INTEGRATING ENERGY STORAGE SYSTEMS INTO THE NEM

OVERVIEW + Q&A FROM STAKEHOLDER ENGAGEMENT

AUGUST 2021

AEMC

Context

This document has been prepared to:

- provide a summary of some of the key draft decisions made
- give examples of how these would apply in practice
- share with all stakeholders the questions that have been raised since publishing the draft determination and the project team's responses.

Contents

New terms

The draft determination and rules introduce a number of new terms and acronyms, and amend existing ones. For ease of reference the new terms referred to in this pack are outlined below:

Term	Definition/ description
Integrated Resource Provider (IRP)	A person registered by AEMO as an IRP under NER chapter 2. IRPs may classify generating units, IRUs, ancillary service units, scheduled loads and connection points, as shown on slide 7.
Integrated resource unit (IRU)	A production unit (plant used in the production of electricity) that also consumes electricity that is not, or is in addition to, auxiliary load of the production unit. (Note: Auxiliary load has been defined to exclude load used to charge a production unit or to pump water for a pumped hydro unit.) A small IRU is defined as an IRU with a nameplate rating for both production and consumption that is less than 5MW, and which is owned, operated or controlled by a person who is exempt from registering as an IRP in respect of that IRU.
Small resource aggregator (SRA)	An IRP who has classified one or more connection points for small generating units or small IRUs as its market connection points. Includes entities currently registered as small generation aggregators.
Coupled production unit	A production unit with separate plant for the production of electricity, each of a different plant type (for example, intermittent and non-intermittent) and capable of separate operation but that share equipment (such as an inverter) essential to the functioning of each (Commonly referred to as a DC coupled system)
Integrated resource system	Integrated resource systems can be any combination of IRUs, load and generation. Typically, an integrated resource system could have, at a single connection point, an IRU and/or: • a load (independent of auxiliary load) and • generation of various types.
Cost Recovery Market Participant	A person registered as a Generator, IRP, Customer or Demand Response Service Provider
Transmission Customer	IRPs (in relation to supply to an IRU) have been added to the existing definition (a Customer, Non-Registered Customer, or DNSP with a connection point to a transmission network).

REGISTRATION AND PARTICIPATION

Registration and participation - Overview (1 of 2)

Key design features of the draft decision:

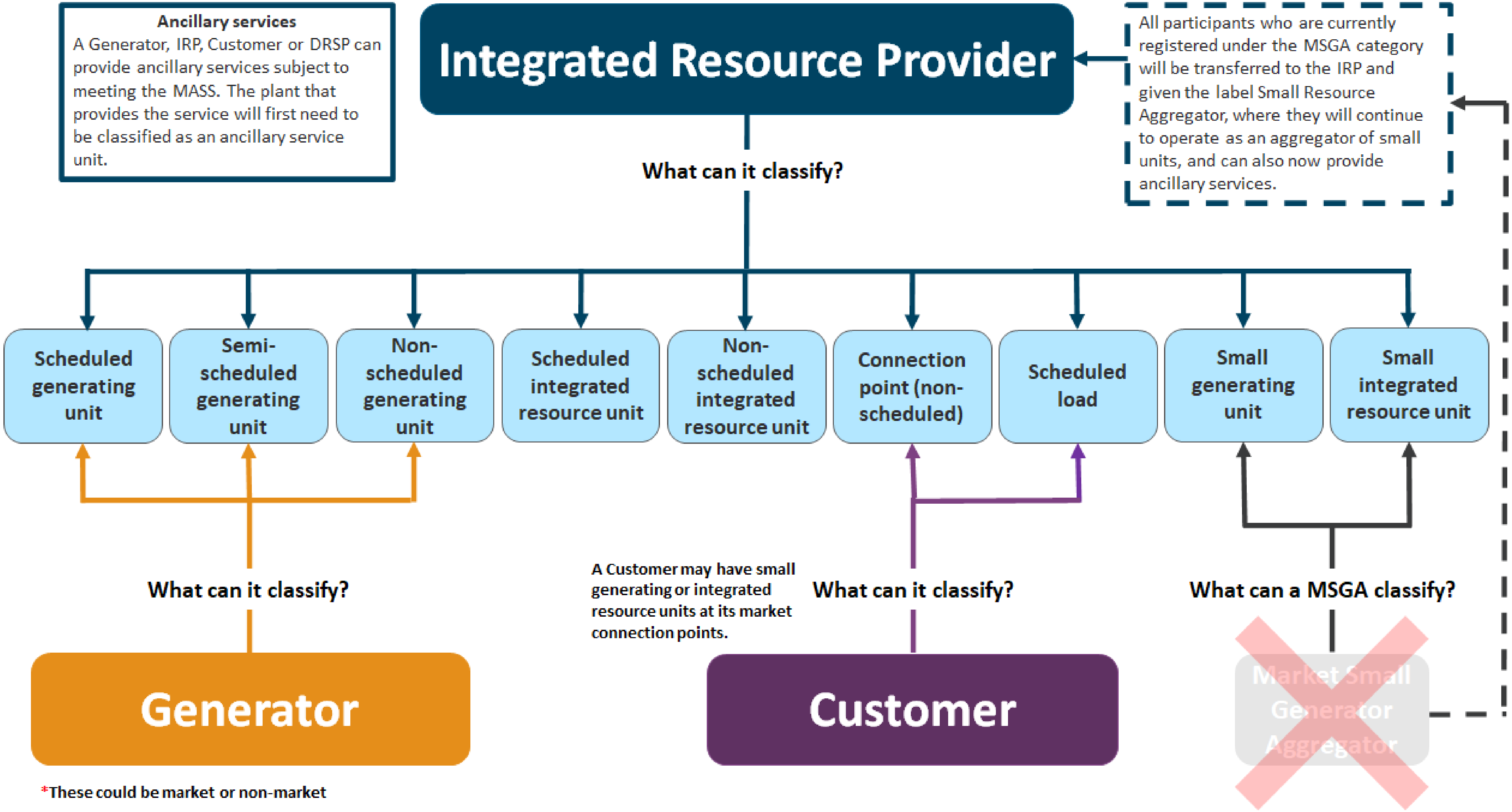
- **All existing and new grid-scale storage (5 MW and above) would be required to register as an Integrated Resource Provider (IRP).**
    - A storage unit that can transition linearly from consuming to producing (and vice versa), like a battery, would have a single classification as an Integrated Resource Unit (IRU). An IRU would have a single DUID with 20 price bid bands (no more than 10 in each direction).
    - A storage unit that cannot transition linearly through zero, like some hydro plants, would have two classifications: a scheduled generating unit and a scheduled load[1]. This type of storage would maintain two DUIDs, one for each classification, with 10 price bid bands for each of the load and generation sides.
- **All current Market Small Generator Aggregator (MSGA) participants would be transferred into the IRP registration category. These participants would be registered as IRPs, and their label in the National Electricity Rules (NER) would be Small Resource Aggregator (SRA). These SRAs would be able to:**
    - aggregate small IRUs (below 5 MW) and small generating units (below 30 MW and exempt from registering as a Generator)
    - provide ancillary services, as long as they meet AEMO's requirements set out in the Market Ancillary Services Specifications (MASS). This, for example, would require these participants to install SCADA onsite to provide ancillary services.
    - sell energy to customers at its market connection points, and if so will need to get an AER retail authorisation or exemption.
- **Market Customers could continue to classify connection points that have small generating units or small IRUs**, as they currently do, for example, in a retailer's Virtual Power Plant.
- **Market Generators and Market Customers (retailers) could become IRPs if they chose**. This may be of interest if that Market Participant intended to have bi-directional energy flows in the future and wanted greater access to classification options.

[1] See draft NER rules clause 2.2.2 (b2)

Registration and participation - Overview (2 of 2)

- **An operator of an Integrated Resource System (commonly referred to as a hybrid system) would register as an IRP and would classify each load, generating unit and IRU as shown in the following slide.**
- **An Integrated Resource System would have its performance standards set under a single connection agreement, with reference to each unit within that system.**
  - The measurement of performance would typically be taken from or close to the connection point, but it can be in respect of a point location other than the connection point (with AEMO’s agreement), as is currently the case for connecting plant.
  - The performance standards for a hybrid system would likely have more than one mode of operation which would be dependent on which units in the system are operating.
- **A clear path for DC coupled systems to connect and participate in the market (four options):**
  - DC coupled systems under 5 MW would be classified as non-scheduled IRUs
  - DC coupled systems over 5 MW could be classified as:
    - a scheduled IRU (in which case the whole system, including load, would be fully scheduled), or
    - a semi-scheduled generating unit (in which case the battery could not operate independent of the wind/solar forecast), or
    - separately as a scheduled IRU and a semi-scheduled generating unit, which would be treated as two separate units in dispatch (but conformance with dispatch would be assessed as a whole, subject to AEMO’s Power system operating procedure).

