Government of **Western Australia**
Department of **Treasury**

Transformation Design and Operations Working Group (TDOWG): Meeting 1

DATE/LOCATION: 12 August 2019, Level 23, David Malcolm Justice Centre, 28 Barrack Street, Perth

TIME: 1.30 pm

MEETING ENDED: 4:00 pm

PRESENT:

Attendees	Organisation	Attendees	Organisation
Aden Barker	ETIU (Chair)	Patrick Peake	Perth Energy
Aditi Varma	ETIU	Paul Arias	Bluewaters Power
Ashwin Raj	ETIU	Peter Huxtable	Water Corporation
Clayton James	AEMO	Rajat Sarawat	ERA
Daniel Kurz	Bluewaters	Rebecca White	ETIU
David Bones	GHD	Robert Pullella	ERA
Drew Harris	Simcoa	Rod Littlejohn	Tersum Energy
Elizabeth Aitken	Perth Energy	Sabina Roshan	Western Power
Geoff Gaston	Change Energy	Sara O'Connor	ERA
Geoff Glazier	Merz Consulting	Simon Middleton	AEMO
Glen Carruthers	Western Power	Stephen Eliot	Rule Change Panel Support
Greg Ruthven	AEMO	Steven Kruit	ETIU
Greg Thorpe	Oakley Greenwood	Teresa Smit	AEMO
Iulian Sirbu	Kleenheat	Tim Robinson	RBP consulting
Jason Froud	Synergy	Troy Santen	Stellata Energy
Jenny Laidlaw	Rule Change Panel Support	Wayne Trumble	Newmont Goldcorp
Kate Ryan	ETIU	Wendy Ng	ERM Power
Kirk Reeve	Alinta Energy	William Street	Alinta Energy
Leon Kwek	AEMO		
Marc Hettler	Perth Energy	**Teleconference attendees**	
Martin Maticka	AEMO	Alex Cruickshank	Oakley Greenwood
Matthew Bowen	Jackson MacDonald	Claire Richards	Enel X
Noel Schubert	Individual	Kristian Myhre	TransAlta
Oscar Carlberg	ETIU	Mike Thomas	The Lantau Group

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<tr><td>1.</td><td>Opening remarks</td><td>The Chair opened the meeting and provided an overview of the ground rules and safety procedures.

Kate Ryan (KR), Program Director of Energy Transformation, welcomed everybody to the TDOWG, which had formed following the closure of the MDOWG and PSOWG MAC working groups, and advised that a revised Terms of Reference for the new group would be available online shortly.

