Government of **Western Australia**
Energy Policy WA

Minutes
Transformation Design and Operation Working Group – Meeting 36

Time: 9.30am – 11.30am
Date: 6 May 2021
Venue: Online meeting via teams

Attendees:

Name	Organisation	Name	Organisation
Aditi Varma	ETIU	**Manuel Arapis**	ERA
Adnan Hayat	RCP Support	**Mark McKinnon**	Western Power
Andrea Chapman	Synergy	**Mark Riley**	AGL
Aniruddha Deshpande	Neoen	**Megan Ward**	Neoen
Antonia Cornwell	Synergy	**Natalie Robins**	RCP Support
Ashwin Raj	ETIU	**Noel Schubert**	Independent
Bobby Ditric	Lantau Group	**Oscar Carlberg**	Alinta Energy
Brad Huppatz	Synergy	**Patrick Peake**	Perth Energy
Clayton James	AEMO	**Paul Arias**	Bluewaters
Dominic Re	ERA	**Rachelle Gill**	EPWA
Donna Tedesco	ACAPMA	**Rajat Sarawat**	ERA
Dora Guzeleva	ETIU	**Rhiannon Bedola**	Synergy
Emma Forrest	ERA	**Richard Peppler**	Western Power
Erdem Oz	Independent	**Rob Chandler**	Western Power
Erin Stone	Point Global	**Sam Lei**	Alinta
Gian Garttan	Synergy	**Sandra Ng Wing Lit**	RCP Support
Glen Carruthers	Western Power	**Sara O'Connor**	ERA
Graham Pearson	AEC	**Sarah Silbert**	AGL
Greg Ruthven	AEMO	**Simon Orme**	Sapere Research Group
Harry Street	Entego Energy	**Simon Middleton**	AEMO
Hubert Liu	AEMO	**Stacey Fontein**	AEMO
Ignatius Chin	Energy Market Consulting	**Stephen Eliot**	ERA
Irina Stankov	ERA	**Steven Kane**	ETIU
Jacinda Papps	Alinta	**Tim Robinson**	RBP
Jenny Laidlaw	ERA	**Trevor Griffiths**	AEMO
Jo-Anne Chan	Synergy	**Toby Price**	AEMO
Judy Hunter	Western Power	**Tom Frood**	Bright Energy Investments
Justin Ashley	Synergy	**Victor Francisco**	PSC
Kang Chew	AEMO	**Vincent Blo**	Kleenheat
Kei Sukmadjaja	Western Power	**Wendy NG**	ERM Power
Katie Franklyn	Clear Energy	**Quentin Jeay**	Kleenheat
Laura Koziol	ERA	**Sarah Graham**	ETIU
Linh Nguyen	Chamber of Minerals and Energy		

Meeting minutes should be read in conjunction with meeting slides.