Registration and participation – Classifications



*These could be market or non-market

Questions and responses (1 of 2)

Stakeholder questions	AEMC project team response
In terms of re-registration of existing storage facilities as IRPs, would this see proponents go to the front or back of the AEMO registration queue?	The draft transitional rules provide that each existing participant with storage must apply to AEMO to change its registration category to an IRP within six months of the final rule taking effect. AEMO and the registered participant must use reasonable endeavours to complete the change in registration category and classification within nine months after the rule takes effect. AEMO must not charge a fee to an applicant who transfers to the IRP category under this rule.
What is the impact on an MSGA changing to a new participant category IRP?	MSGAs can continue to operate the way they do currently, and would be automatically re-registered as IRPs (without needing to apply). The draft rule would also allow them to provide ancillary services, as long as they meet the technical requirements outlined in AEMO's MASS. An MSGA site would require SCADA if it wants to start providing ancillary services that require SCADA (consistent with the current rules).
How will community batteries be treated? Will they need to re-apply to be registered? Can you comment on the concern that community batteries may get missed in the rule change and would not be able to participate in FCAS before 2023?	Community battery operators that are currently registered as MSGAs will be automatically re-registered as IRPs, and those that are Market Customers (retailers) can continue as they are. MSGAs with community batteries that want to provide ancillary service before the final rule is implemented would need to be affiliated with a Market Customer, under the current arrangements.
How do you see the treatment of community batteries before and after 2023 when the new rule comes into effect? They are small enough to be part of a VPP, but would they be too big to be technically considered a "retail customer"?	Before the final rule is implemented, community batteries would continue to be treated as they currently are. After that, community battery operators would register as IRPs and can classify the units under the SRA label, if the battery is less than 5 MW.

Questions and responses (2 of 2)

Stakeholder questions	AEMC project team response
For the purpose of a connection (under NER chapter 5A), is an IRU a retail customer or embedded generator or both?	If connecting under NER Chapter 5A, it would be a small IRU (e.g. a storage unit that is less than 5 MW) and would be both as "retail customer" includes an embedded generator, which includes an IRU.
What would be the benefit for existing Market Customers or Market Generators to register as IRPs?	There are no additional obligations on Market Generators or Market Customers that become IRPs, but it would provide greater flexibility in the services it could provide in the future.
Would the integration of the SGA category into the IRP and SRA retain the exemption for scheduling for assets 5-30MW?	Yes, the existing small generating unit definition (below 30 MW) is maintained. An SRA could classify small generating units less than 30 MW (if AEMO's criteria are met) and small IRUs less than 5 MW. These would remain non-scheduled.
Is the 18-month implementation timeline for the rule change applicable for the 5.3.9/5.3.4 process or only the registration process prior to commissioning? For example, when starting the process now to retrofit a battery at what stage would the rule change come into effect, and what occurs when the development process runs for a period before the rule change and then after?	Between the final rule being made and implemented, Market Participants could start the registration and connections process for an IRP. The project team is continuing to engage to what extent interim arrangements are possible to allow Market Participants to progress these processes. There are draft transitional rules on the treatment of connection enquiries and applications to connect that are on foot when the rule takes effect.
Will existing Market Ancillary Service Providers (MASPs) automatically become IRPs?	No, MASPs will become DRSPs under the wholesale demand response rule. DRSPs remain separate from IRPs.