The Chair encouraged members of the TDOWG to ask questions throughout the following presentations, and to contact the ETIU if they had any further questions after the meeting.</td><td></td><td></td></tr>
<tr><td>2.</td><td>Overview of the proposed approach to capacity credit allocation</td><td>Ashwin Raj (AR) presented on the ETIU’s proposed approach to the allocation of Capacity Credits under a constrained network access model:
The proposed approach had received in-principle support from the Energy Transformation Taskforce (the Taskforce).
The proposal had been updated from the previous approach proposed by the PUO in early 2018.
Oakley Greenwood with the Lantau Group had recently been appointed as a consultant to the ETIU.
AR provided an overview of the purpose of the Reserve Capacity Mechanism (RCM) and the need to change the approach to Capacity Credit allocation under a constrained network access model:
The South West Interconnected System (SWIS) is a small, isolated system with relatively low energy price caps. The RCM complements revenue to provide certainty to investors while providing a reliable electricity supply for consumers.
The introduction of constrained network access introduces the risk that new entrants may connect to constrained sections of the grid and displace the capacity revenue of incumbent generators.
This could create uncertainty for investors, potentially undermining the purpose of the RCM.
This may also result in new entrants being over compensated relative to their incremental value to the system.
AR summarised the PUO’s previous proposal:
Capacity priority rights would be allocated on a “first come, first served” basis to protect the revenue of incumbents.</td><td>Action: ETIU to develop a detailed design proposal for feedback in early September 2019, then consult with industry before releasing an Information Paper in October 2019.</td><td>ETIU</td></tr>
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		• New entrants would be allowed to displace existing capacity, but would be required to reimburse the incumbents for the capacity revenue that they had displaced. • Capacity Credits would be allocated to facilities that contributed the least to network constraints, in order to maximise the overall level of Reserve Capacity. AR summarised issues raised by stakeholders in relation to the PUO proposal and outlined further issues the ETIU had identified. AR noted that developing solutions to the issues would create a level of implementation complexity that was difficult to justify. Issues include that capacity priority rights could interfere with existing bilateral contracts for the sale of Capacity Credits and could also interfere with reserve capacity obligations. • For similar reasons, stakeholders had suggested a similar approach to the Generator Interim Access (GIA) solution be adopted instead. The ETIU considered that any solution should reward capacity that is available when required, while minimising the level of contractual interference and barriers to entry and exit. AR outlined the ETIU's updated proposal: • The updated proposal was for the introduction of "Capacity Credit Rights", which would protect existing Capacity Credits from being displaced for a set period of time. Capacity Credit Rights would only protect displacement from new entry, not under all circumstances (e.g. the given facility must still be able to fulfil its technical requirements and meet its reserve capacity obligations). • Capacity would be rewarded based on its incremental value to the system. • Capacity Credit Rights would be allocated to existing generators for the 2022 Capacity Year based on their Capacity Credit allocation for the 2021 Capacity Year, subject to the facility meeting appropriate performance requirements. • If new entrants applied for Capacity Credits, their technical capability would be assessed and the capacity of the network to accept new capacity would be modelled. Capacity Credits would only be allocated up to the capacity of the network. The constraint equations used for the modelling would be based on the expected network configuration for the relevant Capacity Year. • Daniel Kurz from Bluewaters Power asked whether the network modelling would consider the true limit of the network, or whether there would also be a contingency included. AR replied that the model would likely consider the thermal limit of the network, but the modelling parameters were still to be determined and the ETIU was open to feedback.		

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		• The Chair stated that limits advice, including risk margins, was in the scope of the project and more information on the advice being developed, and by whom, would be released within the next few weeks. • Drew Harris (DH) from Simcoa asked whether demand side management (DSM) would be considered in the model. AR replied that this was still to be determined, although he did think that it had been included in previous modelling. • Elizabeth Aitken (EA) from Perth Energy stated that the proposal may 'bake-in' the current level of market power in terms of Capacity Credit allocation; and asked how AR saw the transition of market power in capacity being managed over the next 15 years. AR replied that existing generators would originally be given Capacity Credit Rights, meaning these generators may continue to receive Capacity Credits even though they may not be the most reliable or the cheapest option; and that the duration of those firm rights was still to be determined. • EA asked what the current proposal for the duration of Capacity Credit Rights was, and whether industry would be consulted on the duration. AR replied that the current proposal was for 10 years, based on the PUO's previous proposal, and that there would be consultation going forward. • Wayne Trumble from Newmont Power stated that the 10 year horizon appeared to be an arbitrary choice, and asked why it had been chosen. AR replied that whichever number was eventually chosen would be selected on the basis that it strikes an appropriate balance between providing revenue adequacy and enabling competition. • Patrick Peake (PP) from Perth Energy suggested that the length of time chosen could be tied back to the payback period assumed in the calculation of the BRCP, and asked whether a generator that lost its Capacity Credits due to performance issues would lose them forever. AR replied that this still needed to be determined, and would require feedback from industry. • Jenny Laidlaw (JL) from Rule Change Panel Support asked how the model would account for any network access that is currently unused. AR replied that there would be a "use it or lose it" element to Capacity Credit Rights. • AR stated that the holders of Capacity Credits would retain the obligation to provide their capacity, and that the proposal should be familiar to industry as it was similar to the method in the WEM Rules for calculating a constrained access facility's constrained access entitlement.		