Item No.	Issue
Slide 1 - 4	Aditi Varma (AV) opened the meeting and reminded participants of meeting protocols. • AV noted this will be the final TDOWG before the end of the Taskforce on 14 May 2021, however TDOWG meetings will continue to take place as the main stakeholder forum for ongoing WEM reform activities.
1.	**NCESS Framework – Aditi Varma (ETIU)**
Slide 5	AV gave an overview of the problem definition. • NCESS will replace the concepts of Network Control Services and Dispatch Support Services that currently exist under the WEM rules. • With increased penetration of DER, locational security issues on the SWIS may also become critical. • To balance energy supply and demand in real-time we have already designed the Frequency Control Essential System Services (FCESS) framework. • What we don't have is a framework for locational security and reliability services and emerging power system needs – the NCESS framework will be designed to respond to these issues. • Even after designing these new services, there is still a need for maintaining AEMOs ability to direct facilities in emergency situations – this is drafted as new WEM Rules.
Slide 6	AV gave an overview of potential types of NCESS • NCESS – the list of services is not exhaustive; the idea is to signal the need for emerging PSSR issues which may be resolved by the new framework. • Services will be procured through bilateral contracts and not co-optimised with energy as many of these technical requirements of the system may be based at a location or not be able to be forecast in advance. • NCESS will be procured through contracts and then featured in the dispatch algorithm through constraint equations or procedural parameters for the purposes of dispatch..
Slide 7	Context of NCESS – AV outlined timescales and planning horizons over which NCESS will be procured • NCESS will be procured over long-term system planning time frame. ○ Represented here is a timescale of WP network planning process – through to real-time operation of the system by AEMO. • There are three main entities involved in SWIS long-term planning – Western Power responsible for transmission and distribution network planning, AEMO for operational system planning, and the Coordinator of Energy for the whole of system plan. • The context for NCESS arises in long term system planning activities, where assumptions and scenarios for system planning will be coordinated and discussed between the main planning entities. • This would enable a coordinated approach between WP and AEMO and allow easier hand over in operational planning timeframes enabling AEMO to run the system to a set of pre-agreed standards. • WP would have ability to forecast in the network planning horizon, whether it needs to upgrade or invest in non-network solutions to resolve power system security and reliability problems through procurement of NCESS where it may be more economically efficient to do so when compared with reinforcing or augmenting the network . • In the operational planning timescale (3 year PASA timeframes) – AEMO should also be able to procure for services not already forecast through other existing processes.

	• Currently there is no codified obligation on WP to develop and publish a transmission network plan for a specified period of time, although a transmission network development plan is submitted as part of the access arrangement. ○ Only information currently made publicly available is through the annual planning report (published after the access arrangement determination by the ERA). • Requirements to plan for the network, coordinate with other entities, take customer input, and give adequate consideration to non-network options are not properly codified in the Access Code • Access Code does require WP to produce a 5 year Network Opportunity Map – but this necessarily looks at relatively short term solutions. • As part of NCESS framework, a requirement to develop a 10-year plan for the transmission network will be codified as needed in the Access Code
Slides 8 - 9	AV outlined the NCESS framework design parameters • Any of the 3 entities with system planning functions will be able to trigger procurement process for NCESS – WP, AEMO and Coordinator. Reasons for trigger for WP: • Energy uplift payments – given to generators when they're behind a network constraint and they're required to run to resolve a network constraint (even when offer price indicates otherwise) – they are consequently made whole. ○ If the magnitude of these payments reaches an unacceptable/uneconomic level, and if market power is reasonably controlled - one can conclude that there is a network constraint binding frequently and there's persisting network congestion. The information about binding constraints and the magnitude of energy uplift payments will be made public through AEMO's constraints library and congestion information resource and market settlements system. • WP will be able to use AEMO information on constraints to procure NCESS to resolve locational issue if it is the more economic solution when compared to augmenting the network. • Other reasons for WP triggering include a modification to an existing technical standard or the introduction of a new technical standard, frequent manual intervention by AEMO into the dispatch algorithm to resolve non-frequency related issues such as reactive support. Reasons for trigger for AEMO: • AEMO reasons are straightforward – through operational planning process, AEMO may forecast the need for a new type of frequency management service. • FCESS markets may see cost blow-outs which may imply a new type of service may solve the issue Reasons for trigger for Coordinator: • Coordinator may identify the need for a new type of service and trigger the NCESS procurement process based on their role in developing the whole of system plan and in reviewing the ESS framework. Checks and balances: • Checks on the triggers particularly when WP and AEMO are triggering to ensure that both power system security and reliability and economic costs of procuring new services has been adequately considered. There will be a obligations for AEMO and WP to consult with the Coordinator when they propose to trigger the NCESS process. • Coordinator may appoint an independent technical expert to ensure the system needs are balanced with cost and overall benefit to consumers. Efficiency:

