Government of **Western Australia**
Energy Policy WA

Minutes

Transformation Design and Operation Working Group – Meeting 13

Time: 9.30am – 12.05pm
Date: 09 June 2020
Venue: Online meeting via teams

Attendees:

Name	Organisation	Name	Organisation
Aden Barker	ETIU	**Katie**	
Aditi Varma	ETIU	**Katie Franklyn**	Tersum Energy
Alex Cruikshank	Oakley Greenwood	**Marc Hettler**	Perth Energy
Alice Hobson Ellis	ERA	**Mark McKinnon**	Western Power
Angeline Ong	ETIU	**Mark Riley**	AGL
Ash Raj	ETIU	**Mark Timson**	Energy-Tec
Bobby Ditric	Lantau group	**Matt Shahnazari**	ERA
Brendan Fidock	Synergy	**Mena Gilchrist**	ETIU
Bronwyn Gunn	ETIU	**Natalie Robins**	ERA
Brooke Eddington	ETIU	**Neil Hay**	Western Power
Caroline Cherry	ETIU	**Noel Schubert**	ERA
Clayton James	AEMO	**Oscar Carlberg**	Alinta
Dan Mascarenhas	AGL	**Patrick Peake**	Perth Energy
Dermot Costello	Clean Energy Council	**Paul Arias**	Bluewaters
Dora Guzeleva	ETIU	**Peter Huxtable**	Water Corporation
Drew Harris	Simcoa	**Rajat Sarawat**	ERA
Elizabeth Aitken	Perth Energy	**Rebecca White**	ETIU
Elizabeth Walters	ERA	**Rhiannon Bedola**	Synergy
Emma Forrest		**Ross Davies**	Western Power
Erin Stone	Point Global	**Sabina Roshan**	Western Power
Geoff Gaston	Change Energy	**Sara O'Connor**	ERA
Geoff Glazier	Merx Consulting	**Sarah Silbert**	AGL
Glen Carruthers	Western Power	**Shannon Hewitt**	Future Grid Energy
Graham Pearson	Australian Energy Council	**Simon Middleton**	AEMO
Greg Ruthven	AEMO	**Simon Orme**	Sapere
Irina Stankov	ERA	**Stephen Eliot**	RCP Support
Jake Flynn	ERA	**Steve Gould**	Community Electricity
James Townsend	Lacour Energy	**Susan Cunningham**	EPWA
Jas Bhandal	AEMO	**Teresa Smit**	AEMO
Jenny Laidlaw	RCP support	**Tom Frood**	Bright Energy Investment
Jo-Anne Chan	Synergy	**Troy Santen**	Stellata
John Lorenti	Synergy	**Victor Francisco**	AEMO
John McLean	AEMO	**Wendy Ng**	ERM
Judy Hunter	Western Power	**Wesley Medrana**	Synergy
Justin Ashley	Synergy		

Meeting minutes should be read in conjunction with meeting slides.

Item No.	Issue
1.	**Agenda, ground rules and virtual meeting protocols.**
Slide 1-3	Aditi Varma (Chair) from the Energy Transformation Implementation Unit (ETIU) opened the meeting and addressed the meeting agenda, ground rules and virtual meeting protocols. • Chair noted that ETIU and Energy Policy WA have moved to their new offices at 66 St Georges Terrace.
2.	**Forecasting and PASA process**
Slide 4-5	Jas Bhandal (JB) from the Australian Energy Market Operator (AEMO) introduced the topic and presented the applicability of the current forecasting and the Projected Assessment of System Adequacy (PASA) framework for a move to the Security Constrained Economic Dispatch (SCED).
Slide 6-7	JB presented the purpose of PASA and key PASA issues in relation to a move to SCED. • Slide 7 give a detailed summary of the issues that are associated with power system reliability assessment, power system security and notification, and intervention criteria.
Slide 8-10	JB presented the current medium-term (MT) and short-term (ST) PASA objectives in the context of future PASA objectives. In future objectives, both MT and ST PASA should provide sufficient and timely information about system security and reliability issues to AEMO and the industry.