RECOVERY OF NON-ENERGY COSTS

Recovery of non-energy costs - Overview

The draft decision makes two changes:

1. **The recovery of non-energy costs to be based on what the Market Participant is doing at the connection point, not the category it is registered in.**
2. **Removes the ability for Market Participants to net energy flows across connection points or at the connection point.**

In practice, the draft decision:

- Introduces a new term, a *Cost Recovery Market Participant*. Where the rules currently refer to non-energy costs being recovered from Market Customers or Market Generators etc, the draft rules replace this by referring to recovering costs from Cost Recovery Market Participants, in respect of their separately measured consumed energy or sent out energy at a connection point. A Cost Recovery Market Participant includes a person who is registered as a Generator, IRP, Customer or Demand Response Service Provider.
- Means, for example, non-energy costs currently recovered from Generators would also be spread proportionally across Market Customers who are sending out energy (for example, from excess roof top solar). Similarly, non-energy costs currently recovered from Market Customers would also be spread proportionally across Market Generators who are consuming energy (for example, from auxiliary load).
- Removes the ability for Market Participants to net energy flows across multiple connections or at a connection point.

The following slides outline three simplified scenarios to explain how non-energy costs would apply from the draft decision.

Recovery of non-energy costs - Scenarios (1 of 3)

Scenario 1 – A Retailer (registered as a Market Customer) has 100 customers. Across one trading interval, 50 customers are consuming 1MWh each and the other 50 customers (with roof top solar) are sending out 1MWh each.

Current Rules	This retailer has a net load of 0 MWh, as the amount of energy being consumed is equal to the amount of energy being sent out across the 100 connection points. This is called netting across or among connection points. This retailer would not be liable for any non-energy costs recovered from Market Customers, neither would it be liable for any non-energy costs recovered from Market Generators as it is not registered as a Generator.
Draft Rules	This retailer has a load of 50 MWh from half of its customers and sent out energy of 50 MWh from the other half. This retailer <u>would</u> be liable for 50 MWh share of total consumed energy and 50 MWh share of total sent out energy for the purposes of non-energy cost allocation (noting that some Cost Recovery Market Participants would have SCADA to calculate causer pays for recovery of regulation FCAS costs; the draft rule does not add any new SCADA requirements).

Recovery of non-energy costs - Scenarios (2 of 3)

Scenario 2 – A Retailer (registered as a Market Customer) has one customer. This customer has a load and onsite generation. Across one trading interval, the customer has a steady load, but its generation was variable. Across the trading interval, the customer's load was equal to its onsite generation, but in the first half of the trading interval it sent out 1 MWh through the connection point, and in the second half of the trading interval it consumed 1 MWh through the connection point.

Current Rules	This retailer has a net load of 0 MWh across the trading interval, as the amount of energy being consumed is equal to the amount of energy being sent out at the connection point. This is called netting at the connection point. This retailer would not be liable for any non-energy costs recovered from Market Customers based on its load.
Draft Rules	This retailer has a load of 1 MWh and sent out energy of 1 MWh. This retailer would be liable for 1 MWh share of total consumed energy and 1 MWh share of total sent out energy for the purposes of non-energy cost allocation.

Recovery of non-energy costs - Scenarios (3 of 3)

Scenario 3 – The operator of a hybrid system is registered as an IRP. It has load and generation behind a connection point. It is able to consume and generate energy behind the connection point without drawing energy from or sending energy to the grid (i.e. through the connection point).

Across one trading interval, the hybrid system produces 10 MWh, none of which is exported, and consumes 15 MWh behind the connection point. This means the hybrid system consumes 5 MWh from the grid in this trading interval.

Current Rules	It is not clear how this hybrid system would be treated because there is no example like this, currently.
Draft Rules	This hybrid system has a load of 5 MWh from the grid in the trading interval and it would be liable for its proportional share of non-energy costs recovered from load, based on the amount it consumes from the grid, not its total load. While the hybrid system did produce energy, none of this was sent out to the grid, so it would not liable for any non-energy costs recovered from generation/sent out energy in this interval.

Recovery of non-energy costs – Q&A

Stakeholder questions	AEMC project team response
Will the changes also have the adverse impact of attracting causer pays FCAS for MSGA sites? And therefore attract the requirement to install a SCADA link for sites that are currently small and don't have this link in place at the moment? Again, how are the non-energy costs recovered from MSGA if no SCADA link?	The draft determination does not alter the process for calculating 'causer pays liabilities. If a participant currently has appropriate metering/SCADA to measure its impact, then it would incur 'causer pays' liability in respect of its calculated contribution factor for regulation FCAS. If, however, the participant does not have the appropriate metering/SCADA, its share of the costs would be recovered as part of the residual share of costs spread proportionally across the remaining participants.
In relation to the briefing slides delivered in early August, slide 14 says "all costs would be recovered based on consumed energy". Can you clarify how the cost recovery would work in this example?	'All costs would be recovered based on consumed energy' refers to the costs of the FCAS contingency lower service example, which are currently recovered from Market Customers. This example highlights the draft decision to shift the allocation of non-energy costs to all Market Participants, based on their consumed energy.

