the issues raised by AEMO[231]
- it would be a cheaper solution[232]
- it avoids further complexity of introducing a new category in an already busy environment[233]
- it provides flexibility and doesn't preclude other options as the ESB's work unfolds[234]
- while supporting the intent of a new participant category:
  - a move in this direction should wait till the ESB's work has concluded[235]
  - it is too big change at this time.[236]

Three stakeholders, including AEMO, preferred AEMO's proposed BDRP and considered:

- the BDRP could be implemented in a technology-neutral way[237]
- it is a pragmatic and simpler set of changes to enable storage and aggregated resources access to the market. It also avoids bidding complexities through bi-directional offers, rather than separate load and generation DUIDs.[238]

A number of other stakeholders considered:

- they needed more detail on the alternative options[239]
- the needed a better understanding of the framework of the NEM 2025 reforms[240]
- no option was fit for purpose for DER.[241]

Some stakeholders also commented on transitional arrangements with some stating that traditional grandfathering arrangements should be implemented[242], and transitioning to any new category should be voluntary and free of charge.[243] The AEC emphasised that grandfathering existing assets, as well as those under construction, may diminish the value of this change.[244]

229 Fluence Submission to the options paper, p.6.

230 Submissions to the options paper: ERM, p.1-2; Damien Vermeer, p.1-2.

231 Submissions to the options paper: Engie, p.1-2; AEC, p.1-2; Energy Australia, p.3; Stanwell, p.4-5; Energy Networks Australia, p.2; Alinta, p.2.

232 AEC, submission to the options paper, p.1-2.

233 Submissions to the options paper: Energy Networks Australia, p.2; Essential Energy, p.1.

234 Submissions to the options paper: Highview power, p.2; Stanwell, p.1-2.

235 Submissions to the options paper: Highview power, p.2; Origin, p.2; Alinta, p.2 and Ausgrid, p.3-4.

236 Submissions to the options paper: Engie, p.1-2; EnergyAustralia, p.3.

237 Submissions to the options paper: CEC, p.1; AEMO, p.3-4.

238 AusNet Services, submission to the options paper, p.1-2.

239 Submission to the options paper: AGL, p.1-2; ENEL X, p.1-3.

240 AGL, submission to the options paper, p.1-2.

241 Tesla, submission to the options paper, p.1-2.

242 Submissions to the options paper: CEC, p.5 and Snowy Hydro, p.3-4.

243 CEC, submission to the options paper, p.5.

Scheduling of hybrid facilities

AEMO proposed that scheduling for hybrids would be at the unit level, that is, each unit behind a connection point would be classified as either scheduled, semi scheduled or non-scheduled. The options paper sought feedback on alternative solutions that represented a services-based approach where scheduling hybrid systems could be at the connection point, and where or not a single classification would apply at the connection point or a dynamic approach could be adopted that would allow a participant to shift between scheduled and semi-scheduled based on a dynamic trigger (e.g. state of charge of an on-site storage unit).

While some stakeholders considered an innovative approach may be needed to best facilitate hybrid facilities,[245] the majority of stakeholders did not support scheduling at the connection point or a dynamic approach, with most noting it would increase complexity and may have unintended outcomes on the market.[246]

Alternative solution from ERM Power

ERM Power proposed another scheduling solution where a semi-scheduled participant self-forecasting is used to provide visibility of variable resource availability plus any use of a co-connected scheduled resource. The dispatch instruction issued to the semi-scheduled participant would always be a semi-dispatch interval as this would prevent a participant responding to a higher-than-expected price outcome by utilising its scheduled capacity. Actual output from a semi-scheduled participant would still be able to fall below the semi-scheduled dispatch cap based on input resource availability.[247]

Participation in dispatch

Most stakeholders preferred to maintain the 20 price bid band structure for storage participation in dispatch.[248] Some stakeholders considered:

- more than 20 would be welcomed[249]
- anything less than 20 would restrict operational flexibility.[250]

AEMO noted that it could implement 10 or 20 price bid bands for the BDRP, so it should not be a material driver for deciding to support an alternative registration option.[251]

244 AEC, submission to the options paper, p.4.

245 Submissions to the options paper: Flow Systems, p. 3-4; Energy Queensland, p. p.7-8; Carisbrooke Consulting, p. p.5-6.

246 Submissions to the options paper: Redearth Energy, p. 2; GE Hydro, p. 2; YES Energy, p. 2; AEC, p. 1-2; EnergyAustralia, p. 4; Tesla, p. 6-7; Stanwell, p. 6; Fluence, p. 7-9; CEC, p. 2-3; Acciona, p. 1; ERM, p. 5; Maoneng, p. 2; AEMO, p. 14.

247 ERM Power, submission to the options paper, p. 4-5.

248 Submissions to the options paper: Redearth Energy, p. 2; GE Hydro, p. 2; YES Energy, p. 2; EnergyAustralia, p. 4; Tesla, p. 7-8; Flow Power, p. 4; Stanwell, p. 6-7; Snowy Hydro, p. 2; Tilt Renewables, p. 2; FLuence, p. 9-10; CEC, p. 3; Acciona, p. 1; ERM Power, p. 3-4; ALinta, p. 3;

249 Tesla, p. 7-8; Stanwell, p. 6-7; Snowy Hydro, p. 2.

250 Flow Power, p. 4.

251 AEMO, submission to the options paper, p. 14-15.

MSGAs providing ancillary services

All but one stakeholder who provided feedback on this issue considered MSGAs should be able to provide ancillary services[252] with some of these noting:

- this would align with the aims of the ESB's two-sided market work and will better enable mid-sized assets and community batteries[253]
- if batteries meet the market ancillary service specification (MASS) they should be able to provide ancillary services[254]
- there may need to be some level of differential treatment between small and large units.[255]

AusNet Services recommended not allowing MSGAs to provide ancillary services at this time, as it may take more time to better understand how to efficiently coordinate these smaller units, and minimise operational complexity for participants.[256]

Setting performance standards for hybrid facilities

The options paper proposed that performance standards would be set at the connection for hybrid facilities, maintaining the existing approach for participants, and sought feedback on whether this approach would need to be amended to provide appropriate flexibility for hybrid facilities.[257]

Stakeholders were generally mixed as to whether performance standards should be set at the connection point or behind the connection point for each unit in a hybrid facility. Stakeholders who supported setting performance standards at the connection point considered:

- Identifying every asset behind a connection will reduce flexibility and be unnecessarily complex. The critical issue is that the connection to the system is defined and the requirements at that connection point are defined, rather than metering, identifying and defining each unit behind a connection point.[258]
- The onus should be on developers to meet system standards by factoring performance issues into site designs. This is rather than system standards being weakened to support unusual reticulation configurations.[259]
- Performance standards should be managed in line with arrangements for embedded networks. AGL believes that performance standards should be in place at the connection point level where AEMO and the Financially Responsible Market Participant (FRMP) are counterparties.[260]

252 Submissions to the options paper: Redearth Energy, p. 1-2; Yes Energy, p. 1; Tesla, p. 3; Energy Queensland, p. 5; Enel X, p. 3-4; Carisbrooke Consulting, p. 2-4.

253 Tesla, submission to the options paper, p. 3.

254 Submissions to the options paper: Energy Queensland, p. 5; Enel X, p. 3-4.

255 Carisbrooke Consulting, submission to the options paper, pp. 2-4.

256 AusNet Services, submission to options paper, p. 2.

257 AEMC's I*ntegrating energy storage systems into the NEM - options paper*, p. 23.

258 Highview Power, submission to the options paper, p.2.

259 EnergyAustralia, submission to the options paper, p.5.

260 AGL, submission to the options paper, p.2.

- Energy Queensland is supportive of performance standards being set at the connection point rather than at the generating plant terminals.[261]

Stakeholders who supported setting performance standards at the unit level behind the connection point considered:

- Challenges could occur if the characteristics of the hybrid facility at the connection point are varying significantly from one point in time to the next.[262]
- Consideration will need to be given to how these new performance standards will impact existing generator performance standards for a market participant seeking to co-locate energy storage with an established wind or solar facility.[263]
- Performance standards set at the facility enhance a participant's ability to maintain, monitor and measure their own performance against standards, while AEMO and network service providers still receive SCADA data necessary for their operations.[264]
- A hybrid system may not provide uniform output to comply with a performance standard set at the connection point when a combination of assets is behind that connection point.[265]

A number of stakeholders supported considering both the connection point and units behind it when setting performance standards:

- Performance standards should be defined at the connection point, with the flexibility to define standards at the asset level if required.[266]
- One option could be to create a 'parent-child' approach for hybrid facilities where there would be one set of standards for the connection point (parent) but also an internal subset of standards for each technology in the hybrid facility (child). These guidelines would vary depending on the level and type of hybridisation of the facility.[267]
- The technical requirements of the power system must be the principal factor for analysis. Hybrid connections should not result in an acceptance of a lower performance and access standard than that reasonably achievable by any of the stand-alone assets forming part of the proposed hybrid grouping. The Rules should set out clear guidance for AEMO in this area.[268]

AEMO noted performance standards are currently based on Registered Participant category and that the performance standards for customers are generally less onerous than for generators, and in many respects are not mirror image obligations. AEMO considered the Commission will need to consider how best to draft appropriate performance standards to address energy storage capability.[269]

261 Energy Queensland, submission to the options paper, p.9.
262 GE Hydro, submission to the options paper, p.3.
263 Tesla, submission to the options paper, p.8.
264 Stanwell, submission to the options paper, p.7.
265 CEC, submission to the options paper, p.3.
266 Submissions to the options paper: Citipower, Powercor and United Energy, p.4 and Acciona, p.2.
267 Fluence, submission to the options paper, p.10.
268 ERM Power, submission to the options paper, p.4-5.
269 AEMO, submission to the options paper, p.15.

B.6 The Commission's analysis

BOX 2: DRAFT RULE — REGISTRATION, CLASSIFICATION AND PARTICIPATION FRAMEWORK

The key features of the draft rule are:

- the introduction of a new IRP participant category for storage and hybrid system operators
- the introduction of a new classification category, the integrated resource unit (IRU) which will be utilised by IRPs to classify storage
- scheduling and dispatch obligations are set at the unit level, with compliance with dispatch (for hybrids) measured in aggregate (where possible)
- inclusion of small unit aggregators in the IRP category, with the ability to provide ancillary services.

A more detailed summary of the draft rule can be found in Appendix K.

Definition of storage in the NER

The Commission's draft decision is for a technology-neutral approach for any new definitions in the NER to accommodate storage and hybrid facilities. This involves establishing a new term, integrated resource unit, for a unit that has both load and generation (without referring to energy storage specifically).

Registration and classification

The Commission's draft decision is to create a new participant category, the IRP, for storage and hybrid proponents (including aggregators of small units). It would be optional for any existing Generator or Customer to, with the consent of AEMO, change its registration category to IRP. It would be <u>mandatory</u> for any <u>new</u> participant to register as an IRP if it has both (behind a single connection point):

- generation capability, that on its own would see it register as a Market Generator
- consumption from the connection point above auxiliary load.

It would also be mandatory for an existing participant that is registered as both a Market Generator and Market Customer (in relation to the same facility) to re-register as an IRP. Participants registered as SGAs will be automatically re-registered as IRPs, and as such would be Small Resource Aggregators in respect of each of their small generating units.

An IRP would classify:

- standalone storage, over 5MW, as a scheduled IRU. Storage under 5 MW could be classified as a non-scheduled IRU.

- each generating unit or integrated resource unit within a hybrid system, where scheduling requirements apply, at the unit level.
- connection points (that do not have grid-scale generation or storage facilities) as its market connection points, if it chooses to do so.
- loads as scheduled loads, if it chooses to do so.

Aggregators of small storage units and small generating units will be allowed to register in the IRP category, under the new label Small Resource Aggregator. As well as selling unscheduled generation from these units in the spot market, they could provide market ancillary services from generation and load, where they meet technical requirements to do so. This change includes moving the existing MSGA category into the IRP.

Participation

The Commission notes AEMO's view that it is appropriate for scheduled storage assets to participate in central dispatch as a single asset, a scheduled integrated resource unit, with one DUID covering bids for both generation and load. The Commission considers it preferable for these bi-directional DUIDs to have 20 price bands, instead of AEMO's proposal for 10 bands.

Aligned with AEMO's proposal, if a storage unit is unable to participate through a single bi-directional DUID (for example, certain types of hydro facilities which cannot transition linearly from generating to consuming), it would continue to participate as a scheduled load and a scheduled generating unit, separately. The Commission does not consider it an appropriate time to require aggregators of small units to participate in central dispatch.

Hybrid facility proponents will be required to register as an IRP and each unit within the facility will participate in central dispatch to the extent required by its classification. The Commission considers this will provide IRPs appropriate operational flexibility and will lead to more efficient market outcomes. AEMO will be required to develop a new approach to assessing dispatch conformance for hybrid facilities in aggregate, where that does not risk the stable operation of the system.

For operational and technical issues raised by AEMO, the Commission made the following draft decisions:

- **Ramp rates and aggregation** - Create one aggregation approach for semi-scheduled generating units and storage systems, reflecting NER clause 3.8.3. Set a minimum ramp rate at the lower of 3 MW or 3% of capacity for scheduled units and remove the 6 MW threshold for aggregating semi-scheduled units.
- **Forecasting and energy availability** - In order to integrate the IRP effectively a number of minor changes were made to provisions on forecasting and energy availability. Broader issues with forecasting and unit availability, for all participants not just those with storage, would need to be addressed in a separate rule change.

Benefits of the draft rule

The benefits of making these changes include:

- lower barriers to entry for new storage participants by:
  - creating a clear regulatory framework for storage and hybrid participants to register, classify and participate in the NEM
  - reducing the administrative burden to register and classify storage units and hybrid facilities.
- reduce system costs for AEMO
- increase operational efficiency through providing flexibility for hybrid facilities to manage energy flows between units behind the connection point.

B.6.1 Defining IRPs and IRUs in the NER

The Commission proposes a technology-neutral approach for the new definitions in the NER that are needed to accommodate storage and hybrid facilities. Defining storage or hybrid systems based on their technology (specifically, whether a unit stores energy) is not necessary, because different obligations would instead be attached to a unit based on the services it provides to the market - whether it can provide generation or load, or both.

These changes involve establishing a new participant category and term for a unit that has both load and generation, the IRP and the IRU respectively. Functionally this does not differ significantly from AEMO's proposed new category, the BDRP category, and the term AEMO proposed for storage units, bi-directional unit, other than not including storage specific definitions.

An IRU is defined in the draft rule as a production unit that also consumes electricity that is not, or is in addition to, auxiliary load of the production unit. Production unit is defined as the plant used in the production of electricity and all related equipment essential to its functioning as a single entity, taken from the current definition of generating unit. (To assist integration of IRUs into the NER, generating unit has been re-defined as a production unit that is not an IRU.) Auxiliary load has been defined to exclude electricity consumption used to charge a production unit.[270]

The Commission acknowledges that there is already technology specificity in the NER and in some cases this may be necessary. However, the Commission does not want to introduce more technology-specific drafting where it is not necessary. This aligns with the ESB's longer term view to move to a trader-services based model for participation in the NEM. This would mean that obligations are attached to services provided by traders (participants), not the assets that deliver them. This would provide a level playing field for services.

The Commission considers that the approach to defining IRPs and IRUs in the draft rule addresses issues raised in the rule change request, resolving regulatory and operational uncertainty while allowing appropriate obligations to be placed on the new participant, and

270 See amendments to NER chapter 10 in the draft rule.

new unit, in a way that maintains a level playing field with other types of participants and units that provide generation, load and ancillary services.

B.6.2 Registration and classification

The Commission considered stakeholder feedback and worked with AEMO staff to understand the practical and implementation issues of each of the options presented in the options paper. The Commission's proposed solution is a refined version of option 4 that aims to deliver some of the more critical objectives identified in the ESB's work, as outlined earlier. The refined option also addresses views from stakeholders to make smaller, no-regrets changes now with the ability to make further changes once the details of the ESB's post-2025 work are clearer.

As set out above, the Commission's draft decision is to provide grid-scale storage and hybrid system participants a single participant category, the IRP, and a new unit classification category, the IRU.

The ESB's longer term view is to move to a universal category, into which all current participant categories are collapsed. Establishing the IRP is the first step toward that longer-term outcome. Creating the IRP now for small and large storage as well as hybrid system participants is a 'no-regrets' step as it serves the purpose of removing barriers to integrating storage in a manner aligned with the ESB's potential future reforms. This future will involve determining how to manage small and large participants selling the same services, and how they will participate in activities like scheduling. This process is better served if all of these participants are registered in a single category.

The Commission considers it important to provide clarity on the threshold for scheduling IRUs, and has therefore specified this in the draft rule at 5 MW, so there is certainty for AEMO and participants.[271] This threshold is consistent with AEMO's current approach to scheduling storage facilities in the NEM. In addition, to provide clarity for participants on what load is auxiliary load, the Commission has defined it as electricity consumption used for the operation of auxiliary plant at a power station.[272]

The Commission does not consider it appropriate to move the classification level for grid-scale storage and hybrid facilities to the connection point. The Commission proposes to maintain classification at the unit level for grid-scale storage and hybrid systems, as this approach addresses the issues raised in the rule change request by allowing participants to operate units within a hybrid system in a flexible and efficient way.

The Commission considers introducing the IRP and IRU addresses:

- the issues raised in AEMO's rule change request relating to registration, classification and participation of storage and hybrid facilities
- additional issues raised in the course of consultation, including:
    - allowing hybrid systems to manage their own energy behind the connection point

271 See clause 2.2.2(a1) in the draft rule.

272 In addition the definition specifies that auxiliary load does not include electricity consumption used to charge a production unit or to pump water for a pumped hydro production unit.

- allowing small storage units to provide ancillary services
- balancing the objectives of the ESB's longer term reforms and stakeholder views to make appropriate incremental steps.

The Commission considers that allowing existing storage participants to maintain the current registration and classification model would lead to unnecessary regulatory complexity and create an uneven playing field. Given this, the draft rule requires existing storage participants to apply to AEMO to change their registration category to IRP and to reclassify their systems.[273] To reduce the impact on existing storage participants the draft rule provides that AEMO must not charge a fee for these applications.[274] The Commission does not consider that this application process will require the re-negotiation of a participant's performance standards.

The Commission considers that introducing the IRP provides a number of benefits which align with the assessment framework principles, including:

- Minimising administrative and regulatory burden - By clarifying, consolidating and streamlining the registration and classification process for storage and hybrid facilities.
- Enhancing system reliability and security - By facilitating storage to participate in the NEM and help increase the proportion of dispatchable resources which are needed to support increasing amounts of renewable generation.
- Promoting transparency - By clarifying the obligations that apply to storage and hybrids.
- Promoting competition - By removing barriers to entry for proponents of storage, and hybrid facilities, and aggregators of small generating units and batteries.

Small storage

The IRP category will include aggregators of small generating/storage units, below the threshold of 5 MW, under the label Small Resource Aggregator. Small Resource Aggregators will be allowed to provide market ancillary services from generation and load, where they meet technical requirements to do so. However, it will not be mandatory for aggregators to utilise the IRP as they will continue to be able to utilise the Market Customer category. Aggregators in the IRP category will have no obligation to classify small units as scheduled in any form, consistent with the existing approach for MSGAs.

To address AEMO’s concerns and minimise administrative and regulatory burden relating to unnecessary changes to systems and procedures as well as confusion for participants, the Commission proposes to transfer the MSGA category into the IRP. This is instead of leaving the MSGA as a separate category as proposed by AEMO and in the options paper. From a participant’s experience there would be no change (except they could now provide ancillary services, if their sites are classified to do so).[275]

273 See draft rule Chapter 11, Savings and Transitional Rules.

274 Ibid.

275 This approach is similar to how the Market Ancillary Service Provider category will transfer into the Demand Response Service Provider category as part of the AEMC's Wholesale Demand Response Mechanism rule, see here.

Small resource aggregators will be allowed to classify connection points at which a small generating or integrated resource unit consumes or sends out electricity to the grid, as market connection points.[276] The Commission considers that (as with MSGAs currently), AEMO and participants would continue to use AEMO's Market Settlement and Transfer Solution (MSATS) for this process.[277] A small resource aggregator will then be required to purchase all supplied electricity and sell all sent out electricity to the grid through the spot market, in the same manner as an MSGA does now.

The alternative approach of modifying the current MSGA category to classify exempt storage and provide ancillary services does not align with the long-term goal of the trader-services model. It would be implementing an interim approach when there is an opportunity to create a more permanent, streamlined solution. The Commission considers that it is important to include small battery aggregators in the IRP as this achieves a number of objectives of the ESB's two-sided market work, including:

- reducing participant categories and providing long-term rather than interim solutions
- demonstrating that small and large participants can be in the same category
- providing a market signal to investors that the IRP is being set up as the future universal category.

This change also supports the ESB's flexible trading arrangements reforms by establishing a clear participation category for aggregators within the IRP which can provide energy and ancillary services. Flexible trading arrangements are a way to encourage the separation of controllable from uncontrollable resources so customers can be rewarded for their flexible demand and generation whilst not requiring a significant behavioural change for other parts of their household load.[278]

B.6.3 Participation

Central dispatch

The Commission notes AEMO's view that it is appropriate for scheduled storage assets to participate in central dispatch as a single asset, which is labelled as a scheduled integrated resource unit in the draft rule. If these units are to have one DUID as proposed by AEMO, rather than two (as per current arrangements), the Commission considers it necessary to provide a bidirectional DUID with 20 price bands, 10 for generation and 10 for load, instead of AEMO's proposal for 10 bands in total, for the reasons discussed below.[279] Aligned with AEMO's proposal, if a storage facility is unable to participate through a single bi-directional DUID (ie it cannot transition smoothly through zero) it would need to participate as a scheduled load and a scheduled generating unit separately.

The Commission does not consider it an appropriate time to require aggregators of small units to participate in central dispatch.

276 Clause 2.2.8 of the draft rule.

277 For more information see AEMO's SGA fact sheet here.

278 For more information see the ESB's January directions paper here.

279 Clause 3.8.6(g1) of the draft rule.

Each unit within a hybrid facility will participate in central dispatch to the extent required by its classification. The Commission considers that this will provide IRPs appropriate operational flexibility and more efficient market outcomes. AEMO will be required to develop a new approach to assessing dispatch conformance for hybrid facilities in aggregate.[280] AEMO will however be able to require hybrid facilities to comply with dispatch at the unit level in specified dispatch intervals when certain conditions are met, for example where required for stable power system operation, as discussed further below.

For the avoidance of doubt, the Commission's draft decision would continue to require each unit, regardless if it is stand alone or in a hybrid facility, to provide forecast information into the pre-dispatch, short-term and medium-term projected assessment of system adequacy (PASA) processes, to the extent that is required by its classification (as scheduled, semi-scheduled or non-scheduled).[281]

Single bidding form for storage units

The Commission considers that a single, bi-directional bidding form, as proposed by AEMO, may provide a number of benefits which align with the assessment framework principles, including:

- Minimises administrative and regulatory burden - Reducing administrative cost on AEMO dealing with two separate units. This includes initially in the registration and classification stage but also ongoing in various IT and system processes such as forecasting and constraint formulation.
- Promotes competition - Reduces the set-up costs and ongoing operational complexity of participating in central dispatch for participants.
- Promotes transparency - Transparency of information in the market will increase as storage will be more visible compared to if it was two relatively unrelated DUIDs.

The Commission understands that redeveloping the dispatch model to allow for a single bid form will be a considerable task for AEMO. AEMO highlighted that its implementation costs for its proposed rule were estimated to be $8 million; the proportion of which that can be attributed to the creation of the single dispatch model is unclear. Additionally, participants would incur costs updating their bidding systems. The Commission acknowledges stakeholder feedback which highlighted that dispatch conflicts are rare, insignificant and that there are available solutions in changes to participant software or AEMO systems.

However, the Commission considers that a single bidding form enables a simple and clear framework for participants, in alignment with a single registration and classification process. The Commission agrees with AEMO that the current arrangements, in the context of the introduction of the IRP in this draft determination, makes participation unnecessarily complex and expensive for AEMO and scheduled storage units, which could create barriers to entry and impact on efficient investment and operation. The Commission considers that the introduction of a single bidding form is in the long term interests of consumers.

280 Clause 4.9.2A of the draft rule, requiring AEMO to make a power system operating procedure on this issue.

281 The short-term and medium-term PASA processes are outlined in rule 3.7 of the NER.

Therefore, the Commission's draft decision is to introduce a new unit classification which would participate in central dispatch as a single unit across generation and consumption, with a single bidding form. However, the Commission agrees with stakeholders that the number of bands should be maintained at 20 (that is, 10 for the load side and 10 for the generation side of the IRU) rather than be reduced to 10 for storage participants. The Commission considers the extra costs to enable 20 bid bands are worthwhile because the alternative, maintaining 10 bid bands, would reduce the flexibility of scheduled storage facilities in dispatch and make them less competitive than other participants.

Aggregated dispatch conformance

The Commission explored the potential to move towards an approach for grid-scale systems that was based on services provided at connection points, rather than by individual units. Generally, while stakeholders supported this sentiment, the general view was that this was a step too far, too soon. Given this stakeholder view and the potential cost and complexity for AEMO, the Commission considers the existing approach where dispatch instructions are sent to the unit, should be maintained for grid-scale facilities.

However, the Commission agrees with stakeholder feedback that highlighted a need for the approach for hybrids in dispatch to reflect the unique capabilities of a hybrid facility. Given this, the Commission's draft decision is to allow hybrid systems the ability to manage their energy flows (i.e. deviate from unit level dispatch instructions) to comply with dispatch in aggregate. AEMO will however be able to require hybrid facilities to comply with dispatch at the unit level in specified dispatch intervals in certain circumstances, for example where required for stable power system operation or where the unit is providing ancillary services, in accordance with a power system operating procedure AEMO will develop.[282] To be clear, the default position is for dispatch conformance for hybrid facilities to be set as 'in aggregate', and by exception AEMO can specify in the dispatch instruction that unit level conformance is required, in accordance with the power system operating procedure.

The approach of allowing the management of energy flows at the connection point should reduce barriers to the integration of storage and hybrids by increasing operational flexibility and reducing curtailed energy. Specifically, this approach would allow a hybrid system operator to:

- Use a storage or generation unit to firm up intermittent generation output up to its semi-scheduled dispatch target. This would allow it to reduce causer pays liabilities. Practically, this would involve the scheduled IRU or generating unit DUID exceeding its dispatch target, where this action does not impact FCAS enablement or response, to firm up a semi-scheduled generating unit DUID.
- Exceed a unit’s semi-scheduled dispatch target to charge a storage unit within a hybrid facility, for example if:
    - forecast output is lower than actual output
    - it is constrained off from exporting to the grid

282 Clause 4.9.2A of the draft rule.

- prices are negative.

The Commission considers it important for AEMO's ability to operate a secure power system that this approach is limited to stable operating conditions. If market or network conditions require, the rules will continue to provide for AEMO to apply constraints to, instruct or direct a unit (depending on its classification) within an integrated resource system to operate at specified levels to ensure secure operation of the NEM. This means that AEMO may assess conformance in aggregate during stable conditions and revert to the unit level if required. The Commission's draft rule includes a requirement for AEMO to make a power system operating procedure setting out arrangements it will follow to specify whether dispatch instructions may be complied with in aggregate or individually at each unit with the system.

The Commission considers that allowing aggregated dispatch conformance for hybrid systems reduces barriers to entry and ongoing operational costs which promote competition and enhance system reliability and security, through:

- Allowing a semi-scheduled generating unit that would otherwise often be constrained off, leading to spilt energy, to instead charge a storage unit which reduces barriers to entry and ongoing operational costs for these combined systems.
- Allowing storage or generation output to firm up a semi-scheduled generation unit's output to reduce causer pays liabilities.

Aggregators in central dispatch

To address AEMO's concerns in relation to the complexity and cost of scheduling aggregated portfolios of small generation and storage at this stage, the Commission proposes to place no additional scheduling or central dispatch participation obligations on aggregators of small units. The current approach for MSGA small generating units to be non-scheduled generation will be maintained for aggregators in the IRP. The longer term path for the trader-services model will consider how this may change in future.

Currently, the ESB's two-sided market workstream includes exploration of options for the scheduling threshold and scheduling obligations (scheduling lite).[283] Given the accelerating uptake of aggregated portfolios, the Commission considers there is a pressing need to consider appropriate scheduling and dispatch obligations for aggregators through this process; for example, if scheduling thresholds should apply at the aggregated level. Integration into central dispatch would provide efficient integration into wholesale markets as well as provide a market solution to emerging system security risks of large portfolios of unscheduled small generation units.

Ramp rates and aggregation

The Commission agrees with AEMO's proposal and stakeholder feedback that there should be one aggregation approach for semi-scheduled generating units and storage systems, reflecting NER clause 3.8.3. The Commission agrees that it is appropriate for the NER to

283 Further detail on scheduling lite can be found in the ESB's Post 2025 market design options here.

allow AEMO the discretion to consider whether different technology types can be aggregated under Chapter 3 of the NER.

The Commission's draft decision is to set a minimum ramp rate at the lower of 3 MW or 3% of scheduled load capacity and remove the 6 MW threshold for aggregating semi-scheduled units in NER chapter 2. For participants with the same number of units and total MW capacity, this would see a consistent minimum ramp rate set for:

- storage and non-storage participants
- load and generation units
- scheduled and semi scheduled units.

The Commission's draft decision is aligned with AEMO's proposal but makes the change consistent across scheduled load and generation. The Commission does not consider it appropriate to make changes specific to storage, in order to keep a level playing field. The Commission considers setting minimum ramp rates in this way would have the following benefits:

- set a more level playing field for scheduled generation and load
- make storage participation less complex
- allow semi-scheduled participants to aggregate units above 6 MW
- better align with the longer-term two-sided market vision (more consistent treatment of load and generation).

However, there will remain an inconsistency with how minimum ramp rates are set for large units versus aggregation of smaller units, although this issue is outside the intent and scope of this rule change proposal and beyond what stakeholders have engaged on. This inconsistency is significant and was explored in the 2015 rule change Generator ramp rates and dispatch inflexibility in bidding. The Commission did not adopt, as part of that rule change, a more consistent approach due to the technical limitation of older generation facilities to respond to higher minimum ramp rates.

Forecasting and energy availability

The Commission considers that it is important for AEMO to have visibility of a battery's state of charge, however this is a matter that is best reviewed in the context of broader issues relating to forecasting and unit availability. This should be considered in future rule change requests dealing with these issues.

Performance standards

The Commission's draft decision is to maintain the existing approach of setting performance standards at the connection point. An IRP would have a single performance standard apply to its facility; however, this performance standard would reflect the technical and performance capabilities of each unit behind the connection point. This approach provides clarity to how performance standards would apply to stand alone storage and hybrid facilities without any significant policy changes to the way in which standards are established and applied under chapter 5 of the NER. This approach is consistent with AEMO's proposal and is generally supported by stakeholders.

The Commission considers that beyond making it clear how performance standards should apply to hybrid systems, there is not enough justification at this stage to reassess the work done in the *Generator technical performance standards* rule change. The benefits to the market from the other changes made in this draft determination to integrate storage can be achieved without making significant changes to how performance standards are set.

The main changes required to integrate IRPs and IRUs into chapter 5 of the NER are detailed in Appendix K.

C RECOVERY OF NON-ENERGY COSTS

C.1 Overview

The Commission's draft rule will create a more level playing field for storage and all participants. The draft decision aligns with the two-sided market work as it looks to treat all participants equitably based on their interactions with the market.

In its rule change request, AEMO identified that non-energy cost recovery is inconsistent between grid-scale storage and other participants including small storage participants. This is because the recovery of non-energy costs for:

- grid-scale storage participants is based on registration in two participant categories (market customer and market generator), and separately measured energy flows that are not netted
- small storage participants is based on registration in one participant category (Market Small Generation Aggregators (MSGA)), and a single measurement of net metered energy flow.