Slide 11- 12	JB presented on the current uses for demand forecast relating to dispatch and pre-dispatch load forecast, PASA and the Electricity Statement of Opportunities (ESOO), the current different forecast quantities used in a PASA assessment, and examples of demand definitions in the National Electricity Market (NEM).
	Question:
	• Jenny Laidlaw (JL): what do you mean by ‘dispatchable’ quantities?
	  ○ JB: Dispatchable quantities are modified to account for ‘behind the fence’ loads.
	  ○ JL: Still unclear on what aspects of dispatch and forecasting are going to be done on a ‘sent-out’ basis and what will remain on a ‘as generated’ basis – for future.
	  ○ JB: It will be covered in the next few slides.

Slide 13	JB presented on intermittent generation forecasts. • For intermittent facilities, participant offers should reflect their generation forecast. • PASA assessments need to allow flexibility for AEMO to use a range of ‘potential’ or ‘likely’ intermittent generation outputs in order to assess adequacy.
Slide 14-15	JB presented the key principles for PASA Rules. Rules should prescribe the type of forecast quantities to be used in PASA, but linked to an overarching PASA objective, and to Power System Security and Reliability (PSSR) principles. • Rules to allow for flexibility to use the most appropriate forecast quantities in order to assess adequacy over the various PASA timeframes – hard-coded requirements in the current WEM Rules to be removed. • AEMO to be required to document the assessment methodology to determine PSSR in a Market Procedure- a new requirement will be required for transparency. • AEMO to specify the information required from Market Participants in the Market Procedure for transparency.

	• Granularity and publication of the PASA reports will be increased to improve usability and provide flexibility– specifics located on slide 15. The shortened horizon is to build a model that reflect physical reality and have better outcomes.
	• AEMO to publish all quantities used in the assessment, as well as the summary report. This is a new requirement to aid transparency and improve usability.
	• New requirement to develop notification and intervention criteria specifying how key shortages are identified, what AEMO can do to intervene and the obligations of participants (to be discussed later)
	
	Questions:
	• Elizabeth Aitken (EA): Will AEMO have a better view on generation output for intermittent than the power station owners?
	    o Clayton James (CJ): The intention is to use forecasts provided by power station owners. The challenge is using forecast scenarios in advance to assess an outage (or similar). We are allowing for some flexibility to run different scenarios and test if there are any security implications.
	• Drew Harris (DH): What are the additional information requirements for Demand-side Programs (DSP)?
	    o CJ: No specific requirements yet. It depends on the information that can be used with respect to offer information and assessment. AEMO will need to determine the availability of DSP over a longer-term horizon. Similar to a scheduled generator and using the outage support information, outage plans may potentially be used to help in the longer-term assessment.
	• JL: Why shouldn't minimum requirements be specified in the Market Rules?
	    o Chair: The intention is to have a minimum requirement in the Rules. We want to at least outline the principles to be used in the operational planning and PASA process. Guidance and examples will be moved to procedures. This will become clearer during the drafting of the rules, but happy to take feedback from industry about what level of information must be retained in the Market Rules. And what level of information to retain in the procedures.
	• EA: Is there value in having 30minute PASA for 3 years?
	    o CJ: There is potentially a lot of information. The current weekly MT PASA provides minimal value. The 30minute timeframe is related to using consistent data to run through modelling. If it is too much information to provide to Market Participants, we can vary the amount of data to be published.
	    o EA: Market Participants using MT PASA will be using to forecast outage in days or weeks not in 30min increments. What is the intention of the 3 year MT PASA?
	    o CJ: To assess reliability 3 years out and align with the outages framework. For example, for the supplementary Reserve Capacity Mechanism (RCM) this will provide a 3 year view of reliability taking into account more detailed analysis.
	    o EA noted it shouldn’t take long for existing mechanisms and raised concern that assumptions may not have been validated.
	    o JB clarified reporting will be daily.
	    o CJ: If there is too much data, reporting can be adjusted to assist Market Participants. Perhaps provide a daily data maximum and minimum. It’s about how to model the data underneath.
	    o EA: Questioned the timing of 3 years as excessive, 2 years seem reasonable.
	    o CJ claimed it is currently 3 years in the Rules.
	• Mark Riley (MR): If the information is too variable - how can Participants link one forecast to another. How will Market Participants be able to identify trends if the hard coding of obligations and assumptions are removed, and the scenarios and assumptions change each month?