TUOS AND DUOS CHARGES

TUOS and DUOS - Overview

The draft decision can be summarised as follows:

1. **We decided not to define storage as a service that is distinct from load and generation. Rather, as an IRP, a participant will provide both load and generation.**
2. **We then considered whether the process for determining TUOS and DUOS liability for generation and load is clear:**
   - **Generation** – the rules are clear that generators do not incur TUOS charges.
   - **Load** – while the rules are reasonably prescriptive in form and process for load, they are designed to provide flexibility to negotiate different outcomes in certain circumstances.
3. **We have made minor amendments:**
   - Transmission customers (including IRPs) may receive shared transmission services as a prescribed service should they wish for services to be provided on that basis.
   - IRPs will be Transmission Customers for the purposes of Chapter 6A (Transmission) in relation to electricity taken from the grid and so will pay TUOS for prescribed transmission services.
   - The Chapter 6 (Distribution) pricing principles will apply when determining access disputes involving distribution customers who are not retail customers (including that prices should reflect efficient costs).

The next slides illustrate if and how TUOS and DUOS charges apply to different scenarios under the current arrangements and the draft decision.

TUOS and DUOS - Framework overview

- **Generation** connected to distribution network
  - Currently does not incur DUOS and TUOS charges.
    Separately, the DER Access and Pricing rule change will allow DUOS to apply to exports (subject to restrictions).
- **Load** connected to the distribution network
  - Incur DUOS and TUOS charges, approved through AER's TSS process.
- **Generation** connected to the transmission network
  - Currently does not incur TUOS charges.
- **Load** connected to the transmission network
  - Incur TUOS charges. The draft rule provides the option for the load to receive a prescribed or negotiated transmission service.
    - **Prescribed transmission services**
      - Regulated price and service standards
    - **Negotiated transmission services**
      - Storage proponent and TNSP agree to a price for a level of service received. Price must be the same for all transmission users unless the costs to provide the service are materially different.
      - If no agreement, the storage proponent may seek arbitration or receive the prescribed transmission service

Notes:

- The draft rule clarifies that load and generation from IRUs should be treated **consistently with other load and generation**. There have been no material changes made to how network charges currently apply to load and generation.
- It is intended that existing negotiated agreements between TNSPs and storage facilities (such as grid scale batteries and Hydro plant) would stand.
- Storage operators that are currently registered as both Market Generators and Market Customers would migrate to the IRP category, but this would not impact existing network charging arrangements.

TUOS and storage scenarios

Scenario 1 – Existing grid-scale storage connected to the transmission network

No change for existing transmission connected storage

The draft determination does not impact on or affect existing arrangements (whether they be prescribed services or negotiated agreements) between existing grid-scale storage operators and transmission network service providers (TNSP).

If an existing transmission-connected storage participant has a negotiated agreement with its TNSP, this arrangement can be left unchanged if the draft rule is made final.

Scenario 2 – New grid-scale storage intending to connect to the transmission network

Two options for new transmission-connected storage participants

Under the current arrangements the TNSP is not obliged to offer storage a prescribed transmission service.

The draft determination would allow new transmission-connected storage participants to choose between a prescribed TUOS service or a negotiated agreement. For the avoidance of doubt, new storage participants could still choose to negotiate an agreement with their TNSP, but would also have a prescribed TUOS service option available if it was preferred.

DUOS and storage scenarios

Scenario 1 – Existing grid-scale storage connected to the distribution network

No change for existing distribution connected storage

The draft determination does not affect existing arrangements (whether they be a direct control service or a negotiated distribution service) between existing grid-scale storage operators and distribution network service providers (DNSP).