AEMO considered that this inconsistency creates inefficient outcomes that includes the ability for MSGA participants to reduce their share of non-energy costs compared to a grid-scale storage participant. AEMO also noted that the existing framework may:

- Provide incentives to register in certain registered participant categories to avoid the financial cost of non-energy services, and potentially other services like DUOS.
- Result in the burden of non-energy services being borne by customers that cannot afford to own and connect 'exempt' generating units or storage systems behind their connection point. This impost would be made worse if the base of registered participants to recover costs from diminishes further.

The Commission agrees with AEMO's position that there is an inconsistency with how non-energy costs are recovered from all participants due to the increasing amount of bi-directional energy flows. The Commission notes that some participants with bi-directional energy flows are currently able to reduce their share of non-energy costs through netting. This increases the share paid by other participants who do not have bi-directional energy flows.

The Commission's draft decision is to amend the non-energy costs recovery framework so that recovery of these costs is based on a participant's gross consumed energy and/or gross sent out energy in an interval (as applicable), irrespective of what participant category they are registered in.

This chapter outlines:

- what non-energy costs are
- the issues raised by AEMO
- AEMO's proposed solution
- stakeholder feedback
- the Commission's draft decision and analysis

- further analysis on each non-energy service.

C.2 What are non-energy costs?

AEMO's responsibility is to operate the power system in a safe, secure and reliable manner. AEMO fulfils this by using a range of non-energy services to control technical characteristics of the system through various market and non-market ancillary services and regulatory mechanisms. AEMO generally recovers the cost of these services and mechanisms from participants:

- according to the participant category they belong to, and
- in proportion to the net energy consumed or sent out in relevant trading intervals (currently 30 minutes).

Table C.1 identifies the NEM non-energy services and the participants from whom the costs are recovered under the current framework.

Table C.1: **NEM non-energy services and cost recovery framework**

NON-ENERGY SERVICES	CURRENT COST RECOVERY FROM	NER REFERENCE
Market ancillary services		
Frequency control ancillary services (FCAS) – contingency raise	Market Generators, MSGAs	3.15.6A(f)(3)
FCAS – contingency lower	Market Customers	3.15.6A(g)(3)
FCAS – regulation	Market Generators, MSGAs and Market Customers on causer pays basis	3.15.6A(i)
Non-market ancillary services		
Network support control ancillary services (NSCAS)	Market Customers	3.15.6A(c2)(1)
System restart ancillary services (SRAS)	Market Customers, Market Generators, MSGAs	3.15.6A(c2)(2)
Interventions		
Direction – energy	Market Customers	3.15.8(b)
Direction – FCAS	Market Customers, Market Generators and MSGAs on a causer pays basis	3.15.8(f)
Direction – other	Market Customers, Market Generators, MSGAs	3.15.8(g)
RERT	Market Customers	3.15.9(d)
Affected Participant	Scheduled Generator, Scheduled	3.12.2

NON-ENERGY SERVICES	CURRENT COST RECOVERY FROM	NER REFERENCE
Compensation	Network Service Provider, Market Customer	
Market suspension	Market Customer	3.15.8A(b)
Other events		
Market shortfall and surplus	Market Participants (typically Market Generators, MSGAs)	3.15.22, 3.15.23
Administered price cap or administered floor price compensation payments	Market Customers	3.14.6(a)

C.3 Issues raised by AEMO

In its rule change request, AEMO identified that non-energy cost recovery is inconsistent between grid-scale batteries and other market participants, including exempt batteries, which can be registered as a MSGA. This is because:

- Most registered participants including market generators, market customers and MSGAs are charged based on being registered in a single participant category, where their consumed and sent out energy is netted within an interval (net meter data with one data stream) across their connection points. This net meter data provides an energy value for market settlement, fees and non-energy cost recovery calculations. This arrangement has been in place since the commencement of the NEM and is reflected in the NER settlement formula as adjusted gross energy (AGE).
- However, grid-scale batteries are charged based on the two participant categories they are registered in (market generator and market customer). This results in charges incurred for both consumed and sent out energy, which are measured separately (gross meter data with two data streams). That is, grid-scale batteries cannot net between their consumed and sent out energy flows.[284]

AEMO considered the current arrangements for non-energy cost recovery results in market participants with technologies other than grid-scale batteries being able to minimise the costs and charges that apply to them as they are only required to register in one participant category. This results in inefficient outcomes, that in turn can create incentives for participants to act in an inefficient way:

- can reduce the amount it is liable for due to the effect of netting between consumed and sent out energy, compared to if consumed and sent out energy occurred at separate connection points that belonged to different market participants.

284 AEMO, Integrating energy storage systems into the NEM - rule change request, p. 15.

- can be paid rather than pay for non-energy costs if sent out energy exceeds energy consumed.[285]

C.4 AEMO's proposed solution

AEMO proposed that MSGAs (and grid-scale battery participants in the proposed BDRP) should be treated the same as grid-scale storage participants. That is, they should pay non-energy costs based on consumed and sent out energy, not netted between the two. AEMO considered that this approach is consistent with causer or beneficiary pays principles since it reflects, and places a value on, a registered participant's contribution when non-energy services are needed.[286]

AEMO also proposed that, to ensure non-energy cost recovery occurs consistently for all registered participants, the Commission may wish to consider whether it is also appropriate to recover non-energy costs from market customers and market generators in the same way as AEMO has proposed for BDRPs and MSGAs.[287] This would require changes to all NEM non-energy settlement recovery formulas.

C.5 Stakeholder feedback

In response to the consultation paper, most stakeholders did not provide specific comments on non-energy costs. However those that did were generally split between 'support' and 'oppose' for AEMO's proposed solution:

- Stakeholders who supported AEMO's proposal wanted it extended to other market participants.[288]
- A number of stakeholders considered the cost recovery framework should be technology neutral and based on a beneficiary or causer pays approach.[289]
- Stakeholders who did not support AEMO's proposed solution considered that:
  - behind-the-meter power flows should not be included in calculating fees and charges.[290]
  - netting of energy flows should be maintained.[291]
  - given the materiality of non-energy costs is small, storage participants should be exempt or only apply the charges on round-trip losses as their energy loads are not 'final consumption'.[292]

285 AEMO, Integrating energy storage systems into the NEM - rule change request, p. 19.
286 AEMO, Integrating energy storage systems into the NEM rule change request, p. 29.
287 Ibid, p. 29.
288 Submissions to the consultation paper: Yes Energy, p. 1; AEC, p. 3; Neoen, p. 3; Tesla, p. 1; ARENA, pp. 9-10; Monash Energy Institute, p. 12.
289 Submissions to the consultation paper: Essential Energy, p. 3; Energy Queensland, p. 16; Grids Energy, 3. X; Ausgrid, p. 3.
290 BECA, submission to the consultation paper. p. 7.
291 Submissions to the consultation paper: Enel X, pp. 11-12; EnergyAustralia, p. 5.
292 ERM, submission to the consultation paper, p. 6.

- a subscription style charge ($ per MW/month) could be applied to storage participants based on capacity size as this would level the playing field between small and large storage participants.[293]

In the consultation paper, the Commission identified an alternative option of a broader change to the framework which would see AEMO's proposed solution apply to all market participants. However, the Commission considered this was not fully tested with stakeholders through the consultation paper given stakeholders primarily considered AEMO's proposed solution. Therefore, the Commission engaged further on this proposal through the options paper, highlighting to stakeholders the alternative option of applying a 'beneficiary/causer pays' approach to all participants, not just small and grid-scale storage participants.[294]

All stakeholders who commented on the non-energy costs framework in the options paper (20 of a total of 31 submissions) supported the alternative option, where all participants would pay for non-energy services based on a beneficiary/causer pays approach.[295] That is, not based on the participant category they are registered in. However, while supporting the intent of the alternative option some stakeholders did consider that:

- netting of consumed and sent out energy at the connection point should still be allowed[296]
- those participants who help to maintain system stability should not have to pay, and instead should be paid for providing this service[297]
- storage participants should be exempt from non-energy costs.[298]

BECA and ERM noted in their submissions to the consultation paper and options paper, respectively, that behind the meter energy flows should not be considered in the calculation of non-energy costs.[299] [300]

The AEC also noted that some non-energy services may need to apply differently to storage participants. For example intervention and administered price compensation cost recoveries that are levied on market customers should not be levied on storage, as these are to the benefit of end-use customers.[301]

293 Enel Green Power, submission to the consultation paper, p. 11.

294 The options paper can be found here on the project page.

295 Submissions to the options paper: Redearth Energy Storage, p. 3; Engie, p. 2; Origin, p. 2; Enel X, p. 6; AustNet Services, p. 2; Tesla, p. 9; Alinta, p. 4; ERM, p. 7; AEC, p. 3; Carisbrooke Consulting, p. 8; Flow Power, p. 5; Stanwell. p. 8; Energy Queensland, p. 9.

296 Submissions to the options paper: EnergyAustralia, pp. 2, 5; Yes Energy, p. 3; CitiPower, pp. 2, 4.

297 GE Hydro, submission to the options paper, pp. 4-5.

298 Highview Power, submission to the options paper, p. 3

299 BECA, submission to consultation paper, p. 7.

300 ERM, submission to options paper, p. 7.

301 AEC, submission to the consultation paper, p. 3.

C.6 The Commission's analysis

BOX 3: DRAFT RULE - RECOVERY OF NON-ENERGY COSTS

The draft rule amends the non-energy costs recovery framework so that recovery is based on a participant's gross consumed energy and/or gross sent out energy in an interval across their connection points, irrespective of the participant category they are registered in. To be clear, under the draft rule netting of energy flows at a connection point or among a participant's connection points would not occur.

Benefits of the draft rule

The draft rule will:

- create a level playing field for all participants, including storage and hybrid facilities
- remove inefficient outcomes that may favour participants with large bi-directional energy flows
- provide a permanent resolution for the settlement and equity issues raised by AEMO and Infigen in separate rule changes.

The draft rule will amend the non-energy costs recovery framework to align with the overarching principle to base the recovery of these costs on a beneficiary/causer pays approach, or if that is not possible then disperse the costs as broadly as possible. That is, the recovery of non-energy costs will be based on a participant's gross consumed energy and/or gross sent out energy in an interval (as applicable), irrespective of what participant category they are registered in. Consumed and sent out energy will be measured separately for all market participants i.e. consumed and sent out energy data in an interval will be measured separately and not netted at the connection point, or among connection points. The Commission notes this approach will not include the energy that is both produced and consumed behind the connection point for the purposes of calculating non-energy costs, for example, rooftop solar production that is consumed on site. This will require two main changes:

- The use of two new data streams in non-energy cost recovery – adjusted sent out energy (ASOE) and adjusted consumed energy (ACE), which will be available after global settlement is implemented in May 2022 (where the necessary metering is in place).
- Non-energy cost recovery would be based on a participant's gross energy flows i.e. gross consumed (i.e. ACE) or exported (i.e. ASOE) during relevant intervals, rather than the category a participant is registered in.

The Commission considers the draft decision is more preferable to AEMO's proposed solution or other solutions suggested by stakeholders for the following reasons:

The existing approach is outdated and does not reflect how the current market operates

The existing non-energy cost recovery framework was created at NEM start, when all participants either predominantly generated energy or consumed energy at any one connection point. Participants are registered as market generators or market customers, and these participant categories are used to calculate and recover non-energy costs based on how much energy a participant consumes or generates. As the number of connection points with bi-directional electricity flows continues to grow, the assumption of participants either predominantly consuming or generating energy no longer holds. This draft decision provides a forward-looking framework that incentivises participants to manage their demand for these services by recovering non-energy costs proportionally from those who benefit from or cause the need for them.

It would create a level playing field for all participants and aligns with the path towards a two-sided market

The draft decision will remove the disparity between how storage participants are currently treated compared to other participants, by recovering non-energy costs from all participants in the same way they are currently recovered from grid-scale storage participants. This change aligns with a move towards a two-sided market, as the costs will be recovered from participants proportionally based on how they interact with the market through the services they provide (demand and supply of energy), not the assets or participant categories that deliver them.

The draft decision would remove inefficient outcomes created through the existing net metering approach

The existing non-energy cost recovery framework calculates non-energy cost recovery from registered participant categories based on net metering data. This creates inefficient outcomes including:

- Reducing the amounts recovered from a market participant who contributed to the need for or benefited from the service. For example, non-energy cost recovery from a Market Customer (retailer) with significant generation behind its market load connection points will be less than it would be if the same amount of generation and load were located at separate connection points that belonged to different market participants. This means participants with significant generation behind their market load connection points can avoid paying their fair share of the non-energy costs caused by their customers' loads and therefore other retailers are paying higher costs as a result.
- Inappropriate payments made to Market Customers rather than recovery from them. For example, in some recovery calculations, if the sent out energy exceeds consumed energy in an interval, payments would be made to the Market Customer based on the net export, even though that Market Customer did have load that contributed to the need for the non-energy services in that interval. This occurs because the net consumption amounts

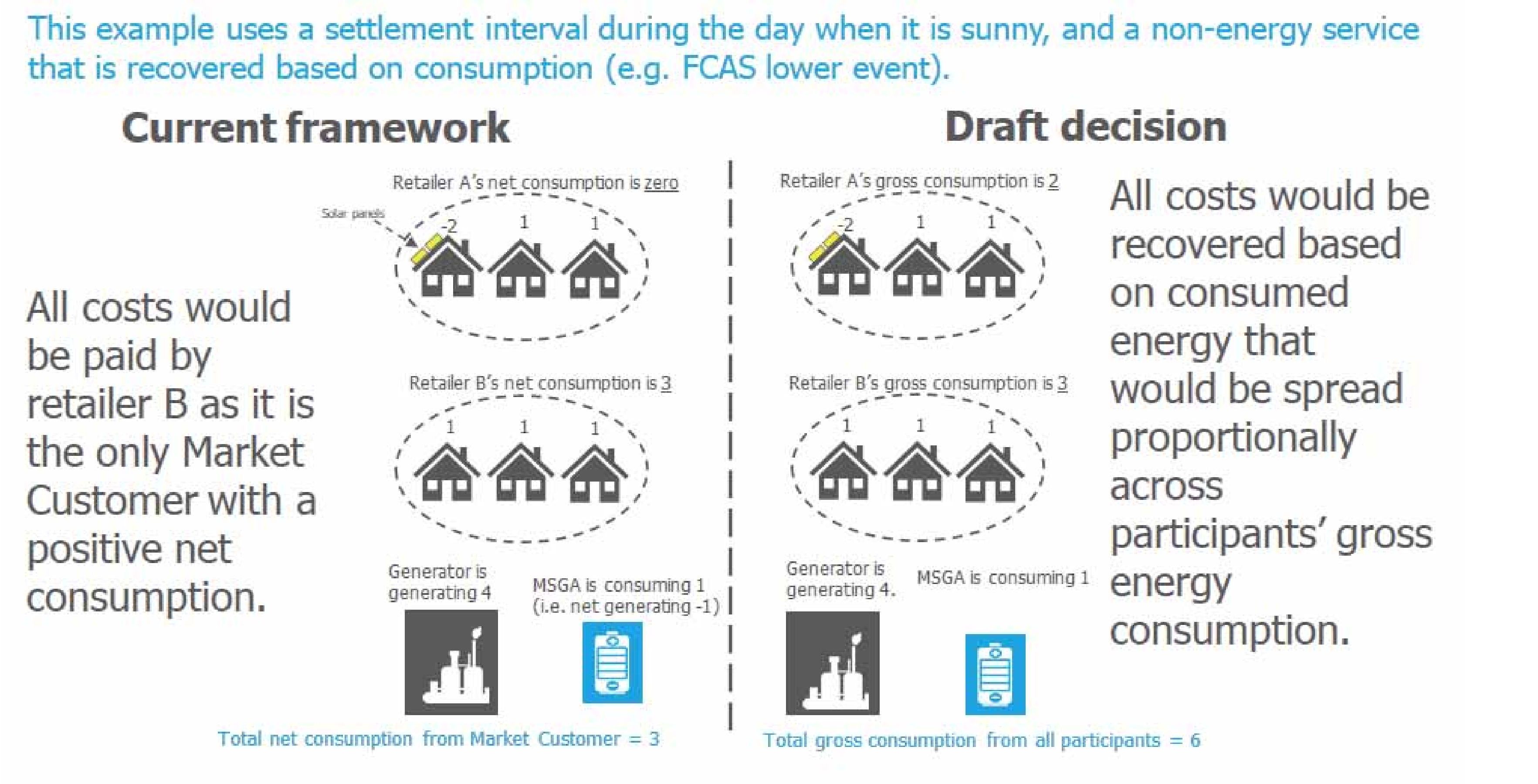
for Market Customers are not floored, unlike the corresponding amounts for Market Generators.[302]

The Commission considers that by removing the ability to net energy flows and avoiding possible inefficient outcomes, participants will have greater incentives for more efficient behaviour as their costs will reflect how they benefit from the provision of non-energy services. But, if participants continue to net energy flows to avoid paying their part of the costs caused by their consumption or generation, that incentive will be ineffective - an issue which will become more acute as bi-directional flows increase over time.

Figure C.1 provides an example of how the draft decision will change the recovery of non-energy costs compared with the current framework.

302 For example, in clauses 3.15.6A(o) (ancillary service recovery) and 3.15.8(h) (directions compensation), the sent out energy amount assessed for recovery from Market Generators and MSGAs has a floor of zero, so they cannot receive payment if there is net consumed energy in a trading interval. There is no corresponding floor for consumed energy amounts - see for example the definitions of "customer energy" and "generator energy" in cl 3.15.6A(a0).

Figure C.1: **Recovery of non-energy costs - an example of the draft decision**



The draft decision would permanently resolve settlement and equity issues raised by AEMO and Infigen in separate rule change requests

In February 2021 AEMO and Infigen submitted separate rule change requests raising issues in relation to the calculation of non-energy costs:

- AEMO has identified that the formula used to calculate non-energy costs and settlement of the market cannot be solved if the regional demand used in the formula is below zero. This means that if a region records demand at or below zero AEMO cannot settle the NEM for the settlement period.
- Infigen considered that there exists an equity issue that can arise and increase exponentially in intervals where non-energy costs are recovered when regional demand approaches zero but is still positive, and there are participants recording negative net consumption values due to netting and no 'flooring' applied to market customers' net consumption. Under these circumstances participants may be required to pay non-energy costs that exceed the actual cost of the service and result in payments from participants with positive net consumption to participants with negative net consumption.[303]

On 17 June 2021, the Commission made a rule in response to AEMO's *NEM settlement under low, zero and negative demand conditions* rule change request that amended rule 3.15 of the NER to ensure the NEM can continue to settle during periods of low, zero or negative demand conditions. The final rule allows AEMO to substitute AGE values for a market customer's average AGE from the previous four billing periods, when net regional demand is less than 150 MWh in a trading interval.[304] The rule provides a temporary low cost solution to address the urgent settlement risks and the inequitable payment risks that can take place when net demand is low, as raised by AEMO and Infigen in their respective rule change requests. In the final determination, the Commission noted that an enduring solution to these issues is being developed in the *Integrating energy storage systems into the NEM* rule change.

The Commission considers its draft decision in this rule change will resolve the issues raised by AEMO and Infigen in their rule change requests by removing calculations based on net metering. By removing netting, negative net values will not be possible. However, this draft change, if made as final, will not come into effect until April 2023, to allow AEMO the necessary implementation time frames, and noting that separate consumed and sent out energy data streams are only available after the Global Settlement & Market Reconciliation rule is implemented on 1 May 2022. The temporary solution implemented in the *NEM settlement under low, zero and negative demand conditions* rule change will remain in place until the changes made by the *Integrating Storage* rule are implemented.

303 This is highlighted in Infigen's rule change request, Settlement under low operational demand, p. 5.

304 On 17 June 2021, the Commission made a draft decision to make no rule for Infigen's *Settlement under low operational demand* rule change request as the issues it raised were adequately dealt with in the final determination for the *NEM settlement under low, zero and negative demand conditions* rule change. A final determination for the Infigen rule change request is expected in August 2021.

A broad brush approach now, leaving specific non-energy cost allocations to future reviews or rule change proposals

The Commission notes the primary objective of this rule change is to better integrate storage and hybrid facilities into the NEM. The draft rule achieves this by realigning the non-energy costs recovery framework to create a consistent approach for all participants. That is, the recovery of costs for each non-energy service will be based on how much energy a participant consumes or sends out from the network, which would be proportional to the benefit received from or the contribution to the need for the relevant non-energy services, not the category the participant is registered in.

The AEC, in a letter to the AEMC, considered whether the allocations of non-energy costs continue to remain appropriate in today's market.[305] That is, should non-energy costs continue to be recovered under the existing allocation between the supply and demand sides of the market? The Commission notes the AEC's query, but considers that in this rule change stakeholders have only engaged on how to share the existing allocation of costs, not on changing the allocation of costs between the supply and demand sides of the market.

The Commission considers a bottom-up approach of how each of the non-energy costs should be allocated is appropriate. The Commission welcomes feedback on whether this additional work should proceed and if so, whether a review (as suggested by the AEC), an ESB process or a rule change process is the preferred path.[306]

Customers on accumulation meters would continue to net consumed and sent out energy at the connection point

The Commission notes that there are still a significant number of Type 6 accumulation metering installations, which cannot separately measure bi-directional energy flows. AEMO estimates up to 8.5 million of these meters are currently used across the NEM. Under the draft decision, these sites would continue to have non-energy cost recovery calculated on an energy flow amount netted over the meter-reading period (typically three months). This would change over time as accumulation meters are replaced.

305 AEC letter sent on 25 February 2021 can be accessed here.

306 Ibid.

C.7 Further analysis on each non-energy service

The section provides further detail on each of the non-energy services, how their costs are currently recovered, how this would change under the draft rule, and the likely materiality of the change for market participants.

The draft rule creates a new term, a 'Cost Recovery Market Participant', defined to include Market Customers, Market Generators and Integrated Resource Providers. This term captures all market participants that are financially responsible for connection points in the NEM from which costs are being recovered, and provides an avenue to recover non-energy costs from them.

Table C.2: **Non-energy services - changes to cost recovery**

NON-ENERGY SERVICE	DESCRIPTION OF WHAT THE SERVICE DOES	CURRENT FRAMEWORK	FRAMEWORK IN DRAFT RULE	MATERIALITY AND WHO IS IMPACTED
Market ancillary services				
FCAS - contingency raise	Contingency FCAS corrects the supply/ demand balance in response to major frequency disturbances causing frequency to move outside the normal operating frequency band, which can occur after contingency events such as the loss of a generating unit or a major load. Contingency raise is a service to add MW to the system in order to raise the frequency over either 6	Contingency raise FCAS costs are recovered from Market Generators and Market Small Generation Aggregators (MSGA) in the relevant Requirement region(s) (including all regions for a Global Requirement) for the relevant trading intervals. (See NER clause 3.15.6A(f)(3))	Recover from all Cost Recovery Market Participants based on their proportion of adjusted sent out energy amounts for the relevant trading intervals.	Record high FCAS costs in 2020 of $356m due to the SA-VIC separation. Contingency raise is the largest proportion of this sum. (For more information see here.) As an example of how costs are recovered, in Q1 2020, NEM quarterly FCAS costs increased to record levels of $227 million. Of these costs, $166 million was recovered from

NON-ENERGY SERVICE	DESCRIPTION OF WHAT THE SERVICE DOES	CURRENT FRAMEWORK	FRAMEWORK IN DRAFT RULE	MATERIALITY AND WHO IS IMPACTED
	second, 60 second or 5 minute periods after an event.			generators, with the remainder ($61 million) recovered from retailers. (For more information see here.) Recovery is expected to be spread across a wider base as net generating Market Customers will now be included in this calculation. Given this, the change will be most material for Market Customers who frequently have net export amounts (rather than consumption), those with lower exports would pay less.

NON-ENERGY SERVICE	DESCRIPTION OF WHAT THE SERVICE DOES	CURRENT FRAMEWORK	FRAMEWORK IN DRAFT RULE	MATERIALITY AND WHO IS IMPACTED
FCAS - contingency lower	Contingency lower is a service to take MW out of the system in order to lower the frequency over either 6 second, 60 second or 5 minute periods after an event.	Contingency lower FCAS costs are recovered from Market Customers only, in the relevant Requirement region(s) (including all regions for a Global Requirement) for the relevant trading intervals. (See NER clause 3.15.6A(g)(3))	Recover from all Cost Recovery Market Participants based on adjusted consumed energy for the relevant trading intervals.	
FCAS - regulation	Regulation FCAS provides frequency correction in response to minor deviations in the demand/ supply balance. There are two types of Regulation FCAS: Raise and Lower.	Regulation FCAS recovery calculations recover the cost of meeting the binding Regulation FCAS constraints on a causer pays basis, i.e. the amount paid by AEMO for the Regulation FCAS service is recovered from Market Participants deemed to have 'caused' the need for the service, where this is possible to determine from metering. The residual amount of Regulation FCAS costs that cannot be allocated to metered 'causers' is smeared across all Market Customers based on energy consumption for the relevant trading intervals.	Recover on a causer pays basis from all Cost Recovery Market Participants with appropriate metering. Recover the residual amount from all Cost Recovery Market Participants without appropriate metering based on adjusted consumed energy or adjusted sent out energy.	

NON-ENERGY SERVICE	DESCRIPTION OF WHAT THE SERVICE DOES	CURRENT FRAMEWORK	FRAMEWORK IN DRAFT RULE	MATERIALITY AND WHO IS IMPACTED
		(See NER clause 3.15.6A(i).)		
Non-market ancillary services				
Network support control services (NSCAS)	NSCAS acquired by AEMO are typically used to control voltage at different points along the network to within prescribed standards and to keep power flow on the networks and interconnectors within operational limits. Generally, these services are provided by voluntary load shedding or the supply or absorption of reactive power. AEMO currently defines two types of NSCAS: • Reliability and Security Ancillary Service • Market Benefit Ancillary Service.	AEMO aggregates the relevant payments (excluding testing payments) for each trading interval and each type of NSCAS, and recovers them fully from Market Customers in proportion to their energy consumption in that relevant Requirement region for that trading interval. (See NER clause 3.15.6A(c2)(1))	Recover from all Cost Recovery Market Participants based on adjusted consumed energy for the relevant trading intervals.	The last two years there have been no NSCAS services acquired by AEMO. In previous years NSCAS has cost $10-$14m per year. (For more information see here.) As with FCAS, retailers with larger proportions of exports would pay a greater share of these costs than they would currently, and those with lower exports would pay less.
System restart ancillary services (SRAS)	SRAS enable generation to be restarted to energise the transmission system following a major supply	AEMO aggregates the relevant payments for an SRAS event (excluding testing payments) for each trading interval and recovers	Recover 50 per cent from all Cost Recovery Market Participants based on their proportion of adjusted sent out energy amounts	SRAS has cost $20-40m annually across the NEM since 2015. (For more information see here.)

NON-ENERGY SERVICE	DESCRIPTION OF WHAT THE SERVICE DOES	CURRENT FRAMEWORK	FRAMEWORK IN DRAFT RULE	MATERIALITY AND WHO IS IMPACTED
	disruption.	the relevant costs on a 50/50 split basis from Market Customers and collectively from Market Generators and Market Small Generation Aggregators on a regional basis. (See NER clause 3.15.6A(c2)(2))	for the relevant trading intervals. Recover 50 per cent from all Cost Recovery Market Participants based on adjusted consumed energy for the relevant trading intervals.	Retailers with larger proportions of exports and MSGAs (with bi-directional flows) will pay a greater share of these costs than currently, and those with lower exports would pay less.
Testing of SRAS and NSCAS	For both services above (SRAS and NSCAS) testing is carried out to ensure confidence that service can be provided.	The recovery calculation uses the same approach as above though it is done in proportion to the aggregate of the relevant energy over the entire testing period. Testing payments are paid and recovered as a lump sum in the billing period in which the successful test is confirmed by AEMO. This lump sum is summed together with that billing period's non-testing recovery amounts. (See NER clause 3.15.6A(c2)(1) and 3.15.6A(c2)(2))	Same approach as for SRAS and NSCAS above.	Included above.
Interventions				
Direction - Energy	If there is a risk to the reliable or secure operation	Where the reason for the intervention event is to address a	Recover from all Cost Recovery Market Participants based on	Directions for energy include directions to

NON-ENERGY SERVICE	DESCRIPTION OF WHAT THE SERVICE DOES	CURRENT FRAMEWORK	FRAMEWORK IN DRAFT RULE	MATERIALITY AND WHO IS IMPACTED
	of the power system AEMO can direct scheduled or semi-scheduled resources to change output/ consumption or take certain actions. Compensation is then payable both to participants directed to provide services and, where a direction is in response to a shortage of energy or FCAS, those participants which are dispatched differently ("affected") as a result of the direction.	shortage of energy, compensation costs will be recovered from market customers and hence consumers in the region which benefited from the intervention. This is calculated based on the energy share of a Market Customer for each trading interval from the start to end of the direction period. This includes affected participant compensation (APC). (See NER clause 3.15.8(b))	adjusted consumed energy for the relevant trading intervals.	provide system strength. Such directions have been issued frequently in recent years, particularly in South Australia. In 2020, total costs for directing South Australian generators for system strength was $49 million, $23 million higher than 2019. (For more information see here.) As with FCAS, retailers with larger proportions of exports would pay a greater share of these costs than they would currently, and those with lower exports would pay less.
Direction - FCAS		Where the reason for the intervention is to address a shortage of FCAS, compensation costs will be recovered in line with the normal process for recovering	Recovery of FCAS will change as outlined above.	Directions for FCAS are uncommon. No material impact expected.

NON-ENERGY SERVICE	DESCRIPTION OF WHAT THE SERVICE DOES	CURRENT FRAMEWORK	FRAMEWORK IN DRAFT RULE	MATERIALITY AND WHO IS IMPACTED
		the cost of the FCAS service in question: i.e. from generators, small generation aggregators and/or market customers. This includes affected participant compensation (APC). (See NER clause 3.15.8(f))		
Direction - Other	A direction to provide a service other than energy or FCAS. For example this could be for a generator to remain in service as a synchronous condenser or to a battery to maintain a state of charge.	The cost of compensating participants directed to provide services other than energy and FCAS is recovered from Market Customers, Market Generators, and MSGAs in proportion to their net consumed or sent out energy. This is calculated based on the energy share for each trading interval from the start to end of the direction period. (See NER clause 3.15.8(g))	Recover from all Cost Recovery Market Participants based on metered gross consumed and sent out electricity.	Such directions are rare and resulting compensation amounts are generally small. Retailers with larger proportions of exports and MSGAs (with bi-directional flows) will pay a greater share of these costs than currently, but this impact is not expected to be material.
RERT	RERT allows AEMO to contract for emergency reserves, such as generation or demand response, that are not otherwise available in the market. RERT is	Direct costs associated with emergency reserves (including usage or activation charges and net affected participant compensation costs) are recovered, where possible, from	Recover from all Cost Recovery Market Participants based on adjusted consumed energy for the relevant trading intervals.	$40-50m per year from 2017-2020. (For more information see here.) Retailers with larger proportions of exports

NON-ENERGY SERVICE	DESCRIPTION OF WHAT THE SERVICE DOES	CURRENT FRAMEWORK	FRAMEWORK IN DRAFT RULE	MATERIALITY AND WHO IS IMPACTED
	activated when all market options have been exhausted, typically during periods when the supply demand balance is tight.	those consumers who contributed to the need for the RERT, in the region in which the RERT was activated. The costs are recovered in proportion to market customers' consumption during the RERT activation. Other costs (such as availability charges, pre-activation charges and general administrative costs associated with the RERT) are recovered from customers based on consumption over the billing period (as opposed to the trading intervals during which the RERT was activated). In addition to the cost of procuring the RERT, affected participant compensation may be payable where the RERT is activated in response to a shortage of energy or FCAS and other participants are dispatched differently ('affected') as a result. (See NER clause 3.15.9(f))		and MSGAs (with bi-directional flows) will pay a greater share of these costs than currently, but this impact is not expected to be material.