	◦ CJ: The change is to understand the level of risk for dispatch scenarios, outage scenarios and understanding the high-risk periods. ◦ MR queried how will one forecast be linked to another? Noting that running different scenarios is hard to identify trends as there are changing assumptions. There is no trending position to see which risk direction you are heading. ◦ Chair: The closer to real time that the forecasts are, the more accurate they become. ◦ CJ: Once the assessment methodologies are published it may make more sense. A lot of the variations are accounting for seasonal changes and catering for more realistic outputs. ◦ MR agreed supportive information about the assumptions being used would be useful. • Matt Shahnazari (MS): AEMO already does a system adequacy assessment as part of the Electricity Statement of Opportunities. How does MT PASA that goes three years forward differ from the analysis conducted for determining the Reserve Capacity Target and expected unserved energy? ◦ CJ: The key difference is to cater for more up to date information. Factoring in more known variables the closer to dispatch timeframe. • DH: As with any risk management, an increasing complexity of the possible drivers increases the uncertainty and total number of future possibilities, to the point where it becomes meaningless. ◦ Chair: The intent is to keep building on models and forecasts, when it becomes meaningless or time horizons become too long it might be worth reconsidering at that time.
Slide 16 - 18	JB presented on Power System Security and Reliability Assessment, the current factors used in Reserve Margin calculations (slide 17) and current issues for Reserve Margin. • A methodology is required that assess reliability over a range of possible outcomes.
Slide 19 -21	JB presented on the type of capacity adequacy measures going forward, WEM Implementation for MT PASA probabilistic approach and the MT PASA key inputs (slide 21). • JB noted that under the new Operating States framework, AEMO is required to develop and publish the Reliability Standard Implementation Procedure that includes key criteria for how AEMO will assess reliability in MT and ST PASA. More details on slide 19. • The new MT PASA is intended to use a probabilistic modelling approach and could be made up of three different analysis incorporating Monte Carlo simulations. Questions: • EA: Will the Reserve Margin methodology replace the requirements under the RCM? ◦ CJ: No, that is not the expectation.
Slide 22-24	JB presented on the three high-level methodologies that could be used in the probabilistic modelling approach. • Reliability run to forecast unserved energy over the three-year horizon. AEMO to issue a notice to market identifying any issues and if it is not addressed in time, AEMO may utilise existing powers or initiate supplementary reserve capacity for projected energy shortages (slide 22). • Assessment of likelihood of binding constraints to forecast the likelihood of constraints binding or violating over the three-year horizon. AEMO will develop a report to provide stakeholders with information on constraints and resulting network congestion that are updated regularly. • Loss of Load Probability Run to assist participants in timing planned outages to reduce the risk of unserved energy (by determining which days have higher risk of load).

	Question: - EA: What happens if MT PASA indicates a reliability problem 3 years out, but the RCM does not? - CJ: It may mean we need to reschedule some outages if there is a risk of not being able to meet load. - Greg Ruthven (GR): Will the reliability assessment produce a forecast for unserved energy (USE) for each 30 mins in the 3-year horizon? Or one number for the full 3 years? - CJ: We will still need to work through the details. - MS: What is the threshold for USE used for outage planning? Why would outage planning use USE and e.g. not Loss of Load Expectation? - CJ: The idea is that these are all valid risk values and where there is a risk identified an action can then be taken.
Slide 25	JB presented on ST PASA model detail, where there will be a move to a shorter horizon.
Slide 26 - 30	JB presented on the intervention criteria, notification and obligations in relation to the current WEM intervention process and the new intervention process. - New requirements added to the WEM Rules for AEMO to identify low reserve conditions and details will be described in the market procedure. - AEMO may intervene in different ways to resolve the issue, details of the principles are listed on slide 29. - Examples of possible interventions are listed on slide 30. Questions: - JL: Who decides what constitutes a too high risk? - CJ: This will be published in the Reliability Implementation Market Procedure - EA: Rescheduling of outages should be voluntary - particularly where the outage plan was submitted 12 months in advance - alternatively the market should pay for the reschedule costs. What will the pricing look like under all these directions? It won't be at short run marginal cost. - CJ: This is all well in advance of real time, the idea is to try and avoid these issues before dispatch occurs. - MR: An outage recall may not be possible - depending on the reason for the outage - or may lead to a much longer outage (e.g. damaged equipment) - CJ: this would really be one of the last things that we would look to do, it would be in accordance with the contingency plan submitted as part of the outage submission. - Patrick Peake (PP): There is a real cost to rescheduling outages and it also places additional risk onto the system. Rescheduling is not simple where international support is required. There should be a stronger emphasis of using Demand Side Management (DSM) to cover expected high-risk situations. - CJ: I understand rescheduling outages is not ideal for participants, the concept is the same as today where this would only be the case where the outage can no longer be approved due to security/reliability issue. The PASA tools just help us to identify those issues (including network constraints), and to provide assistance to participants plan ahead to avoid planning outages during high risk times if possible.
Slice 31- 33	JB summarised the reserve levels and intervention design principle and presented the next steps.
3.	**GPS compliance and monitoring – Transitional Arrangements**