Scenario 2 – Intending (new) grid-scale storage wanting to connect to the distribution network

Focus on cost reflective charges

The draft rule does provide greater focus on the need for a negotiated distribution service to be reflective of the efficient cost to service distribution customers that are not retail customers. The draft rule does this by the addition of new NER clause 6.22.2(b1): if these customers have a dispute over the terms and conditions of access to a direct control service, the AER must apply the principles outlined under NER clause 6.7.1. In practice, this new clause allows storage participants, intending to connect to a distribution network, the opportunity to dispute and challenge DUOS charges that they consider do not reflect the efficient cost to serve that storage participant.

The final rule of the *Access, pricing and incentive arrangements for DER* removes the ban on export charges, but introduces protections for customers. Further information is available here.

Summary of NEO assessment of TUOS/DUOS policy options

Characteristics of policy	Current arrangements	Draft determination	Rule change proposal – Exempt storage from TUOS
Definition of storage	Storage not defined in the NER; it is considered to be load and generation.		Storage is defined in the NER
TUOS/DUOS for generation	Generation does not pay TUOS.		
TUOS/DUOS for load	Loads pay TUOS.	As per current arrangements.	**Storage exempt from TUOS.**
Other key characteristics		• TNSPs must offer prescribed service • IRPs pay TUOS for prescribed (if consuming) • Application of Ch. 6 pricing principles to non-retail distribution customers (reflect efficient costs).	
Preliminary NEO assessment			
Appropriate risk allocation (cost reflectivity)	Distribution services generally more cost reflective than transmission services (shared transmission service charges vary, with no TUOS charges in some cases).		Arguably a subsidy as storage paying below even incremental network cost
Level playing field (technology neutrality)	Relatively technology neutral as between different types of loads/ generators.	Relatively technology neutral as consistent with current TUOS situation for gen/load.	Not technology neutral. Exempting storage from TUOS charges would advantage it, compared to other loads such as households, and also compared to other forms of generation which have to pay for transport of their fuel.
Promote competition (remove barriers to entry, investor certainty)	TUOS charge uncertain as TNSP not required to offer prescribed service.	Improvement as storage proponent can ask for prescribed service if it wants.	No overall benefit as advantages some participants (storage) at expense of others (demand response and generation).
Promote transparency (reduce information asymmetry)	Lack of transparency over negotiated vs prescribed offers.	Improved transparency as TNSP must offer prescribed service.	Subsidy to storage/ relative penalty for other load (eg households) and other generation not transparent.
Enhance security and reliability	Issue of locational signals to reflect impact of new storage on security/ reliability at the transmission level. Separate ESB (transmission price signals) and AER (Ringfencing) work on this.	As per current arrangements.	New storage may alleviate or worsen transmission congestion. Potential for inefficient location decisions.

TUOS and DUOS – Q&A (1 of 2)

Stakeholder questions	AEMC project team response
New IRP category and TUOS - The logic seems inconsistent? The new IRP category is required because storage doesn't fit existing generator or load categories, but then for TUOS it is forced to fit within current framework?	• The IRP caters for participants with both load and generation (it is not only for storage). • The rules are clear how TUOS should apply to load and generation.
FCAS lower service and TUOS If IRPs are charged TUOS wouldn't that penalise them for providing lower FCAS services compared to other generators?	**In providing a lower FCAS service, Generators:** • do not pay TUOS as they do not need to use the network to consume energy to provide the service • incur costs for fuel and transportation of fuel to generate and be in a position to provide the service. **IRPs in providing a lower FCAS service:** • pay TUOS if they need to use the network to consume energy to be able to provide the service. • **If the energy price is positive –** An IRP consuming energy from the network pays energy and network charges (i.e. when use of network charges positive) and earns revenue for providing lower FCAS. • **If the energy price is negative –** An IRP would be paid if consuming energy from the network and paid to provide lower FCAS. In relation to DUOS, as per the final rule of the 'Access, pricing and incentive arrangements for distributed energy resources', a load participant could be paid for providing a load service on the distribution network.
FCAS lower service and stability If the battery is providing an FCAS lower service to bring the network frequency back to within 50HZ +0.015, incurring TUOS would seem to be "penalising" the battery when it's offering network stability?	**Technology neutrality** – there are many technologies (not just batteries) that can provide essential system services to support the stability of the grid. **Cost of supply** • Most plant that provide services incur costs that inform the prices that they bid. • For generators, this can include costs associated with the use and transport of fuel. • For loads, this includes costs associated with their use of the network (TUOS). TUOS is not a penalty.