NON-ENERGY SERVICE	DESCRIPTION OF WHAT THE SERVICE DOES	CURRENT FRAMEWORK	FRAMEWORK IN DRAFT RULE	MATERIALITY AND WHO IS IMPACTED
Market suspension	A scheduled generator or ancillary service provider that provides services during a Market Suspension Pricing Schedule (MSPS) period is automatically entitled to compensation if its estimated costs during the MSPS period exceed the revenue it earns from the MSPS.	Costs are recovered as through the directions framework – i.e. from Market Customers based on proportion of consumed energy for each interval during a market suspension period. (See NER clause 3.14.5A)	Recover from all Cost Recovery Market Participants based on adjusted consumed energy for the relevant trading intervals.	Unlikely to have a material impact given market suspension events are rare.
Other events				
Market shortfalls	Compensation is payable when there is a market shortfall.	If a market participant defaults AEMO will draw upon credit support to cover shortfalls. If shortfall is not covered - Market participants, likely generators, have payments reduced on a pro-rata basis. Either for a billing period or financial year. (See NER clauses 3.15.22 & 3.15.23)	No change needed here as the NER do not prescribe specific market participants to recover from.	No change here.
Administered price cap or administered floor	Compensation is payable for the entire period from when the administered price cap	Currently recovered from market customers in the region in which the price cap or floor was set	Recover from all Cost Recovery Market Participants, within relevant region, based on the sum	Only one claim has been lodged under this framework (by Synergen

NON-ENERGY SERVICE	DESCRIPTION OF WHAT THE SERVICE DOES	CURRENT FRAMEWORK	FRAMEWORK IN DRAFT RULE	MATERIALITY AND WHO IS IMPACTED
price compensation payments	or floor first sets the dispatch price to the end of the trading day, and is based on the difference between total generator costs and total spot market revenues.	based on the sum of the consumed amounts for each trading interval during the eligibility period. (See NER clause 3.14.6(a))	of the adjusted consumed energy for each trading interval during the eligibility period.	in 2009, for more information see here). So unlikely to have any material impact.

Source: AEMC

D TUOS AND DUOS CHARGES

D.1 Overview

In its rule change request, AEMO considered that there is a lack of clarity on how transmission use of system (TUOS) and distribution use of system (DUOS) network charges apply to grid-scale storage and hybrids because they are not defined in the NER.[307]

AEMO's proposal was to exempt storage from TUOS and DUOS charges as it considered an exemption would increase investor certainty and eliminate inefficient storage location decisions.[308]

The Commission's draft decision is not to amend the NER to exempt storage from TUOS and DUOS charges. The Commission considers that AEMO's proposed exemption would not promote the NEO as it would not reflect the efficient cost of providing the service or the benefit or cost impact it may have on the network.

The Commission's draft decision proposes amendments to the NER to clarify how TUOS and DUOS apply in relation to grid-scale storage and hybrids and to accommodate the new IRP participant category within the framework.

D.2 What are TUOS and DUOS charges and who pays them?

D.2.1 What are TUOS and DUOS?

The charges of TNSPs include amounts for the provision of shared network services. Shared network services refers to the services required to convey electricity from sources of generation to transmission-connected customers and distribution networks connected to the transmission network. Where these services are provided at the service standard provided for under the NER, the service is classified as a prescribed transmission service. The TNSP's charges for shared transmission services, when provided as a prescribed service, are typically known as TUOS.

The term DUOS is not defined but refers to the charges or tariffs of a DNSP for the corresponding service it provides - that is, the conveyance of electricity to customers, either from the transmission network, or from generators embedded in the distribution network. The AER currently classifies these services as direct control services.

TNSPs and DNSPs charge for other services, including for connecting new facilities to their networks. These charges are typically referred to as connection charges, and not as TUOS or DUOS charges.

307 AEMO Integrating Energy Storage Systems into the NEM rule change request p 20.

308 ibid p 29, 54

D.2.2 Customers pay TUOS and DUOS

Currently, customers pay for the costs incurred by network service providers (NSPs) in providing shared network services (capital and operating costs) through TUOS charges.[309]

TUOS is paid by customers who are directly connected to the transmission network and by DNSPs, who pass the TUOS charges through to their distribution customers. Generators connected to the transmission network do not pay TUOS, as the view has historically been taken that networks are planned for the needs of customers who consume electricity rather than for the generators who generate it. NSPs must connect and reliably supply their customers and meet network performance requirements while doing so.

At present, DUOS is paid only by electricity consumers as the NER prevent DNSPs from charging for the export of electricity.[310] Increasingly, networks are having to consider how to accommodate connections that have bi-directional flows - that is, customers at a connection point that consume electricity at times and generate it at other times. The Commission has recently proposed changes to the NER that would allow DNSPs to charge for export services.[311]

The NER require each TNSP to submit a pricing methodology to the AER for each regulatory period covering its TUOS charges. TNSPs must demonstrate compliance with the pricing principles for prescribed transmission services and the AER's TNSPs pricing methodology guidelines.

DNSPs are required to develop a tariff structure statement (TSS) outlining the proposed DUOS pricing structure for the next regulatory period and an indicative pricing schedule for each regulatory year (including TUOS cost allocations).[312]

The process for developing the TSS is prescriptive and contains clear timelines and DNSPs are required to develop it in consultation with its customers, and in accordance with the pricing principles.[313] While the TSS process (and pricing principles) are directed at retail customers, DNSPs typically use this process for all their network tariffs. The application of the TSS and pricing principles to non-retail customers is discussed in appendix D.6.1

D.2.3 Negotiated use of system charges

A transmission customer can request shared transmission services to be provided as negotiated transmission services, rather than as prescribed transmission services.[314] While the underlying service is the same (a shared transmission service) it will be a prescribed

309 Under the transmission and access market design initiative of the ESB's Post 2025 project, reforms are being considered for transmission investment costs to be recovered from customers and generators. The ESB's work on developing a two-sided market will seek to ensure a level playing field for all participants by focusing on services rather than the technology that provides it.

310 Clause 6.1.4.

311 Access, pricing and incentive arrangements for distributed energy resources, Draft Determination, 25 March 2021.

312 NER clause 6.18.1A.

313 National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014 final determination, pp 57-58.

314 A negotiated transmission service is a shared transmission service where the network is not required to meet network performance requirements. It is a commercial arrangement with the TNSP and not subject to economic regulation under Chapter 6A of the rules. However, the TNSP is obligated under clause 5.2A.6 to adhere to S5.11 negotiating principles for negotiated transmission services.

transmission service when provided at the service levels for prescribed services set in the NER and a negotiated transmission service when provided at different service levels.[315] This is a feature of the NER which gives a transmission customer a choice of service levels. It is recognised in the economic regulatory framework through the cost allocation principles and the setting of a TNSP's annual revenue allowance, which covers the provision of prescribed transmission services only.

Where a shared transmission service is provided as a negotiated transmission service, the TNSP may still charge for the service. The amount of the charge is governed by principles in the NER.[316] The revenue a TNSP receives for negotiated transmission services sits outside its annual revenue cap.

Although a TNSP's charges for negotiated transmission services can be thought of as a form of use of system charge, for present purposes the term TUOS is used to refer only to charges for prescribed transmission services.

D.2.4 If grid-scale storage is registered as both a customer and generator, what does it currently pay?

There are five grid-scale batteries in the NEM and their current treatment in regard to TUOS and DUOS is outlined in Table D.1below.

Table D.1: **Current treatment of grid-scale batteries in the NEM - TUOS and DUOS**

BATTERY	NET-WORK	TREATMENT
Gannawarra (owned and operated by a third party)	Powercor	The Commission understands there are no storage specific tariff classes. Powercor applies its default sub-transmission DUOS tariff for Gannawarra's consumed energy (i.e. when the battery is charging) in accordance with its AER approved 2016-2021 TSS.
Various	Victorian DNSPs	In their initial proposed 2021-2026 TSS, all Victorian DNSPs proposed their own grid-scale storage be exempt from network tariffs. However, in some cases they proposed different treatment for storage owned by other parties. The AER's final TSS decision determined that ownership of energy storage assets should not be the basis for differential tariff treatment. It required the TSS to be amended so that storage, unless providing network support services, be exposed to the same network tariff as other customers in that tariff class (consistent with clauses 6.18.4(a)(2) and (3)).

315 NER chapter 10, definitions of 'prescribed transmission service' and 'negotiated transmission service'.

316 Chapter 5, Schedule 5.11.

BATTERY	NET-WORK	TREATMENT
ESCRI (owned by ElectraNet)	ElectraNet	The scheduled load is treated as a negotiated transmission service and not charged TUOS. The transmission service provided to the ESCRI battery when it is charging will be a negotiated transmission service as it will not meet network performance requirements under jurisdictional electricity legislation (including it will not need to specify an agreed maximum demand) or the NER (including in relation to the power transfer capability) when the battery is charging.
Lake Bonney	AusNet	The Commission understands the scheduled load is treated as a negotiated transmission service and not charged TUOS.

Source: Gannawarra energy storage system knowledge sharing report p 16. AusNet Services revised TSS 2021-26 pp 23-24, Jemena revised TSS 2021-26 p 18, Powercor revised TSS 2021-26 p 14. AER Tariff structure statement Final decision - AusNet Services, CitiPower,Jemena, Powercor and United Energy 2021–26, p 16. AER submission to the consultation paper p 2. ENA submission to the consultation paper p 5. ElectraNet ESCRI-SA project summary report pp 19-20

D.3 Issues raised

D.3.1 AEMO considered TUOS and DUOS arrangements for grid-scale storage and hybrids are unclear

AEMO considered that there is a lack of clarity on how TUOS and DUOS charges apply to grid-scale storage and hybrids because they are not defined in the NER.[317]

AEMO, in its rule change request, stated that NSPs typically charge market customers TUOS and DUOS for load (i.e. when the customers draw energy from the grid). However, because storage is not defined, NSPs apply their own interpretation of the rules for determining charges. AEMO is concerned that, if the rules are not clarified, different arrangements may be implemented across the NEM. In its view, this could create incentives for locating storage in areas where charges can be avoided but not where storage is most needed for market efficiency. Further, it considers that without certainty of charges, it is difficult for proponents to consider these costs for investment decisions.[318]

D.4 AEMO's proposed solution

AEMO proposed to define storage (which includes pumped hydro and grid-scale batteries) in the NER to provide clarity to storage proponents that:[319]

317 AEMO Integrating Energy Storage Systems into the NEM rule change request p 20

318 ibid p 20

319 ibid p 28, 45, 63

- TUOS charges for sent out or consumed energy would not apply to a storage scheduled resource (either standalone or within a hybrid facility) which can be 'constrained off' (amendments to NER Chapter 6A and Chapter 10 definitions)
- TUOS would apply to non-scheduled market load (that is not storage) within a hybrid facility (if it can be separately metered)
- DUOS would not apply to sent out energy (amendment to Clause 6.1.4)
- DUOS charges would continue to apply for consumed energy.

AEMO's rationale is:[320]

- NSPs would not increase the capacity of the shared network to provide unrestricted access for storage
- NSPs treat storage as a connecting asset subject to negotiated connection charges, the same as a generating unit or system
- it increases investor certainty and eliminates inefficient storage location incentives (i.e., based on whether it would be subject to TUOS/DUOS charges) and
- it increases operational efficiency as networks and proponents do not need to calculate these charges.

D.5 Stakeholder feedback

Overview

Most stakeholders (except DNSPs) generally supported AEMO's proposal to clarify and exempt storage from TUOS charges.[321] DNSPs considered the rules are clear on the treatment of storage and hybrids, and they should not be exempt from DUOS.[322]

Some stakeholders considered storage should be exempt from DUOS charges on both consumed and sent out energy.[323] Others considered DUOS charges payable on consumed energy must be cost reflective.[324]

D.5.1 Is there ambiguity and uncertainty on the application of TUOS and DUOS charges to storage in the rules?

Some stakeholders considered there is uncertainty in the rules because AEMO changed its battery storage registration requirements meaning NSPs must treat storage as both a market customer and generator for pricing purposes.[325] The ENA noted that while TNSPs have had to interpret the Chapter 6A rules, they are confident their approach for transmission connected

320 ibid p 29, 54

321 Submissions to the consultation paper: AEC p 3, AGL p 6, CEC p 4, CEIG p 3, ENA p 5, Engie p 5, Enel Green p 2, ERM Power p 2, Firm Power p 5, Fluence p 19, GE Hydro p 16, Infigen p 4, Maoneng pp 7-11, Monash Energy Institute pp 15-18, Neoen p 3, Origin p 2, Snowy Hydro p 4, Tesla p 6, Tilt Renewables p 2, Transgrid p 2, Yes Energy p 14

322 Submissions to the consultation paper: AusNet Services pp 15-16, ENA pp 4-5, 11-12, Endeavour Energy p 3, Energy Queensland p 19, Essential Energy p 2

323 Submissions to the consultation paper: AEC p 3, AGL p 6, Beca pp 9-10, CEC p 4, Enel Green p 2, Energy Australia p 2, ERM Power p 4, Firm Power p5, GE Hydro p 16, Monash Energy Institute pp 15-18, Tesla p 6, Tilt Renewables p 2

324 Submissions to the consultation paper: Ausgrid p 3, Beca p 11, Essential Energy p 2

325 Submissions to the consultation paper AusNet Services p 13, Energy Australia p 3

storage is compliant with the rules i.e. that a battery's scheduled load receives a negotiated transmission service and so should not be charged TUOS.

Nevertheless, it suggested the rules could be amended to clarify their approach is compliant.[326]

DNSPs and the ENA considered the Chapter 6 rules are clear. Storage does not need to be defined as it should be treated the same as other load services. They consider consistent treatment ensures cost reflective DUOS pricing, limits cross subsidies and preserves technology neutrality.[327] Furthermore, as the AER approves network tariffs consistent with the rules, there is no compliance risk for how DNSPs apply charges to storage.[328]

Other stakeholders considered there is ambiguity and uncertainty on how networks apply storage TUOS and DUOS, and also whether transmission or distribution storage are treated consistently.[329] Some stakeholders noted networks may diverge from published tariffs at the offer to connect stage due to operational requirements, and this can reduce the commercial viability of storage projects. There is also a question of incentives for networks to support alternative tariff arrangements or third party storage if they do not deliver additional revenue streams.[330]

The AER is concerned that some DNSPs may exempt DUOS for its own storage, but charge DUOS for other storage. This is likely to create distortions and may lead to inefficient storage location decisions.[331]

D.5.2 Should storage be defined and exempt from TUOS and DUOS charges?

Most stakeholders largely agreed with AEMO that storage should be exempt from TUOS to maintain consistency with generators (and because they provide valuable technical services).[332] However, some considered TUOS should apply to non-storage load, including within a hybrid facility (if it can be separately metered).[333] Other stakeholders were concerned if storage is subject to TUOS, it amounts to double charging, once for the energy it draws from the grid, and again when it transmits through the distribution system. These costs would be added to wholesale costs and power purchase agreements, ultimately flowing through to customers.[334]

326 Submissions to the consultation paper: ENA p 5

327 Submissions to the consultation paper: ENA pp 12-13, Endeavour Energy p 3, Energy Queensland p 19, Essential Energy p 2

328 Submissions to the consultation paper: Energy Queensland p 21

329 Submissions to the consultation paper: AGL p 6, AER p 2, ARENA p 8, Beca p 9, CEC p 4, CEIG p 3, Enel X pp 13-14, ERM Power p 3, Firm Power p 1, Fluence pp 19- 20, Maoneng pp 7-11, Monash Energy Institute pp 15-18, Origin p 2, Telsa p 6, Tilt Renewables p 2, UPC/AC Renewables p 5

330 Submissions to the consultation paper: Arena pp 8-9, Firm Power p 4, Maoneng pp 7-11

331 Submissions to the consultation paper: AER p 2

332 Submissions to the consultation paper: AGL p 6, AusNet Services p 14, CEIG p 3, ENA p 5, Enel Green p 13, ERM Power p 2, Fluence p 19, Firm Power, GE Hydro p 16, Infigen p 4 Maoneng pp 8-10, Monash Energy Institute p 15, Neoen p 3, Origin, p 2, Snowy Hydro p 4, Telsa p 6, Transgrid, p 2, Yes Energy, p 14

333 Submissions to consultation paper: AEC p 3, Ausnet Services p 14, ENA p 16

334 Submissions to the consultation paper: AEC p 3, ENA pp 15-16, Enel Green p 11, Engie p 5, Firm Power p 6, Maoneng pp 8-9, Tesla p 6

Some DNSPs considered storage should not be exempt from TUOS as they can draw energy comparable to large load customers who pay TUOS. Furthermore, by not treating storage on an equal basis with other network users, it would embed a cross-subsidy where other customers' costs increase as more storage enters the market. Under a revenue cap if storage pays TUOS, customers will not be double charged as the amount of TUOS revenue received from storage will result in a corresponding reduction in TUOS revenue to be recovered from all other customers.[335] DNSPs also noted exemptions are inconsistent with AEMO's objective to ensure consistency in how fees and non-energy costs are recovered from all participants.[336]

Several stakeholders considered the same argument for TUOS exemption applies to DUOS, and stated they should be treated consistently. Otherwise, there may be inefficient market outcomes when distribution level storage is subject to high DUOS charges, but transmission level storage is exempt from TUOS charges.[337]

DNSPs stated storage should generally be required to pay DUOS but may also be eligible for network support payments and avoided TUOS for deferring network expenditure; they should have the discretion to design tariffs to reflect each networks' circumstances, including the ability to waive DUOS charges (to attract investment into their network) if it will be operated to the net benefit of customers.[338]

D.5.3 Are there future alternative TUOS and DUOS charging solutions?

As a future alternative to TUOS and DUOS charging based on asset type, there was limited support for charging all market participants based on the services provided.[339] Other stakeholders considered end use customers should continue to pay for the network because they are the ultimate beneficiaries.[340]

Some DNSPs and the ENA stated that distribution and transmission network charging arrangements do not need to be consistent because they have different operational characteristics. For example, transmission network constraints impact on a generator's ability to be dispatched and earn revenue.[341] Furthermore, DUOS charging is more appropriately addressed in the Access, pricing and incentive arrangements for distributed energy resources rule change.[342] NSPs and other stakeholders noted the ESB's two-sided market design and transmission access reform are considering broader pricing reform and therefore, changes proposed in this rule change need to be consistent with these reforms or risk becoming obsolete.[343]

335 Submissions to the consultation paper: Energy Queensland p 24

336 Submissions to the consultation paper: Citipower, Powercor, United Energy p 16, Endeavour Energy p 3, Energy Queensland p 22, Essential Energy p 1

337 Submissions to the consultation paper: Arena p 1, CEC p 4, Enel Green p 13, Energy Australia p 4, ERM Power p 4, Firm Power p 5, GE Hydro p 16, Infigen p 4, Tilt Renewables p 2, Telsa p 6

338 Submissions to the consultation paper: AusNet Services p 13, CitiPower, PowerCor, United Energy p 15, Energy Queensland pp 20-21

339 Submissions to the consultation paper: Firm Power pp 8-9, Maoneng pp 10-11

340 Submissions to the consultation paper: Enel Green, p 2

341 Submissions to the consultation paper: AusNet Services p 13, ENA p 12

342 Submissions to the consultation paper: Ausgrid p 2, AusNet Services p 16, Endeavour Energy p 3, ENA p 17, Energy Queensland p 25, Essential Energy, p 3

D.6 The Commission's analysis

> BOX 4: DRAFT RULE — TUOS AND DUOS
>
> The Commission's draft decision is to not define storage or hybrid facilities in the NER. Therefore, in the absence of a definition for storage, the Commission has considered whether the process for determining TUOS and DUOS for generation and load is clear.
>
> In the Commission's view, the NER are clear on the treatment for TUOS and DUOS for generation and load:
>
> - For generation: The rules are clear that generators do not incur TUOS or DUOS charges. Changes to the rules for charging DUOS for exports are being considered in a separate process.
> - For load: While the rules are reasonably prescriptive both in form and process for load, they are designed to provide flexibility to negotiate different outcomes in certain circumstances.
>
> However, the Commission's draft rule is to make minor amendments to provide additional clarity on three issues:
>
> - the application of the Chapter 6 pricing principles to non-retail distribution customers under the TSS process (non-retail tariffs should reflect efficient costs)
> - transmission customers may receive shared transmission services as a prescribed transmission service should it wish the services to be provided on that basis
> - the new market participant category, the IRP, will be treated as a Network Customer for the purposes of Chapter 6A in relation to electricity taken from the grid and so will pay TUOS for prescribed transmission services.

D.6.1 The rules provide a clear process for the application of TUOS and DUOS charges to storage (generation and load)

At the transmission level, the rules leave it open to TNSPs and transmission customers including grid scale storage to agree that a shared transmission service will be provided as a negotiated transmission service (and so subject to negotiated charges) or a prescribed transmission charge (and so subject to TUOS charges determined under the economic regulation framework in chapter 6A of the NER). The economic regulation framework is intended to take into account the provision of services on a negotiated basis, for example through the principles governing the determination of the regulatory asset base (RAB) and the cost allocation principles. The Commission considers that shared transmission services provided to grid scale storage when charging can be accommodated within this framework, subject to the clarifications outlined in the next section.

343 Submissions to the consultation paper: Ausgrid p 2, AusNet Services pp 16-17, Energy Queensland pp 25-26, ENA p 17, Endeavour Energy pp 1-3, Essential Energy pp 2-3, Infigen p 4

At the distribution level, the AER classifies services and approves the DNSP's tariff classes and levels in accordance with the pricing principles. Because the pricing principles allow DNSPs to implement prices in the way that best suits their customer and network characteristics (while accommodating jurisdictional requirements e.g., reliability and technical standards), the fact that different outcomes may occur is consistent with the intent of the rules.[344] For example, customers that provide net benefits to the network, such as alleviating network congestion, may face reduced TUOS/DUOS charges.

If the Commission were to make any substantial changes to the NER, it would need to consider how all market participants (including generators) contribute to the need for networks and should be charged. As set out in the next section, other processes are considering the application of network charging, including TUOS and DUOS, more broadly.

While the Commission's draft decision is to not make amendments to the rules to clarify arrangements for TUOS and DUOS for storage, the draft rule makes minor amendments to provide additional clarity on two issues outlined below and to accommodate the new participant category, the IRP, within the existing framework.

Application of the Chapter 6 pricing principles to non-retail distribution customers

While in practice, DNSPs use the TSS process for all customers, there are no clear pricing principles for non-retail customers receiving a common distribution service, even though the approved pricing proposal and TSS applies in some instances.[345] The draft rule makes clear that in the event of a dispute, the tariffs that a DNSP charges for the provision of common distribution services for customers who are not retail customers should reflect its efficient costs of providing those services to the customer.[346]

Transmission customers are entitled to receive a prescribed transmission service for ongoing shared transmission network services subject to network performance requirements

In the two examples of grid scale storage referred to in Table D.1 above, the shared transmission service is being provided as a negotiated service and no TUOS is being charged (although negotiated charges may be applicable). The Commission proposes an amendment to the rules to clarify that TNSPs must provide shared transmission services as prescribed transmission services if the prescribed service is sought by the connection applicant.[347] This is intended to ensure that scheduled storage system loads are not precluded from seeking a prescribed service merely by reason of being scheduled, or due to the service classification applied to other grid scale storage projects. Second, given the creation of the new IRP participant category, the definition of Transmission Customer would be amended to include the IRP in relation to its consumption of electricity.[348]

344 AEMC National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014 final determination, p 27.

345 See for example clauses 6.18.1A, 6.18.2 and 6.18.7A.

346 Draft rule, clause 6.22.2(b1).

347 Draft rule, clause 5.2A.3(b1).

348 Draft rule, amendment to definition of Transmission Customer in chapter 10.

D.6.2 Exempting storage from TUOS and DUOS charges would not be technology neutral

The Commission previously considered whether storage should pay network use of system charges, specifically TUOS charges. The Commission's position was that it is important to adopt a technology neutral approach and not create cross subsidies. The Commission's role is to maximise economic efficiency in the long term interests of all consumers. Incentivising the uptake of particular technologies or the provision of particular services is best determined by governments as an overlay to the technology-neutral framework the NER seeks to provide.[349]

This position has not changed. However, other reforms including the ESB two-sided market design and transmission access reform will seek to provide a level playing field for all participants by focusing on services rather than the technology that provides it. AEMO's proposed technology specific exemptions will not, or are not likely to, contribute to the achievement of the NEO. A blanket exemption would not reflect the efficient cost of providing the service to an IRP or the benefit or cost impact it may have on the network.

The Commission considers it is not a question of whether stand-alone storage or storage within a hybrid facility should pay TUOS or DUOS charges; rather, it is a question about what market participants (including generators) and customers should pay for the services provided to them.

Under transmission access reform, price signals regarding the cost of using the transmission network would be provided to generators as well as customers. In particular, generators would face price signals reflecting the marginal cost of congestion on the transmission network. This means that the TUOS component of a customers' bills will decrease as they would no longer be the only party contributing to the costs of the transmission network.

At the distribution level, the AEMC's Access, pricing and incentive arrangements for distributed energy resources draft determination proposes to remove the prohibition in the rules (NER clause 6.1.4) on distributors charging for export services.[350] Distribution level generators (including grid-scale) may eventually face cost reflective DUOS export charges. However, any decision on these charges (including if they would apply) would be determined (following extensive customer consultation) in accordance with the NER as part of the AER's revenue determination and TSS approval process. The proposed amendments to clause 6.1.4 in the rule change request to exempt storage from sent-out energy DUOS charges[351] would be inconsistent with the Access, pricing and incentive arrangements for distributed energy resources draft determination.[352]

TUOS and DUOS are consistent with the proposed changes to the non-energy cost framework

The approaches to TUOS and DUOS are consistent with the proposed changes to the non-energy cost recovery framework as both seek to allocate costs on a consistent and technology neutral basis - in the case of TUOS and DUOS, to the user of the service and in the case of non-energy costs, on a causer pays basis.

349 AEMC COGATI options paper p 114.

350 https://www.aemc.gov.au/rule-changes/access-pricing-and-incentive-arrangements-distributed-energy-resources

351 AEMO, Integrating energy storage systems into the NEM, Rule change request p. 45.

352 The rule change request was submitted before that draft determination.

D.6.3 AEMO's concern about inefficient location decisions

Exempting storage from network charges, as proposed by AEMO, would not address concerns of the potential for inefficient location decisions made by storage. However, separate work outside of this rule change may address AEMO's concerns by providing more efficient and consistent network charges for storages:

- the ESB's medium term access reforms, if implemented, would provide efficient locational signals to storages through setting a more accurate and dynamic price for use of the transmission network, and
- the AER's transmission ringfencing guidelines review, which may result in a more consistent treatment of setting transmission network charges for storages.

The ESB’s post 2025 market design initiative

The ESB is considering the price signals for using the transmission network provided to generation and load through the transmission and access market design initiative. The ESB has a particular focus on the price signals provided to storage. With one of its four objectives of the reform being:[353]

“The market design does not reward emerging technologies for providing services that enable the efficient integration of renewables. In particular, **measures to promote the efficient location and operation/use of network for storage** and new large flexible loads (e.g., hydrogen) is critical given the potential for these technologies to both alleviate and worsen transmission congestion. Better price signals are needed to support new business models so these technologies work within, and not against a high variable renewable energy power system.”

The ESB has developed a set of medium term access models which would provide more accurate and dynamic price signals regarding the cost of congestion on the transmission network. This is particularly important for storage given its flexibility to respond to price signals in operational timescales and its ability to be quickly deployed in a wide range of locations within the network.

Ring fencing

AEMO’s concerns about inefficient storage location decisions, for example, where a storage provider chooses to locate in a jurisdiction or connect to a network where there are favourable or no TUOS or DUOS charges, are more likely to occur where ring-fencing is ineffective rather than how TUOS and DUOS is applied.

DNSPs are subject to strict AER ring-fencing guidelines. The guidelines require DNSPs to separate all non-distribution services into a different legal entity to the DNSP that provides distribution services, and the guidelines have strong compliance reporting obligations.[354] The AER notes ring fencing benefits consumers by addressing the potential risk of consumers paying more than they should for regulated services. This risk arises because an NSP could

353 Energy Security Board, 2025 Market Design Options - A paper for consultation Part A, p. 84.

354 Updating the ring-fencing guidelines for stand-alone power systems and energy storage devices p 8.

(absent the ring fencing guidelines) cross-subsidise the cost of its unregulated services by attributing costs to its regulated services or discriminate in favour of its business or affiliate operating in contestable markets.[355]

The transmission ring-fencing guidelines have weaker protections against the cross subsidisation of unregulated activities by regulated revenue. TNSPs are allowed to engage in retail, generation and distribution activities under a certain threshold.[356]

The Commission notes that the AER considers the current guidelines,which have not been updated since 2005, do not adequately address the risk of cross-subsidisation between prescribed transmission services and other TNSP services that a TNSP or an affiliate provides.[357] In particular, the current guidelines do not provide sufficient transparency over how costs should be allocated between transmission and non-transmission services.[358]

The AER considers this may give rise to potential harms, for example, a TNSP may prioritise investment in the shared network to remove congestion and network constraints or schedule outages in a way that provides its affiliate with preferential access to the wholesale market during high price events.[359] These potential harms may be difficult for the AER to detect from normal network congestion management[360] - especially for assets and services that can switch between functions at short notice. To address these potential harms, there is an argument that transmission ring fencing arrangements should more closely align with the stronger protections in the distribution ring fencing guidelines.

The AER is in the process of reviewing its transmission ring-fencing guideline and expects to complete its review in 2022. This will likely necessitate a review of the cost allocation guidelines for transmission. The AER cost allocation guidelines must give effect to the cost allocation principles in clause 6A.19.2. These embody economic principles and give effect to principles in the transmission ring-fencing guidelines which aim (in part) to avoid cross subsidies from regulated activities to unregulated activities. As storage can perform a number of services and potentially receive a prescribed transmission service or a negotiated transmission service, issues for consideration may include how costs are allocated, and where it is a network owned battery, what proportion of the battery should be included in the regulatory asset base.

355 Ibid.

356 AER electricity transmission ring-fencing - a review of current arrangements p 9.

357 Ibid p 22.

358 Ibid p 22.

359 Ibid p 31.

360 Ibid p 31.

E DRAFTING AND OTHER INTEGRATION ISSUES

This chapter outlines how the draft rule addresses the issues covered in section 3.5 of AEMO's rule change request which relate to drafting and other integration issues.[361] Table E.1 below lists each of these issues and summarises the Commission's draft decision.

Table E.1: Summary of Commission's conclusions for the drafting and other integration issues

ISSUE	COMMISSION'S CONCLUSION
Technology specific drafting in the rules	The draft rule implements AEMO's proposal to change all mentions of 'offer' to 'bid' in Chapter 3 of the NER and to make generic references to scheduled plants and registered market participants throughout the rules where possible. It makes a more preferable rule to address the ambiguity of the terms 'load' and 'generation' as they apply throughout the NER.
Retailer Reliability Obligation	The draft rule makes IRPs liable entities under the RRO in respect of their load, if aggregate annual load exceeds 10GWh in a particular NEM region, in addition to Market Customers. In practice, an IRP's aggregate annual load might not exceed this threshold.
Intervention compensation frameworks	Given other rule changes on foot in relation to intervention compensation provisions, the only change the draft rule makes to the intervention compensation frameworks is to integrate IRPs into the existing frameworks.
Network losses and marginal loss factors	The draft rule makes no changes to the way network losses and marginal loss factors (MLFs) are calculated for bi-directional connection points.
Reliability Panel representation	The draft rule does not amend the Reliability Panel representation provisions to require storage and hybrid representation.
Other integration issues	The draft rule makes a more preferable rule to address the majority of the other integration issues identified by AEMO.