Slide 34	Bronwyn Gunn (BG) introduced the Generator Performance Standards (GPS) compliance and monitoring – transitional arrangements, in relation to existing generators that are connected to Western Power's (WP) network.
Slide 35 -36	BG recapped on the framework and how it applies to existing generators. • The purpose of the presentation is to discuss the elements of the framework highlighted in yellow. • The new compliance and monitoring framework will commence on 1 February 2021 for generators that finalise a network access offer after that date. It will apply to existing generators (defined as generators with a finalised network access offer prior to 1 February 2021) once the register is populated with the standards for that generator and they have a monitoring plan approved by AEMO.
Slide 37	BG presented on the register of GPS • The standards that will be captured under the register and be reported against for self-reporting are on slide 37. • Standards presented were compared to the existing technical requirements. Most are existing standards with the exception of three new standards – System strength, disturbance ride-through (multiple contingencies) and disturbance ride-through (quality of supply).

Slide 38	BG talked through the register process.
	• There are two elements to the process – for new standards and existing standards.
	• Existing standards
	  o First step will be to rely information available through contracts or publicly available information on exemptions from the Technical Rules. Existing standards should be populated for generators that have connected under the Technical Rules using this method.
	  o Where information is not readily available, reference standards from the time of connection will be used as a reference point, however generators will be able to propose an alternative based on the capability of their machine. Generators will have an obligation to provide technical justification are seeking an alternative standard – this may be through advice signed off from a suitably qualified engineer (National Engineers Register) on the capability of the machine
	  o WP must consult with AEMO on any deviation from the reference standards. If WP and AEMO accept the technical justification provided by the generator, WP must populate the register with that information.
	• New standards
	  o If generators can meet the minimum standard, WP must accept the standards. If generators cannot meet the minimum standard, the generator is required to provide evidence to demonstrate why it is not capable of achieving that standard.
	  o Western Power must consult with AEMO and both parties must accept the proposed standard if they believe the advice represents the capability of the generator.
	  o AEMO may provide advice about the potential real time impacts of a generator not being able to comply with the minimum however this will not be included in the register
	• New and existing standards
	  o If parties are unable to in the steps above they may negotiate. The generator will negotiate with WP, who will be obliged to seek approval from AEMO before accepting any negotiated standard
	  o If negotiations fail, WP and the generator can agree to testing to determine standards.
	  o If the parties are unable to reach agreement they will proceed to dispute resolution.

	Questions:
	• Dan Mascarenhas (DM): What evidence/justification does WP/AEMO need to provide to a generator if it rejects a negotiated standard proposed?
	  ○ BG: We will have to work through the exact detail of what will be provided. Justification will be required by both parties as part of negotiations, and will need to be based on technical advice from technical experts or manufacturing specifications. Disputes resolution process will provide incentives for good faith negotiations.
	  ○ DM: What obligations apply to WP/AEMO to ensure a consistent negotiation and market process with all generators?
	  ○ BG: Principles will apply to ensure consistency. However, there will be no visibility about the application of principles to individual generators as the standards will be confidential.
	• Wendy Ng (WN): How long are you allowing for this registration process to take?
	  ○ BG: this will be discussed next.