	• The new facilities investment test provisions will continue to apply to ensure the procurement process is run efficiently and transparently by WP. • For AEMO, the ERA will conduct regular compliance checks including checking whether AEMO ran the procurement process efficiently. • Procurement doesn't apply for Coordinator as she or he will generally be directing AEMO/WP to procure services. Mark Riley (MR) noted that WP triggers are somewhat market based and asked if there is any reason WP shouldn't also consult with AEMO and vice versa. • AV noted that yes, the intent is that WP and AEMO will be able to coordinate with each other as well as with the Coordinator Liz Aitken (LA) asked how the 'unacceptable threshold' of energy uplift payments is defined? • AV stated that many factors can constitute this – e.g. could be the number of times a particular constraint is binding, or a dollar threshold. What an acceptable threshold is will be need to be worked out further. MR asked whether all three parties would need to agree that the trigger is correct given there may be temporary issues? • AV answered that yes – the process needs to be agreed and would need ongoing consultation. LA asked what is the envisaged term of these services? If it's too short you're not going to get responses, or it will be extremely expensive. • AV noted that service specification will be responsibility of triggering entity, the tenure of a service will depend on what it has been planned for e.g. a temporary solution could be procured cheaply while a long-term solution is worked on. MR asked whether this should be considered within long-term system plans? Investment should suit these requirements. • AV clarified this is the intent of the NCESS framework, it is meant to be cost efficient and needs to be considered within system planning process which is why a 10-year network and system planning horizon is being recommended. There is also scope in the long-run for the whole of system plan to evolve into a more integrated approach to system planning which considers generation adequacy, network adequacy, low-load etc. Focus here is to build upon planning processes that currently exist and then move to a more integrated long-term approach. Dean Sharafi (DS) asked if one party whose responsibility it is to procure a service does not do so; would this responsibility fall on others to do? • AV answered that the framework will be codified – once Coordinator approves the trigger, the relevant party has an obligation to procure the service and will be subject to a compliance breach if they do not do so.
Slide 10	• AV summarised the procurement process – noting it will be codified in the WEM Rules. Noel Schubert (NS) noted that services procured by contract provide certainty, but are often expensive and inflexible, especially if they are required to be available every day for the whole term, but hardly ever required (e.g. system restart). If signals were provided to potential providers closer to the need, it is likely that flexible providers could supply the service at lower cost. Information on the need, and signals when it is needed, are what is missing. • AV noted the point as a comment and indicated that there are certain needs that can be signalled in the longer-term planning horizon. Also unforecasted and unexpected events are occurring on the system closer to real time which would require a quick response. Rhiannon Bedola (RB) asked if there were to be other Network Operators, can the Coordinator direct them or only WP, noting the rules have replaced WP with Network Operators? • AV answered that intent of the framework will be applicable to any network operators in the SWIS.