The following sections cover:

- an overview of technology specific drafting in the rules
- AEMO's view
- stakeholder views
- Commission's analysis.

361 AEMO, *Integrating energy storage systems in to the NEM,* rule change request, pp. 20-26.

E.1 Technology specific drafting in the rules

E.1.1 Overview

In its rule change request, AEMO identified that the NER currently contain technology specific language which does not recognise bi-directional flows at a connection point. AEMO considered this impedes the effective integration of storage and hybrids into the NEM. This issue is separate from the decision to include a definition of storage in the NER, and instead focuses on amending existing terms and definitions in the NER to make them more consistent with the way the market is evolving.

The Commission sought feedback on this issue from stakeholders in the consultation paper, asking if they consider the existing terms for generation and load are ambiguous as they apply to storage and if AEMO's proposed solution would resolve the issues it describes.

The draft rule implements AEMO's proposals to change all mentions of 'offer' to 'bid' throughout the NER, and to make generic references to scheduled plants and registered market participants throughout the NER where practicable. It makes a more preferable rule to address the ambiguity of the terms 'load' and 'generation' as used in different contexts throughout the NER.

E.1.2 AEMO's view

According to AEMO, a collection of terms currently used in the rules are technology specific as they tend to either indicate a type of asset, a direction of energy flow or both.[362] It says this makes it difficult to fully integrate assets which make significant use of bi-directional flows. [363]

AEMO proposed a solution to this issue in its rule change request, which is made up of three parts. These are:

- changing the definitions of electricity flows[364]
- replacing all mentions of 'offer' with 'bid' in Chapter 3 of the NER[365]
- making generic references to scheduled plants and registered participants where possible.[366]

The remainder of appendix E.1.2 provides a brief overview of the content and rationale for these changes proposed by AEMO.

Changing the definitions of electricity flows

To better integrate storage and hybrids, AEMO proposed the NER incorporate new terms which recognise that registered participants can consume and produce electricity at their

362 AEMO, *Integrating energy storage systems into the NEM* — rule change request, pp. 20-21.

363 Ibid.

364 Ibid, p. 21.

365 Ibid, pp. 32-33.

366 Ibid, p. 35.

connection points. Specifically, AEMO proposed defining an additional three terms for electricity flows in Chapter 10 in the NER:[367]

- Consumed electricity: The amount of electrical power delivered from a network at a defined instant or over a defined period at a connection point, or aggregated over a defined set of connection points. This would represent a quantity of electricity flowing from the network at a connection point, which replaces the term 'load' where it is used in that sense (rather than as an asset).
- Sent out electricity: In relation to a generating unit or bi-directional unit, the amount of electricity supplied to the transmission or distribution network at its connection point. This would represent a quantity of electricity flowing to the network at a connection point, which replaces the term 'sent out generation'.
- Produced electricity: The amount of electrical power (measured in MW) produced by a generating unit or bi-directional unit and measured at its terminals. This would represent a quantity of electricity produced by a generating unit or bidirectional unit as measured at its terminals, which replaces the term 'generation'. The use of term 'terminals' also implies that measurement would occur at the asset level, rather than at the connection point.

Replacing all mentions of 'offer' and 'bid' in Chapter 3 of the NER

AEMO proposed to amend Chapter 3 of the NER to replace all mentions of 'offer' with 'bid' where the term 'bid' would refer to all participants' interactions with the central dispatch process, whether to supply or consume electricity. AEMO rationalised this proposed amendment by noting:[368]

- the use of the terms 'offer' and 'bid' are asset specific, in that supply-side participants offer and demand-side participants bid, which makes it confusing for bi-directional assets to participate in the market
- the term 'rebid' applies to both bids and offers
- the declared gas wholesale market uses 'bids' to apply to both scheduling injections and withdrawals.

Making generic references to scheduled plants and registered market participants where possible

AEMO proposed to change the way the rules refer to multiple kinds of participants or facilities at once, by replacing lists with group terms, where doing so does not change the meaning of provisions, as follows:[369]

- replace lists of registered market participants (e.g. 'Scheduled Generators, Semi-Scheduled Generators and Market Participants') with a generic reference to 'Registered Participant' or 'Market Participant'

367 Ibid, Table 6, p. 48 and p. 21.

368 Ibid, pp. 32-33.

369 Ibid, pp. 33 - 34.

- replace lists of scheduled plants (e.g. 'generating units, scheduled network services and scheduled loads') with a generic reference to 'scheduled plant'.

AEMO's rationale for these amendments is to simplify and improve the drafting of the NER.[370]

E.1.3 Stakeholder views

Feedback on these proposed amendments was limited and these issues were only addressed by eight stakeholders. Those eight stakeholders were split on whether the current terms used in the rules are ambiguous as they applied to storage, and whether making the proposed drafting changes would be worthwhile. Three stakeholders who commented on this issue also considered these proposed changes would significantly impact on private contracts.

Some stakeholders considered the proposed changes appropriately provided technology neutrality in the rules, particularly in relation to the terms generation and load due to the ambiguity of applying these terms to storage and hybrid systems.[371] However, others disagreed and considered the current definitions as sufficiently clear.[372]

Monash Energy Institute was the only stakeholder that provided a specific view on this issue and notes the proposal to replace all mentions of 'offer' with 'bid' in the rules as an important change to implement.[373] This was because it considers it appropriate for market design to 'allow storage units to bid as buyers.'[374]

Three stakeholders considered these drafting changes would impact private contracts:

- Fluence noted that the costs of these changes could be significant as this may require redrafting private contracts or reopening the registration for some projects if no grandfathering arrangements are applied[375]
- Reposit Power and Enel Green Power stressed that the cost impact of changing these terms is large and should be avoided, where possible.[376] Reposit Power also considered that there would potentially be system change costs as a result of these changes, particularly in settlement and billing processes.[377] It also noted that it would incur external documentation costs due to these changes.[378]

370 Ibid.
371 Submissions to the consultation paper: CitiPower, Powercor & United Energy, p. 19; Tesla, p. 2; Maoneng, p. 12.
372 Submissions to the consultation paper: Monash Energy Institute, p. 18; Enel Green Power, p. 16; Reposit Power, p. 16.
373 Monash Energy Institute, submission to the consultation paper, p. 18.
374 Ibid.
375 Fluence, submission to the consultation paper, p. 26.
376 Submissions to the consultation paper: Reposit Power, p. 17; Enel Green Power, p. 17.
377 Ibid.
378 Ibid.

E.1.4 Commission's analysis

BOX 5: DRAFT RULE — TECHNOLOGY SPECIFIC DRAFTING IN THE RULES

The draft rule makes a more preferable rule for addressing technology specific drafting. It directly incorporates two of the solutions proposed by AEMO for addressing this issue:

- replacing all mentions of 'offer' with 'bid' in the NER
- making generic references to scheduled plants and market participants where practicable.

The draft rule also considers the use of the terms generation and load throughout the NER, and replaces them with clearer, more accurate terms where necessary. This has been done to address the concerns AEMO raised about existing terms being based on an assumption of one-way electricity flows in the NER, which does not reflect the current reality of the NEM.

Benefits of the draft rule

The draft rule will reduce regulatory burden in the longer term and make the NER more future-proof, by:

- improving the drafting of the rules by reducing the extent of technology specific language in them
- addressing the ambiguity of how certain terms and concepts apply to energy storage and hybrids
- better reflecting the fact that a large and increasing number of connection points in the NEM have two-way flow
- updating the NER to provide a more suitable basis for future reforms under the ESB's P2025 program.

The Commission agrees with AEMO's concern that technology specific drafting in the rules is an issue impeding the integration of energy storage and hybrids into the NEM and considers the draft rule effectively resolves this issue. The remainder of this section details the Commission's rationale for implementing each component of AEMO's proposed solution for addressing technology specific drafting in the rules.

Changing definitions relating to electricity flows

The Commission acknowledges there are issues with the way electricity flows are currently defined in the NER, but does not consider the terms AEMO proposed in its rule change request as the best means of addressing them. The draft rule amends the existing definitions for load and generation, and where necessary in context, replaces references to those terms with more accurate terms throughout the NER.

The draft rule proposes to expand the definition of generation and clarify the definition of load as follows:

generertion

According to context:

(a) The production of electrical power by converting another form of energy in a generating unit or integrated resource unit.

(b) The amount of electrical power (measured in MW) produced by a *generating unit* or *integrated resource unit* and measured at its terminals.

(c) The amount of electrical power (measured in MW) at a defined instant at a *connection point*, or aggregated over a defined set of *connection points.*

load

~~A connection point or defined set of connection points at which electrical power is delivered to a person or to another network or the amount of electrical power delivered to a person or to another network or the amount of electrical power delivered at a defined instant at a connection point, or aggregated over a defined set of connection points.~~

According to context:

(a) the amount of electrical power (in MW) delivered at a defined instant at a *connection point*, or aggregated over a defined set of *connection points*; or

(b) a *connection point* or defined set of *connection points* at which electrical power is delivered to a person or to another *network.*

In some places in the NER, the context indicates that the above terms are not appropriate, and the draft rule replaces them with more accurate terms - some existing, some new. For example:

- where the rules refer to the amount of electricity supplied to the transmission network or distribution network at a connection point by a generating unit or an integrated resource unit, the term 'sent out generation' is used (this is an existing defined term)
- where the rules refer to the quantity of electricity produced over time, the draft rule refers to MWh
- some references to load are replaced with references to a connection point with two-way flows
- the new term 'consumed electricity' is used where the context indicates a quantity of electricity consumed over time (in MWh)
- the new term 'scheduled resource' would refer to all plant subject ot AEMO's central dispatch process: scheduled generating units, semi-scheduled generating units, scheduled IRUs, scheduled load, wholesale demand response units and scheduled network services
- references to 'market load' would be removed and end user connection points would be classified as market connection points.

The Commission is interested to understand if there are particular instances where these changes would be incorrect or would cause unintended consequences. The intention is to clarify the language and make it more accurate, rather than to change the policy intent of the relevant provisions.

The Commission considers that this approach effectively resolves the ambiguity associated with how the terms generation and load apply to energy storage and hybrids, addresses existing ambiguities in the NER caused by one-way terms used in contexts where two-way flow occurs, and more broadly, updates the NER to be a more suitable regulatory framework for the transitioning energy system.

Replacing all mentions of 'offer' with 'bid' in the NER

The Commission considers it appropriate to replace all mentions of 'dispatch offer' with 'dispatch bid' throughout the NER for the following reasons:

- the use of the terms 'offer' and 'bid' are asset/direction specific (offer being used for generation and bid for load), which makes it confusing for bi-directional assets to participate in the market using a single bid form
- the term 'rebid' applies to both bids and offers which adds further confusion for the relevant market participants
- this change will make the language used in the NER around bidding consistent with the declared gas wholesale market.

Making generic references to scheduled plants and registered market participants where possible

The Commission considers it appropriate to make generic references to scheduled plants and registered market participants where practicable, for the reasons given by AEMO in its rule change request. Currently, the rules contain many lists of references to different kinds of participants and plant which unnecessarily contribute to the length and complexity of the rules. The draft rule reduces this complexity by replacing lists with references to group terms for the relevant registered market participants or plant, e.g. using 'market participants' or 'scheduled plants' where relevant. This approach also avoids the need to insert additional mentions of the terms 'Integrated Resource Provider' and 'integrated resource unit' in many places throughout the rules.

E.2 Retailer Reliability Obligation

E.2.1 Overview

The RRO is designed to encourage Market Customers to contract and invest in dispatchable capacity and demand response to support the reliability of the power system.[379] A Market Customer is considered a liable entity under the RRO if its aggregate annual load is over 10GWh in a particular NEM region.[380]

379 COAG Energy Council Energy Security Board, *Retailer Reliability Obligation Final Rules Package*. Available here.

380 See Part D in Chapter 4A of the NER.

In its rule change request, AEMO raised the issue of whether storage and hybrids should be liable entities under the Retailer Reliability Obligation (RRO) in respect of their loads. The Commission sought feedback on this issue in the consultation paper, asking if stakeholders thought it was appropriate for operators of these facilities to be liable entities under the RRO.

The Commission's draft rule determination is for IRPs to be treated the same as other participants with load (i.e. Market Customers), that is, considered liable entities under the RRO if their aggregate annual load exceeds the threshold.

E.2.2 AEMO's view

In its rule change request, AEMO identified that storage and hybrid facilities are RRO liable entities (subject to the energy use threshold) as they are required to register as Market Customers under the current framework. AEMO proposed for a BDRP to not be a liable entity under the RRO, except for where a BDRP is co-located in a facility that includes a separate load.[381]

AEMO considered that energy storage is likely to draw electricity from the grid when demand and prices are low, and to produce electricity in periods of high demand.[382] Therefore, storage assets should be regarded as improving system reliability and not be made liable under the RRO.[383]

E.2.3 Stakeholder views

Feedback on this issue in submissions to the consultation paper was limited; the issue was only addressed by six stakeholder submissions. All agreed with AEMO's proposal to exempt storage assets as liable entities under the RRO.[384] Some stakeholders noted that this should be the case because grid-scale storage assets are scheduled, meaning they are not only dispatchable but can also be directed by AEMO, which improves their contribution to system reliability.[385] ENGIE also noted that if the Commission decided to not exempt energy storage and hybrids as liable entities under the RRO then an exception should be made for the purpose of providing FCAS services.[386]

381 AEMO, *Integrating energy storage systems into the NEM - rule change request*, p. 24.

382 Ibid, p. 23.

383 Ibid.

384 Submissions to the consultation paper: Infigen, p. 4; Tesla, p. 7; Clean Energy Council, p. 4; Engie, p. 5.

385 Submissions to the consultation paper: Monash Energy Institute, p. 20; GE Hydro, p. 16.

386 ENGIE, submission to the consultation paper, p. 5.

E.2.4 Commission's analysis

> **BOX 6: DRAFT RULE - RETAILER RELIABILITY OBLIGATION**
>
> The draft rule amends chapter 4A of the NER to include an IRP as a liable entity under the RRO if its load exceeds 10GWh in a particular NEM region in a year.
>
> However, storage facilities would be taken as a whole in the new IRP category - that is, consisting of both load and generation rather than just being considered in respect of their load, as is currently the case for their Market Customer registration. This would result in consistency with the current treatment of Market Customers (that are not storage proponents); these entities may also have considerable aggregate generation (e.g. from their customers' rooftop solar). This equal treatment may mean that, in practice, some IRPs do not reach the 10GWh annual aggregate consumption threshold for being liable entities. The draft decision would mean that it is unlikely any of the five existing grid-scale batteries would be liable under the RRO once they are registered as IRPs.
>
> **Benefits of the draft rule**
>
> The draft rule would ensure that there is consistent treatment of load, in respect of RRO liability, across participant types, avoiding any inefficient incentives that may arise if the load of certain participant types was exempted.

Storage should not be explicitly exempt from the RRO

The Commission does not consider it appropriate to exempt storage and hybrid facilities as liable entities under the RRO, because:

- it is not appropriate to introduce technology-specific exemptions; obligations under the NER should be based on the services provided rather than an entity's technology or its participant category, as discussed in Chapter 2
- the annual consumption threshold was designed to exclude small batteries, and with the introduction of the IRP category (covering a battery's generation and load), this threshold will operate as it appears was originally intended.

When the RRO was first introduced in 2019, ESB policy documents indicate that exemptions for batteries were considered, but rejected in favour of the threshold approach, which was designed to exclude small batteries. It was not considered appropriate to include a battery-specific exemption.[387]

A consistent approach to measuring annual aggregate consumption would likely result in IRPs not being liable under the RRO

387 ESB, Retailer Reliability Obligation, cover paper for the Final Rules Package, 3 May 2019, p. 20. The paper states "Stakeholders suggested that market participants should be exempt from complying with the Obligation under certain conditions (for example, batteries or pumped hydro). The final Rules, unlike the draft rules, provide that market customers with annual energy consumption equal to or below 10 GWh will be exempt from compliance with the Obligation. This exemption would generally serve to exclude small batteries."

The Commission's draft rule, while treating IRPs equally with Market Customers, would most likely result in IRPs not reaching the threshold to be liable under the RRO.

The Commission notes that under the current framework a Market Customer's annual aggregate load would be calculated with reference to both its load and its generation.[388] This means that Market Customers with generation, such as a retailer with customers with behind-the-meter generation, use that generation to reduce their aggregate load (and their liable load, if over the threshold). Whereas storage participants, being registered in two participant categories, one solely for their load and the other solely for their generation, are not able to net their load with their generation; their generation is classified under the Market Generator category and is therefore measured separately.

The Commission considers that the new IRP participant category, in which existing and new grid-scale storage participants would be required to register, should be treated consistently with how Market Customer load is treated, for the purpose of liability under the RRO. This would mean that an IRP's aggregate load, like a Market Customer's, would be calculated with reference to its generation as well as its load. In practise, this would mean a storage unit that generally consumes energy from the grid and discharges to the grid is unlikely to have a net load greater than 10GWh per annum, and would therefore be unlikely to be a liable entity under the RRO, under NER clause 4A.D.2(b)(2).[389]

A consistent approach using non-netted load values is not an appropriate change for this draft determination

Newly defined terms in this draft determination, adjusted consumed energy (ACE) and adjusted sent out energy (ASOE), are gross measurements of consumed energy and sent out energy respectively, i.e. they are non-netted values, which will be used to calculate liability for non-energy costs.[390] The Commission considered whether it would be preferable, for the purpose of measuring liable load under the RRO, for IRP participants to have their load measured using ACE, or for all participants to have their loads measured using ACE. However, the Commission considers it appropriate not to make either of these changes in this draft determination because:

- measuring an IRP's liable load using ACE would be inconsistent with how it is measured for non-IRP participants and this would create a barrier for storage which contradicts the overall objective of this rule change - to level the playing field and reduce barriers to storage participation
- measuring all liable load using ACE would be a material change to how load is measured for non-storage participants, could increase financial liability for these participants, and (to the extent it relates to Market Customers) does not directly relate to an issue raised in the rule change request. While this form of measurement may be an option, as all load

388 While the method of measuring "load" for the purposes of the threshold is not specified in NER clause 4A.D.2(b), later provisions on calculating liable load (clause 4A.F.3(b)) specify that adjusted gross energy is to be used, which allows for generation and load to be netted.

389 A storage unit may, however, record an annual net load above 10GWh, and become liable under the RRO, if it is very large or if it charged from the grid and supplied energy to loads behind the same connection point.

390 See Appendix C.

would be measured consistently using gross data, this change has not been tested with stakeholders in this rule change.

E.3 Intervention compensation frameworks

E.3.1 Overview

In its rule change request, AEMO questioned how the intervention compensation frameworks should apply to storage and hybrid facilities. In particular, AEMO questioned how the frameworks would apply to the BDRP registered participant category it proposed. AEMO did not set out an approach for applying these frameworks to storage and hybrids because the frameworks were subject to rule change requests that were yet to be submitted at the time.

The Commission sought feedback from stakeholders in the consultation paper asking if the current frameworks can appropriately accommodate storage and hybrids, and if this would require the development of a unique intervention compensation framework for these kinds of facilities.

The Commission's draft decision is not to develop any unique arrangements for storage and hybrids in the intervention compensation frameworks.

E.3.2 AEMO's view

When AEMO lodged its rule change request, it did not propose any specific changes to the affected participant compensation frameworks to accommodate storage and hybrids. This was because these frameworks were to be the subject of other rule change requests by AEMO which had not yet been submitted at the time.[391] Noting this, AEMO did propose BDRPs should be eligible under the intervention compensation frameworks, but indicated further consideration would be required to evaluate how this compensation is calculated and recovered.[392]

E.3.3 Stakeholder views

Feedback on this issue in submissions to the consultation paper was limited and only addressed by four stakeholders, who were split on whether to develop a compensation framework specifically for storage and hybrid facilities.

Stakeholders who supported a unique framework for storage and hybrids considered that the unique operating characteristics of these assets prevented them from being correctly compensated:

- Monash Energy Institute considered the current framework unusable for storage not only because these assets cannot always respond to events (because an empty battery cannot discharge), but also because it is currently impossible to identify exactly how much

391 For more information on this, please refer to the section below containing the Commission's analysis on the Intervention compensation frameworks issue.

392 Ibid.

revenue a battery forgoes when forced to participate in an intervention because of its unique operational relationship with opportunity cost. [393]

- Neoen considered that another framework should be considered which allows for 'partial capital cost recovery similar to the compensation framework for conventional generators [as] it is currently possible for a battery with "zero" fuel cost to be directed without compensation commensurate to status quo operation'.[394]

Stakeholders who did not support a unique framework for storage and hybrid pointed to existing Commission processes which are dealing with these issues:

- EnergyAustralia did not see any benefits in considering intervention compensation frameworks in the rule change, given they are being considered more closely in other Commission rule changes.[395]
- Tesla provided support for resolving the asymmetries in the existing frameworks as the most effective means of improving technology neutrality. Tesla highlighted the submission it made for the *Compensation following directions for services other than energy and market ancillary services*[396] and *Compensation for market participants affected by intervention events*[397] rule changes to support this.[398]

E.3.4 Commission's analysis

> **BOX 7: DRAFT RULE — INTERVENTION COMPENSATION FRAMEWORKS**
>
> The draft rule does not develop any unique arrangements for storage and hybrids in the intervention compensation frameworks, but does integrate the IRP market participant category into these frameworks.
>
> **Benefits of the draft rule**
>
> The draft rule will:
>
> - provide a level playing field for storage, hybrids and other participants by maintaining the same approach for all assets
> - allow for a separate rule change process currently under way to more closely consider issues with how affected participant compensation applies to storage and hybrids.

The Commission does not consider it appropriate to develop specific intervention compensation arrangements for storage and hybrid assets in this rule changes process because:

393 Monash Energy Institute, submission to the consultation paper, p. 19.
394 Neoen, submission to the consultation paper, p. 3.
395 EnergyAustralia, submission to the consultation paper, p. 2.
396 The final determination for this rule change was published in December 2020, project page available here.
397 The final determination for this rule change is currently set to be published in August 2021, project page available here.
398 Tesla, submission to the consultation paper, pp. 5-6.

- developing a unique intervention compensation framework for storage and hybrid assets would not align with the intention of this determination to provide a level playing field for storage, hybrids and all other participants
- the Commission has another rule change process under way which is designed to address issues relating to how market participants are compensated when dispatched differently due to intervention events, and is seeking to adopt an approach which is broadly consistent for all relevant market participants.

The Commission considers developing a unique intervention compensation framework for storage and hybrid assets would be contrary to the overall intention of this rule change where changes being made are to provide a level playing field for storage, hybrids and all other relevant participants. The Commission's draft rule will only require new storage assets and hybrid facilities to register in the proposed IRP registered participant category. However, the long-term vision is to eventually transition all market participants into this single category. As the Commission's intention is to harmonise the obligations of all NEM participants over the long-term, introducing a separate compensation framework for storage and hybrids would not align with the broader changes being proposed in this draft determination as they relate to the NER's participation frameworks.

The only changes the draft rule makes to the intervention compensation frameworks are to integrate the IRP into the existing frameworks.

The Commission also notes that several changes have recently been made to intervention-related compensation frameworks, and that two rule changes dealing with the affected participant compensation frameworks are still being progressed. Since the publication of the *Investigation into intervention mechanisms in the NEM* final report in 2019, which identified issues with the functioning of the NEM's intervention mechanisms and recommended a number of changes, AEMO has lodged several rule change requests which have sought to action these recommendations and others identified by AEMO's Intervention Pricing Working Group[399]. Most of these rule change requests have since been lodged and completed by the Commission, and include:

- the *Changes to intervention mechanisms* rule change[400]
- *Application of compensation in relation to AEMO interventions* rule change[401]
- *Threshold for participant compensation following market intervention* rule change[402]
- the *Compensation following directions for services other than energy and market ancillary services* rule change[403]
- the *Compensation for market participants affected by intervention events* rule change.[404]

399 For more information on the Intervention Pricing Working Group refer to: AEMC, Compensation for market participants affected by intervention events, draft determination, pp. 16-17, available here. The project page for the AEMC review is available here.

400 Project page available here.

401 Project page available here.

402 Project page available here.

403 Project page available here.

404 Project page available here.

The *Compensation for market participants affected by intervention events* rule change is the only remaining process which is actively considering issues with these frameworks. This process, which consolidates two rule change requests, is addressing issues that could result in participants being under-compensated when they are dispatched differently due to an intervention event which triggers intervention pricing. These include extending the compensation framework to include changes in FCAS revenue and revising the formula used to calculate compensation for scheduled loads.

In addressing these issues, the Commission is seeking to create appropriate consistency between the compensation frameworks that apply to generators and loads. In so doing, the Commission is mindful that IRPs are subject to both frameworks, and hence an appropriate level of consistency is important to avoid potential market distortion.

A directions paper for the *Compensation for market participants affected by interventions* rule change has been published on the same date as this draft determination. The directions paper explores issues raised in response to the draft determination for that rule change, and options for addressing them. This includes a discussion of how the compensation framework for participants affected by intervention events should apply to energy storage and hybrids.

The timing of the final determination for this rule change and the *Compensation for market participants affected by interventions* rule change have been aligned such that the final rule will have regard to these issues if and where necessary.

Beyond the issues already being considered as part of the *Compensation for market participants affected by interventions* rule change, the Commission does not consider it necessary to further amend other intervention related compensation frameworks.

E.4 Network losses and marginal loss factors

E.4.1 Overview

MLFs notionally describe the marginal electrical energy losses for electricity transmitted between a regional reference node and a transmission connection point in the same region for a defined time period and associated set of operating conditions.[405] MLFs are also commonly referred to as intra-regional loss factors, transmission loss factors and static loss factors.

In its rule change request, AEMO noted how network losses and MLFs should apply to storage and hybrids. As AEMO did not propose any significant changes to how MLFs are calculated for these assets from the current arrangements, the Commission sought feedback in the consultation paper on whether these arrangements are appropriate.

The Commission's draft decision is to not make any amendments to how MLFs are applied to storage and hybrids.

405 Clause 3.6.2(b)(1) of the NER.

E.4.2 AEMO's view

The requirements to calculate MLFs and inter-regional loss factors for the NEM transmission networks are found in clauses 3.6.1, 3.6.2 and 3.6.2A of the NER. In addition to these provisions, AEMO also publishes its calculation methodology.[406]

In its rule change request, AEMO described how MLFs currently apply to storage and hybrid assets. Using a stand-alone battery system as an example of a storage asset, AEMO notes that separate loss factors are required for both the load and generation components of the battery.[407] For hybrid facilities the same principle applies: separate MLFs are given for both the load and generation components of the facility, whereby both MLFs together account for all load and generation components of all the assets within the facility.[408] AEMO noted that this approach has been determined in accordance with its Forward Looking Loss Factor Methodology.[409]

E.4.3 Stakeholder views

Feedback on loss factors in submissions to the consultation paper was limited and only addressed by eight stakeholders. The majority considered the current arrangements are appropriate and did not see any need for changes to better integrate storage and hybrids.[410]

Some stakeholders considered it appropriate to make some amendments to the MLF framework to reflect the unique operational characteristics of energy storage. Fluence noted that there should be a benefit for storage systems optimising charging to reduce MLFs relative to conventional generating units.[411] Tilt Renewables considers that participants should have flexibility to choose either single or multiple MLFs as appropriate for their facility, noting that AEMO currently assigns a single MLF to storage behind the connection point of an existing generator if the net energy balance is calculated as less than 30 per cent.[412] Monash Energy Institute considered this rule change as a good opportunity to update the MLF methodology to have them calculated dynamically.[413]

406 This can be found on AEMO's website here.

407 AEMO, *Integrating energy storage systems into the NEM* - rule change request, p. 11.

408 Ibid.

409 Ibid.

410 Submissions to the consultation paper: Neoen, p. 3; Energy Queensland, p. 31; ERM Power, p. 6; EnergyAustralia, p. 2; Energy Networks Australia, p. 17.

411 Fluence, submission to the consultation paper, p. 28.

412 Tilt Renewables, submission to the consultation paper, p. 3.

413 Monash Energy Institute, submission to the consultation paper, p. 21.

E.4.4 Commission's analysis

> **BOX 8: DRAFT DECISION - NETWORK LOSSES AND MARGINAL LOSS FACTORS**
>
> The Commission's draft decision is to make no amendments to the way MLFs are calculated for storage and hybrid systems from the current arrangements. Separate loss factors will continue to be applied for the generation and load components of these facilities, as is consistent with AEMO's Forward-Looking Transmissions Loss Factor Methodology.
>
> **Benefits of the draft decision**
>
> The draft rule will:
>
> - maintain the current arrangements for MLFs, as is consistent with previous Commission determinations on the matter
> - provide a level playing field for storage, hybrids and other generation by maintaining the same approach for all assets.

The Commission considers the current treatment of storage and hybrids by the MLF methodology as appropriate and does not observe evidence that change is required.

The Commission considers that the limited stakeholder feedback received on this issue did not indicate sufficient issues with the current arrangements to merit change. As mentioned above, the majority of stakeholders who responded to this issue acknowledged the current arrangements are appropriate. However, several stakeholders advised the Commission about issues or potential improvements which could be made to the current arrangements.

The Commission does not consider there are sufficient grounds for making changes to the MLF framework for the following reasons:

1. With the introduction of the IRP market participant category, the Commission is seeking to create a level playing field for storage and other generation for participation in the market. Amending the MLF framework to introduce storage specific provisions would counter this.
2. As discussed above, the Commission considers it appropriate for two MLFs to apply for grid-scale assets where bi-directional flows apply at the connection point.
3. The Commission recently updated the loss factor methodology in the 2020 Transmission loss factors rule change and considered it was still appropriate to maintain the existing static calculation of loss factors.[414]

E.5 Reliability Panel representation

E.5.1 Overview

In its rule change request, AEMO asked the Commission to consider if it would be appropriate to adjust Reliability Panel representation provisions to include a requirement for

414 AEMC project page available here.

representation of BDRPs.[415] The consultation paper sought feedback from stakeholders on this issue, and whether storage and hybrids should be represented more generally.

The Commission's draft decision is to not explicitly require storage participants to be represented on the Reliability Panel.

E.5.2 AEMO's view

In its rule change request, AEMO asked the Commission to consider if it would be appropriate to adjust Reliability Panel representation provisions to include a requirement for representation of BDRPs, as with the current requirements for representation of generators, market customers, transmission and distribution network service providers, and end use customers.[416] The Reliability Panel reviews and reports on the safety, security and reliability of the national electricity system and also sets a number of technical standards and guidelines.[417]

E.5.3 Stakeholder views

Feedback on this issue was limited in submissions to the consultation paper and was only addressed by five stakeholders. The majority did not consider it appropriate to amend the Reliability Panel membership provisions to require storage and hybrids be represented. The reasons for this conclusion included:

- the Commission should wait until the presence of these assets in the NEM becomes more material[418]
- the Panel should use its three discretionary seats to enable participation[419]
- there is no clear benefit for making this change.[420]

Two stakeholders supported requiring storage and hybrids to be represented on the Reliability Panel.[421] GE Hydro stressed that this representation should be diversified amongst the full range of storage technologies as opposed to exclusively battery energy storage.[422]

415 AEMO, *Integrating energy storage systems into the NEM* — rule change request, p. 46.
416 Ibid, p. 46. See NER clause 8.8.2(a)(3).
417 More information available here.
418 AEC, submission to the consultation paper, p. 3.
419 Submissions to the consultation paper: AEC, p. 3; Respoit Power, p. 20.
420 Energy Networks Australia, submission to the consultation paper, p. 18.
421 Submissions to the consultation paper: Monash Energy Institute, p. 22; GE Hydro, p. 17.
422 GE Hydro, submission to the consultation paper, p. 17.