Slide 39	BG presented the timing of the register.
	• Populating the register can commence immediately after the WEM Rules are made (late 2020).
	• February 2022 deadline for negotiations unless an extension is agreed.
	• If the register is not completed by February 2022 and no extension has been agreed it will be referred to dispute resolution.
	Questions:
	• MR: Is there a potential for a negotiated standard for one generator to limit the connection of a future generator?
	  ○ BG: Not sure about the existing negotiated process perhaps AEMO and WP could comment. But the future register will allow for trigger events which may encompass this.
	  ○ Mena Gilchrist (MG) clarified that this process is about discovering what the standards are, not a chance to renegotiate.
	  ○ Glen Carruthers (GC): Trigger events will be used to mitigate this issue.
	  ○ Sabina Roshan (SR): Trigger could be a network/system condition, connection/disconnection of another generator or a network reinforcement.
	• WN: For new standards, the information may not be readily available even with the manufacturer's information. February 2022 may not be adequate time to finalise this information. If testing for the new standards is required it will be costly and time consuming, and cost recovery for this may be an issue for generators.
	  ○ BG: consultation so far hasn't indicated that the cost or timeframe for determining the capability for new standards will take long or be particularly expensive. There will be the ability for extensions if negotiations are progressing well.
	  ○ Invited more information to be provided offline if there is reason to believe the timeframes will not be adequate or the process will be particularly expensive.
	  ○ CJ: the intent is also to use information that is readily available or existing data to fill in the register.
	  ○ WN: Will AEMO be looking at all events and sift through data for all generators.
	  ○ CJ: If there is an event that has occurred to demonstrate compliance to the standards, it will be used as the basis to be put in the register to illustrate a standard that can be complied with.
	  ○ BG: AEMO and Western Power will have an obligation to use existing information where available to populate the register.

Slide 40	BG discussed content of self-monitoring plans • Template will be published in a WEM Procedure and Market Participants will be consulted as it is developed. The ETIU expects it will look similar to the template in the NEM where there is guidance on appropriate testing methods for each standard. • A framework will provide guidance to existing generators proposing modifications to the self-monitoring plans and to AEMO might assess the proposals for modification.

Slide 41 -42	BG presented the self-monitoring plan process and factors AEMO must consider when assessing a proposal for modification.
	• AEMO must accept self-monitoring plans that are consistent with the template.
	• If the generator proposes a modification to the self-monitoring plan, AEMO must consider a number of factors when making a decision (slide 42). If AEMO rejects the proposed modification, they must outline why it wasn't acceptable for power system security and/or reliability reasons. They may advise they require a generator to test in the way specified in the template or propose an alternative way.
	• If agreement can't be reached in negotiations, then it will be referred to dispute resolution.
	Question:
	• MR: Where would historic agreements with WP sit in this process
	  o BG: In relation to self-monitoring plans with WP, this will be touched upon later.
	• EA: Does AEMO have the skill set to undertake assessments of monitoring plan revisions?
	  o CJ: We are working on recruiting some new roles for the GPS monitoring functions at the moment.
	  o EA: Will this result in another increase in market fees?
	  o BG: This is a new function that AEMO will need to take on, however I cannot comment on the quantum.

Slide 43	BG presented on self-monitoring plans approved by WP. • AEMO is required to accept a WP approved self-monitoring plan unless doing so would create an unacceptable risk to power system security and reliability. AEMO would be required to provide technical justification for making such a decision • Generators will still be required to propose method of testing for new standards, and if the proposed method differs from the template they will be required to negotiate with AEMO. Question: • PP: Given this is a new obligation and potentially expensive, will generators be able to recover their costs? An increase in the Reserve Capacity price perhaps? o BG: This is not something that has been considered.
Slide 44	BG discussed the timing for self-monitoring plans. • Generators will be required to submit proposed self-monitoring plans to AEMO by 1 August 2021. Failure to do so will be considered a breach of the WEM Rules and civil penalties may be imposed. • AEMO and the generator will be required to negotiate a self-monitoring plan within 12 months of the submission of the proposed plan, unless an extension is provided. If this does not occur, it will be automatically referred to dispute resolution and the contents of the plan will be determined by an independent arbitrator.
Slide 45	BG discussed the dispute resolution process. • Existing dispute resolution processes in the WEM Rules were not considered fit for purpose due to the specific nature and the time sensitive aspect of the disputes.