Slide 11	• NCESS contracts will be bilateral contracts that can be procured from any new or existing facilities that meet the technical requirements. • Intent is to make NCESS procurement an open and transparent process - existing procurement processes are not public. • Requirement for new and existing facilities to declare in their submissions whether they have capacity credits or whether they are applying or about to receive certified reserved capacity ○ Main message is that customers should not be to double paying NCESS facilities for costs already being compensated for through other components of the WEM. Jenny Laidlaw asked does that mean if a NCESS as triggered by high energy uplift costs the market would continue to pay those costs. • AV answered that no – the intent is that NCESS will reduce the energy uplift payment by either contracting that relevant entity and paying for costs of relieving network congestion or enabling a more cost-efficient supplier to meet that network need.
Slide 12	AV summarised process for dispatching NCESS • NCESS contract information will come through as limit advice and reflected into SCED, however no real time co-optimisation. • AEMO will need to be instructed as to how NCESS contract is to be dispatched in the market. • Clayton James (CJ) indicated that in addition to reflecting NCESS in dispatch through constraint equations, procedural dispatch can also take place i.e., not an energy based dispatch instruction for some of these services, it may be a service to support system strength etc. Rebecca White (RW) asked how contract revenues interact with the market power mitigation regime? Will the contract need to be provided to the ERA for consideration? • AV noted that the idea is that the NCESS contract is there to address a PSSR need, and we have to assume all market power controls were in place. NCESS will be resolving the system security problem. Peter Huxtable (PH) asked if NCESS is a market mechanism (and potentially localised service) why doesn't the cheapest bidder provide service whether they are already getting capacity credits or not? • AV answered that NCESS would be for incremental services like reactive power, which will be in addition to the energy service provided in the WEM. Intent is to not double pay party currently being compensated through RCM or other markets. • DG noted that customers should not be paying for the same service twice.
Slide 13	• Cost recovery of NCESS contracts will be over the tenure of the contract and for the intervals where the service is being provided. • Next steps – framework is at a fairly high level and will be converted into a Taskforce paper to be released for public information. • June/July working to implement detailed design which will be brought to TDOWG for further consultation. Patrick Peake noted that where these services are localised those offering services will likely have market power. Addressing this, to minimise costs, will be a challenge. • AV noted yes. The NCESS framework assumes market power mitigation controls are in place. Where there is local monopoly generator able to game the uplift payments, we need to ensure market power controls are correctly exercised and that a NCESS contract is resolving local congestion problem. RW asked whether consumption share cost recovery is for gross or net consumption? E.g. if a transmission connected battery was stand alone, would all its consumption be counted for cost recovery purposes?

<table>
<tr><td></td><td>AV answered this would need to be worked through in greater detail. However, market customers will pay similar to cost recovery for current dispatch support services.
LA asked what happens if no one is available to provide the service.
AV noted this might mean technical specifications are too onerous, consider breaking the service not different components. If the service cannot still be provided, generally speaking there will be ways to break up the service into different components or figure out asset reinforcement alternative.
DS asked if there is a need for a service and no one participates, would there be a provision for a reverse auction?
DG and AV will take this comment on notice, but noted that reverse auctions were not being considered.</td></tr>
<tr><td>2.</td><td>Forced outage Refunds and availability declarations – Dora Guzeleva (ETIU) and Clayton James (AEMO)</td></tr>
<tr><td>Slide 15</td><td>DG gave overview of In Service/Available quantity declarations
Issue discussed in consultation on Tranches 2 and 3 last year
In current market, participants must declare capacity unavailable for purposes of dispatch offers.
If participant declares facility unavailable, they will need to declare forced outage and they will not be dispatched and face a reserve capacity refund.
If capacity declared available, AEMO will provide dispatch instruction and if the participant cannot respond there will be capacity refunds and a potential non-compliance investigation.
Under the new market, availability declarations submitted with offers, but change to ‘in service’ or ‘available’
For both declarations – quantity should equal available capacity – to enable capacity available but not in service to be dispatched.</td></tr>
<tr><td>Slide 16</td><td>DG gave overview on Policy Intent
When we published Tranches 2 and 3 for consultation, we indicated that the policy intent is what currently applies would need to equally apply to new declarations in new market.
If a facility is not available, they should indicate this with a forced outage declaration – we will not have a declaration for just unavailable in the new WEM.
In the consolidated rules – we included an explanatory note explaining that if a facility is available but not in service, they will either have to change their declaration and make themselves in service or submit a forced outage.
Comments at the time indicate that there were no objective means prescribed in the rules as to how this will be judged by AEMO – participants wanted an objective measure.
ETIU has worked with AEMO to ensure there is an objective measure.
The difficulty is that in the current declarations, if a facility declares themselves available, they will be dispatched and need to respond to instructions. However, in the new WEM if a facility is available but not in service, AEMO will skip them in the merit order and customers will pay higher price in the market.</td></tr>
<tr><td>Slide 17</td><td>CJ gave general In Service/Available examples
Facilities with a single generating unit – participants should offer the full capacity as available (i.e. not “in service”) where not expecting to commit indicates that facility will not be running in particular interval, and this will be factored into things like pre-dispatch.
Multi generator facility – if the intent is to run only one of the units in particular interval, then the offers would be part in-service and part available.</td></tr>
</table>