E.5.4 Commission's analysis

> **BOX 9: DRAFT DECISION - RELIABILITY PANEL REPRESENTATION**
>
> The Commission's draft decision is to make no change to the Reliability Panel provisions to specifically require IRPs be represented on the Panel.
>
> **Benefits of the draft decision**
>
> The draft rule will:
>
> - maintain the existing representation of market segments on the Reliability Panel
> - maintain the Commission's ability to select up to three discretionary members for the Panel in order to broaden overall sector representation, which could include representation from energy storage or hybrid Market Participants.

The Commission does not consider it appropriate to amend the Reliability Panel provisions to specifically require IRPs be represented on the Reliability Panel. This is for two reasons:

- the Commission already has discretion to appoint up to three other persons to broaden its overall sector representation[423]
- additional specific representation requirements based on participant categories or asset types would be contrary to the long-term vision of the trader-services model, with a universal participant category, being proposed under the ESB's two-sided market project.

Therefore, the Commission does not see the need to amend the Reliability Panel representation provisions to require this representation. Currently, these assets make up a very small proportion of total market load and generation. Given the purpose of the three discretionary seats is to ensure a broader range of stakeholder interests are represented on the Reliability Panel beyond the required representation, the Commission recognises the current arrangements as sufficient for ensuring the interests of storage and hybrids are represented in the work.

Furthermore, requiring IRPs to be represented on the Reliability Panel would be contrary to the long-term vision of the trader-services model being proposed under the ESB's two-sided market project. The long-term vision for the trader-services model is to simplify existing market participation frameworks in the NEM by accommodating existing registered market participant categories into a single 'trader' category. This would move the NER away from asset-based regulation towards a focus on regulating the services which participants provide to the market.[424] This model would eventually lead to all market participants being registered in a single participant category and for the distinction of regulatory treatment to be made via services rather than the assets which provide them.[425]

423 NER clause 8.8.2(a)(3)(F).

424 ESB, Post 2025 market design, directions paper, p. 71, available here.

425 Ibid.

Therefore, given this longer-term vision, it would be inappropriate for the Commission to make a draft rule which would increase the number of registered participant categories required to be represented on the Panel. As the progression of the trader-services model continues, the Commission will need to formally consider how to cater for the effective representation of stakeholders on the Reliability Panel when using a list of registered participant categories no longer achieves this.

E.6 Other drafting issues raised in AEMO's request

E.6.1 Overview and AEMO's view

When writing its detailed drafting proposal for Chapters 2, 3 and 10 of the rules, AEMO also identified a collection of additional issues in the existing drafting of the NER that do not directly relate to the integration of storage and hybrid facilities. AEMO has suggested the Commission consider these in the rule change request process.[426] However, these issues do not explicitly relate to achieving the core objective of the rule change. Table E.2 further below identifies these additional drafting issues raised by AEMO.

The Commission sought feedback from stakeholders in the consultation paper about whether it is appropriate to address these additional drafting issues in this rule change, and whether there are other issues AEMO did not identify which should also be addressed.

The Commission's draft rule determination is to address the majority of these drafting issues identified by AEMO.

E.6.2 Stakeholder views

Two stakeholders gave feedback on this issue in submissions to the consultation paper. Neither supported addressing these other drafting issues AEMO identified when writing its detailed drafting proposal.

Reposit Power acknowledged the merit in identifying these issues in the rules, but recommended that they be dealt with more closely in different rule change processes as some of them are reasonably material.[427] Given the complexity of this rule change, BECA discouraged making any changes to the rules which do not directly relate to the integration of storage and hybrids.[428]

426 AEMO, *Integrating energy storage systems into the NER — rule change request, p. 24*

427 Reposit Power, submission to the consultation paper, p. 21.

428 BECA, submission to the consultation paper, p. 11.

E.6.3 Commission's analysis

BOX 10: DRAFT RULE - OTHER DRAFTING ISSUES

The draft rule addresses the majority of the other drafting issues identified by AEMO in its rule change request.

Benefits of the draft rule

The draft rule will help to make the NER more coherent by improving their drafting and reducing administrative burden.

The Commission's draft rule determination is to make a more preferable rule which addresses the majority of the other drafting issues identified by AEMO. Table E.2 outlines the issues and the Commission's analysis.

Although these issues do not directly relate to the integration of storage and hybrids into the NEM, the Commission considers it appropriate to address a number of these issues, where they are minor corrections to errors in the NER. The Commission is comfortable addressing these issues as part of this rule change as they will improve the drafting of the rules by making them more coherent. Where the issues are more material, the Commission has carefully considered whether they are best dealt within this rule change or otherwise.

Table E.2: **Commission response to other drafting issues in the NER identified by AEMO**

CLAUSE	ISSUE	COMMISSION'S ANALYSIS
2.2.1(c) and (d)	Note in paragraph (c) is incomplete and therefore inaccurate. Paragraph (d) only identifies that AEMO can exempt a person or class of persons from the requirement to register as a Generator for only a generating system or class of generating systems. This should also include generating units.	In relation to (c), the note has been removed as the provision has been redrafted. In relation to (d), the Commission has determined not to make this change given the wording of the relevant registration and exemption provisions in the NEL.
2.2.6(b), (e)(2), 2.3.5(b)(1)(e)(1A), (2)	Where occurring, the references should be to an ‘applicant’ since the person is not yet a registered participant.	These provisions have been redrafted.
2.2.6(d), 2.3.5(d), 2.9.1(c) and 2.9A.2(d)	These clauses require AEMO to deem an application as withdrawn if AEMO has not received all the necessary information or clarifications within 15 business days of AEMO requesting	The Commission agrees with AEMO's suggestion to give it discretion to treat an application as withdrawn if an applicant does not provide information or clarification required

CLAUSE	ISSUE	COMMISSION'S ANALYSIS
	the information. It is more appropriate to allow AEMO the discretion to withdraw an application instead.	by AEMO within 15 business days of a request by AEMO. If AEMO exercises the discretion then it must notify the applicant. This approach is more flexible compared to the current provision that deems the application to have been withdrawn. Changes made in the draft rule.
3.6.3(c)and (d)(1)	References to 'predominant load flows' is incorrect. These flows refer to NER clauses 3.6.3(b)(2)(A) and (B), which refers to consumed and sent out electricity. Delete reference to 'load'.	The Commission's draft determination is not to make these changes in light of subsequent advice from AEMO that the meaning of "load flow" is understood and appropriate in this context.
3.6.5(4) and (4A)	"then" is duplicated.	The draft rule makes this correction.
3.7C, 3.8.10, 3.9.3D	Consistent with other provisions, new paragraphs are proposed to be included to allow AEMO to make minor and administrative changes to the Constraint Formulation Guidelines, EAAP Guidelines and reliability standard implementation guidelines without undertaking a Rules consultation.	The Commission does not consider it appropriate to address this issue in this rule change, as it will be addressed more comprehensively in the Improving consultation procedures in the Rules rule change.
3.8.4(c)(3)	Should refer to 'energy constrained scheduled generating units'.	The draft rule makes this correction.
3.8.5(b)	Repetitive and extraneous information. Requirement for off-loading prices in the generation dispatch offer is also incorrect, this information is not required.	The draft rule adopts the simplified drafting provided.
3.8.6(c), (h)(3)(ii), (f), (h)(1)and (2), 3.12.2(2)	Duplicated use of terms - delete either 'multiplied by' or 'product of'.	The draft rule makes these corrections.
3.8.7(m)	The reference to 'may' is incorrect. Other references in the clause refer to 'must'. Where a scheduled generating unit has an energy constraint it must indicate its daily	The Commission considers AEMO's proposed change appropriate, and the draft rule makes this correction. Additionally, the Commission has also amended clause 3.8.6(b) to the same

CLAUSE	ISSUE	COMMISSION'S ANALYSIS
	energy availability.	effect.
3.8.17(c), 3.8.18(a)	Should refer to Scheduled Generator, not Generator.	The draft rule makes these corrections.
3.8.18(e)	Reference to 'Market Participant' is incorrect, the obligation is only on Scheduled Generators.	The draft rule makes this correction.
3.8.21(d)	Dispatch instructions are not always issued using automatic generation control (AGC) system and not via an electronic display in the plant control room. For future proofing, the drafting should only refer to electronic communication.	The Commission agrees with AEMO's issue with the current drafting and recognises that the proposed re-drafting helps to future proof the rules. The draft rule makes the proposed change.
3.13.3(a)(3)	Refers to 'Scheduled Generators' and Semi-Scheduled Generators', this is an error since only Market Participants can be suspended.	The draft rule makes this correction.
3.13.3(l2)	This clause misinterprets the requirements in S5.2.4, which currently only applies to 30MW+generating systems, whether pre- or post-registration. Therefore, the requirement is not separate from a registered Generator's obligation and can be covered by slightly expanding 3.13.3(a).	The Commission agrees with AEMO that S5.2.4(b) is currently only intended to capture generators with a generating system of 30MW or more, or connection applicants who need to provide this information in respect of a generating system of 30MW or more but are not yet formally registered as a Generator. The draft rule extends this clause to also cover integrated resource systems with a combined nameplate rating of 5MW or more. The Commission has amended the language in clause 3.13.3(l2) to make this clearer and to clarify that it applies to Generators, IRPs, or persons required to register in either category under the rules.
3.13.3(l2)(5)	Transmission Network Service Provider is not italicised.	The Commission will address this error in the next minor rule change, which will take effect before the changes for this rule change will be implemented.
3.13.4(p)(5)	Inappropriate reference to "as	The draft rule makes this correction.

CLAUSE	ISSUE	COMMISSION'S ANALYSIS
	measured by AEMO's telemetry system". The Market Participant's SCADA measures and AEMO receives via SCADA.	
3.15.8(f)(2), 3.15.8A(g)(2), 3.15.10C(b)(7)(i),(c)(3)(iii)(B)	Delete 'TSRP', this is not defined.	The draft rule makes these corrections.
3.15.8(f)(2)	Delete 'TRSP', this is not defined.	This change is no longer required as the term no longer appears in the clause as of NER v158.
3.15.21(c2)(2)(ii)	Market Ancillary Service Provider omitted from the clause. Under the Ancillary Services Unbundling Rule 2016 this provision was to exclude retailers (Market Customers) only. Although it is unlikely that a MASP would incur liabilities, excluding them was not the intent.	The draft rule expands this provision to all Market Participants and makes a consequential change to delete the following clause, 3.15.21(c2)(2)(iii).
3.8.20(g)	Reference to scheduled generating unit and semi-scheduled generating unit omitted.	The Commission agrees with AEMO's proposal to amend this clause, which makes it clear that dispatchable plants are obliged to comply with clauses related to central dispatch. Changes made in draft rule.
3.8.20(i)	AEMO should make documentation on the operation of the pre-dispatch process available only to Market Participants.	The Commission agrees with AEMO's proposal to only make documentation available to Market Participants. Market Participants captures all registered participants which participate in central dispatch and non-market generators would not require this information. Changes made in draft rule.
3.8.20(j)(2)	This should refer to a unit instead of an entity.	The draft rule makes this correction.
3.8.20(k)	'Scheduled load' omitted.	The draft rule makes this correction.
7.4.1(e)	MSGA omitted from this clause.	The draft rule makes this correction (using the new term Small Resource

CLAUSE	ISSUE	COMMISSION'S ANALYSIS
		Aggregator).
dispatched load	Redundant definition, this is the same as scheduled load.	The draft rule amends the definitions of both dispatched load and scheduled load, and with these changes the definitions are not the same. Both terms are retained.
peak load	Definition is circular.	The draft rule retains this definition following changes to the definition of load.

Source: AEMO, *Integrating energy storage systems into the NEM — rule change request,* pp. 24-25, 46-47, and Commission analysis.

F NETWORK SERVICE PROVIDER CONNECTION POINTS

F.1 Overview

AEMO's submission to the consultation paper identified that the NER currently do not contemplate a connection agreement process for assets where the connection applicant and the local network service provider (NSP) are the same party. This was one of the issues which AEMO became aware of after submitting the rule change request in August 2019.[429]

AEMO did not propose a solution to this issue in its submission to the consultation paper. Because of this, the Commission proposed a solution to this issue and sought stakeholder feedback on it. Specifically, the Commission sought feedback on whether stakeholders supported the proposed solution and if they considered there to be a more preferable means of resolving this issue.

The Commission's draft decision, due to the reason outlined in appendix F.4, is not to create a unique connection pathway for NSP owned energy storage systems. Therefore, a connection agreement for an NSP-owned battery in relation to contestable market services must continue to be filed by a separate third party operator.

F.2 Proponent's views

In its submission to the consultation paper, AEMO outlined that, although the primary function of these energy storage facilities is to provide regulated network support services, NSPs tend to earn a return on these investments, at least partly, through trading in the energy and FCAS markets.[430] The AER's ringfencing guidelines permit these assets to participate in the NEM's contestable energy and FCAS markets as long as these market trading operations are conducted by a separate party who registers as an intermediary. Intermediaries operate the relevant asset instead of its owner, which in the case of ringfencing arrangements is the relevant NSP.[431]

There are currently two NSP-owned energy storage projects operating in the NEM. These are:

- ElectraNet's Dalrymple Battery Storage Project operating in South Australia's Lower Yorke Peninsula.[432]
- AusNet's Ballarat Battery Storage System operating in regional Victoria.[433]

In October 2020, TransGrid announced another NSP-owned energy storage project, the Wallgrove Grid Battery Project. This project is set to begin operations October 2021.[434]

429 AEMO, submission to the consultation paper, p. 6.

430 AEMO submission to the consultation paper, p. 6.

431 The AER published an issues paper in November 2020 discussing the application of these guidelines to NSP owned energy storage devices, available here. Refer to clause 2.9.3 of the NER for more information about intermediaries.

432 ElectraNet project page available here.

433 AusNet project page available here.

434 Media release available here.

F.2.1 Issue with connecting NSP owned energy storage systems

The definition of a 'connection agreement' in Chapter 10 of the NER and the process for establishing or modifying connections in the NEM under rule 5.3 of the NER both contemplate that the registered participant seeking to connect an asset to the NEM and the relevant NSP are separate parties. AEMO considers that if the connection applicant and the local NSP are the same entity, there isn't a process in the NER to facilitate the negotiation of a connection agreement.[435] AEMO noted that without any point of distinction between one person's facilities and another, the connection concepts in the NER are subject to a theoretical failure and do not allow performance standards and system strength assessments and remediation to be applied.[436]

This has not been an issue until now because of the specific ownership and operational arrangements pursued in existing NSP-owned energy storage projects. For example, although AusNet is the asset owner of the Ballarat battery project mentioned above, market operations are formally leased to Energy Australia, which was also responsible for completing the connection application.[437] Similarly, while ElectraNet owns the Dalrymple battery project and is responsible for the provision of its regulated services, AGL leases this asset from ElectraNet for the provision of all competitive market services and was also responsible for filing the connection agreement with ElectraNet.[438] In both of these circumstances, separate parties other than the relevant NSPs formally leased part of these energy storage assets and were therefore able to create sufficient ownership boundaries to permit their connection under the NER through formally negotiating connection agreements.

The NER does not prevent a situation where an NSP could both own and operate energy storage and seek to connect it to its own network. However, if this were to occur, the NER would not support the establishment of a connection agreement for this type of project.[439] To deal with this, AEMO requested that a clear pathway be made for NSP-owned energy storage to establish a set of performance standards and system strength requirements for operation in the market.[440]

F.2.2 Proposed solution

AEMO did not propose a solution to this issue in its submission to the consultation paper so the Commission proposed a solution to it in the options paper.

The Commission proposed that AEMO have a role in establishing the relevant standards and requirements for connections, in conjunction with the NSP, where the local NSP is also the asset owner and applicant. This solution could be seen as a logical extension of AEMO's existing function to advise NSPs to accept or reject certain negotiated access standards proposed by connection applicants.[441]

435 AEMO, submission to the consultation paper, p. 6.

436 AEMO, submission to the consultation paper, pp. 6-7.

437 AusNet, *Ballarat BESS: knowledge sharing report,* August 2019, pp. 28-29, available here.

438 ElectraNet, ESCRI-SA project summary report: the journey to financial close, May 2018, p. 13 and 19., available here.

439 AEMO submission to the consultation paper, p. 7.

440 Ibid, pp 6-7.

441 Refer to the definition of 'AEMO advisory matter' in Chapter 10 of the NER.

The Commission considered AEMO as uniquely placed as the only party other than an NSP who could effectively participate in the technical standards negotiation process. Functionally, this could be achieved by amending the obligations of NSPs and AEMO [442] to account for circumstances where technical standards are required for assets which are owned by an NSP and connected to their network. This process would only apply if there was no other third party that could enter into the connection agreement, such as a separate operator.

As this process relates to the setting of performance standards and system strength requirements, this would require AEMO to move beyond its existing advisory role in relation to negotiated access standards. Instead of exclusively advising on whether to accept or reject negotiated access standards for connection agreements, AEMO would negotiate the technical standards for NSP-owned storage and also have a role in approving the automatic and minimum access standards for relevant new connections.

This solution would likely incur establishment and ongoing costs on AEMO's operations. Firstly, AEMO would incur costs establishing the internal processes and personnel required to be able to negotiate the relevant technical standards. Secondly, AEMO would incur ongoing costs related to personnel that would negotiate these standards. It would likely be appropriate to recover these costs directly from the relevant NSP, as NSPs are currently obligated to recover these costs from typical connection applicants.

F.3 Stakeholder views

Approximately half of all stakeholders responded to this issue in the options paper, and provided little support for the proposed solution in the options paper.

NSPs did not support the proposal to increase AEMO's responsibilities in the connection process because they:

- did not consider it in the best interest of NSPs to connect assets which fail to meet existing network performance or system strength requirements[443]
- did not consider it appropriate for NSPs to form connection agreements for their assets as the required information can be supplied to AEMO independently of this process.[444]
- consider AEMO's powers in the connection process are already sufficiently strong, and that this issue does not merit expanding them[445]
- note it is unclear if this issue is sufficiently material to merit any changes to the rules.[446]

Stakeholders other than NSPs also disagreed with the proposed solution given in the options paper because:

- it would impose too many additional costs on consumers[447]

442 For example, in clauses 5.2.3 and 5.2.6.

443 Submissions to the options paper: Energy Networks Australia, p. 5; Essential energy, p. 2; AusNet, p. 2.

444 Submissions to the options paper: CitiPower, Powercor, United Energy, p. 3; Ausgrid, p. 4.

445 Submissions to the options paper: Energy Networks Australia, p. 5; Essential Energy, p. 2.

446 AusNet, submission to options paper, p. 2; Energy Queensland, p. 9.

447 Submissions to the options paper: Readearth Energy Storage, p. 4; Stanwell, p. 8.

- it would allow NSPs to leverage the use of their regulated networks and infrastructure to their competitive advantage[448]
- it could potentially impact AEMO fulfilling its other responsibilities as the system operator[449]
- the rules and penalties for non-compliance with the connection process are sufficiently clear
- better alternatives for resolving this issue might include:
  - requiring third parties to file a connection agreement on behalf of the NSP[450]; or
  - investigating if engineering consultants could deliver a more cost effective outcome than AEMO under the proposed solution.[451]

AEMO also disagreed with the proposed solution and suggested an alternative solution to allow for performance standards and system strength requirements to be submitted and documented independently of a connection agreement.[452] AEMO did not consider there was any need to expand its responsibilities in the connection process beyond its existing advisory role.[453] It also stressed that the issue derives from the NER's requirement that performance standards be recorded in a connection agreement, rather than any inherent issues with documenting or verifying performance standards for these assets. Therefore, it did not seem logical to require some kind of connection agreement to be made for these assets, particularly given the NSP's inherent interest in ensuring all network assets are securely connected.[454]

Only two stakeholders provided any support for the proposed solution. PIAC supported increasing AEMO's responsibilities in the connection process, but only on the condition that this process does not apply to smaller-scale, community batteries.[455] EnergyAustralia suggested 'tightening' the shared asset guidelines if the Commission found the cost implications of the proposed solution were material.[456]

448 Alinta Energy, submission to the options paper, p. 5.
449 Carisbrooke Consulting, submission to the options paper, p. 8.
450 Submissions to the options paper: Red Earth Storage, p. 4; Carisbrooke Consulting, p. 8; Alinta Energy, p. 5.
451 Stanwell, submission to the options paper, 8.
452 AEMO, submission to the options paper, pp. 16 -17.
453 Ibid.
454 Ibid.
455 PIAC, submission to the options paper, p. 1.
456 EnergyAustralia, submissions to the options paper, p. 2.

F.4 Commission's analysis

BOX 11: DRAFT DECISION — NETWORK SERVICE PROVIDER CONNECTION POINTS

The draft decision would not create a unique connection pathway for NSP owned energy storage systems. Therefore, the current arrangements will remain whereby an NSP owned battery must make use of a separate operator for contestable market services to file a connection agreement.

Benefits of the draft decision

The draft decision will:

- not prejudge any outcomes from the AER's review of its transmission and distribution ringfencing guidelines
- avoid a situation which might allow for NSP owned storage to be given preferential treatment in the connection process.

As the AER is currently reviewing the ring-fencing arrangements which apply to NSPs at both the distribution and transmission level, the Commission does not consider it appropriate to establish a unique connection pathway for NSP owned storage in the rules as this might prejudge outcomes in this separate process. In August 2019, the AER commenced a review of the current Electricity Distribution Ring-fencing Guideline. Similarly, in November 2019, the AER published a discussion paper on the Electricity Transmission Ring-fencing Guideline Review, which commenced a review of ring-fencing arrangements for TNSPs. These reviews were paused through the middle of 2020 to address other work priorities in response to COVID-19.

In November 2020, the AER recommenced its review of the Distribution Ring-fencing Guideline. The AER published an issues paper focused on the changing nature of services offered by DNSPs via stand-alone power systems (SAPS) and energy storage devices (ESDs). It also clarified certain guideline obligations to make them clearer and less administratively complex. On 26 February and 3 March 2021, the AER held stakeholder forums to further explore issues in relation to SAPS and ESDs. The AER released a draft distribution ring-fencing guideline for stakeholder consultation on 27 May 2021, where submissions to it closed on 8 July 2021.

Given the AER manages ring-fencing arrangements for NSPs in the NEM, the Commission does not consider it appropriate to establish a new framework for connecting NSP owned assets whilst a review of these arrangements is ongoing.

Furthermore, by not creating a unique connection pathway the draft rule avoids a situation which might allow for NSP owned storage to be given preferential treatment in the connection process. Nearly all stakeholders disagreed with the efficacy of the proposed solution in the options paper, and some had specific concerns about the ability for NSPs to give storage assets they own preferential treatment in the connection process given their unique access to regulated networks and infrastructure. The draft decision minimises the chance of this happening by maintaining the current arrangements for connecting these kinds of assets to the NEM.

G DC COUPLED SYSTEMS

G.1 Overview

A 'DC coupled' system is a grid-scale hybrid facility that comprises inverter-based generating and storage units that share an ac/dc inverter. An example of a DC coupled system is a battery unit coupled to a solar photovoltaic generating unit. These coupled elements share equipment that is essential to the functioning of each element (the inverter), but have different operational characteristics; such units were not originally contemplated in NER provisions on classification and market participation.

AEMO's submission to the consultation paper outlined that:[457]

- it has been receiving enquiries from proponents that are seeking to connect DC coupled systems
- the fact that the NER currently provide no guidance for how these systems ought to register and participate in the NER is obstructing their deployment in the NEM.

AEMO requested the Commission consider this issue as part of this rule change process. This is one of the three new issues related to the integration of storage and hybrids AEMO has become aware of since submitting the rule change request in August 2019.[458] Whilst the Commission specifically sought stakeholder feedback on this issue in the options paper, several stakeholders also mentioned a need to consider this issue in their submissions to the consultation paper.

The Commission agrees that it is important to address this issue given the benefits in reducing barriers to entry and lowering system costs that exist from integrating DC coupled systems in the NEM. The Commission's draft rule determination is to introduce a framework for the registration and operation of DC coupled systems, where participants can choose from three different options for classifying DC coupled systems within an IRP facility. This is intended to provide clarity and flexibility in how these systems can register and operate.

G.2 AEMO's views

AEMO has received enquiries from proponents seeking to connect facilities where generating units and energy storage share a single inverter. Facilities that share different technologies behind an inverter (such as a battery and a solar PV system) are known as DC coupled systems.[459]

AEMO considered the NER currently provide no guidance for how DC coupled systems should register and participate in the NEM and that this poses a barrier to their participation. In its submission to the consultation paper, AEMO requested that the Commission consider this issue as part of this rule change process, as it relates to the integration of storage and hybrid facilities into the regulatory framework (given such systems are hybrids, and typically include

457 AEMO, submission to the consultation paper, p. 6.

458 Ibid.

459 AEMO submission to the consultation paper, p. 8.

storage).[460] AEMO considered it reasonable for these facilities to be classified as a scheduled asset, but otherwise did not provide any detailed solution for integrating these hybrid configurations into the NEM.[461]

G.3 Solutions proposed in options paper

The Commission proposed two different means of integrating DC coupled systems into the NER in the options paper: assign a single set of system obligations or establish dynamic trigger-based obligations.[462]

G.3.1 Assign a single set of system obligations

The first option proposed was to assign these systems a single set of performance obligations to permit them to participate together. Under this solution, a DC coupled system would be assigned scheduled or semi-scheduled central dispatch obligations.

The advantage of this proposed solution is that it would permit the registration of DC coupled systems and allow their generation components to be aggregated to operate together in the NEM. However, given the mix of different technologies inherent to DC coupled systems, it might not be operationally efficient to have their generation bound to a single set of operational obligations and technical performance standards at all times.

G.3.2 Dynamic trigger based obligations

As it may be inefficient to assign DC coupled systems a single set of obligations to operate in the NEM, an efficient outcome could be for obligations to switch between scheduled and semi-scheduled obligations when the system triggers a dynamic operational threshold. Theoretically, it should be possible to design regulation for DC coupled systems where their obligations are reflective of the operating constraints of a system at any given point in time to promote their most efficient use and therefore maximise their market benefit.

The Commission's options paper suggested that time of day or energy storage state of charge are two metrics that could be used to assign obligations dynamically for these systems.[463] Using time of day, the system could nominate to operate as semi-scheduled during the daylight hours (if the system involves solar PV, for example) and then operate to discharge this capacity as a scheduled generator at peak times later in the day. Using energy storage state of charge, the system might be classified as a scheduled generator above a certain threshold of state of charge and then be classified as semi-scheduled below this threshold.

The advantages and disadvantages of this potential solution concern a trade-off between optimising system participation and administrative complexity. This approach may better encourage optimal use of DC coupled systems as it would not constrain them to only operating under a single set of requirements. This would allow these systems to dynamically

460 AEMO submission to the consultation paper, p. 8.

461 Ibid.

462 AEMC, Integrating energy storage systems into the NEM - options paper, p. 38.

463 AEMC, Integrating energy storage into the NEM, options paper, p. 39.

optimise their output by having their obligations reflect operating constraints in real-time. This may not only increase the private benefits for proponents, but would likely also promote reliability outcomes for the NEM via this operational efficiency. However, these potential advantages must be weighed against the likely costs of implementing such a solution and reflects the scale of changes required to integrate complex assets into energy systems.

G.4 Stakeholder views

Several stakeholders discussed issues related to DC coupled systems in their submissions to the consultation paper. This included:

- Energy Queensland noted in its submission that it has been increasingly fielding enquiries to install DC coupled configurations, and that the NER should permit the registration and aggregation of these hybrid systems.[464]
- BECA advised the Commission that generating systems are being designed such that energy storage can be cost-effectively installed to create either DC coupled or AC coupled hybrid systems in the future.[465]
- Kinelli considered that the addition of DC coupled storage, that cannot charge directly from the grid, to an exempt or non-scheduled solar farm should not force it to become a scheduled generator.[466]

Approximately half of all stakeholders responded to this issue in their submissions to the options paper, and of those who did the majority supported integrating DC coupled systems into the NER. Fewer stakeholders commented on:

- the efficiencies this particular type of hybrid system configuration provides for participants and the broader system
- their preferred mechanism for integrating these systems.

Of those who responded to questions related to DC coupled systems, the vast majority were supportive of the Commission considering their integration into the NER as part of this rule change process.[467] CitiPower, Powercor & United Energy considered that more guidance is required on the registration arrangements for DC coupled systems, particularly where total capacity is much greater than the grid-side inverter.[468]

Some stakeholders also commented that these systems also provide capital, operational and efficiency benefits for proponents and the NEM as a whole.[469] Fewer stakeholders provided further details about what they consider the specific benefits of these hybrid system

464 Energy Queensland submission to the consultation paper, p. 9.

465 BECA submission to the consultation paper, p. 2.

466 Kinelli submission to the consultation paper, p. 1.

467 Submissions to the options paper: YES Energy, p. 4; Australian Energy Council, p. 3; EnergyAustralia, p. 2; Tesla, p. 10; Stanwell, p. 9; Energy Queensland, p. 10; Fluence, pp. 11-12; Clean Energy Council, p. 3; Acciona, p. 2; Damien Vermeer, p. 6; Carisbrooke Consulting, p. 9; ERM Power, p. 8; Maoneng, p. 2; AusNet, p. 2; Energy Queensland, p. 10.

468 CitiPower, Powercor & United Energy, submissions to the options paper, p. 4.

469 Submissions to the options paper: Tesla, p. 10; Clean Energy Council, p. 3; Acciona, p. 2; Damien Vermeer, p. 6; Carisbrooke Consulting, p. 9; Maoneng, p. 2.

configurations to be. Those who did detailed that pursuing the deployment of DC coupled systems may lead to:

- reducing grid connection, deployment and operating costs, which will lead to lower capital costs[470]
- lower electricity costs for consumers by permitting DC coupled batteries to locally store energy generated during low demand periods for discharge during peak times.[471]

Stakeholders were split on a preferred solution to integrate DC coupled systems into market:

- some stakeholders preferred a single set of system obligations, but views were mixed on whether this should be scheduled or semi-scheduled central dispatch obligations.[472]
- Tesla and Carisbrooke consulting were the only stakeholders who supported a dynamic trigger based set of obligations, whereas Fluence, EnergyAustralia and Acciona specifically advised against this given the likely complexity of their design and implementation.[473]
- ERM Power supported the ability to register systems as non-scheduled, semi-scheduled or scheduled generating units or hybrid generator/load pairings under the options and threshold proposed for consideration under this rule change.[474]

Other stakeholders were less specific about how integration should be achieved, but considered two principles important:

- the flexibility of how DC coupled systems operate should be reflected in their regulatory arrangements[475]
- there should be little difference between how AC coupled and DC coupled hybrids systems are treated in the rules[476]

470 Submissions to the options paper: Tesla, p. 10; EnergyAustralia, p. 6; Damien Vermeer, p. 7.

471 Submissions to the options paper: Damien Vermeer, p. 7; Carisbrooke Consulting, p. 9.

472 Submissions to the options paper: Fluence, p. 11; Damien Vermeer, p. 6; Carisbrooke Consulting, p. 9.

473 Submissions to the options paper: Tesla, p. 11; Carisbrooke consulting, p. 10; Fluence, p. 11; EnergyAustralia, p. 6; Acciona, p. 1.

474 Submissions to the options paper: ERM, p. 6;

475 Submissions to the options paper: Clean Energy Council, p. 3; Acciona, p. 1.

476 Australian Energy Council, p. 3. AC Coupled systems are a different type of hybrid system in which there is no shared inverter, rather they only share connection assets to the grid.