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		• In response to a question from Wendy Ng (WN) from ERM, AR clarified that while the new process for allocating Capacity Credits would be similar to the Constrained Access Entitlement process under the GIA solution, there was no intention to retain GIA for energy dispatch. • Geoff Gaston from Change Energy asked whether the proposal would continue using the current reliability standard of 10% PoE as a basis, and suggested this level may need to be reviewed as it locks in high capacity costs for customers. KR replied that while this was not in the scope of the project, she agreed that there were elements of the RCM, including the 10% PoE level used in the planning criterion, that required review going forward. Matthew Bowen (MB) from Jackson MacDonald asked if the proposed model would work if the second limb of the planning criterion were to come into use in future. KR replied that there was no reason to believe it wouldn't, but that this had not been tested with respect to potential impacts on other elements of the RCM. AR presented on the advantages and disadvantages of the updated proposal: • The model is simple to understand and implement, it doesn't interfere with existing contracts, it doesn't change reserve capacity obligations, it maintains the principle that 1MW of Capacity Credits is equal to 1MW of physical capacity, and it introduces locational signals. • However, the new proposal could cause a disconnect between capacity mechanism and energy market outcomes, as the facilities dispatched when required to maintain reliability may not be the facilities rewarded with Capacity Credits. • EA asked whether the disconnect between energy and capacity market outcomes was an inherent flaw in the proposal. AR replied that it simply reflected that capacity would be paid to be available during periods when it is required, regardless of whether it is actually dispatched. • EA stated that there may be gaming issue, as DSM providers that don't currently receive Capacity Credits may now rush into the capacity market to attempt to receive Capacity Credit Rights before the new proposal is implemented. • AR stated that the proposal could also limit opportunities for new entrants to secure Capacity Credits relative to the previous proposal, but that new entrants would receive a greater benefit in not being required to pay for capacity upgrades when they connect to the network. AR provided a worked example, demonstrating how Capacity Credit Rights and Capacity Credits would be allocated in a section of the network with incumbents and new entrants under the proposal.		

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		• JL stated that DSM behind a constraint could cause problems. • EA asked whether an existing generator that replaced equipment or built a new facility on its premises would retain its Capacity Credit Rights. AR replied that it likely would, although the ETIU would work with industry to determine rules around how Capacity Credit Rights would be treated when generators were upgraded, retired etc. • Kirk Reeve from Alinta Energy asked how regularly facilities would be tested to ensure compliance with the technical standards required for Capacity Credit allocation. AR replied that facilities would likely be subject to the same compliance regime that currently applies to the capacity market. AR presented on the work that would still be required to be undertaken, as well as the next steps: • A process for accrediting and allocating residual capacity to new entrants would need to be developed. • Interaction with the Relevant Level Method and impacts on the existing Reserve Capacity Cycle timeline would need to be considered. • The ETIU was well aware of the challenges inherent in trying to progress the changes in time for the 2020 Reserve Capacity Cycle, and planned to have the required Market Rules in place by mid-2020. • The ETIU and consultants would develop a detailed design proposal for feedback in September 2019, then consult with industry before releasing an Information Paper in October 2019. Draft Rule amendments would then be developed from October through to early 2020. • AR acknowledged that there may be a lot of questions that still needed to be answered, and provided his contact details and encouraged the members of the TDOWG to contact him to discuss further. • William Street (WS) from Alinta Energy stated that modelling 2 years in advance may lead to forecast errors in the network configuration, introducing volume risk in addition to price risk, and asked whether more certainty would be provided to new entrants. AR replied that the ten-year lock-in period for Capacity Credits should provide the required certainty. WS replied that it would still be a tough sell for a new investor. AR replied that he would be keen to explore why that may be the case in the consultation period. • The Chair thanked AR and asked the TDOWG to provide their feedback as soon as possible so that any concerns may be considered before the ETIU drafted the design proposal.		