TUOS and DUOS – Q&A (2 of 2)

Stakeholder questions	AEMC project team response
Hybrid solar + battery If the hybrid battery is not charging from the grid, would it be exempt from TUOS/DUOS?	• Yes – if it is not charging from the grid, it would not be charged TUOS/DUOS. • The calculation of network charges are based on load at the connection point.
Standard for prescribed vs negotiated service Who and how is the standard decided if a prescribed or negotiated TUOS is required?	• The draft rule enables a connection applicant to receive a shared transmission service as either a prescribed transmission service or to pursue a negotiated service agreement. • **Negotiated service –** the service standard and price is negotiated between the connection applicant and the TNSP. They can negotiate a different level of service from a prescribed transmission service. • **Prescribed service** – the service standard is regulated by the AER.
Impact of TUOS on investment in batteries Have the AEMC modelled how TUOS might impact battery investments vs the requirement to encourage storage onto the grid?	• No. The Commission's scope for the rule change is to accommodate storage under the existing network pricing arrangements/framework. • The NER establish principles for setting network charges. The AER and NSPs use the NER to propose and approve cost reflective tariffs to recover the efficient costs of operating and maintain electricity networks.
What is the downside of explicitly exempting storage from TUOS? Is there some critical problem here (e.g., can't distinguish between scheduled loads in the IRP, etc.)	An explicit exemption of network charges for storage would create a cross subsidy between batteries and other consumers of electricity. An explicit exemption does not guarantee that storage would locate in the most efficient location or behave in a way that provides maximum benefit to consumers.
Batteries can reduce the cost to operate the system - therefore should it really be left up to the TNSPs to reduce the cost of bringing these services providers into the system?	Yes, batteries can provide services that reduce costs but, like generators, they incur costs to provide them. A storage applicant can seek a prescribed transmission service covered under the AER's independent review of the TNSP's pricing methodology and prices.

RETAILER RELIABILITY OBLIGATION

Retailer Reliability Obligation

The primary change is that storage operators registered as IRP participants will, like Market Customers, be assessed as liable (or not) under the RRO based on their net consumption.

- This means that participants with load will be treated consistently between the Market Customer and IRP registration categories.
- This draft change 'levels the playing' field for storage participants, as currently storage participants are assessed as liable or not under the RRO based on gross consumption.

A battery that is liable under the RRO (net consumption above 10GWh per annum) providing load ancillary services during a reliability event would need hedging to cover its load

- A liable entity's liable load is measured as its total consumption. That is, it does not exclude load that is providing ancillary services.
- While it is possible for storage operators to provide load ancillary services during a reliability event (for which they would need to hedge), it is unlikely. A possible scenario is provided on the following slide.
- The project team did explore if ancillary services load could be excluded from total load when measuring a liable entity's liable load, however, this was not considered a practical option given the difficulties in measuring FCAS response.

The RRO and a battery – an example of how it may play out

A summary of the RRO process

>3 years out	T-3	T-1	T
Reliability event triggered through the ESOO or by the South Australian Government/ Minister.	RRO liable entities start to enter contracts. Liable entities are required to enter into sufficient qualifying contracts to cover their share of a one-in-two year peak demand event.	If reliability gap is confirmed 12 months out, a liable entity submits a Net-contract Position report. This report identifies how much coverage the liable entity has for the relevant period. There is no penalty at this stage for not having coverage.	**If the reliability event occurs** AEMO will calculate each liable entity's share for every compliance trading interval and submit to the AER. The AER will assess the liable share vs net-contract position reported at T-1 for all liable entities. **If no reliability event occurs** No assessment of compliance is required.
How a battery may respond →	A battery is unlikely to acquire load hedging contracts as it is unlikely to charge during a reliability event. This is because a battery's strategy would typically be to use its generation side during a reliability event as the spot/ contract price is likely to be high.	A liable battery would therefore likely submit a Net-contract Position report with zero load hedging contracts.	**If the reliability event occurs** If a liable battery with no load hedging did not consume energy it would not attract any costs, penalties or non-compliances. If the battery did consume energy it would be liable and can be penalised proportional to its load amount.