	• Multi-fuel facility – where there is a higher price on alternative fuel, would offer capacity related to primary fuel (unless intending to run on alternative fuel). Representing that the extra capacity could be made available in appropriate time.
	JL asked how you would expect a peaking generator with a high mingen to offer when it doesn't expect to need to run, i.e. available/in-service and what price it would offer for its mingen
	• CJ noted there is no specific expectation on price – but intent would be to offer as available if it is not intended to commit. Further examples should help illustrate this point.
	PP asked whether a plant that is idle but ready to be dispatched would declare "in service"
	• CJ noted if by idle you mean 'not committed' as in it hasn't started, then its status should be available to show that it is ready to be committed but not yet "in service".
	JL asked how would a hybrid ESR/wind farm offer?
	• CJ would be like any semi-scheduled facility so would offer based on forecast output – all "in service"
	• DG noted they would be subject to dispatch instructions to reduce – i.e. dispatch cap.
	LA asked what happens when switching to the alternative fuel requires a restart?
	• CJ answered in this case the available declaration should indicate how long the capacity start-up should take – essentially capacity start up time represents time to restart the machine on alternative fuel.
	• DG noted with any change to offer, facilities will need to provide start-up time and minimum generation will also be in standing data.
	LA asked whether it would be easier to peg the available quantities to the limits based on fuel type?
	• CJ noted that this is what is being provided by in service quantities and that there will be no fuel nominations in market anymore
	    o What this does is allow for us to identify when capacity is available – scenario will expand on this later in the presentation
	    o CJ further highlighted that alternative fuels and restart time likely to be fairly static

Slide 18	CJ provided overview on Simple Scenario 1 – Facility Commits • Case where facility is forecast to run, and participants want to commit facility. • T-7days: In this example participants offered 0 in service, but 100 MW available • T-5days: As we move close to the dispatch interval – reference scenario looks at expected load forecast. Showing that there is an expected dispatch quantity. • T-2days: Participant has obligations in this case to offer 90 MW as they have capacity credits. Can adjust STEM pricing based on what pre-dispatch is showing them. No shortfall in this example. • T-1days: hitting start up time for facility – participant showing intent to commit • Dispatch Interval: Obligation to offer all available capacity covered by RCOQ. o Adds up all in service and available quantities and checks required capacity was offered – in this example no shortfall • Settlement – in arrears (5 weeks later) • Summary – At the point of no return, from minimum start up time, participant changes to in service and is dispatched accordingly (can change offers at any time). JL asked in the example, if the dispatch engine needed another 10 MW (above the forecast 50) would it not dispatch the facility for the extra 10 because that was not in service (sorry, probably missing the point) • CJ answered that yes it would do this in the dispatch interval as the capacity is not in service. If it was forecasted that extra capacity was needed than the pre-dispatch/market schedules would be showing 60MW for that facility- showing ahead of time how much of marked capacity is actually needed and allow time for participants to make changes.

<table>
<tr><td></td><td>
JL followed up by stating that the actual dispatch is quite likely to differ from forecast.

CJ noted that yes – actual dispatch will always use actual in service capacity. This is about identifying ahead of time what commitment is required and providing information through pre-dispatch. At the moment we only see balancing forecast it doesn’t show how much of each facility is likely to be needed and whether any of this is from components of facilities that aren’t intending to commit.
JL noted that you could make half your facility’s capacity available rather than in service
Mike Hales (MH) clarified that when making submissions you need to consider start-up time, what you can provide in intervals, any outages etc.
In this example we have to assume that the facility is two 50MW units – with only one available for dispatch – if the facility was 100 MW submissions would need to be modified to show that more capacity could be provided than the 50MW.