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3.	Essential System Services – Frequency Control	The Chair introduced Tim Robinson (TR) from Robinson Bowmaker Paul to present on frequency control services.TR informed the TDOWG that he would be presenting on the procurement of services after Clayton James (CJ) from AEMO first presented on the technical characteristics of the proposed new frequency control services. CJ presented on the new frequency control services, explaining that their design was based on the recommendations from GHD's technical review of essential system services, which had recently been published: • The current state consisted of mandatory requirements, a load following service, a single spinning reserve service and a load rejection reserve service. • GHD's report had recommended new measures to ensure system security, including a safe level of rate of change of frequency (RoCoF), faster response to contingencies, separate regulation and contingency reserve services, and tighter DER inverter standards. • EA stated that she didn't get the impression that GHD considered inverter standards to be a "must have". KR clarified that there was already work underway on inverter standards in the DER workstream. EA stated that this was a political issue too, as stricter standards would cause higher costs or greater inconvenience for consumers. The Chair replied that around 75,000 customers would stop receiving the feed-in tariff in 2020 and many would likely upgrade their systems, meaning there was a substantial opportunity to implement new standards beforehand without inconveniencing those customers. Customers on average replaced their inverters around every 7 years, so the inverters conforming to the new standards would gradually become more prevalent over time. • CJ stated that the current inverter standards already required DER to respond under certain circumstances. • TR noted that requirements are currently only really placed upon synchronous generators, which fails the principle of technology neutrality, so changes to connection standards are intended to align treatment of non-scheduled generators. Rooftop PV systems in aggregate formed the largest generator on the SWIS, but they were subject to looser frequency control requirements than other generators. AB noted that DER also potentially had a large role to play in locational voltage control services. • EA noted that there was a broader issue with households facing obligations being placed on their DER without receiving any compensation. AB replied that ETIU will investigate whether certain services or settings should be considered a "price of entry" for connection or should instead be a compensated service.		

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		• WN asked whether any additional mandatory frequency response would be imposed. CJ replied that the settings would be the same as in the proposed generator performance guidelines (GPG), where droop settings would remain similar but with more specificity regarding the operation of non-scheduled generators. • PP stated that mandatory obligations would need to be compensated unless they applied to everything on the grid. CJ replied that the intent was to ensure that the imposition of obligations would be equitable across all participants. CJ presented on the future state, based on GHD's recommendations, which would consist of mandatory requirements, a regulation service, a single contingency reserve service (separated into up and down) and a RoCoF service. • The regulation service would essentially be the same as the current load following service, and would consist of an up and a down service. • A ramping service may be required in future. • Sabina Roshan (SR) from Western Power asked whether anything would need to be added to the GPG to enable participants to provide ESS services. CJ replied that extra requirements would be dealt with in the accreditation process, rather than the GPG. SR noted that when connecting, a generator may not signal whether they intended to participate in the energy or ESS markets, so there needed to be a signal to ensure participants would be aware that there would be further requirements imposed on them if they wanted to provide ESS. CJ noted that work was underway to improve the communication between Western Power and AEMO in the connection process. AB noted that a paper on the power system security and reliability standards would soon be released which would include details on the new GPG and the roles of Western Power and AEMO. • Geoff Gaston asked whether there would be any kind of cost forecasting done on the proposed new services. TR replied that this would be covered later in the session in discussion on procurement to supplement real-time markets and on market monitoring and forecasting. • CJ explained that AEMO was undertaking modelling to determine the quantity of regulation service required. A detailed method for setting the requirement would be put in a market procedure, which would be reviewed within a year of market start. CJ presented on the contingency response service, which would be split into a Contingency Reserve service, replacing the spinning reserve and load rejection reserve services, and a RoCoF Control service.		