Retailer Reliability Obligation – Q&A

Stakeholder questions	AEMC project team response
Is the AEMC aware that any battery over ~200MWh is still likely to become a liable entity under RRO (due to round-trip losses)? To avoid this liability, would this prevent FCAS (lower) services during reliability events even if needed?	Yes, the Commission is aware that large batteries may be subject to the RRO but their owners can operate them in a manner that would reduce or eliminate the chance of incurring costs or penalties. If a battery wanted to provide FCAS (lower) services during a reliability event it would need to consider a hedging strategy (which may include its own generation) or seek AER advice on how it would treat this load.

OTHER QUESTIONS

Other – Questions and responses (1 of 3)

Stakeholder questions	AEMC project team response
What is the timeframe for these proposed rule changes coming into effect?	The draft decision is for an 18-month implementation, so the rules would be in effect from April 2023. In responding to the draft determination, stakeholders may respond in relation to the implementation time; supporting 18 months or justifying why it should be a different length of time for certain parts of the rule.
What is the interaction between the IRP participant and the Demand Response Service Provider (DRSP) participant? How would that work? Is it an either/or scenario where you can't have a distinct DRSP and IRP assigned to a NMI?	An IRP cannot itself classify a Wholesale Demand Response Unit (WDRU) because the IRP is a Financially Responsible Market Participant (FRMP) classification, whereas a DRSP is not. However, an entity could register as an IRP and also as a DRSP, if it wants to provide demand response as well as energy.
AEMO has estimated significant costs associated with these reforms but has not quantified the value of the intended benefits. Will AEMC undertake a CBA to inform its final determination, to confirm that the benefits are likely to outweigh the cost to industry?	The Commission's draft determination provides a breakdown of the estimated costs and benefits (Chapter 2, section 2.2). The Commission's draft decision is that the benefits outweigh the costs. The Commission intends to provide further details on the costs and benefits based on engagement with stakeholders and further analysis. Since the draft determination was published, the project team has generally received positive feedback on the changes that result in the majority of the costs (registration, participation and non-energy costs recovery).

Other – Questions and responses (2 of 3)

Stakeholder questions	AEMC project team response
Do AEMO's cost estimates only include only AEMO's costs, or do they include estimated costs to other market participants?	AEMO's costs estimate only includes AEMO's costs to implement. The project team encourage market participants to provide cost estimates they would incur if the draft rule was implemented as final.
AEMC stated that most stakeholder submissions favoured incremental reform over 'big bang' changes, but the costs and the size of the changes proposed seem significant. Does the draft determination include aspects that aren't strictly necessary to achieve the immediate objectives, but are intended to allow for potential future reforms like Multiple Trading Relationships? If so, can these be deferred, given there is likely significant further work to do to on the mooted 'trader services' model to determine its practical viability? Is the approach proposed the minimum viable change required to address the issues that have motivated it?	The draft decision makes changes necessary to remove barriers and better integrate storage and hybrid systems, including: a new registration category that caters for both small and large participants with bi-directional energy flows, flexibility for participants to include DC coupled storage units, and a 'leveling of the playing field' in relation to how non-energy costs are recovered from participants. The 'big bang' changes that were tested with stakeholders in the options paper, including a move towards a service-based model that would have impacted on how all existing participants classify their activities and participate in the market, have not been pursued in the draft determination. All changes being made are directly related to addressing issues of better integrating storage and making relevant terminology simpler and more consistent throughout the rules, as requested in the rule change request.

Other – Questions and responses (3 of 3)

Stakeholder questions	**AEMC project team response**
Does the rule draw a distinction between auxiliary loads (actual consumption) vs battery charging loads (energy storage)?	The draft rule includes a new definition of auxiliary load which specifically excludes energy to charge a battery. The definition is: Auxiliary load - Electricity consumption used for the operation of auxiliary plant at a power station. Auxiliary load does not include electricity consumption used to charge a production unit or to pump water for a pumped hydro production unit
Now that the Access and Pricing rule change has been finalised, does that change any aspect of what is proposed in relation to DUOS?	The DER Access and Pricing rule change, among other things, removes the prohibition on export charging. This decision effectively allows DNSPs to charge or pay participants who use networks to export electricity to the grid. This change aligns with the Integrating energy storage rule change as it makes participants more accountable for their actions and provides for more opportunities for participants to utilise storage technologies to reduce the cost of running the power system, and ultimately reduces costs borne by all consumers.