G.5 Commission's analysis

BOX 12: DRAFT RULE — DC COUPLED SYSTEMS

The draft rule introduces a framework for the registration, classification and participation of DC coupled systems. This framework is intended to promote flexibility in how these assets operate in the NEM, where participants can choose from four different options for classifying DC coupled systems within an IRP facility. DC coupled system proponents would be expected to register as an IRP and would then have the option to classify the system in one of the following ways:

- as a non-scheduled IRU (only for systems under 5 MW in total)
- as a scheduled IRU
- as a semi-scheduled generating unit
- separately as both a scheduled IRU and a semi-scheduled generating unit, which would be treated as two separate units for dispatch purposes.

Where the participant seeks to classify the DC coupled system as either a scheduled IRU or a semi-scheduled generating unit it would be treated as a single unit, with a single DUID, by the market. Where the participant seeks to classify the DC coupled system as two separate units (a scheduled IRU and a semi-scheduled generating unit), each classified unit will have its own DUID which will allow the relevant assets to be dispatched independently of one another.

The draft rule also sets a requirement for AEMO to develop a registration and classification guide. This guide should provide guidance to DC coupled system proponents on the registration and classification options available to them.

Benefits of the draft rule

The draft rule will:

- permit the registration and classification of DC coupled systems in the NER
- promote the flexibility of potential commercial arrangements for these resources to give participants the freedom to decide how to operate in the market.

The Commission agrees with AEMO and other stakeholders more broadly that it is important for the NER to provide guidance on the registration, classification and participation of DC coupled systems. The Commission recognises the capital and operational efficiencies DC coupled systems offer their proponents, that allowing for their deployment and participation is in the long-term interest of consumers, and considers the draft rule reflects this. Furthermore, the draft rule is consistent with the NER Chapter 3 market design principle to provide Market Participants the greatest amount of commercial freedom to decide how they will operate in the market.[477]

477 Clause 3.1.4 of the NER.

The options paper proposed assigning a single set of system obligations as an approach for integrating DC coupled systems into the NER. The Commission considers applying exclusively scheduled or semi-scheduled dispatch obligations would act as a barrier to entry. This is because, if the system was:

- scheduled, the proponent might have to invest in a larger battery than would be otherwise be commercially efficient to reduce the risk of missing dispatch targets and incurring significant causer pays liabilities (given the inherent output variability of the renewable generating plant). This risk could delay the investment decision or instead to encourage the proponent to develop these assets as separate facilities, at higher cost.
- semi-scheduled, the output of the system would be constrained by AEMO's unconstrained intermittent generation forecast (UGIF).[478] Thus, if the UGIF was zero, even if the battery was available for dispatch it would not be permitted to discharge. However, the battery would be useful in reducing causer pays liabilities.[479]

The Commission's draft decision is to allow proponents of DC coupled systems the ability to choose from four different options for classifying DC coupled systems within an IRP facility. DC coupled system proponents would be expected to register as an IRP and would then have the option to classify the system as either:

- a non-scheduled IRU (only for systems under 5 MW)
- a scheduled IRU
- a semi-scheduled generating unit
- separately as a scheduled IRU and a semi-scheduled generating unit, which would be treated as two separate units in dispatch.

The Commission is interested to hear feedback from stakeholders on the practicality, cost and usefulness of this approach for DC coupled systems.

Single classification

To classify an IRU that is a 'coupled production unit' as a semi-scheduled generating unit, a participant would make an application to AEMO, which AEMO may approve on such terms and conditions as it considers appropriate. If AEMO is satisfied that the output of some or all generating plant comprised in the IRU is intermittent and will not consume electricity from the grid, except for auxiliary load, it may be classified as a semi-scheduled generating unit.[480] A 'coupled production unit' is defined in the draft rule as a production unit with separate plant for the production of electricity, each of a different plant type and capable of separate operation but the shared equipment (such as an inverter) is essential to the functioning of each.[481]

478 See clause 3.7.1(c)(2) of the NER. AEMO calculates the UGIF using the Australian Wind Energy Forecasting System (AWEFS) and, Australian Solar Energy Forecasting System (ASEFS) as well as generator self forecasts.

479 Causer pays provisions under clause 3.15.6A incentivise a semi-scheduled generator to ramp (increase or decrease) its actual generation at a uniform rate. Any deviations from a uniform rate of change that contribute to frequency deviation will add to the regulation FCAS causer pays factors for that generating unit, thereby increasing the proportion of regulation FCAS costs attributable to that generating unit.

480 Clause 2.2.7(c1) of the draft rule.

481 See chapter 10 definition of "coupled production unit" in the draft rule.

The Commission considers it appropriate to limit semi-scheduled generators' consumption to auxiliary load, as now defined in this draft rule. This limitation leaves the primary purpose of the battery, under this option, to firm up intermittent output and reduce causer pays liabilities. If a proponent decided to classify its DC coupled system as a semi-scheduled generating unit it would then be limited by the existing requirements placed on this classification.[482] This includes dispatch output being limited by the UGIF as well as the level specified by AEMO during 'semi-dispatch' intervals.[483]

To classify an IRU that is a 'coupled production unit' as a scheduled IRU or non-scheduled IRU an IRP would follow the same process to classify a battery as outlined in Appendix B. That is, if the integrated resource unit is over 5 MW for production or consumption it must be classified as a scheduled IRU and under 5 MW it could be classified as a non-scheduled IRU.

The scheduled IRU option would be attractive, for DC coupled systems over 5 MW, given it provides the participant the flexibility to act as a scheduled resource, for both load and generation, without the limitations of the semi-scheduled classification, mentioned above. This would likely be suitable where the storage capacity of the system is of sufficient size to provide the participant confidence it could meet dispatch targets.

Where the participant seeks to classify the DC coupled system as either a scheduled IRU or a semi-scheduled generating unit it would be treated as a single unit, with a single DUID, by the market. If a participant's system was under 5 MW name plate rating, that is the MW amount it can consume or supply to the grid with that inverter, it could be classified as a non-scheduled IRU.[484] Guidance on this process of classifying an IRU as a semi-scheduled generating unit is expected to be provided by AEMO as part of the guide to registration and classification.[485]

Multiple classifications

To classify an IRU that is a 'coupled production unit' as both a scheduled IRU and a semi-scheduled generating unit, a participant would make an application to AEMO, which AEMO may approve on such terms and conditions as it considers appropriate. Classification would apply as follows:

- *semi-scheduled generating unit* - in respect of that part of the plant that satisfies the criteria for classification as a semi-scheduled generating unit
- *scheduled IRU* - in respect of that part of the plant that satisfies the criteria for classification as a scheduled IRU.[486]

Where the participant seeks to classify the DC coupled system as both a scheduled IRU and a semi-scheduled generating unit, two DUIDs will be applied to it. This will allow the relevant assets to operate independently of one another for the purposes of submitting dispatch bids and receiving dispatch instructions. Operating each asset in the market independently could

482 See the AEMC's recent rule change that amended obligations on semi-scheduled generators, here.

483 Chapter 10 of the NER, definition of semi-dispatch interval and dispatch level; clause 4.9.5(a)(6) of the NER.

484 Clause 2.2.3(a1) in the draft rule.

485 See clause 2.1.3 of the draft rule.

486 Clause 2.2.2(b4) of the draft rule.

be useful option for participants seeking to access different revenue streams from each asset. Additionally, this option allows a participant to contract output from a specific asset, for example the semi-scheduled generating unit's output could be sold through a power purchase agreement contract to a specific counter-party.

The Commission considers the ability for proponents to classify these systems as both scheduled and semi-scheduled concurrently as a suitable solution which retains the flexibility envisioned in the proposal for dynamic scheduling within existing market frameworks. By giving proponents the flexibility to choose scheduled or semi-scheduled, or both, Market Participants can choose the arrangements which best suit their operations.

To assist participants and provide clarity to this approach, AEMO is expected to outline the requirements, including telemetry and metering requirements, determined by AEMO for the classification of a unit that shares equipment essential to its functioning with another unit (specifically an integrated resource unit and a semi-scheduled generating unit), in its guide under NER chapter 2. This Commission considers this guidance will reduce the discussion and negotiation currently required between participants and AEMO, and provide clarity on the approach AEMO would consider suitable.

Performance standards for DC coupled systems

The Commission understands from discussions with AEMO that existing approaches to connections and performance standards, as amended in the draft rule, require no specific changes to cater for DC coupled systems compared to other forms of hybrid facilities. Given this, DC coupled systems would be required to meet access and performance standards in the same way as any other hybrid systems.

H ANCILLARY SERVICE PROVISIONS IN CHAPTER 2 OF THE NER

H.1 Overview

In its submission to the consultation paper, AEMO proposed revised drafting for ancillary services provisions in Chapter 2 of the NER as an improvement to its original rule change request. AEMO proposed a simpler drafting approach that is more in line with the trader-services model being developed as part of the ESB's post-2025 work. Given this was a new issue relating to the rule change request, the Commission sought feedback on this in the options paper.

The Commission's draft decision is to make a rule which streamlines the ancillary services provisions in Chapter 2 of the NER, similar to the approach that AEMO outlined in its submission to the consultation paper.

H.2 AEMO's view

AEMO noted that ancillary services are provided by Market Participants with assets that are classified as ancillary service generating units[487] or ancillary service loads.[488] To be eligible to provide these services, a Market Participant must apply to AEMO to classify its unit, which involves meeting various requirements under the NER.[489]

In its rule change request, AEMO proposed a drafting approach for ancillary services provisions in Chapter 2 of the NER that would set requirements based on assets. In its submission to the Consultation Paper, AEMO revised its position to make it more consistent with future market reforms.[490] AEMO reflected that it would be preferable to take a simpler drafting approach in line with the trader-services model in the ESB's post-2025 work.[491] The trader-services model is described in section 1.6.3. AEMO considered moving away from an asset-based approach to regulation as a step towards recognising 'the reality that the assets that connect to the grid no longer result in those "traditional" energy flows' associated with certain registered market participants.[492]

H.2.1 AEMO's proposed solution

AEMO proposed that the Commission consider consolidating clauses that relate to the provision of ancillary services, to permit simpler drafting consistent with the long-term two-sided market reform. AEMO did not propose any specific drafting for this consolidation, but provided the following advice on how it believes this could be achieved:[493]

487 Clause 2.2.6 of the NER.
488 Clauses 2.3.5 and 2.3AA.1 of the NER.
489 AEMO submission to the consultation paper, p. 7.
490 AEMO submission to the consultation paper, p. 7.
491 Ibid, pp. 7-8.
492 Ibid.
493 AEMO, submission to the consultation paper, p. 7.

- Define an umbrella term (e.g. 'ancillary services facility') to replace the separate definitions of ancillary service generating units, ancillary service loads and the proposed ancillary services bi-directional unit. AEMO considered that alternatively, this definition could be specified in the market ancillary service specification (MASS).
- Allow the relevant types of Market Participant (Market Customer, Market Generator, and BDRP or IRP, depending on the participation option chosen) to provide FCAS from 'ancillary services facilities' in accordance with the MASS.
- All other policy requirements would remain the same (but consolidated), noting most are currently replicated requirements for each asset.
- The MASS would identify the service (consumption or production-side) that can be provided from an asset or connection point.

AEMO noted that this approach would be more consistent with a two-sided market where NER frameworks are more adaptable to change and better able to facilitate innovation.[494] AEMO also considered these proposed changes would be aligned with the reality that market participant categories no longer determine the behaviour of market participants at the connection point.[495] That is, these changes move the NER away from the notion that customers and generators only draw or discharge electricity into the grid respectively, and that it is equally desirable to clarify that ancillary services facilities can provide FCAS by varying import and export quantities at a connection point.[496]

AEMO also pointed out the effective implementation of this proposed solution would require changes to the definition of load in the NER. In its rule change request, AEMO proposed changes to the definition of load in Chapter 10 of the NER. Please refer to the consultation paper for a discussion of this as well as other drafting language changes AEMO proposed in its rule change request.[497]

H.3 Stakeholder views

Most stakeholders commented on this issue in their submissions to the options paper, where the majority of respondents supported AEMO's proposed approach to the ancillary service provisions in Chapter 2. Respondents who supported this proposed change to the rules did so for two reasons:

- Chapter 2 ancillary service provisions are complex and should be simplified, where possible[498]
- this proposal is a good, low-cost means of pursuing the ESB's trader-services model reform agenda immediately.[499]

494 Ibid, p. 7.
495 Ibid, p. 8.
496 Ibid.
497 AEMC, *Integrating energy storage systems into the NEM,* consultation paper, p. 88
498 Submissions to the options paper: YES Energy, p. 5; Tesla, p. 11; Flow Power, p. 6; Energy Queensland, p. 10; AusNet, p. 2.
499 Submissions to the options paper: GE Hydro, p. 6; Australian Energy Council, p. 3; Acciona, p. 2; Carisbrooke Consulting, p. 11.

Some stakeholders had concerns about resolving this issue in this rule change process. Three stakeholders were cautious about implementing these changes as part of this rule change process, and recommended this change be made either as part of the ESB Post 2025 process or to wait until this process has concluded.[500]

ERM Power requested the Commission confirm:[501]

- the compatibility of requirements for ancillary services generating units and ancillary services loads
- if subsequent changes would also be required for Chapter 3, 4 and 10 of the NER
- if amendments should also be made to require the MASS be technology neutral with regard to the provision of services.

H.4 Commission's analysis

BOX 13: DRAFT RULE — CHAPTER 2 ANCILLARY SERVICE PROVISIONS

The draft rule defines a new umbrella term for the provision of ancillary services to replace the separate clauses which relate to ancillary service generating units and ancillary service loads, noting that the required changes to the definition of load have also been made to achieve this. Additional changes have also been made to properly integrate the IRP.

Benefit of the draft rule

The draft rule will:

- be consistent with the policy objectives of the ESB's two-sided market work stream by aligning the rules with the trader-services model reform agenda
- accommodate the reality that an increasing number of connection points (controlled by participants of various types) have two-way flow and may be able to provide ancillary services both by varying import and by varying export quantities, not just one or the other
- reduce administrative burden by making the rules less complex by reducing the number of clauses that currently relate to the provision of ancillary services for each type of asset, and removing unnecessary distinctions between ancillary services provided by varying import quantities and those provided by varying export quantities.

The Commission agrees with AEMO's rationale for proposing the redrafting of Chapter 2 ancillary service provisions.

The draft rule replaces the existing clauses for ancillary services generating units, ancillary services load and market ancillary service providers (clauses 2.2.6, 2.3.5 and 2.3AA.1 of the

500 Submissions to the options paper: EnergyAustralia, p. 7; AGL, p. 2; Alinta, p. 6.

501 ERM Power, submissions to the options paper, pp. 6-7.

NER respectively) and combines them together in a new rule named *Ancillary Service Units and Ancillary Service Providers.*[502] This drafting approach provides a single point of reference in Chapter 2 for market participants seeking to become ancillary service providers, as the process for classification of ancillary service units and the requirements applying to ancillary service providers are detailed in this single provision, and are consistent for ancillary services provided from load and generation. This provision avoids unnecessary restrictions as to which types of registered participants can provide ancillary services from load and which from generation, providing greater flexibility for participants and improving the potential for competition in the provision of ancillary services. For example, aggregators of small units (generation or storage) will be able to provide ancillary services from generation and load.

Furthermore, the Commission recognises that the majority of stakeholders who commented on this issue support making this change to progress the ESB's trader-services model reform agenda. The draft rule primarily serves to improve the drafting of Chapter 2 ancillary service provisions, integrate the new participant category (Integrated Resource Provider) into the ancillary service provisions, and increase the flexibility regarding which types of market participants can provide which services. The Commission does not share the concerns raised by some stakeholders that making these changes should wait until the conclusion of the ESB's post 2025 process, as these are no-regrets changes that are consistent with future NER reforms being considered in the post 2025 process.

In response to ERM Power's concerns about making this draft rule, the Commission considers:

- ancillary service generating units and ancillary services loads are suitable to be combined at the level of the NER, noting that any required technical distinctions can be made in the MASS
- consequential amendments to Chapters 3, 4 and 10 of the NER are made in the draft rule, as required
- it is not appropriate for the NER to specify that the MASS must also be made technology neutral, given the technical nature of this document.

502 Clause 2.3D of the NER in the draft rule.

I SUMMARY OF OTHER ISSUES RAISED IN SUBMISSIONS

This appendix sets out the issues raised in the consultation on this rule change request to date, and the AEMC's response to each issue. If an issue raised in a submission has been considered in the main body of this document, it has not been included in this table.

Table I.1: Summary of other issues raised in submissions

STAKEHOLDER AND REFERENCE	COMMENT	AEMC RESPONSE
GE Hydro, Submission to the consultation paper, p. 1.	GE Hydro considered that there is a misalignment between benefits and costs, in which (pumped hydro) developers incur 100% of the cost, but receive less than 15% of the market benefits their projects create. The remaining >85% of benefits flow as 'positive externalities' to consumers in the form of lower prices. Simplistically, this misalignment could be fixed by addressing either or both sides of the cost benefit equation, i.e.: • Reduce the share of the up-front capital expenditure that must be paid by the developers. • Increase the share of benefits captured by the owners during operation.	The Commission considers market benefits are no different in the electricity market than in any other market. Competition drives down prices for consumers because new suppliers invest capital in markets where they have a competitive advantage. A new investor hopes to increase its market share (generation, in this case) but its added supply tends to lower market prices if it competes on price alone. The market benefit that flows to consumers from lower prices is an increase in consumer surplus – that is, the value they derive from consuming the good or service. This is not a positive externality because consumers are not a third party to the transaction - retailers are consumer's agents in the wholesale market. Lower electricity prices increase the well being of consumers and the productivity of the sector in the economy because electricity is an input cost to most goods and services. Any new entrant investor can only capture more of the consumer surplus in a competitive market if it can compete on factors other than price and those factors convince consumers

STAKEHOLDER AND REFERENCE	COMMENT	AEMC RESPONSE
		to pay them more the market price after they enter.
Monash Energy Institute, submission to the consultation paper p, 3.	Monash Energy Institute submission expressed that attention should be drawn to three important points. These points are summarised as: **Market Design** - With the introduction of storage, two aspects of the bidding process should be modified. Firstly, storage can buy or sell which changes the fundamentals of bids and their interaction with the market and the sensitivity of price setting in the NEM. Secondly, state of charge is a state variable in a dynamic optimisation problem as the optimal strategy depends on the future environment. **Dynamic dispatch** - A dynamic problem for each storage operator results in a similar problem for the dispatcher. NEMDE is unable to tackle such a dynamic optimisation problem and requires an update to keep track of the state of charge of all registered units at all times. **Industrial organisation** - To the extent that entry can be controlled by AEMO, the entry of many small(er) players should be encouraged and the concentration of capacity should be discouraged in order to foster competition in the provision of storage services.	The Commission agrees that storage will have a significant impact on the market thus its efficient integration requires updates to the rules and AEMO systems and processes. This includes, as part of this draft decision, participants' bidding forms and subsequently AEMO's dispatch engine itself. The Commission agrees that there are significant benefits from facilitating a competitive market in the NEM.

STAKEHOLDER AND REFERENCE	COMMENT	AEMC RESPONSE
ERM, submission to the consultation paper, p. 5	ERM considered that currently, individual storage facilities have been approved to provide FCAS at various levels with varying droop rates that appear to be inconsistent with AEMO's published policies. Also, greenfield utility scale storage projects cannot determine the volumes of ancillary service they will be registered to provide in NEM FCAS markets until they complete their commissioning process, which may be more than a year after an investment decision.	The Commission notes these issues but considers they are best addressed through alternative avenues.

J LEGAL REQUIREMENTS UNDER THE NEL

This appendix sets out the relevant legal requirements under the NEL for the AEMC to make this draft rule determination.

J.1 Draft rule determination

In accordance with s. 99 of the NEL the Commission has made this draft rule determination in relation to the rule proposed by the Australian Energy Market Operator.

The Commission's reasons for making this draft rule determination are set out in section 3.4.

A copy of the more preferable draft rule is attached to and published with this draft rule determination. Its key features are described in section 2.2 and in further detail in Appendix K.

J.2 Power to make the rule

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

J.3 Commission's considerations

In assessing the rule change request the Commission considered:

- its powers under the NEL to make the rule
- the rule change request
- submissions received during first and second round consultation
- the Commission's analysis as to the ways in which the proposed rule will or is likely to, contribute to the NEO.

There is no relevant Ministerial Council on Energy (MCE) statement of policy principles for this rule change request.[503]

The Commission may only make a rule that has effect with respect to an adoptive jurisdiction if satisfied that the proposed rule is compatible with the proper performance of AEMO's declared network functions.[504] The more preferable draft rule is compatible with AEMO's declared network functions because it would not affect those functions.

503 Under s. 33 of the NEL the AEMC must have regard to any relevant MCE statement of policy principles in making a rule. The MCE is referenced in the AEMC's governing legislation and is a legally enduring body comprising the Federal, State and Territory Ministers responsible for energy. The MCE is now called the Energy Ministers Meeting.

504 Section 91(8) of the NEL.

J.4 Civil penalties

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

The NEL sets out a three-tier penalty structure for the NEL and NER.[505] A Decision Matrix and Concepts Table,[506] approved by Energy Ministers, provides a decision-making framework that the AEMC applies, in consultation with the AER, when undertaking the assessment of whether to recommend that provisions of the NER be classified as civil penalties, and if so, under which tier.

J.4.1 New provisions the Commission proposes to recommend be classified as civil penalty provisions

The Commission's more preferable draft rule inserts the provisions set out in the table below into the NER.

The Commission considers that these new provisions should be classified as civil penalty provisions for consistency with similar provisions (currently classified as civil penalty provisions) that apply to other types of registered participants, and to promote compliance with these new obligations so that they operate effectively. The Commission will seek the AER's agreement to a joint recommendation to the Energy Ministers Meeting to this effect at the time the final rule is published.

Table J.1: **New provisions in more preferable draft rule proposed to be recommended as civil penalty provisions**

CLAUSE	SUBJECT OF CLAUSE	PROPOSED CLASSIFI-CATION	REASON
2.2.5A(b)	Requirement on Integrated Resource Providers (IRPs) to sell all sent out generation through the spot market and accept payments from AEMO n accordance with Chapter 3.	Tier 1	Align with existing provisions for other participant categories.
2.2.5A(c)	Requirement on IRPs to purchase all electricity supplied through the national grid to the IRP at that connection point from the spot market and make payments to AEMO n accordance with Chapter 3.	Tier 1	Align with existing provisions for other participant categories.
2.2.7(c2)	Requirement on a person who wishes to	Tier 1	Align with

505 Further information is available at: https://www.aemc.gov.au/regulation/energy-rules/civil-penalty-tools.

506 The Decision Matrix and Concept Table are available at: https://energyministers.gov.au/sites/prod.energycouncil/files/publications/documents/Final%20-%20Civil%20Penalties%20Decision%20Matrix%20and%20Concepts%20Table_Jan%202021.pdf.

CLAUSE	SUBJECT OF CLAUSE	PROPOSED CLASSIFI-CATION	REASON
	classify a semi-scheduled generating unit to comply with terms and conditions imposed by AEMO under clause 2.2.7(c1).		existing provisions for other participant categories.
2.2.8(c)	Requirement on Small Resource Aggregators (SRAs) to sell all sent out generation from their market supply points through the spot market and accept payments from AEMO in accordance with Chapter 3.	Tier 1	Align with existing provisions for other participant categories.
2.2.8(d)	Requirement on SRAs to purchase all electricity supplied through the national grid to their market connection points from the spot market and make payments to AEMO in accordance with Chapter 3.	Tier 1	Align with existing provisions for other participant categories.
2.3.4(g)	Requirement on Market Customers to purchase all electricity supplied to their connection points from the spot market and make payments to AEMO n accordance with Chapter 3.	Tier 1	Align with existing provisions for other participant categories.
2.3.4(g1)	Requirement on Market Customers to sell all sent out generation from connection points they have classified as market connection points through the spot market and accept payments from AEMO n accordance with Chapter 3.	Tier 1	Align with existing provisions for other participant categories.
2.3D.2(a)	Requirement on Ancillary Service Providers (ASPs) to comply with terms and conditions imposed by AEMO under clause 2.3D.1(g).	Tier 1	Align with existing provisions for other participant categories.
2.3D.2(b)(1)	Requirement on ASPs to ensure that the market ancillary services provided are in accordance with the co-ordinated central dispatch process operated by AEMO and the market ancillary service specification.	Tier 1	Align with existing provisions for other participant categories.
2.3D.2(b)(3)	Requirement on ASPs that submit a market ancillary service bid to comply with the dispatch instructions from AEMO.	Tier 1	Align with existing provisions for other participant

CLAUSE	SUBJECT OF CLAUSE	PROPOSED CLASSIFI-CATION	REASON
			categories.
2.3D.2(c)	Requirement on ASPs with an ancillary service unit to sell the market ancillary services produced using that ancillary service unit through the spot market.	Tier 1	Align with existing provisions for other participant categories.
4.9.8(b2)	Requirement on IRPs to ensure each of their scheduled integrated resource units (IRU) is able to comply with the latest dispatch bid for that IRU.	Tier 1	Align with existing provisions for other participant categories.
5.2.5A(a)	Requirement on IRPs to plan and design their facilities and ensure they operate to comply with the relevant and applicable performance standards, connection agreement and system standards.	Tier 1	Align with existing provisions for other participant categories.
5.2.5A(c)	Requirement on IRPs to comply with any terms and conditions of a connection agreement for their systems that provide for the implementation, operation, maintenance or performance of a system strength remediation scheme.	Tier 1	Align with existing provisions for other participant categories.
5.2.5A(d)	Requirement on IRPs to provide information to AEMO and the relevant NSP in accordance with the Power System Model Guidelines, the Power System Design Data Sheet and the Power System Setting Data Sheet if AEMO believes there is a risk that the IRPs' plant will adversely affect the network or other users.	Tier 2	Align with existing provisions for other participant categories.
5.2.5A(e)	Requirement on IRPs to provide certain information to AEMO and the relevant NSP, if requested by AEMO, to allow the NSP to conduct the assessment required under clause 5.3.4B.	Tier 2	Align with existing provisions for other participant categories.
5.3.9(b)(2A)	Requirement that an IRP submit to the relevant NSP and AEMO, in respect of a proposed alteration to a unit, design data and setting data in accordance with the	Tier 2	Align with existing provisions for other participant

CLAUSE	SUBJECT OF CLAUSE	PROPOSED CLASSIFI-CATION	REASON
	Power System Model Guidelines, Power System Design Data Sheet and Power System Setting Data Sheet.		categories.
5.3.10(a1)	Requirement on IRPs not to commission altered generating plant until the NSP has advised the Generator that the provider and AEMO are satisfied.	Tier 1	Align with existing provisions for other participant categories.
5.7.3(a1)	Requirement for IRPs to, in accordance with rule 4.15, provide evidence to any relevant NSP with which that IRP has a connection agreement and to AEMO, that its generating system or integrated resource system (as applicable) complies with the applicable technical requirements and connection agreement.	Tier 3	Align with existing provisions for other participant categories.
5.20B.6(b1)	Requirement on Inertia Service Providers to register the IRU with AEMO as an inertia unit and specify that the IRU may be periodically used to provide inertia network services and will not be eligible to set spot prices when constrained on to provide inertia.	Tier 2	Align with existing provisions for other participant categories.
5.20C.4(b1)	Requirement on System Strength Service Providers that procure system strength services from an IRP under a system strength services agreement to register the IRU with AEMO as a system strength unit and specify that the IRU may be periodically used to provide system strength services and will not be eligible to set spot prices when constrained on to provide system strength services.	Tier 2	Align with existing provisions for other participant categories.
11.[xxx].2	Requirement for Registered Participants to whom clause 11.[xxx].2 applies to apply to AEMO under new rule 2.9B to change their registration category to IRP and to reclassify their integrated resource system under the updated new Chapter 2.	Tier 2	To ensure that relevant Registered Participants are transferred into the IRP category.

J.4.2 Amendments to existing provisions

The Commission's more preferable draft rule amends the provisions of the NER set out in the table below. These provisions are currently classified as civil penalty provisions under Schedule 1 of the National Electricity (South Australia) Regulations.

The Commission considers that these provisions should continue to be classified as civil penalty provisions and therefore does not propose to recommend any change to their classification to the Energy Ministers Meeting.