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		• JL asked whether “nesting” services would add too much complexity. TR explained that the Contingency Response referred to a category of services, which included both Contingency Reserve and RoCoF Control. • CJ explained that with more inertia in the system, the amount of spinning reserve required decreases. The RoCoF Control service would provide a mechanism for scheduling providers of inertia, potentially allowing for less Contingency Reserve service to be procured. The RoCoF Control service would not depend on the size of a generator in megawatts, but rather its inertial response, measured in megawatt seconds. • CJ explained that there would be 3 main classes of future ESS provider: synchronous machines, interruptible loads and inverter-based technologies. All 3 could provide primary and secondary frequency response, albeit with different response times and durations. • JL asked whether Contingency Reserve would be a primary or secondary response service. CJ replied that it would provide both, and would cover the entire duration of a contingency. TR added that the definition was based on the primary response, but would also take advantage of facilities that were able to provide the secondary response. JL asked how that could be incorporated into the dispatch instructions. TR replied that current expectations were that for the first dispatch after a contingency, the ESS requirements would be set to zero. The ESS requirements would then apply again for the next dispatch interval. JL asked whether instructions from the clearing engine would then be overridden by local control systems in such an event. CJ replied they would, and that this was a quite common feature of control systems. Frequency would be restored to 50Hz via automatic generation control. TR presented on the relative benefits of having multiple reserve services, explaining that splitting the Contingency Reserve service into multiple reserve segments may unnecessarily increase complexity. However, upcoming modelling would include assessment of multiple reserve segments to consolidate the finding. • PP stated that this was essentially a step forward from the previous proposal for 3 different reserve segments. JL stated that there may be a problem if the single service locked out some technology types that were unable to provide all of the services required. TR replied that that could be dealt with in the accreditation process. CJ presented on the accreditation approach. Facilities would be assigned a “contribution factor” depending largely on response time and profile. Facilities would		

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		still offer a $/MW figure, and the contribution factor would be accounted for by the clearing engine in the co-optimised dispatch. CJ presented on reserve and RoCoF quantities. The amount of reserve and RoCoF Control required would depend on the size of the largest credible contingency, system inertia and load relief from the underlying system load. • SR asked whether the largest credible contingency also included network contingencies. CJ replied that it did. • JL asked whether the dispatch optimisation process for the various services would iterate between different calculation engines, as that may be expensive to implement. TR noted that while they were confident of finding a simple solution, there may be a need for some iteration if it provided better outcomes, and this approach is common in other electricity markets. • JL asked if they would be looking to dynamically change the level of inertia, and if so, over what timeframe. TR replied that they did intend to do so, and while there would be no room for flexibility in real time there would be an opportunity in pre-dispatch to signal the need for different inertia levels. CJ added that there may be other longer-term solutions that would be discussed later on. • JL stated that the GHD report had discussed that very fast frequency response could potentially be used interchangeably with inertia, and asked how the very fast frequency response would interact with the RoCoF service. CJ replied that the amount of megawatts required would be directly dependent on the level of inertia in the system, measured in megawatt seconds, and that there may be a way to find some measure of equivalency between the two, but that would require further consideration. Geoff Glazier added that inertia was the only feasible solution to the sub-250 millisecond response identified as a requirement in the GHD paper. JL asked how fast frequency response and inertia would be differentiated within the RoCoF service. CJ replied that the fast frequency response would be provided by the Contingency Reserve service, whereas inertia would be provided by the RoCoF service. TR presented on the procurement of ESS. • Real-time co-optimisation of energy and all of the ESS services would be required. • A supplementary mechanism would likely be required to maintain system security and revenue certainty in a small, concentrated market. • The new arrangements would move away from prescribed services based on specific technologies to more technology-agnostic, market-based services.		