Rhiannon Bedola (RB) asked how differing views of real time are managed? In pre-dispatch it shows up you are needed but your view is that in real time you won’t be as you expect changes to demand or higher DER?

CJ clarified whether RB was asking how forecast uncertainty is managed – and answered that in pre-dispatch the intent is to provide as much information as possible on the variability of that particular interval for participants to make decisions (including multiple pre-dispatch scenarios).
This variability is as true in current WEM as it is in the new market,
RB asked how you avoid being penalised when you put bid in – how is information fed back through?
CJ noted the mechanism AEMO will use is the reference case – which is the best estimate of what demand is expected to be – participants can still price themselves as needed to make own commitment decisions.

</td></tr>
<tr><td>Slide 19</td><td>
CJ provided overview of Simple Scenario 2 – facility that does not commit

Same facility as above scenario - 7 days head facility decides not to offer ‘in service’
5 days ahead market schedule now indicates likely to be needed – offers can still be adjusted within allowable trading boundaries to avoid needing to be run
2 days ahead – still not likely to be required but participant has to offer in to match RCOQ
1 day ahead – still not likely to be required and participant prices reasonably to avoid needing to commit
Participants are required to manage themselves.

LA asked whether the ERA will ping you for not responding to pre-dispatch signals? Would the ERA require you to keep all data sets on your decisions?

DG answered that – we are moving to a new market where offers can be adjusted closer to real-time and what we’re discussing today is applicable when the new market starts. We expect that participants do record reasons for changes in offers (alongside other market power mechanisms)

CJ further noted that the main thing here is start up times - both examples show how pre-dispatch can be used to commit a machine or not.
</td></tr>
<tr><td>Slide 20</td><td>
CJ gave overview of Refund Scenario 1 – facility does not commit and faces refunds

Same scenario – focused on where the refunds may kick in which is based on the last time you can make a decisions for your facility (which is based on start-up time and whether or not you have reserve capacity obligations)
In this example - 5days ahead market schedule indicates likely dispatch – participant adjusts offers to avoid being committed however the schedule is still indicating likely dispatch.

</td></tr>
</table>

	• 2days ahead still showing likely need for 50MW for plant – STEM offers can be adjusted based on what pre-dispatch is showing
	• 1.5days – Pre-dispatch indicates facility likely to be dispatched however offer of 0MW in service is maintained. Based on 24 hour start-up time, if in the next pre-dispatch interval, the change has not been made then this will be a shortfall and will be processed as a refund in settlement.
	    ○ This would vary for facilities with longer or shorter start up times.
	• Need to consider what is the last point in time a decision can be made – if the change is not made than this will become a shortfall.
	
	LA asked for the interval in question whether we are setting bid price bands 7 days out? Or do we have ability to change bid price bands and thereby potential change our dispatch? (e.g. for gas plant)
	
	• CJ answered yes – pricing for offers can be changed at any time throughout the cycle.
	    ○ LA had assumed we were doing fixed price bands and changed volumes i.e. the case in the NEM, but this is not the case here.
	• Tim Robinson (TR) clarified that the rules as drafted allow both prices and quantities to be changed right up to gate closure keeping in mind considerations for representing reasonable cost etc.

Slide 21	CJ gave overview of Refund Scenario 2 – facility does not respond to direction
	
	• This scenario is about a shortage – a reason AEMO is asking for this data is to identify when a shortage situation will occur.
	• There are times where dispatch interval cannot be moved into next in service quantity – in this example at 1.5days ahead and the dispatch interval – we can just move to the next in service quantity as there are none.
	    ○ Pricing signals should be high
	    ○ AEMO in this case would need to direct the facility to offer in service
	    ○ If failure to update offer to show in service as directed – than this would be treated as a shortfall (noncompliance with direction)
	• Shortage situations are currently allowed for in the PASA process where a low reserve condition is declared, and notification sent out – with timeframes.
	• Notice goes out – expectation that participants will use info to make offersas the price incentive should be strong.
	• This is last point in time where AEMO can intervene to solve shortage problem.
	• In this case, no refunds for facility – just demonstrates what would happen if chose not to change the declaration.
	