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A bespoke disputes process will be implemented for the register and self-monitoring plans.
An arbitrator will be appointed, who will have the ability to make binding determinations on the standards that apply to a particular generator, or the content of a self-monitoring plan
The bespoke process will be time limited to February 2023, with the opportunity to extend if required.
The arbitrator will be able to dismiss frivolous referrals if the party hasn’t negotiated in good faith or provided appropriate technical justification. In this case they may refer the dispute back to negotiations, or automatically make a ruling against the party that has acted in a frivolous manner.
A panel of technical experts that the arbitrator can seek further advice from (where necessary) will also be appointed.
ETIU to continue working through detail of the appointment of the arbitrator and technical panel

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BG discussed cost recovery for dispute resolution.

The arbitrator will have the ability to assigned dispute related costs (including the cost of seeking technical advice) from the parties. In doing so, they will be required to consider a set of factors including the conduct of the parties and the final decision relative to the positions of the parties prior to the hearing.
Factors the arbitrator must consider are detailed on slide 46

Questions:

EA indicated preference away from AEMO recovering costs via Market Fees. Stated that if AEMO brings frivolous matters then it shouldn’t be recovered by Market Fees.

BG: AEMO recovers all of its costs through Market Fees. The arbitrator would be able to dismiss the dispute if frivolous before they seek expert advice. That should mitigate any large costs associated with frivolous disputes being passed onto the market.
EA was concerned that AEMO may seek ‘engineering nirvana’ and it shouldn’t be recovered from the Market. EA suggested AEMO must be forced to apply a degree of judgement before they bring proceedings to the arbitrator, and if there was no validity in the request, ERA should have the ability to disallow the recovery of the cost through Market Fees.

MR: If that happened then a review would be needed to explain why AEMO took that path - since it would be smeared across the market.

MG: it is not clear what is meant by AEMO cost recovery. If they cannot recover from the Market, I am not sure there are any other options.
EA: AEMO should be able to reallocate costs, noted there is precedent for this.
CJ: even where costs are reallocated, they are still recovered through Market Fees in some form.
EA expressed concern over the three new standards and how that will generators will prove their ability to comply with a particular standard, and self-monitor that compliance, and would like AEMO to be realistic in their expectations.
MG noted that AEMO will be required to consider certain principles when looking considering modifications to self-monitoring plans, noted that ETIU was happy to take suggestions on other principles that should be taken into account. Noted that ultimately the arbitrator looks at the principles to determine whether AEMO have fairly considered them.
EA: Concern that AEMO will be overly conservative and won’t be held accountable for the costs they incur in acting that way.

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DM: How is AEMO held accountable and liable for matters they take to dispute? What you have described means that there is no incentive or process to hold AEMO account. Further, allowing AEMO to operate in line with broad principles does not provide clear guidance or transparency. How would the ERA even know if AEMO was acting inappropriately or inconsistently?

Chair: There are several questions around cost recovery. For the interest of time, perhaps Mena and Bronwyn will put a fuller response in relation to how frivolous requests are stopped at the beginning.
BG clarified that where the generators ability to monitor is reliant on data from AEMO or WP, the framework for the self-monitoring plan will allow the use of data that is centrally collected to demonstrate compliance where a generator is unable to do themselves. This is something the generator can propose and AEMO must consider.

MR: Will the Dispute Adviser publish outcomes to the Market?

MG: We can look to publishing an arbitrator's decisions
MR: Thanks - this aligns with the NER Dispute process framework

Noel Schubert (NS): Shouldn't the same apply to Western Power as EA is suggesting for AEMO?

MG: a similar issue applies, although costs are recovered from Network Users.

MG: Arbitrator will have the ability to immediately refer matters back to negotiations or decide on the party with good faith. If the dispute is not genuine, the arbitrator can make the decision immediately and it shouldn’t be costly. MG invited participants to contact ETIU if they wish to discuss cost recovery matters further.

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<td>Slide 47 -48</td>
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BG presented the civil penalty framework application and scope.

Noted that the focus is on early rectification - if a breach is self-reported and a rectification plan is agreed with AEMO, an amnesty would apply during the time of the rectification plan and that the ERA would not conduct an investigation or issue a compliance response during this time.
Civil penalties framework is a backstop when everything else fails. Noted that in the new market, ERA will have a range of compliance responses such as education, infringements etc.
Slide 48 sets out the requirements that will be associated with a civil penalty.
Relevant generator modifications will be defined in the WEM Rules.

Questions:

MR: would a generator need to also notify AEMO about a relevant modification, or must WP do that for a modification?