Table J.2: **Amendments to existing provisions**

CLAUSE	SUBJECT OF CLAUSE (AS AMENDED)	PROPOSED CHANGE	CURRENT CLASSIFICATION
2.2.2(c)	Requirement on a person who wishes to classify a unit as a scheduled generating unit or scheduled IRU to comply with terms and conditions imposed by AEMO under clause 2.2.2(b1), (b3) or (b4).	It is proposed to amend this provision to capture IRPs.	Tier 1
2.2.4(c)	Requirement on Market Generators to sell all sent out generation through the spot market and accept payments from AEMO in accordance with Chapter 3.	It is proposed to amend this provision to remove the reference to spot price at the connection point.	Tier 1
2.2.4(d)	Requirement on Market Generators to purchase all electricity supplied through the national grid to the Market Generator at the connection point from the spot market and make payments to AEMO n accordance with Chapter 3.	It is proposed to amend this provision to capture IRPs.	Tier 1
2.5.3(e)(4)	Requirement on a Scheduled Network Service Provider (NSP) to submit to AEMO a schedule of dispatch bids for the scheduled network services in accordance with Chapter 3.	It is proposed to amend this provision to remove dispatch offers and replace it with dispatch bids.	Tier 1
2.10.1(c1)	Requirement on a Scheduled Generator, or Semi-Scheduled Generator, or Scheduled IRP to include certain information in a notice to AEMO that it wishes to terminate the	It is proposed to amend this provision to capture IRP.	Tier 1

CLAUSE	SUBJECT OF CLAUSE (AS AMENDED)	PROPOSED CHANGE	CURRENT CLASSIFICATION
	classification of one of its units.		
2.10.1(c2)	Requirement on a Scheduled Generator, Semi-Scheduled Generator, or Scheduled IRP not to give a first notified closure date for a unit that is earlier than 42 months from the date of the notice given under clause 2.10.1(a)(2), unless the AER has granted an exemption.	It is proposed to amend this provision to capture IRPs.	Tier 1
2.10.1(c3)	Requirement on the closure date included in notices issued to AEMO by Scheduled Generators, Semi-Scheduled Generators, or Scheduled IRPs under clause 2.10.1(c1).	It is proposed to amend this provision to capture IRPs.	Tier 1
3.3.16(a)	Prohibition on market participants bidding to transact with AEMO where the potential value of all transactions exceed the trading margin for the market participant.	It is proposed to amend this provision to omit the reference to offers.	Tier 3
3.6.3(b)(2)	Requirements on distribution loss factors for a connection point for an embedded generating unit or embedded integrated resource unit with generation of more than 10MW.	It is proposed to amend this provision to capture IRPs.	Tier 3
3.6.3(b1)	Requirement for Distribution Network Service Providers (DNSPs) to calculate a site-specific distribution loss factor applying to generating units when costs of calculation are met.	It is proposed to amend this provision to capture I.	Tier 3
3.7.2(d)	Requirement for medium term PASA inputs to be submitted in accordance with the timetable and to represent the participants current intentions and best estimates.	It is proposed to amend this provision to capture IRPs.	Tier 1
3.7.3(e)	Requirement on certain Registered Participants to submit short term PASA inputs that represent the participants current intentions and best estimates.	It is proposed to amend this provision to capture IRPs.	Tier 1

CLAUSE	SUBJECT OF CLAUSE (AS AMENDED)	PROPOSED CHANGE	CURRENT CLASSIFICATION
3.8.2(a)	Requirement for Generators and IRPs to submit dispatch bids for each trading day according to clause 3.8.6.	It is proposed to amend this provision to capture IRPs and to replace dispatch offers with dispatch bids.	Tier 2
3.8.2(b)	Requirement for dispatch bids for scheduled generating units to include self dispatch levels and prices/quantities for generation above and below a level.	It is proposed to amend this provision to capture IRPs and to replace dispatch offers with dispatch bids.	Tier 2
3.8.2(b1)	Requirement for NSPs to submit dispatch bids for each of its scheduled network services each day.	It is proposed to amend this provision to replace dispatch offers with dispatch bids.	Tier 2
3.8.3A(b)	Requirement for Generators and Market Participants to provide an up ramp rate and down ramp rate for each unit, network service or load.	It is proposed to amend this provision to capture IRPs.	Tier 1
3.8.3A(d)	Requirement for Market Participants to provide a maximum ramp rate to AEMO that the relevant unit can safely attain.	It is proposed to amend this provision to capture IRPs.	Tier 1
3.8.3A(j)	Requirement for Generators and Market Participants to provide only the maximum ramp rate for relevant generating unit or scheduled integrated resource unit in addition to obligation under clause 3.8.3A(d) if clause 3.8.3A(i) applies.	It is proposed to amend this provision to capture IRPs.	Tier 1
3.8.4(a)	Requirement for Market Participants to notify AEMO of the available capacity of their scheduled resource each trading interval of each trading day.	It is proposed to amend this provision to capture IRPs.	Tier 1
3.8.4(c)	Requirement for Scheduled Generators to notify AEMO of the available capacity two days ahead of	It is proposed to amend this provision to capture IRPs.	Tier 1

CLAUSE	SUBJECT OF CLAUSE (AS AMENDED)	PROPOSED CHANGE	CURRENT CLASSIFICATION
	each trading day.		
3.8.7A(l)	Requirements for a market ancillary service bid to represent technical characteristics of the ancillary service unit.	It is proposed to amend this clause to reflect the consolidation of ancillary services in Chapter 2.	Tier 1
3.8.7A(m)	Requirements for re-bids to represent technical characteristics at the time of dispatch of the ancillary service.	It is proposed to amend this clause to reflect the consolidation of ancillary services in Chapter 2.	Tier 1
3.8.8(b)	Requirement for Generators and Market Participants to check that the date contained in their dispatch bids or market ancillary service bids to AEMO are correct.	It is proposed to amend this provision to capture IRPs and to reflect the consolidation of ancillary services in Chapter 2.	Tier 2
3.8.19(a)	Requirement for Scheduled Generators and Market Participants to advise AEMO when they expect their scheduled resources to be unable to operate in accordance with dispatch instructions in a trading interval.	It is proposed to amend this provision to capture IRPs.	Tier 1
3.8.19(a1)	Requirement for semi-scheduled generators to advise AEMO when they expect their scheduled resources to be unable to operate with dispatch instructions.	It is proposed to amend this provision to replace dispatch offers with dispatch bids.	Tier 1
3.8.19(b)(1)	Requirement for Generators and Market Participants to provide AEMO with specific and verifiable reasons for their inflexibility.	It is proposed to amend this provision to capture IRPs.	Tier 1
3.8.20(g)	Requirement on Market Participants to ensure that they are able to dispatch under the pre-dispatch schedule.	It is proposed to amend this provision to capture IRPs.	Tier 1

CLAUSE	SUBJECT OF CLAUSE (AS AMENDED)	PROPOSED CHANGE	CURRENT CLASSIFICATION
3.8.22A	Requirements that the court must consider when adjudicating a rebid.	It is proposed to amend this provision to capture IRPs.	Tier 1
3.9.7(a)	Requirement for scheduled resources to comply with dispatch instructions from AEMO and be excluded from spot price determinations when they are constrained.	It is proposed to amend this provision to capture IRPs.	Tier 1
3.9.7(c)	Requirement for inertia units or system strength units to comply with dispatch instructions from AEMO in accordance with their availability.	It is proposed to amend this provision to capture IRPs.	Tier 1
3.13.2(h)	Requirement on Market Participants to notify AEMO of, and AEMO must publish, any changes to submitted information within the times prescribed in the timetable.	It is proposed to amend this provision to simplify the drafting.	Tier 1
3.13.3(b)	Requirement on Generators and Market Participants to provide AEMO with bid validation data relevant to their scheduled resource.	It is proposed to amend this provision to simplify the drafting.	Tier 2
3.13.3(b1)	Requirement on Market Participants with aggregated scheduled resources to provide AEMO with the maximum generation of each individual unit that could be dispatched.	It is proposed to amend this provision to capture IRPs.	Tier 2
3.13.3(c)	Requirement on Market Participants to provide AEMO with information about forecasts for connection points and metering information for settlements.	It is proposed to amend this provision to simplify the drafting.	Tier 2
3.13.3(h)	Requirement on Market Participants to notify AEMO of changes to bid validation 6 weeks before planned changes and without delay for unplanned changes.	It is proposed to amend this provision to simplify the drafting.	Tier 2
3.13.12(g)	Requirement for market customers or small resource aggregators to only use NMI standing data provided by	It is proposed to amend this provision to capture IRPs.	Tier 1

CLAUSE	SUBJECT OF CLAUSE (AS AMENDED)	PROPOSED CHANGE	CURRENT CLASSIFICATION
	AEMO and under relevant purpose permitted by relevant Jurisdictional NMI standing data schedule.		
3.15.8(b)	Requirement for AEMO to calculate figures for each cost recovery market participant in each region using prescribed formula.	It is proposed to amend this provision to capture IRPs and to update the CRP formula.	Tier 3
3.15.8A(c)	Requirement that the cost recovery market participant is liable to pay the value of that amount to AEMO if the CRA figure is negative.	It is proposed to amend this provision to capture IRPs.	Tier 1
3.20.3(h)	Prohibition on entering scheduled reserve contracts in relation to capacity for which dispatch bids were submitted or was available for dispatch, in the 12 months before the date of execution of the scheduled reserve contract.	It is proposed to amend this provision to remove dispatch offers.	Tier 1
4.4.2(b)	Requirement on Generators to ensure all of their units meet technical requirements for frequency control.	It is proposed to amend this provision to capture IRPs.	Tier 1
4.4.3	Requirement on Generators to, in accordance with schedule 5.2 and Chapter 5, provide any necessary automatically initiated protective device or systems to protect their plant and associated facilities against abnormal voltage and extreme frequency excursions of the power system.	It is proposed to amend this provision to capture IRPs.	Tier 1
4.8.5A(d)	Requirement on Scheduled NSPs and Generators to provide information to AEMO to allow it to estimate the time it would need to intervene after unforeseen circumstances.	It is proposed to amend this provision to capture IRPs.	Tier 1
4.8.12(d)	Requirement on Generators and NSPs to develop local black system procedures.	It is proposed to amend this provision to capture IRPs.	Tier 1

CLAUSE	SUBJECT OF CLAUSE (AS AMENDED)	PROPOSED CHANGE	CURRENT CLASSIFICATION
4.8.14(b)	Requirement for Generator and NSPs to comply with requirements of local black system procedures quickly if AEMO advises them of a major supply disruption.	It is proposed to amend this provision to capture IRPs.	Tier 1
4.8.14(d)	Requirement on Generators and NSPs to comply with AEMO's directions in relation to restoration of the power system if there is a major supply disruption.	It is proposed to amend this provision to capture IRPs.	Tier 1
4.9.2(d)	Requirement on a Generator to have an availability offer of more than 0MW, and appropriate personnel available at all times to follow AEMO's dispatch instructions.	It is proposed to amend this provision to capture IRPs.	Tier 1
4.9.3A(c)	Requirement for market participants with ancillary service units which have submitted market ancillary service bids to ensure appropriate personnel or electronic facilities available to follow AEMO dispatch instructions.	It is proposed to amend this clause to reflect the consolidation of ancillary services in Chapter 2.	Tier 1
4.9.4(a)	Requirement for Generators not to send out energy from a generating unit except according to 4.9.4(a)(1)-(4), unless public safety would be threatened.	It is proposed to amend this provision to capture IRPs.	Tier 1
4.9.4(b)	Requirement for Generators not to adjust the transformer tap position or excitation control system voltage set point of a scheduled generating unit or semi-scheduled generating unit.	It is proposed to amend this provision to capture IRPs.	Tier 1
4.9.4(c)	Requirement for Generators not to energise a connection point in relation to a generator unit without AEMO approval immediately prior.	It is proposed to amend this provision to capture IRPs.	Tier 1
4.9.4(e)	Requirement for Generators not to change frequency response mode of a scheduled generating unit without AEMO approval prior.	It is proposed to amend this provision to capture IRPs.	Tier 1

CLAUSE	SUBJECT OF CLAUSE (AS AMENDED)	PROPOSED CHANGE	CURRENT CLASSIFICATION
4.9.4(f)	Requirement for Generators not to remove or interfere with the operation of any power system stabilising equipment on the generating unit.	It is proposed to amend this provision to capture IRPs.	Tier 1
4.9.8(b1)	Requirement for NSPs to ensure each of their scheduled network services are always able to comply with the latest dispatch bid.	It is proposed to amend this provision to replace network dispatch offer with dispatch bid.	Tier 1
4.9.8(d)	Requirement on a Market Participant which has classified a generating unit as an ancillary service unit to ensure that the ancillary service unit is at all times able to comply with the latest market ancillary service bid for the relevant trading interval.	It is proposed to amend this clause to reflect the consolidation of ancillary services in Chapter 2.	Tier 1
4.9.8(e)	Requirement on a Semi-Scheduled Generators to ensure that each of their semi scheduled generating units are at all times able to comply with its latest dispatch bid generation dispatch offer.	It is proposed to amend this provision to replace network dispatch offer with dispatch bid.	Tier 1
4.9.9	Requirement for Scheduled Generators to notify AEMO without delay of any event that might change the operational availability of their schedule generating units as soon as the provider is aware of the event.	It is proposed to amend this provision to capture IRPs.	Tier 1
4.9.9B	Requirement on a Market Participant that has classified a unit or connection point as an ancillary service unit to without delay, notify AEMO of any events that could change the availability of a market ancillary service, as soon as the Market Participant becomes aware of the event.	It is proposed to amend this clause to reflect the consolidation of ancillary services in Chapter 2.	Tier 1
4.11.1(a)	Requirement for all remote control operational metering and monitoring	It is proposed to amend this provision	Tier 3

CLAUSE	SUBJECT OF CLAUSE (AS AMENDED)	PROPOSED CHANGE	CURRENT CLASSIFICATION
	devices and local circuits to be installed and maintained according to the standards/protocols advised by AEMO.	to capture IRPs.	
4.11.1(e)	Requirement for NSPs and Generators to comply with notices received from AEMO under clause 4.11.1(d) within 120 Business days.	It is proposed to amend this provision to capture IRPs.	Tier 3
4.11.1(g)	Requirement for NSPs and Generators to comply with AEMO's requirements for control signals to receive dispatch instructions electronically.	It is proposed to amend this provision to capture IRPs.	Tier 3
5.2.3(d)(11)	Requirement to provide AEMO information from Generators in relation to a connection agreement and details of any connection points with other NSPs.	It is proposed to amend this provision to capture IRPs.	Tier 2
5.2A.7(e)	Requirement that a person who owns a third party IUSA must not own, operate or control a generating system or integrated resource system.	It is proposed to amend this provision to capture IRPs.	Tier 1
5.3.3(b5)	Requirement for NSPs to provide the connection applicant with certain written details for a connection point for a proposed new connection of a generation system or market network service facility.	It is proposed to amend this provision to capture IRPs.	Tier 3
5.3.4B(a)	Requirement for NSPs to undertake a system strength impact assessment for each proposed new connection.	It is proposed to amend this provision to capture IRPs.	Tier 2
5.3.4B(e)	Requirement for NSPs to undertake system strength connection works at the cost of the Connection Applicant if the guidelines indicate that it will have an adverse system strength impact.	It is proposed to amend this provision to capture IRPs.	Tier 2
5.3.6(j)	Requirement that an offer to connect made by NSPs to embedded generators in respect of a distribution	It is proposed to amend this provision to capture	Tier 3

CLAUSE	SUBJECT OF CLAUSE (AS AMENDED)	PROPOSED CHANGE	CURRENT CLASSIFICATION
	network must conform with rule 5.3AA.	Embedded IRPs.	
5.3.7(g)	Requirement for NSPs and the relevant Registered Participant to notify AEMO that an agreement has been entered into within 20 business days of executing a connection agreement.	It is proposed to amend this provision to capture IRPs.	Tier 2
5.3.9(h)	Requirement for NSPs and Generators to immediately jointly advise AEMO if application of clause 5.3.9 leads to a variation to an existing connection agreement.	It is proposed to amend this provision to capture IRPs.	Tier 2
5.3A.12(b)	Requirement for NSPs to register the generating unit with AEMO if the NSP or DNSP decides to implement a generation option as an alternative to network augmentation.	It is proposed to amend this provision to capture IRPs.	Tier 2
5.6.2(b)	Requirement for Generators not to commission facility in respect of a connection if an inconsistency is identified under clause 5.6.2(b) unless it has been removed.	It is proposed to amend this provision to capture IRPs.	Tier 1
5.7.3(c)	Requirement for Generators to notify AEMO and the NSP and undertake remedial work if tests indicate the relevant system is not complying with technical requirements in clause S5.2.5 or the connection agreement or performance standards.	It is proposed to amend this provision to capture IRPs.	Tier 1
5.7.3(d)	Requirement for Generators to conduct tests to show that the system complies with performance standards if directed by AEMO.	It is proposed to amend this provision to capture IRPs.	Tier 2
5.7.6(e)	Requirement for Generators to conduct tests under clause 5.7.6 at the next scheduled outage of the unit	It is proposed to amend this provision to capture IRPs.	Tier 1

CLAUSE	SUBJECT OF CLAUSE (AS AMENDED)	PROPOSED CHANGE	CURRENT CLASSIFICATION
	or in 9 months.		
5.20B.6(b)	Requirement for Inertia Services Providers to register generating units with AEMO as an inertia unit and specify that they will not be eligible to set spot prices when constrained on to provide inertia.	It is proposed to amend this provision to capture IRPs.	Tier 2
5.20C.4(b)	Requirement for System Strength Service Providers to register generating units with AEMO as a system strength unit and specify that they will not be eligible to set spot prices when constrained on to provide system strength.	It is proposed to amend this provision to capture IRPs.	Tier 2
7.10.5(b)	Requirement for type 4, 4A, 5 and 6 metering installations to be converted into trading intervals in accordance with the metrology procedure, which must specify the parameters to be used in preparing the data including the algorithms.	It is proposed to amend this provision to remove first tier load and market load.	Tier 2
7.10.6(a)	Requirement on metering providers to set the times of clocks for all installations to Eastern Standard Time when installing, testing and maintaining metering installations.	It is proposed to make minor amendments to this provision, including to remove the reference to load.	Tier 2
7.11.3(d)	Requirement for an on-site test of a metering installation to be based on actual energy consumed at that connection point.	It is proposed to make minor amendments to this provision, including to remove the reference to load.	Tier 2

J.5 Conduct provisions

The Commission cannot create new conduct provisions. However, it may recommend to the Energy Ministers Meeting that new or existing provisions of the NER be classified as conduct provisions.

The more preferable draft rule does not amend any rules that are currently classified as conduct provisions under the NEL or National Electricity (South Australia) Regulations. The Commission does not propose to recommend to the Energy Ministers Meeting that any of the proposed amendments made by the more preferable draft rule be classified as conduct provisions.

J.6 Review of operation of the rule

The more preferable draft rule does not require the Commission to conduct a formal review of the operation of the rule. The Commission may however self-initiate a review of the operation of the rule at any time if it considers such a review would be appropriate, pursuant to section 45 of the NEL.

K SUMMARY OF AMENDMENTS TO THE NATIONAL ELECTRICITY RULES

This appendix outlines the amendments to the National Electricity Rules (NER) made under the more preferable draft rule. It starts with an introduction to the key concepts used in the drafting.

K.1 Introduction to key concepts

Under the proposed rule, several new concepts would be introduced or existing concepts modified.

K.1.1 Unit categories

- The current defined term *generating unit* (covering 'plant used in the production of electricity and all related equipment essential to its functioning as a single entity') would become the new term *production unit*. The term *generating unit* would be redefined as a production unit that is not an integrated resource unit.
- A new term, *integrated resource unit*, would be a production unit that also consumes electricity that is not, or is in addition to, its auxiliary load. A new defined term *auxiliary load* would cover electricity consumption used for the operation of auxiliary plant at a power station but would not include electricity consumption used to charge a production unit or to pump water for a pumped hydro production unit.
- The current terms *ancillary service generating unit* and *ancillary service load* would be replaced with a new umbrella term, *ancillary service unit* which would encompass generating units, integrated resource units and other connected plant classified as an ancillary service unit.
- The new term *small integrated resource unit* would correspond to the existing term *small generating unit* to cover units exempt from registration. Similarly, *embedded integrated resource unit* would correspond to the existing term *embedded generating unit.*

K.1.2 System Categories

- A *generating system* would be defined as in the current NER but would exclude an *integrated resource system*.
- A new defined term *integrated resource system* would cover:
  - a system comprising one or more integrated resource units (and which may also comprise one or more generating units or other connected plant that is not part of an integrated resource unit); or
  - a system comprising one or more generating units where the connection point for the system is used to supply electricity for consumption that is not, or is in addition to, auxiliary load (but not solely auxiliary load).

K.1.3 Registration categories

- An *Integrated Resource Provider* (**IRP**) would be a person registered as such. The units and plant that could be classified by an IRP are described below.
- The new term *Small Resource Aggregator* would replace the Market Small Generation Aggregator registration category. A Small Resource Aggregator is an IRP that has classified the connection point for a small generating unit or a small integrated resource unit as one of its market connection points.

K.1.4 Other new or replacement terms

- References to dispatch offers would be replaced with references to *dispatch bids* and references to market ancillary service offers would be replaced with references to *market ancillary service bids*.
- References to bid and offer validation data would be replaced with references to *bid validation data*.
- Reference to *market load* would be removed and connection points at which electricity supplied through the national grid is purchased or sold by an end user (end user connection points) would be classified as market connection points by a registered Customer or an Integrated Resource Provider.
- A new term *scheduled resource* would refer to all plant subject to AEMO's central dispatch process - scheduled generating units, semi-scheduled generating units, scheduled IRUs, scheduled load, wholesale demand response units and scheduled network services.

K.2 Proposed changes to Chapter 2

Chapter 2 has been amended to introduce the new IRP registration category and the classification arrangements for integrated resource units. Other changes have been made to remove redundant registration and classification categories from the rules and re-order chapter 2 to clarify meaning and improve readability.

K.2.1 Obligations to register or classify

The obligation to register under the NER in relation to the generation of electricity (or to be exempt) and for the purchase and sale of electricity through the spot market is derived from the NEL. The current NER in turn sets out the registration requirements in more specific terms. The proposed amendments to chapter 2 would bring these obligations together in a new rule 2.1A.

This rule would cover the obligation to register in relation to generating systems, integrated resource systems, purchasing and selling electricity directly in the spot market, providing wholesale demand response and providing market ancillary services.

AEMO's power to exempt a person or class of persons from the requirement to register in relation to a generating system would be extended to integrated resource systems and would be included as new clause 2.1A.2.

K.2.2 Market Participant registration categories for the sale or purchase of electricity

A new rule 2.1B would bring together the requirements for registration as a Generator, Customer or Demand Response Service Provider and would be extended to cover the requirements for registration as an IRP. The rule would also include, in modified form, the current requirements for the provision of closure year notices.

The *Generator* registration category would continue to be available for a person who wishes to be the Participant for a generating unit.

The *Customer* registration category would continue to be available for a person who wishes to be the Market Participant for electricity supplied to end users but would be modified to recognise that the end users may be exporting electricity to the grid as well as importing. The Customer registration category would also continue to be available for registration in relation to a scheduled load.

The *Demand Response Service Provider* registration category would be open to a person that wishes to classify a connection point to provide wholesale demand response or who wishes to classify plant at a connection point as an ancillary service unit to provide market ancillary services.

The new *Integrated Resource Provider* registration category would apply as follows:

- as a Market Participant category for registration as the owner, operator or controller of a generating system or an integrated resource system,
- as a Market Participant category for a person who wishes to participate in the market in relation to small generating units or small integrated resource units, acting as a Small Resource Aggregator,
- as a Market Participant category for a person who wishes to purchase or sell electricity directly in the market in relation to any other customer connection point, including a connection point that connects scheduled load, acting as a Market Customer.

Under the draft rule, the terms Market Generator and Market Customer would continue to be used as labels to identify Market Participants who are financially responsible for generating units or end user connection points.

Proposed rule 2.9B would allow Generators and Customers to transfer to the new Integrated Resource Provider registration category.

K.2.3 Classification of generating units and integrated resource units

The requirements for classification of generating units and integrated resource units would be brought together in a revised rule 2.2.

As under the current NER, a generating unit may be classified as a scheduled generating unit, a semi-scheduled generating unit or a non-scheduled generating unit.

The draft rule proposes that an integrated resource unit could be classified as a scheduled integrated resource unit or a non-scheduled integrated resource unit. In general:

- a scheduled integrated resource unit would be an integrated resource unit with a nameplate rating for both production and consumption of 5MW or more unless AEMO has approved the classification of the integrated resource unit as a non-scheduled integrated resource unit.
- a non-scheduled integrated resource unit would be an integrated resource unit with a nameplate rating for both production and consumption of less than 5MW.

There is no concept under the draft rule of a semi-scheduled integrated resource unit. However, to allow flexibility for 'DC-coupled systems' (integrated resource systems comprising intermittent generation such as wind and integrated resource units where the units use a single inverter), the draft rule allows these to be classified as scheduled integrated resource units, separate units with separate classification or, subject to conditions in the rules, as a semi-scheduled generating unit. These options are provided for under clause 2.2.2(a1) of the draft rule, together with clauses 2.2.2(b4) and 2.2.7(c1).

Some facilities that would satisfy the definition of 'integrated resource unit' (pumped hydro) cannot move linearly from one mode of operation to the other (ie from generation to consumption or vice versa). The draft rule would require these units to continue to be classified as a scheduled generating unit and a scheduled load. This is provided for in clauses 2.2.2(a1)(2) of the draft rule, together with clauses 2.2.2(b2) and 2.3.4A.

Under the draft rule, Generators may only classify scheduled generating units, semi-scheduled generating units and non-scheduled generating units. IRPs will be able to act in several different roles and so may classify:

- scheduled integrated resource units and non-scheduled integrated resource units
- scheduled generating units, semi-scheduled generating units and non-scheduled generating units
- scheduled load
- market connection points (other than market connection points which connect a market generating unit, market integrated resource unit or network service to the national grid), and
- connection points for small generating units and small integrated resource units (as a Small Resource Aggregator).

Generators and IRPs would also be required to classify their generating units and integrated resource units as 'market' or 'non-market'. The 'market' classification would be required unless AEMO approves the 'non-market' classification. The 'non-market' classification would only be permitted where the generating unit or integrated resource unit is non-scheduled and a Market Customer has classified the connection point for the plant as one of its market connection points.

K.2.4 Connection point classifications

Under the draft rule, current rule 2.3 would be amended extensively to provide for classification of connection points other than the connection points for generating units or integrated resource units.

- The jurisdictional classification requirements and thresholds would be preserved in cause 2.3.1A.
- The First-Tier Customer and Second-Tier Customer registration and classification categories would be deleted.
- The provision for registration as a Customer would be moved to rule 2.1B.
- Clause 2.3.4 would:
  - deem the connection points for classified generating units, integrated rersource units and market network services to be market connection points of the Market Participant which has classified the relevant unit or service;
  - deem connection points that connect small generating units or small integrated resource units to the national grid, and which have been classified by an IRP, to be a market connection point of the IRP;
  - require end user connection points to be classified by a Customer or an IRP, and
  - allow classification of a child connection point as a market connection point by a customer or an IRP. It would preserve the requirement for local retailers to classify the connection points of franchise customers as their market connection points.
- The draft rule no longer uses the term 'market load' for classification since end users buying from retailers may both import and export electricity. The draft rule removes the term 'market load' from chapter 2 and elsewhere in the NER.[507]

K.2.5 Ancillary services

Under the draft rule, the ancillary service classification provisions and the Ancillary Service Provider compliance provisions in current clauses 2.2.6 (ancillary service generating units) and 2.3.5 (ancillary services load) have been merged into new clause 2.3D.

The draft rule proposes to remove distinctions between classification of generating units or load for the provision of ancillary services by different Market Participant categories by allowing a Market Participant, in respect of plant at a market connection point for which it is the financially responsible Market Participant, or a Demand Response Service Provider in respect of plant connected at a market connection point, to seek its classification as an ancillary service unit. This approach is consistent with the overall approach to 'load' in the draft rule. The draft rule aims to make it clear that it is plant at a connection point (whether a generating unit, integrated resource unit or other connected plant) that is classified as an ancillary service unit, rather than classification of the connection point or the electrical load.

K.2.6 Market Participant labels

Consistent with the approach in the current rules, under the draft rule, participant 'labels' would be used to identify a Market Participant according to the plant or connection points it has classified. The following table summarises the proposed approach.

507 The term "market load" is preserved in Chapter 10 of the NER for the purposes of its use in the National Electricity (South Australia) Regulations.

Table K.1: **Market Participant labels**

WHAT HAS BEEN CLASSIFIED?	REGISTERED PARTICIPANT WHO MAY CLASSIFY	LABEL USED IN THE NER
scheduled integrated resource unit	Integrated Resource Provider	Scheduled Integrated Resource Provider
non-scheduled integrated resource unit	Integrated Resource Provider	Non-Scheduled Integrated Resource Provider
scheduled generating unit	Generator or Integrated Resource Provider	Scheduled Generator
semi-scheduled generating unit	Generator or Integrated Resource Provider	Semi-Scheduled Generator
non-scheduled generating unit	Generator or Integrated Resource Provider	Non-Scheduled Generator
small generating unit	Integrated Resource Provider	Small Resource Aggregator
small integrated resource unit	Integrated Resource Provider	Small Resource Aggregator
scheduled load	Customer or Integrated Resource Provider	Market Customer
end user connection point	Customer or Integrated Resource Provider	Market Customer
ancillary service unit	Generator, Integrated Resource Provider, Customer, Demand Response Service Provider	Ancillary Service Provider
scheduled network service	Network Service Provider	Scheduled Network Service Provider

K.2.7 Redundant classification categories removed from the *NER*

The draft rule removes redundant classification categories from the rules. The following classification categories would be removed on the basis:

- First-Tier Customers and first-tier loads,
- Second-Tier Customers and second-tier loads, and
- Non-market scheduled generating units, and
- intending load.

K.2.8 Other consequential changes

- Some redundant provisions would be deleted (such as 2.2.2(g) and (h)) and the semi-scheduled generating unit aggregation provisions (2.2.7(i) to (l)) would be deleted in chapter 2 and moved to clause 3.8.3.

- Clause 2.3A which relates to the categories of Small Generation Aggregator and Market Small Generation Aggregator would be deleted as this registration category would be transferred into the IRP registration category, using the label 'Small Resource Aggregator'.
- Clause 2.3B, which relates to Demand Response Service Providers, would be deleted as the provisions would be covered under new clause 2.1A.4 and clause 2.3.6.
- Consequential changes would be made to the Metering Coordinator registration provision (rule 2.4A) and the administration and interpretation provisions in the chapter.

K.3 Proposed changes to Chapter 3

Chapter 3 has been amended to introduce the new IRP registration category and integrated resource units into the market rules and to use terms such as 'load' and 'generation' in a more consistent manner. Other changes have been made to give effect to the policy for recovery of non-energy costs.

K.3.1 Incorporation of the IRP and IRUs

Under the draft rule, chapter 3 would be amended to incorporate the new IRP registration category.

In respect of integrated resource units it has classified as scheduled integrated resource units, an IRP would be a Scheduled IRP. Under chapter 3, Scheduled IRPs would have the same obligations in respect of scheduled integrated resource units as Scheduled Generators have in respect of scheduled generating units except as follows:

- Dispatch bids for scheduled integrated resource units, unlike dispatch bids for scheduled generating units:
  - would not specify an intended self-dispatch level,[508]
  - would not specify loading and off-loading prices for quantities above and below the intended self-dispatch level, [509]
  - could contain up to 10 price bands for generation and 10 price bands for load (clause 3.8.6(g1)), and
  - would be required to specify the energy available for energy constrained IRUs[510] for the trading intervals in the trading day (clause 3.8.6(g2)). Dispatch bids for scheduled generating units would be required to specify daily energy availability.[511]
- There would no concept of slow start IRUs. Slow start generating units are generating units which are unable to synchronise and increase generation within 30 minutes of receiving an instruction from AEMO and must self-commit to be eligible for dispatch.[512]

508 The requirement for Scheduled Generators to specify an intended self-dispatch level in their dispatch bids for scheduled generating units is in clause 3.8.6(a)(1).

509 The requirement for Scheduled Generators to specify loading and off-loading prices in their dispatch bids for scheduled generating units is in clause 3.8.6(a)(3).

510 Defined in Chapter 10 as scheduled IRUs in respect of which the amount of electricity it is capable of producing or consuming for a period is less than the amount of electricity it would produce or consume in that period if it were dispatched to its full nominated availability for that period

511 Under clause 3.8.6(b).

512 Clause 3.8.17(a).

- Scheduled IRPs would not be required to self-commit or self-decommit (synchronise and de-sychronise from the power system) in accordance with clauses 3.8.17 and 3.8.18.
- Scheduled IRPs would be required to submit projected energy availability for energy constrained scheduled IRUs:
    - for each 30-minute period as an input to AEMO's short term projected assessment of system adequacy (PASA) (clause 3.7.3(e)(5)), and
    - for each trading interval in the trading day as part of its notification of scheduled capacity two days ahead of the trading day (clause 3.8.4(c)(3A)).

In comparison, Scheduled Generators must provide projected daily energy availability for energy constrained scheduled generating units for short term PASA (clause 3.7.3(e)(4)) and two days ahead of the trading day (clause 3.8.4(c)(3)).

AEMO would be required to prepare and publish the same type of information to the market in respect of scheduled integrated resource units as it does in respect of scheduled generating units except that the rules would recognise that integrated resource units both consume and produce electricity and so would be taken into account in respect of both their consumption and generation. For example, clause 3.7.2(f)(1) requires AEMO to take into account the load of scheduled integrated resource units in its PASA forecasts of peak load.

In respect of integrated resource units classified as non-scheduled integrated resource units:

- IRPs would have the same obligations as Generators in respect of non-scheduled generating units, and
- AEMO would be required to prepare and publish the same type of information to the market (clause 3.7.2(f)(2), 3.7.3(h)(4B), 3.7F(b)(1a), 3.13.4(f)(5A), (r)(1A), (t), (u) and (x)).

In respect of generating units an IRP classifies as scheduled generating units, semi-scheduled generating units or non-scheduled generating units, an IRP would have the same obligations as a person registered as a Generator. In relation to these units, the IRP would have the same label as a Generator — that is, Scheduled Generator, Semi-Scheduled Generator or Non-Scheduled Generator respectively.

In respect of the connection point for small integrated resource units and small generating units classified by an IRP, the IRP would be called a Small Resource Aggregator. A Small Resource Aggregator would have the same rights that a Market Small Generation Aggregator currently has in relation to obtaining site-specific distribution factors (clause 3.6.3(b1)). It would be the financially responsible Market Participant for the market connection points for the small generating units or small integrated resource units it has classified and would contribute to the recovery of non-energy costs in relation to any consumption of electricity at its market connection points.

In respect of end user connection points an IRP classifies as market connection points or connected plant it classifies as a scheduled load, the IRP would have the same obligations as a Customer and would have the label Market Customer.