	RB asked whether long start facility dispatch will be impacted by short start dispatch but without having the "known" commitment of the short start facilities a day out how can you manage that risk?
	
	• CJ noted that long start facilities face this risk today with less information than what will be provided in the new market – It is true today in the balancing market.
	• DG noted that there’s no reason for a facility not to change declaration and make themselves in service, except for the obvious reason that the facility is on a forced outage and cannot start

Slide 22	Policy intent – Issue 2 • DG explained that the intent of this work is to provide a more objective function to ensure that (within constraints) facilities should be made available when they say they will be. ○ ETIU and AEMO were focused on finding an objective way to do this without unnecessary complexity • Clause 7.5.9 allows storge facilities to ask AEMO to use constraint equations in their dispatch algorithm e.g. AEMO using charge levels data to put constraints around facilities

	• The issue is, because AEMO is taking action on behalf of participants and actually constraining their dispatch, there are no means of reconciling this with RCM RCOQ requirements on that facility to make themselves available • Aim of examples was to make sure AEMO dispatch in accordance with constraints but also ensure obligations fulfilled under RCM with refunds treated in the same way as for other facilities.
Slide 23	CJ gave overview of Storage Scenario 1 – Standalone ESR • 50MW CC allocated between 4pm and 8pm • In this case the dispatch interval is 5pm so RCM obligations apply • 7days 50MW and 20MW of regulation raise • 5days – likely to be dispatched based on reference scenario • Based on level of charge the maximum quantity is 24MW – participant has to show 50MW in service however physical dispatch can only be 24MW (based on real-time state of charge) • Shortfall in real-time for capacity credits carrying facility. LA asked whether you are saying that batteries are only incentivised to be in play based on pre-dispatch regardless of any other circumstances? • DG noted specific carve out in the rules that reduces reserve capacity obligation – if a storage facility dispatched to provide ESS due to shortage LA noted that level of manual intervention would be onerous – and would require back adjustment – asking how would this impact on balancing prices? • DG noted that the participant cannot be penalised if AEMO request they meet a particular need • CJ confirmed that refund in this example was given as dispatch impacted by state of charge. JL noted that the pre-dispatch process won't recognise the charge of the battery is low? • CJ answered that pre-dispatch cannot forecast SCADA and this cannot be factored in easily in pre-dispatch
Slide 24	CJ gave overview on Storage Scenario 2 – Hybrid with ESR • Same scenario for storage in a hybrid facility. • Based on expectations of what the wind may do. • Day ahead – still likely to clear however get to dispatch interval and real time state of charge showing they couldn’t meat reserve capacity obligation. • Proposal to use real-time state of charge to determine difference and pass through to settlement. • DG noted this is aimed at treating these facilities equally with the rest of the market ensuring they face same penalties as other participants if they do not make their capacity available.
3.	**Rule Drafting Timeline - Dora Guzeleva**

Slide 26	DG gave brief overview of status of WEM Rules changes
	• Tranche 4A (split tranche 4 in 2)– has arrangements for ESS accreditation and ROCOF and changes to implement the RCM mechanism in 2021.
	    ○ Mainly relate to need to clarify certain things in rules to allow AEMO to complete procedures – Including for indicative facility class.
	    ○ Second important procedure – submetering for hybrid facilities with changes mainly relating to making rules more flexible.
	    ○ Head of power to formalize Operating Protocol
	    ○ Rules completed and going to Minister for approval and gazettal.
	    ○ Also contains commencement notices to gradually commence rules around RCM.

	• Tranche 4B – UFLS rules, system restart rules, additional changes to RCM • Tranche 5 – implementation of Taskforce decisions on NCESS, Market Information, reliability standards and MPM. • There will be a Tranche 6 – around fixing minor errors (cleaning up of the rules).