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		• Key considerations would be to respond to scarcity, provide revenue certainty for new entrants, mitigate and monitor market power, and minimise overall costs. • Options investigated for the supplementary mechanism have been: – Option A: Additional RCM obligations. – Option B: Availability retainer and real time offer limits. – Option C: Contracts for difference. – Option D: Facilitated bilateral contract market. • EA noted that the PUO had explicitly ruled out Option A around a year ago. TR replied that Option A had been included for completeness but was not the preferred option. • If Options B, C or D were chosen then the initial requirements would likely be set in the Market Rules with 2 lots of 1-year procurement. In subsequent years, longer procurement periods could be set if deemed appropriate. • Under all options, all facilities could participate in the real-time market, with co-optimisation of the whole fleet, regardless of their participation in the supplementary mechanism. • Option B would include an annual mechanism providing a fixed payment for availability in return for restrictions on offers into the real-time market, either in the form of a price cap or a delta from a generator's historical energy offer. • EA stated that new entrants would already be receiving a poor deal in terms of energy prices and capacity payments, and under option B they would also only receive certainty on ESS payments for a 12-month period. TR replied that the current RCM is administered on an annual basis. The 12-month period would also place control on market power. EA asked how new entrants could be attracted to the market without a period of investment certainty greater than 12 months. • EA stated that the justification for previous proposed market reforms, including a capacity auction, had been that ESS revenue would increase to complement falling energy and capacity revenue, and that this no longer appeared to be the case. TR replied that the 12-month period was still an indicative figure and could be lengthened if required. • Geoff Glazier noted that each year generators could participate in the process, and that there was no reason new entrants couldn't also receive the same deal in year 2 as they had in year 1. EA replied that there would only be 3 income		

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		streams for independent power producers (IPPs) and ESS wouldn't provide enough revenue to incentivise new investment. IPPs would need certainty of at least around 5 years. Also, the RCM wouldn't provide locational signals to incentivise new entrants to build where the system required more generation. Leon Kwek (LK) from AEMO replied that frequency control would not require locational services and KR added that locational services would be considered as part of other ESS in future. EA replied that where network separation occured frequency control would still be required on both sides of the constraint. CJ replied that split frequencies were currently dealt with under contract for locational services. EA asked if those contracts would still exist in future and CJ replied that this would be considered in future. • Geoff Glazier summarised that EA was signalling a missing money problem for new entrants and that the upcoming dispatch modelling would likely give the best global view of potential revenue streams. • PP stated that while the SWIS had been operating with excess capacity for some time, it would be a shame if a new market were implemented and suddenly there was a capacity shortfall. TR replied that the market design would be flexible enough to handle that level of uncertainty. • TR added that there would be mandatory participation for participants with facilities that had set the real-time price in a certain percentage of intervals in the previous year. • TR presented on Option C. A Contract for Difference (CFD) price would be set in advance based on the highest priced offer required to meet the desired volume. Facilities would receive the real-time price times the dispatched quantity, plus or minus the CFD amount, whether or not the participant offered or was dispatched. • JL asked if from a consumer's point of view, this would effectively mean an administered price being set for all ESS. TR replied that from a consumer's point of view, it would remove volatility. JL replied that it would also remove efficiency benefits. JL asked if, given there were very few participants capable of being efficient enough to benefit from such a system, would it not simply provide benefits for Synergy. TR replied that it would depend on the price that was set. • TR noted that spinning reserve was administered and hadn't significantly changed, whereas LFAS was not administered and had changed substantially over time. DH replied that while the spinning reserve calculation was administered, the price had in fact changed quite markedly over the last 2 years, going from $16,000 to around $5,000. TR added that he was seeking industry		