K.3.2 Non-energy costs

The provisions in chapter 3 under which non-energy costs are recovered would be amended to give effect to the policy aim of determining liability to contribute to those costs according to energy flows at market connection points, rather than according to the category in which a Market Participant is registered.

A new defined term, *Cost Recovery Market Participant* would be included in chapter 10 and this definition would cover all Market Participant categories other than a Market Network Service Provider.

The calculation of adjusted gross energy or AGE in clause 3.15.4 would be replaced. AGE at a market connection point would be the sum of the adjusted consumed energy (ACE, expressed as a negative value) and the adjusted sent out energy (ASOE, expressed as a positive value) at the connection point. ACE for a transmission connection point would be the metered value. ACE for a distribution connection point would be the metered value adjusted for distribution losses using the applicable distribution loss factor plus the unaccounted for energy allocated under clause 3.15.5.

The result is to have both a net consumption calculation for each market connection point (AGE), a gross consumption figure (ACE) and a gross generation figure (ASOE).

The cost recovery provisions would be amended to provide for Cost Recovery Market Participants to contribute to non-energy costs according to their gross consumption (ACE). These amendments are in clauses 3.15.6A (Ancillary service transactions), 3.15.8 (Funding of compensation for directions), 3.15.8A (Funding of compensation for market suspension pricing schedule periods), 3.15.9 (Reserve settlements), 3.15.10 (Administered price cap or administered floor price compensation payments) and 3.15.10C (Intervention and Market Suspension Pricing Schedule Period Settlements).

The draft rule also proposes drafting changes to rule 3.15.6A (Ancillary service transactions) to take a more consistent approach to the drafting and to assist readability by including headings and relocating some provisions.

Provisions inserted in chapter 3 by the *National Electricity Amendment (NEM settlement under low, zero and negative demand conditions) Rule 2021* would be deleted.

K.3.3 Drafting of ancillary service provisions

Under the draft rule, Market Participants could provide market ancillary services from a broader range of plant (ancillary service units) than under the current rules, provided the relevant plant meets the market ancillary service specification. Throughout chapter 3, references to ancillary service loads and ancillary service generating units would be replaced with references to ancillary service units, which would be defined in chapter 10 to include generating units, integrated resource units and other connected plant that has been classified under chapter 2 as an ancillary service unit.

K.3.4 Aggregation of units for dispatch

Under the current rules, provisions relating to the process by which units or connected plant can be aggregated for dispatch are contained in both chapters 2 and 3. Under the draft rule, all aggregation provisions would be relocated to clause 3.8.3.

K.3.5 Ramp rates

The draft rule proposes to amend clause 3.8.3A (ramp rates) to improve the clarity of drafting. The changes would also require minimum ramp rates for scheduled integrated resource units. Scheduled IRPs would be required to provide an up ramp rate or down ramp rate to AEMO in respect of its scheduled integrated resource unit that is at least the 'resource minimum ramp rate requirement' for non-aggregated units. The '*resource minimum ramp rate requirement'* is a new defined term and for a generating unit, scheduled integrated resource unit or scheduled load is proposed to be the lower of 3MW/minute or 3% of the maximum generation provided in accordance with clause 3.13.3(b). For a scheduled network service, it is proposed to remain at 3MW/minute.

The draft rule would also amend the minimum ramp rate requirement for scheduled load so that it is the same as for scheduled generating units and scheduled integrated resource units. This is a change to the current minimum ramp rate requirement for scheduled load of 3MW/minute.

K.3.6 Generic references to plant and participants

The draft rule would streamline the drafting of chapter 3 by replacing references to specific plant or participants with more generic references where the amendment does not change the meaning of the clause. For example:

- a new chapter 10 defined term 'scheduled resource' would be used where provisions apply to all plant subject to AEMO's central dispatch process (scheduled generating units, semi-scheduled generating units, scheduled integrated resource units, scheduled load, wholesale demand response units and scheduled network services), and
- references to lists of specific participants would be replaced with references to Market Participants or Registered Participants.

K.3.7 Bid and offer terminology

Under the current rules, Generators and Scheduled Network Service Providers submit dispatch offers, Market Customers submit dispatch bids in respect of scheduled load and Ancillary Service Providers submit market ancillary service offers. Under the draft rule, chapter 3 would be streamlined by replacing:

- all references to dispatch offers with references to dispatch bids,
- all references to market ancillary service offers with references to market ancillary service bids,
- all references to default dispatch bids and market ancillary service offers with references to a new defined term - default bid (clause 3.8.9), and

- all references to bid and offer validation data with references to bid validation data.

K.3.8 Load and generation terminology

Proposed amendments to chapter 3 and related definitions in chapter 10 aim to use the defined terms 'generation', 'load' and 'sent out generation' in a consistent manner.

- The defined term 'generation' would be extended to reflect its use in chapters 3 and 4 and elsewhere, so that it means, depending on context:
  - the production of electrical power by converting another form of energy in a generating unit or integrated resource unit,
  - the amount of electrical power (measured in MW) produced by a generating unit or integrated resource unit and measured at its terminals, or
  - the amount of electrical power (measured in MW) at a defined instant at a connection point or defined set of connection points.
- Where the rules refer to the amount of electricity supplied to the transmission network or distribution network at a connection point by a generating unit or an integrated resource unit, the term 'sent out generation' would be used.
- The defined term 'load', consistent with its definition in chapter 10, would be used in the rules where the intention is to refer to points at which electricity is delivered or the amount of electrical power (in MW) delivered at a defined instant at a connection point or across connection points.

Where the intention is to refer to MWh produced or consumed, an undefined term such as 'electricity consumed' or 'produced electricity' would be used.

K.4 Proposed changes to Chapter 4

Chapter 4 would be amended to incorporate the new IRP registration category into the power system security rules. This section provides an overview of the proposed changes in chapter 4 to incorporate Scheduled IRPs and scheduled integrated resource units, including a proposed new power system operating procedure for dispatch of hybrid integrated resource systems.

Other proposed changes to chapter 4 align with the changes to chapter 3 described above. References to dispatch offers would be replaced with references to dispatch bids, references to market ancillary service offers would be replaced with references to market ancillary service bids and changes would be made to use the terms 'generation', 'load' and 'sent out generation' in a consistent manner.

K.4.1 Scheduled IRPs and scheduled integrated resource units

Except as specified below, Scheduled IRPs would have the same obligations in respect of scheduled integrated resource units and integrated resource systems as Scheduled Generators have in respect of scheduled generating units and generating systems. This would be given effect in the drafting either through generic references to plant and participants that include scheduled integrated resource units and Scheduled IRPs or specific inclusion of

Scheduled IRPs and scheduled integrated resource units in provisions of chapter 4. The new defined term *scheduled resources* would be used to refer to plant that is subject to central dispatch (other than ancillary service units) and Scheduled IRPs would fall within the definition of Registered Participants and Market Participants. Where the use of generic drafting is not appropriate, Scheduled IRPs and scheduled integrated resource units would be referred to expressly.

Under the draft rule, the obligations imposed on Scheduled IRPs in respect of scheduled integrated resource units and integrated resource systems in chapter 4 would differ from those on Scheduled Generators in respect of scheduled generating units and generating systems in the following respects:

- Under clause 4.9.2(b), AEMO may instruct a Generator or IRP in relation to any of its generating units with a nameplate rating of 30MW or more, or its generating systems of combined nameplate rating of 30 MW or more in relation to transformer tap settings, voltage control settings and operation to supply or absorb reactive power. Under clause 4.9.2(b1) of the draft rule, AEMO would be permitted to give such instructions to IRPs in respect of integrated resource units with a nameplate rating of 5 MW or more, or its integrated resource systems of combined nameplate rating of 5 MW,
- Scheduled IRPs would not require AEMO’s approval under clause 4.9.4(d) to synchronise or de-synchronise a scheduled integrated resource unit, and
- Scheduled IRPs would not be required to follow the processes for self-commitment and self-decommitment of scheduled integrated resource units under clauses 4.9.6 and 4.9.7.

K.4.2 Dispatch instructions to each scheduled resource in an integrated resource system

Integrated resource systems may comprise a combination of generating units, integrated resource units and loads. The policy aim to allow flows between different parts of an integrated resource system even when the flows are not dispatched (for example, a solar panel could charge a battery), subject to system security requirements. To give effect to this policy aim, (clause 4.9.2A) would apply to dispatch instructions to scheduled resources in integrated resource systems that comprise more than one scheduled resource (a hybrid integrated resource system). Under new clause 4.9.2A:

- an IRP for a hybrid integrated resource system could comply in aggregate with the dispatch instructions for a trading interval for two or more of its scheduled resources, except for any scheduled resource in relation to which AEMO has specified that “unit level compliance” is required,
- AEMO could specify in a dispatch instruction for a scheduled resource in a hybrid integrated resource system that the scheduled resource must operate at the level specified in, and otherwise in accordance with, with the dispatch instruction (unit level compliance), and
- AEMO would make a power system operating procedure setting out permitted forms of aggregate compliance by scheduled resources in hybrid integrated resource systems and arrangements for AEMO to specify when unit level compliance is required.

K.4.3 Other proposed changes to incorporate integrated resource units

Definition of contingency events

- The definition of a contingency event in clause 4.2.3(a) would include the failure or removal from operational service of one or more integrated resource units.
- The definition of a credible contingency event in clause 4.2.3(b)(1) would include the unexpected automatic or manual disconnection of, or the unplanned reduction in capacity of, one operating integrated resource unit.
- An example of a non-credible contingency event in clause 4.2.3(e) would include simultaneous disruptive events such as multiple integrated resource unit failures.

System restart ancillary services

- The requirements for SRASs would be amended to provide that sufficient SRASs should be available in accordance with the system restart standard to allow the restoration of power system security and any necessary restarting of generating units or integrated resource units following a major supply disruption (clause 4.2.6(e)).

Power system security responsibilities

- When developing the emergency frequency control schemes (EFCS) settings schedule, AEMO would be required to consult with both Generators and IRPs in the case of information in the schedule relating to an over-frequency scheme (clause 4.3.2 (ha)(3)).
- For each over-frequency scheme, the applicable EFCS setting schedule would be required to set out the manner in which generating units or integrated resource units will be interrupted or have output reduced (clause 4.3.2(n))
- IRPs (as well as Generators) would be required to participate in system restart tests if required by AEMO under clause 4.3.6.

Power system frequency control

- IRPs would be required to ensure that all of their generating units and integrated resource units meet the technical requirements for frequency control in clause S5.2.5.11 (clause 4.4.2(b)).
- IRPs would be required, in accordance with schedule 5.2 and chapter 5, to provide any necessary automatically initiated protective device or systems to protect their plant and associated facilities against abnormal voltage and extreme frequency excursions of the power system (clause 4.4.3).
- Clause 4.4.4(d) which relates to instructions by AEMO to enable inertia network services, would be amended to refer to inertia units rather than inertia generating units. Clause 4.4.5(d), which relates to instructions by AEMO to enable system strength services, would be amended to refer to system strength units rather than system strength generating units. The proposed new defined terms 'system strength unit' and 'inertia unit' refer to both generating units or integrated resource units registered with AEMO to provide system strength services and inertia network services (respectively) under chapter 5.

System strength

- The system strength impact assessment guidelines made by AEMO under clause 4.6.6(a) would be required to set out the methodology to be used by Network Service Providers when undertaking system strength impact assessments under clause 5.3.4B in relation to a proposed new connection of an integrated resource system or integrated resource system to which clause 5.3.9 applies.
- AEMO would be required to provide power system models to IRPs who request the model in connection with a system strength impact assessment in the same circumstances as those models are provided to Generators.

Power system security operations

- Clause 4.8.7(a)(1) would be amended to require AEMO to identify the impact of a contingency event on power system security in terms of the capability of integrated resource units.
- Clause 4.8.9(a1) would be amended to provide that a direction given by AEMO to a Registered Participant could be in relation to scheduled resources, ancillary service units (other than a wholesale demand response unit), market generating units or market integrated resource units.
- Clause 4.8.10, which provides for the process to be followed by AEMO in disconnecting units and services, would be expanded to cover integrated resource units. IRPs would be required to provide reasonable assistance to AEMO for the purposes of a disconnection under the rules.
- Clause 4.8.12 would be amended to require each IRP to develop, and submit to AEMO for approval, local black system procedures.
- Clause 4.8.14 would be amended to required IRPs to comply with local black system procedures if notified of a major supply disruption and comply with AEMO's directions or clause 4.8.9 instructions regarding the restoration of the power system.

Power system related market operations

- AEMO’s load forecasts under clause 4.9.1 would be required to include expected sent out generation from embedded integrated resource units.

Power system security support

- Clause 4.11.1(d) would be amended to allow AEMO to require an IRP to install remote monitoring equipment to enable AEMO to remotely monitor an integrated resource unit or require upgrades, modifications or replacement of that equipment.
- Clause 4.11.1(g) would be amended to require an IRP wishing to receive dispatch instructions electronically from AEMO’s automatic generation control system to comply with AEMO’s requirements in relation to use of that system.

K.5 Proposed changes to Chapter 4A

Under the draft rule, chapter 4A would be amended to incorporate the IRP and integrated resource units. The draft rule would:

- amend defined terms as required,
- provide for IRPs to be liable entities in relation to market connection points for which they are the financially responsible Market Participant, including connection points for integrated resource units (but not generating units), and
- provide for IRPs to be subject to the Market Liquidity Obligations in respect of their production capacity.

The proposed amendments to the definition in Part A of the chapter would replace 'generator capacity' with 'production capacity' and would extend the defined term 'registered capacity' to the production capacity of an integrated resource unit.

In Part D, under which liable entities are defined, IRPs would be included alongside Market Customers or the term changed to refer to the financially responsible Market Participant for the connection point. As IRPs will be able to classify generating units but export from those units is not intended to be included in calculations under Part D or F, the threshold calculation would exclude consumption at connection points for market generating units and small generating units. Corresponding changes would be made to the new entrant provisions (4A.D.3).

In Part F of chapter 4A, in the calculation of the liable load of liable entities, references to Market Customers would be changed to Market Participant. Consistent with the changes to Part D, connection points for market generating units and small generating units would be excluded from the calculation.

In Part G, references to IRPs would be included alongside references to Market Generators and reference to integrated resource units included where appropriate. The term *generated capacity* would be changed to *production capacity*, a new term proposed to be defined under clause 4A.G.3(b).

Drafting changes in clauses 4A.D.2(b)(2), 4A.D.3(c) and 4A.D.5(a)(3) give effect to the policy aim to ensure that 'load' is used in a consistent manner in the rules.

K.6 Proposed changes to Chapter 5

Under the draft rule, chapter 5 would be amended to:

- provide for the obligations of IRPs as owners or operators of plant connected to a network, modelled on the obligations of Generators,
- implement the proposed policy clarifications relating to TUOS charges for services provided in relation to integrated resource units,
- extend the connection arrangements to allow for the connection of integrated resource units and embedded integrated resource units and determination of performance standards for connected integrated resource units, and
- extend the inertia and system strength frameworks to integrated resource units.

K.6.1 Connection obligations and performance standards

As the Registered Participant in relation to connected plant, an IRP would have obligations similar to those of a Generator in relation to its generating units. Proposed new clause 5.2.5A is modelled on the clause applicable to Generators (clause 5.2.5). Among other things, it would require an IRP to plan and design its facilities to ensure they are operated to comply with its performance standards, its connection agreement and the system standards. The other relevant obligations of a Generator under clause 5.2.5 would also apply to the IRP under the new clause.

To support the operation of this clause, the draft rule would amend Schedule 5.2 of chapter 5. Schedule 5.2 sets out the conditions for connection of Generators. Under the draft rule, the schedule would be extended to IRPs in respect of their integrated resource systems, integrated resource units, generating systems and generating units. Changes to the schedule in the draft rule include extending the technical requirements in S5.2.5 in order to apply to an integrated resource unit across its full range of operation, and in both consumption and production modes. The proposed changes are intended to recognise that the requirements applicable to an integrated resource unit in consumption mode will need to mirror (rather than replicate) the requirements applicable when in generating mode.

K.6.2 TUOS charges

To support the proposed policy clarifications with respect to the payment of TUOS in relation to an integrated resource unit, proposed clause 5.2A.3(b1) would provide that where the classification of a shared transmission service as a prescribed transmission service or negotiated transmission service is determined by reference to the network performance requirements in a connection agreement, the connection applicant can specify whether the application is for provision of the service as a prescribed transmission service or negotiated transmission service and the Transmission Network Service Provider must comply with the request.

In clause 5.3AA(f), the term *negotiated use of system charges* would be relaced with a new term, *negotiated augmentation and extension charges,* to describe more accurately the costs these charges are intended to recover. Consequential changes are proposed to clauses 5.3AA(g) and clause 5.1.2(e)(2).

K.6.3 Connection and planning

The draft rule provides for amendments to chapter 5 to incorporate IRPs and integrated resource units in the connection arrangements under Part B and in the related schedules (Schedules 5.5 and 5.6), in the post-connection provisions in Part C of chapter 5 and in the network planning and expansion provisions in Part D and related schedules (Schedules 5.8 and 5.9). The registers of large generators and completed embedded generation projects in rules 5.18.A and 5.18B would be extended to integrated resource units.

K.6.4 Inertia and system strength services

The draft rule would extend the provisions for the procurement of inertia services under rule 5.20B and for system strength services under rule 5.20C to integrated resource units and replace the defined term *inertia generating unit* with a new umbrella term *inertia unit* and the term *system strength generating unit* with the new umbrella term *system strength unit*, in each case covering generating units and integrated resource units that provide the relevant services.

K.6.5 Other changes

Consequential changes in chapter 5 would update the overview table in clause 5.1.2 and provide for the consistent use of the terms load and generation.

K.7 Proposed changes to Chapter 5A

Under the draft rule, chapter 5A would be amended to:

- create consistency between the connection arrangements for embedded integrated resource units and the current arrangements for embedded generating units, and
- reflect the change in registration category for aggregators of small units from Market Small Generation Aggregator to IRP (Small Resource Aggregator).

The draft rule would make the following changes to chapter 5A:

- A person who owns, controls or operates an embedded integrated resource unit or an embedded generating unit would fall within the amended definition of 'embedded generator' (clause 5.A.A.1).
- The definitions of 'micro EG connection' and 'micro embedded generator' would be amended to refer to both embedded generating units and embedded integrated resource units (clause 5.A.A.1).
- The definition of non-registered embedded generator would capture embedded generators (owners, controllers or operators of embedded integrated resource units or embedded generating units) that are not micro embedded generators or Registered Participants. As a result, all rights and obligations of non-registered embedded generators under chapter 5A would apply to owners, controllers or operators of embedded integrated resource units in the same way as they apply to owners, controllers or operators of embedded generating units under the current rules.
- The Distribution Network Service Provider's obligations in relation to the connection process and connection offers for embedded integrated resource units would be consistent with those for embedded generating units (clause 5A.B.2(b)(7)(v), 5A.C.3(a)(3)(v), 5A.D.1(a)(7) and Part B of Schedule 5A.1).
- Clause 5A.D.1A would be amended to require a Distribution Network Service Provider to include embedded integrated resource projects in its register of completed embedded generation projects.
- Clause 5.A.A.3 would be amended to deem Small Resource Aggregators to be the agent of a retail customer where there is an agreement between the Small Resource

Aggregator and the retail customer relating to the retail customer'ssmall generating unit or small integrated resource unit under which the Small Resource Aggregator is financially responsible for the market connection point at which the unit is connected to the national grid.

K.8 Proposed changes to Chapter 6

Proposed changes to chapter 6 incorporate IRPs and integrated resource units and give effect to the policy clarifications relating to TUOS and DUOS.

Under the draft rule, chapter 6 would be amended to incorporate IRPs and integrated resource units connected to a distribution network (defined in chapter 10 using the new terms *Embedded Integrated Resource Provider* and *embedded integrated resource unit*).

- Distribution Network Service Providers would be required to bill Embedded Integrated Resource Providers in the same way they bill Embedded Generators under the current rules (clauses 6.20.1(a)(1) and (e)).
- Distribution Network Service Providers could require an Embedded Integrated Resource Provider to establish prudential requirements for a new connection or a modification in service for an existing connection on the same basis as for Embedded Generators and Distribution Customers under the current rules (clause 6.21.1).

In order to implement the policy clarifications relating to TUOS and DUOS charges for services provided in relation to integrated resource units, proposed new clause 6.22.2(b1) would specify the principles to be applied by the AER when determining an access dispute about the terms and conditions of access to a direct control service for a Distribution Network User other than a retail customer. The clause would require the AER to apply the principles in clause 6.7.1 as if the direct control service were a negotiated distribution service for the purposes of that clause.

Other changes to chapter 6 would remove references to registration categories in the rules that are now redundant (see 'redundant classification categories' in the chapter 2) and correct cross-references to clauses in chapter 5.

K.9 Proposed changes to Chapter 7

Under the draft rule, chapter 7 would be amended to apply to IRPs and integrated resource units in a manner consistent with other Market Participants, including in the IRP's role as Market Customer.

Many of the provisions in chapter 7 will apply to an IRP in its capacity as a Registered Participant, financially responsible Market Participant or Market Customer. Specific amendments are proposed where the provisions apply to Generators or generating units, so as to:

- extend to IRPs and Small Resource Aggregators the provision under which a Generator which is involved in the trading of energy is prevented from being registered as a Metering Provider for connection points where the metering data relates to its own use of energy (clause 7.4.1(e)),

- extend to IRPs and Small Resource Aggregators the provision under which a Generator which is involved in the trading of energy is prevented from being registered as a Metering Data Provider for connection points where the metering data relates to its own use of energy (clause 7.4.2(e)),
- extend the provision specifying who may appoint Metering Coordinators for embedded generating units to embedded integrated resource systems (clause 7.6.2(a)), and
- extend to IRP and Small Resource Aggregators the same requirements imposed on Generators in relation to type 4 metering installations at distribution network connection points for which they are financially responsible (clause 7.8.2(b1)).

Amendments to clause 7.8.2(f) and (g) would extend the application of the requirements for metering installations for non-market generating units to non-market integrated resource units and extend the application of the requirements for metering installations for small generating units to small integrated resource units.

Other change to chapter 7 in the draft rule would clarify provisions referring to load and generation for consistency with the load and generation changes referred to in the chapter 3 overview and remove all references to market load, as that classification would be removed from chapter 2.

K.10 Proposed changes to Chapter 8

Under the draft rule, chapter 8 would be amended to incorporate the new registration category of IRP and the Small Resource Aggregator by:

- providing that the following decisions of AEMO are not subject to dispute resolution under rule 8.2:
  - a decision by AEMO under clause 2.2.2 not to approve the classification of an integrated resource unit as a scheduled integrated resource unit (clause 8.2.1(h)(1A)),
  - a decision by AEMO under clause 2.2.3 not to approve the classification of an integrated resource unit as a non-scheduled integrated resource unit (clause 8.2.1(h)(1A)), and
  - a decision by AEMO to reject a notice from a Small Resource Aggregator under clause 2.10.1(d1) (8.2.1(h)(5C)). The clause currently refers to Market Small Generation Aggregators.
- amending the exceptions to the confidentiality provisions in rule 8.6 to provide that disclosure of NMI Standing Data by an IRP or Small Resource Aggregator or the IRP's or Small Resource Aggregator's Disclosees is subject to the exception in clause 8.6.2(b1). The clause currently only applies to disclosures by Customers or their Disclosees, and
- amending clause 8.10 to allow AEMO to allocate the costs of meeting its consumer advocacy funding obligation to Market Participants that are financially responsible for market connection points at which electricity is consumed. Currently AEMO may only allocate these costs to Market Customers.

K.11 Proposed changes to Chapter 9

Under the draft rule, the Victorian Smelter Trader jurisdictional derogation in clause 9.4.2 would be amended to deem the connection points used to supply the electricity supplied under the Smelter Agreements as the Smelter Trader's market connection points. The purpose of the proposed amendment is to make it clear under the rules that the Smelter Trader's arrangements under the derogation are unaffected by changes to the registration and classification arrangements in chapter 2 of the draft rule.

K.12 Proposed changes to Chapter 10

Under the draft rule, chapter 10 would be substantially amended. A list of the defined terms that would be inserted, deleted or amended by the draft rule is set out below. The defined terms that have been amended have been grouped as:

- amendments to reflect the changes to chapter 2 proposed in the draft rule,
- amendments to incorporate the IRP, and
- minor amendments, including amendments to address the changes in bid and offer terminology described in the chapter 3 summary above.

K.12.1 New defined terms

- Ancillary service unit
- Asynchronous integrated resource unit
- Auxiliary load
- Bid validation data
- Cost Recovery Market Participant
- Coupled production unit
- Default bid
- Dispatchable unit identifier
- Dispatched network service
- Embedded Integrated Resource Provider
- Embedded integrated resource unit
- Energy constrained scheduled integrated resource unit
- Inertia unit
- Integrated Resource Provider
- Integrated resource system
- Integrated resource unit
- Market integrated resource unit
- Minimum ramp rate requirement
- Negotiated augmentation and extension charges
- Network dispatch bid

- Non-Market Integrated Resource Provider
- Non-market integrated resource unit
- Non-Scheduled Integrated Resource Provider
- Non-scheduled integrated resource system
- Non-scheduled integrated resource unit
- Production unit
- Rated maximum demand
- Resource minimum ramp rate requirement
- Scheduled integrated resource system
- Scheduled integrated resource unit
- Scheduled Integrated Resource Provider
- Scheduled resource
- Small integrated resource unit
- Small Resource Aggregator
- System strength unit

K.12.2 Deleted defined terms

- Ancillary service generating unit — replaced with new definition of ancillary service unit
- Ancillary service load — replaced with new definition of ancillary service unit
- Bid and offer validation data — replaced with new definition of bid validation data
- Default dispatch bid — replaced with new definition of default bid
- Default dispatch offer — replaced with new definition of default bid
- Dispatch offer — replaced by amended definition of dispatch bid
- Dispatch offer price — replaced by amended definition of dispatch bid price
- First-Tier Customer — redundant classification
- First-tier load — redundant classification
- Generating unit minimum ramp rate requirement — replaced with new definition of resource minimum ramp rate requirement
- Generation dispatch offer — replaced by amended definition of dispatch bid
- Inertia generating unit — replaced with new definition of inertia unit
- Intending load — redundant classification
- Market ancillary service offer — replaced with new definition of market ancillary service bid
- Market Small Generation Aggregator — market participant category replaced with Integrated Resource Provider (Small Resource Provider)
- Negotiated use of system charges — replaced with new definition of negotiated augmentation and extension charges
- Network dispatch offer — replaced with new definition of network dispatch bid

- Scheduled plant — replaced with new definition of scheduled resource
- Second-Tier Customer — redundant classification
- Second-tier load — redundant classification
- Small Generation Aggregator — registration category replaced with Integrated Resource Provider (Small Resource Provider)
- System strength generating unit — replaced by new definition of system strength unit

K.12.3 Defined terms amended to reflect chapter 2 changes to registration and classification

- Ancillary Service Provider
- Customer
- Demand Response Service Provider
- Financially responsible
- Generating system
- Generating unit
- Generator
- Market connection point
- Market Customer
- Market load
- Market generating unit
- Market Generator
- Non-Registered Customer
- Non-Scheduled Generator
- Non-scheduled load
- Plant
- Scheduled Generator
- Scheduled load
- Semi-Scheduled Generator
- Small generating unit

K.12.4 Defined terms amended to incorporate Integrated Resource Provider

- Affected Participant
- AGC (automatic generation system)
- Available capacity
- Black start capability
- Capacity reserve
- Child connection point
- Connection service
- Constrained off

- Constrained on
- Constraint, constrained
- Continuous uninterrupted operation
- Control system
- Dedicated connection asset
- DER generation information
- DER technical standards
- de-synchronising/de-synchronisation
- Directed Participant
- Dispatch inflexibility profile
- Dispatched load
- Distribution Network User
- Distribution network user access
- Embedded Generator
- energise
- Energy constraint
- Energy support arrangement
- Entry service
- Excitation control system
- facilities
- Frequency response mode
- GELF parameters
- generated
- Generation centre
- Generator Energy Limitation Framework (GELF)
- Generator transmission use of system, Generator transmission use of system service
- Inertia
- Inflexible, inflexibility
- Intermediary
- Intermittent
- Key connection information
- Loading level
- Market Participant
- Market Suspension Compensation Claimant
- Market suspension pricing schedule period
- Network support payment
- Network User

- PASA availability
- Performance standards commencement date
- Planned network event
- Plant availability
- Power station
- Primary frequency response
- Rated active power
- Reactive power capability
- Regulating duty
- Releaseable user guide
- Scheduled reserve
- Sent out generation
- SRAS (system restart ancillary service)
- Supplementary carbon dioxide equivalent intensity indicator
- Supply scarcity mechanism
- Switchyard
- Synchronise
- Synchronising
- Synchronous voltage control
- System strength connection works
- System strength impact assessment
- Tap-changing transformer
- Transmission Customer
- Transmission Network User
- Unscheduled reserve

K.12.5 Defined terms – minor amendments

- AEMO intervention event
- Central dispatch
- Dispatch
- Dispatch bid
- Dispatch bid price
- Enablement limit
- Energy constrained scheduled generating unit
- Energy constrained scheduled load
- Expected closure year
- generation

- Generation shedding
- load
- Loading price
- Market ancillary service bid
- Off-loading price
- Price band
- rebid
- Response breakpoint
- Response capability
- Self-dispatch level
- Wholesale demand response
- Wholesale demand response unit

K.13 Proposed changes to Chapter 11

The draft rule would include a new Part in Chapter 11 setting out transitional arrangements required to implement the rule, if made. The key transitional provisions in the draft rule are:

- a requirement on a Registered Participant who immediately before the commencement of the rule is registered as:
  - a Generator in relation to an integrated resource system, and
  - a Customer in relation to the same integrated resource system,

to apply to AEMO within 6 months of commencement of the rules to change its registration category to Integrated Resource Provider and to reclassify each integrated resource unit comprised in an integrated resource system under new Chapter 2 (clause 11.[xxx].2)

- the deeming, under clause 11.[xxx].3, of a person who immediately before the commencement of the rule is registered with AEMO as a Small Generation Aggregator to be:
  - registered with AEMO as an IRP, and
  - a Small Resource Aggregator in respect of each of the small generating units classified by the Small Generation Aggregator immediately prior to commencement of the rule,
- the provision in clause 11.[xxx].4 for the continuing registrations and classifications for participants and plant at the commencement of the rule in order to clarify the impact of the changes to chapter 2 registration and classification arrangements on existing participants,
- the requirement under clause 11.[xxx].5 for applications made to AEMO under chapter 2 before the commencement of the rule to be determined by AEMO under chapter 2 as amended by the new rule,
- the deeming, under 11.[xxx].6, of generating units that immediately before the commencement of the rule were system strength generating units or inertia generating

units to be system strength units and inertia units respectively on and from the commencement of the new rules,

- the requirement under clause 11.[xxx].7 for AEMO to review and remake the exemption guidelines made under chapter 2 to reflect the new rules,
- the requirement under clause 11.[xxx].8 for AEMO to amend and publish procedures, guidelines and other documents published by AEMO under the Rules to take into account the new rules,
- the requirement under clause 11.[xxx].9 for the AER to amend and publish procedures, guidelines and other documents published by the AER under the Rules to take into account the new rules,
- the requirement under clause 11.[xxx].10 for the Reliability Panel to review and amend the template for generator compliance programs to take into account the new rules, and
- the provisions in clause 11.[xxx].11 applying the new rules to existing connection enquiries,
- the provision in clause 11.[xxx].12 applying the new rules to existing applications to connect,
- the provision in clause 11.[xxx].13 applying the new rules to existing offers to connect, and
- the provision in clause 11.[xxx].14 explaining how the new rules will apply to existing connection agreements.