MG: There is a framework around modifications under 3A. We will run through that in detail at TDOWG next week

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<td>Slide 49</td>
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BG presented the quantum of the civil penalties.
Questions:

EA: Does the ERA have the capability to assess these non-compliances?

BG: Under the new monitoring and compliance framework, there will obligations for AEMO to provide the ERA with the information to undertake investigations. It will be up to the ERA how they manage and resource their responsibilities under this framework.
Chair: ERA have been consulted in the development of both this and the broader monitoring and compliance framework for the new WEM and are working to develop further capability and business processes in this area

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<td>Slide 50</td>
<td>BG presented the next steps.</td>
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4.	NAQ policy issues, connection and access
Slide 51-53	Ashwin Raj presented the agenda
Slide 54	AR presented the NAQ framework, recapping and the next steps. • AR acknowledged it is a tight timeframe and will be managing risk through numerous consultations. • October 2020, will publish the draft rules and commence formal consultation. AR hopes to have one-on-one meetings as well as TDOWG sessions to discuss Rules and feedback.

Slide 55-61	AR presented on the issues surrounding variability in the Relevant Level Methodology.
	• In February 2020 Taskforce requested the ETIU to investigate if measures to provide additional protection for intermittent facilities should be developed. If required, the Taskforce considered a 1-year protection to be acceptable.
	• ETIU recommends that protection for intermittent facilities is not required.
	  o Existing intermittent facilities will be assessed ahead of new facilities for NAQ associated with a subsequent increase in their relevant level.
	  o Noting that for new upgrades to facilities, the resulting increase will need to compete with new facilities.
	  o Under the proposed improvements to the RLM, the ERA has recommended additional measures that will dampen the volatility in relevant levels for intermittent facilities.
	  o Slide 60 provides an example of how smoothing might be reflected in practice. Grey line: actual output from facilities. Blue line: 7 year median data red line: 3 year moving average.
	Question:
	• Rhiannon Bedola (RB): If improvement in RLM is 2 years out, their "lost" NAQs may already have been given away
	  o AR: Yes, this is true. In the year where there is a lower relevant level and a loss in NAQ, a new generator coming in could capture the benefit of the NAQ. However, the NAQ was never intended to protect intermittent facilities from weather variability.
	• NS: Planned network outages can also affect intermittent generator output and so their relevant level.
	  o AR: Currently it is considered as a consequential outage. So the estimation and the relevant level needs to account for that. In times of planned outage there should be a method estimate and calculate the relevant level output that is not affected by network outages.
	• RB: How does lower output due to constraints occurring get taken into account in RLM calculations?
	  o AR: RLM calculation is meant to be an unconstrained assessment of the output of a facility. In this process we would like to take the unconstrained output (CRC) and take and put in the NAQ model that assesses how much of the unconstrained output can be accepted by the network. We need to keep a calculation to account for network outages.

Slide 62 -67	AR presented on the issue relating to the replacement of capacity. • It is very difficult to define a threshold in enough granularity that provides AEMO comfort in applying the threshold. • This issue will be parked and deferred for a future work program to consult with industry and define the threshold. • Slide 64 provides with objectives and points for discussion.

	• Slide 66-67 provide an example of how difficult it is to define a threshold. • A threshold is not required to begin the regime. Questions: • RB: Does the initial NAQ allocation take into account new RLM. When you allocate the new NAQ when RLM is not yet in place. o AR: ETIU will work with ERA to support the RLM proposal (addressed in the Rule Change process). The intent to have the new RLM for the NAQ process. • GR: Point to note regarding the proposed use of a median value in the RLM: a median may not be reflective of the system conditions that the Planning Criterion seeks to cover. This may need to be assessed through the Rule Change process. o AR made a note.
Slide 68 -73	Dora Guzeleva (DG) presented on the treatment of DSM and the impact on network availability. • While DSM can be awarded Capacity Credits (CC), they affect the load in different ways. • Several options were looked into to treat DSM in the same way as generation. • Slide 71 provides an example. o The region generally exports 20MW net capacity. The constraint is 40MW, with 20MW that can provide DSM but not operating and there is a potential new entrant Generator North. • Slide 72 illustrates what will happen if DSM has been assigned CCs. o The network is constrained, and the potential new entrant Generator North cannot be allocated NAQ or CC. o The example provides the reason why DSM requires special treatment to let it work adequately. • Allocate NAQ equivalent to DSM is the recommended option and model DSM and generator in the same manner. Question: • EA for noting: If DSM is being treated the same as generation, then it should be subject to all the same operating & administrative requirements, including outage approvals. o AR: Noted. o DG: We are working with the AEMO to see if the performance regime should be strengthened for all resources. Everything I have mentioned will be subject to adequate performance by DSM. • RB: Assigning NAQs to DSM reduces its exit signals o DG: Once DSM is allocated CC it will become an existing facility and as long as its performance is maintained in the current arrangements, DSM will continue to be able to be provided CC. This will recognise CC pre-existing DSM when allocating NAQs.
Slide 74	AR provided an update on connection and access. • Currently Access Code (Code) changes are out for consultation. As a part of that it covers amendments to the Code to accommodate the new constrained access regime. Changes to WP access instruments are to ensure they fit into the access regime. • AR presented the timelines. • Consultation with industry will commence soon. Questions: • DH response to EA: If DSM is subject to the same requirements as Generators, so should the payment received, and testing requirements be the same. o EA: That is what we are being told, that DSM will get the same amount as generation. Just making the playing field fair.