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		feedback on their relative enthusiasm for the different options under consideration. • PP asked whether financial licenses would be required. TR replied that they would. • JL noted that it would be risky for participants to bid into the mechanism. EA noted that this would be a relatively small part of the market, and CFD already didn't appear to work in the larger energy markets. • WS asked whether the locked-in CFD cost would be distributed to all market participants. TR replied that it would be distributed according to the cost recovery mechanism. WS stated that if he could use the supplementary mechanism to lock in a cheaper contingency response price for his customers then that would incentivise him to participate. • TR presented on Option D, in which AEMO would assign ESS obligations to market participants, and the participants could then choose whether to procure that ESS obligation through the real-time market or via bilateral contracts. • JL asked what the actual obligation would be and how it would be determined. TR replied that this was the most problematic aspect of Option D, as AEMO would need to forecast cost allocation months in advance. EA asked what would happen when the forecast was wrong. TR replied that in that case participants would still pay based on the forecast obligations, not actual out-turns. Greg Ruthven (GR) from AEMO added that by locking in the obligations, the signal to reduce ESS requirements would be blunted. JL added that it would effectively be the opposite of causer pays, as obligations would be locked in. TR replied that it would be similar to the operation of the IRCR, in that a participant's actions during the period would not alter their outcomes in that period, but it would influence their assessment for the next period. • PP asked who the obligation would fall upon. TR replied that he would discuss cost recovery later. • TR noted that Options A and D did not look favourable, and Option B appeared to be most suitable, and that the feedback from the meeting so far had appeared to reinforce that view. • JL asked what the trigger would be to activate the supplementary measure. TR replied that the reform team was still working on whether it would be set to on by default and then triggered off, or set to off by default and then triggered on. One particular trigger would be real-time market price levels.		

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		• JL asked whether Synergy would still be the default provider of ESS. TR replied that the intention was to implement measures that removed the need for a default provider of ESS. If that proved to be impossible, then the default provider would be Synergy, although AEMO would have powers of direction across all facilities to provide emergency response. • JL asked how much of Synergy's fleet would be procured. TR replied that Option B was done on a facility by facility basis. JL asked how many machines would be paid availability payments. TR replied that the requirement would be expressed in megawatts rather than number of machines. JL asked what would happen if any of those machines were to experience an outage. TR replied that this would be handled by contingency response or emergency response services. Geoff Glazier added that anybody could still bid into the real-time market if they weren't part of the supplementary mechanism, sod dispatch wouldn't be constrained by this process. CJ added that there was unlikely to be scarcity issue initially, as a number of machines could provide regulation. • TR reiterated that Option B was currently the preferred option, but implementation details were still being worked through, including length of contract and triggering mechanisms. • JL asked how the RoCoF service would be procured. TR replied that this would be procured via a combination of a real-time market and supplementary mechanism. JL asked whether the generators that were already providing inertia by default would also participate in the RoCoF market. TR replied that they would, and that in intervals where they would be running anyway for energy purposes, the marginal cost of providing RoCoF control service would be zero, so the RoCoF Control service offers and price in those intervals should also be zero. PP noted that the dispatch engine would need to co-optimise this service with all other services to ensure an expensive machine wasn't dispatched simply because it could provide inertia cheaply. TR agreed. • WS asked whether the fleet capability to provide services would be monitored and published moving forward. TR replied that it would, and would be discussed later. TR presented on cost recovery: • Costs would be allocated on the "causer pays" principle. • Frequency control service costs would be allocated to participants in proportion to the demand they induced for those services.		

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		• LFAS costs were currently recovered from loads and non-scheduled generators, with injection or load used a proxy for contribution to variability. However, the rise in behind the meter generation meant some loads were reducing consumption while increasing variability. Under causer pays principles, scheduled facilities would pay for variation from dispatch, intermittent generators would pay for variability from the forecast, and non-scheduled loads would pay in proportion to their volatility. The option for participants to self-forecast would be explored in the Settlements workstream. • Spinning reserve costs were currently recovered based on the runway method. Generators associated with intermittent loads were currently only included for any market portion of their generation, even if an outage to their behind the meter generator would trigger the use of spinning reserve. Load rejection reserve costs were recovered from all market customers according to their consumption, and network constraints were not explicitly considered in spinning reserve cost recovery. The proposed approach for Contingency Response would be to retain the runway method for supply contingencies, but to use interval-by-interval values for scheduled and intermittent facilities behind a network constraint. • JL asked what was meant by “behind a network constraint”. TR replied that this referred to facilities behind a physical network constraint. • JL asked whether for intermittent loads, market customers would be charged where no market generator was involved. TR replied that how that would work was still under consideration, but as a matter of principle a facility that relies upon a particular service should contribute to the recovery of the service’s costs. • Consumption-share-based cost recovery for Contingency Reserve for load contingencies would be retained. • There was no existing RoCoF Control service in the WEM. The size of the RoCoF Control service requirement will be ‘caused’ by two main factors: RoCoF safe limits based on generator ride-through capability, network settings, load characteristics; and contingency size. Spreading costs across all participants would be simplest, but would not provide incentives to improve system performance. As the RoCoF Control service would depend on all those elements, causer pays would require placing incentives on each – generators, network and loads - to improve their performance and reduce the need for the service. • EA stated that she did not like loads being listed on the slides as being a proxy for the network. The network should be specifically required to contribute to cost		

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		recovery, as otherwise it would not be incentivised to improve performance. TR replied that how to incentivise improved network provider performance was under consideration. The extent to which costs were driven network configuration could also be considered by the Whole of System Plan. • DH asked if loads were now going to be penalised, would they also see a reduction in their pass-through ESS charges. TR replied that the new system would replace the current system, for example if a load was perfectly flat it would not be charged for regulation under the new system. DH asked whether ESS providers would be exempt from ESS cost recovery. TR replied that they would still be charged for whatever burden they may place upon the system, while receiving payment for the services they provided. TR presented on governance, review, monitoring and reporting. • Currently ESS reviews were conducted every 5 years. The first review under the new system would occur within 2 years, and would include an explicit economic assessment of the underlying ESS technical parameters based on a set of market performance metrics. Subsequent reviews would occur at least every 3 years, with out of sequence reviews triggered by market conditions. • AEMO would publish data on ESS performance metrics on a weekly or more frequent basis, with the ERA reporting on ESS market data and providing analysis on key trends regularly. EA noted that this data would already be available in AEMO's real-time market data. • AEMO would continue to monitor ESS provider performance and would also take responsibility for annual ESS requirements reporting from the ERA. TR noted upcoming ESS topics to be presented to the TDOWG, which included Locational ESS; Settlement; and Scheduling and dispatch arrangements, including dispatch mechanics, participation requirements, offer characteristics, treatment of intermittent generators and DSM, impacts on STEM, and compliance and monitoring. • EA noted that she had raised the impacts on the STEM at a previous meeting, as there were several factors which would impact the STEM, and asked whether this could be addressed as a separate topic. The Chair replied that it would. TR added that the Energy Scheduling and Dispatch paper, which had recently been released, also contained information on proposed changes to the STEM to account for these impacts. • JL asked whether for Contingency Response, they planned to balance contingency size and inertia in real-time, pre-dispatch or even longer timeframes. CJ replied that optimisation would need to be done in real-time		

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		because the amount of contingency reserve required would be dependent on contingency size and inertia. The pre-dispatch forecast would signal the need for additional RoCoF Control service. JL asked whether the potential for additional RoCoF Control services to reduce the size of the greatest contingency would also be an option, and whether it would be considered in real-time or pre-dispatch. CJ replied that it would be considered and TR replied that it would likely be considered in pre-dispatch as it would be difficult to do in real-time, because new providers could not be synchronised in that timeframe. JL asked if much work had been done on the matter and CJ replied that they had done some initial thinking but there was more work to be done. • WS asked whether the project team had engaged with any of the owners of intermittent loads about the changes to ESS cost recovery. TR replied that they had not yet done so. AV added that the team would be keen to engage with them.		
4.	Meeting close	The Chair thanked TR and stated that there was an ongoing discussion on ESS design, and further work on the matter would be brought to the TDOWG when it was more advanced. Following the meeting, the ETIU would incorporate the feedback into its work and the door was always open for further feedback. The Chair encouraged the TDOWG to contact either himself or AV, who was leading the workstream. Feedback would be incorporated into high-level Taskforce papers, which would be published in due course. The next meeting would be held on 9 September 2019, where Settlements and RCM would be discussed.	ETIU to prepare and publish Taskforce papers.	