	- o DG: Capacity price per MW is different to the refunds that DSM will receive. This will equalise the treatment of generators and DSM, by increasing the refunds. There are certain provisions to equalise the two. To the point practicable they will be treated the same. - o Chair: I can confirm the Reserve Capacity pricing rules that have recently been implemented do equalise the CC price that DSM and generators would receive. - GR: You referred earlier to the NAQ model/tool. Can you please indicate when information about the design parameters for this model will be discussed? o AR: we are still working with AEMO and consultants to develop the tool for the assignment process. Hoping to identify timelines for prototype for testing. Once this is known we will be able to give an outline of the timings to industry. A timeline might be known by the next TDOWG. - EA: Will existing ETACs require changes? o AR: No, not proposing to change existing contracts. - Erin Stone (ES): The various contracts and policies are part of the access arrangement review process, how does your planned consultation on the changes to the policies and contracts fit in (or not) with the AA5 negotiations between Western Power and the ERA? o AR: The current intention is to update the model instruments and to have them apply through transitional arrangements prior to the AA5 process, however this is still being worked through. If this can be achieved, then we don't expect much to be changed as a part of the AA5 process. - EA: Are you intending to address the amount of guarantee that Western Power is allowed to levy under the access code, ie apply limits to the maximum amounts. Under ETAC WP can levy guarantees (bank or cash), they are out of sync with other jurisdictions. WP tends to levy a requirement with retailers providing a huge amount of capital guarantee. This is mainly because there is no tripartite relationship between WP, customers and retailers. WP look to absolve any of their risk from retailers directly. It would be helpful to look at incorporating the equivalent of chapter 5 NER, reference the requirement that guarantees can be levied by transmission/distribution on the east coast. o AR: The priority is to implement the required changes to make the constrained access regime work. ETIU acknowledges that there are a range of legacy issues that merit a broader review. This might be progressed in the AA5 process. o EA: The challenge is that this also links with the DER work stream. As there was a decision for made early on to not implement a tripartite process where WP have direct access to customers. What has been done is increase the risk of holding a retail ETAC quite significantly. o DG: There actions in the road map that would lead to discussion about the DSO/DMO aggregators. Those comments will be taken in that context and will require further consultation on those roles. The role of WP with respect to DER are actions in the roadmap that will require further consultation with industry, if it requires further changes in the Access Code it will be considered. o Chair: Both programs have timelines in place. DSO/DMO function will be active by mid-2023, ETIU are aligning the changes to the best extent possible and examine the overlaps between the three work streams. We will take this on notice. - WN: If DSM is assigned NAQs, does this mean that DSM needs to be available for 14 hours during the peak? o Dora Guzeleva (ETIU): No plan to align the timeframe, Rules will recognise it through the refunds and receive higher refunds at for unavailability. o Chair: RCOQ is slightly different for DSM at this stage we are not looking at changing it significantly. We are looking deeply to make sure they marry properly from NAQ to scheduling and dispatch

	• GR: how will interdependencies between RCM design and other projects (e.g. outages, settlement) be managed in the coming weeks/months? ○ Chair: We are managing the interdependencies both within ETIU and with support from AEMO.
Slide 76	Chair closed the meeting.