Government of **Western Australia**
Energy Policy WA

Minutes

TDOWG Meeting 5, 2019

Time: 9:30am to 12:00pm
Date: Tuesday, 25 November 2019
Venue: AEMO offices, Level 45, Central Park, 152 St Georges Terrace, Perth

Attendees:

Attendee	Organisation	Attendees	Organisation
Aden Barker	ETIU	Sara O'Connor	ERA
Aditi Varma	ETIU	Shannon Hewitt	BSC Solar
Andrew Cook	Western Power	Simon Middleton	AEMO
Brad Huppatz	Synergy	Stephen Elliot	RCP
Chayan Thanachayan	Kleenheat	Steve Gould	Community Electricity
Daniel Kurz	Bluewaters	Sue Paul	RBP
Dean Frost	Western Power	Wendy Ng	ERM Power
Dermot Costello	CEC		
Dev Tayal	Tesla		
Dora Guzeleva	EPWA		
Drew Harris Simcoa	Simcoa		
Elizabeth Walters	ERA		
Emma Rowe	Treasury		
Erin Stone	Point		
Geoff Gaston	Change Energy		
Geoff Glazier	Merz		
Glenn Carruthers	Western Power		
Greg Ruthven	AEMO		
Jacinda Papps	Alinta Energy		
James Eastcott	EPWA		
Jason Froud	Synergy		
Jenny Laidlaw	RCP		
Judy Hunter	Western Power		
Kim Phan	EPWA		
Kristian Myhre	TransAlta		
Mark Riley	AGL		
Martin Maticka	AEMO		
Mathew Fairclough	AEMO		
Noel Schubert	ERA		
Patrick Peake	Perth Energy		
Paul Arias	Bluewaters		
Peter Huxtable	Water Corp		
Rebecca White	EPWA		
Rod Littlejohn	Tersum Energy		
Sabina Roshan	Western Power		
Sam Lei	Alinta Energy		

Item No.	Issue
1.	**Access Code changes**

Kim Phan, Energy Transformation Implementation Unit, outlined the main functions of the Access Code:

- Shaping Western Power's services, performance targets and revenue; and
- Ensuring efficient investment in the network.

The Western Power network services over 2 million customers. 45% of energy prices are transmission and distribution costs.

Kim Phan outlined the need for reform to the Access Code:

- Changes to the Access Code are required to support the Energy Transformation Strategy.
- The Access Code has remained relatively unchanged since 2004.

Kim Phan outlined the main objectives of the reforms to the Access Code:

- Increasing opportunities for new technologies.
- Maximising the utilisation of the existing Western Power network.
- Providing regulatory certainty and streamlining the access arrangement process.

The proposed reforms will support the Energy Transformation Projects including:

- The Whole of System Plan (WoSP). For example, by incorporating the WoSP into existing regulatory processes to minimise duplication.
- Foundational Regulatory Frameworks. For example, by improving access to Western Power's network so that it is consistent with a constrained access regime
- Distributed Energy Roadmap. For example, by facilitating non-network solutions.

Kim Phan outlined the project timeframe which is designed to fit in with the Access Arrangement process; and to give certainty to Western Power and the Economic Regulation Authority.

Kim Phan outlined the project's 'next steps':

- Drafting of regulatory amendments and Consultation Paper (October 2019 – February 2020)
- TDOWG and stakeholder 1:1 consultations (November 2019 – January 2020)
- Workshops on draft regulatory amendments (December 2019 – January 2020)
- Taskforce endorsement before seeking Ministerial approval to consult formally (February 2020)
- Formal public consultation (March – April 2020)

Patrick Peake of Perth Energy said that the proposed reforms should ensure that Western Power is not able to monopolise markets for non-network solutions and distributed energy resources, including storage. For example, other market participants should be able to build community storage.

Kim Phan recognised this feedback.

2. Market settlement – implementation of five-minute settlement and design of settlement calculations

Implementation of five-minute settlement

Rebecca White, ETIU, presented on the implementation of five-minute settlement.

- The recommendation to the Taskforce is to implement five-minute settlement from 1 October 2025.
- This will allow enough time for Western Power, AEMO and market participants to prepare and implement necessary changes, including meter upgrades, and ICT systems to support five-minute meters and manage the increased volume of data.
- This timeframe aims to minimise misalignment between settlement and dispatch.

Daniel Kurz of Bluewaters said 2025 is a better outcome compared to market start. Market start would have been 'too big a bite' whereas 2025 is more sensible considering it gives 3 additional years for implementation.

Chayan Thanachayan of Kleenheat questioned whether infrastructure would be expected to be compatible with 5-minute settlement by market start.

Rebecca White responded that 'business as usual' for market participants will continue until 2025.

Jenny Laidlaw of the Rule Change Panel asked if market participants could be given notice of the changes so that they can plan their own implementation processes and avoid big changes.

Stuart Featham of AEMO said that AEMO will plan its implementation to minimise costs for market participants.

Chayan Thanachayan asked if AEMO's learnings from implementing five-minute settlement in the National Electricity Market (NEM) could be used to bring forward the implementation date.

Rebecca White responded that the feedback from industry and stakeholders was that 2022 was too soon, and that 2025 would better allow for leveraging the learnings from the NEM.

Wendy Ng of ERM Power asked whether a market trial will be held prior to the 2025 implementation.

Stuart Featham responded that AEMO will conduct trials.

Geoff Gaston of Change Energy asked whether Western Power would be mandated to upgrade the meters, or if competitive metering would be considered.

Rebecca White responded that the meter upgrades are proposed to be mandated via changes to the Metering Code.

Geoff Gaston asked how many meters would require upgrades.

Sue Paul of Robinson Bowmaker Paul Consulting responded that approximately 30,000 meters would require upgrading.

Jenny Laidlaw asked how the meter upgrade would relate to Western Power's current Advanced Metering Infrastructure (AMI) roll out?

Rebecca White responded that the AMI roll out would not capture the meters requiring an upgrade for five-minute settlement purposes.

Aden Barker of Energy Policy WA responded that the AMI roll out relates to Synergy's franchise customers.

Jenny Laidlaw asked if these Synergy customer meters would still need to be compatible with five-minute settlement considering they will be used for settlement.

Dean Frost of Western Power said that Western Power will take this question on notice because Western Power's metering subject matter expert is not in attendance.

Patrick Peake questioned whether customers would be required to fund their own meter upgrades.

Aditi Varma of ETIU responded that the meter upgrade costs will be recovered via network charges considering the upgrade will be mandated via the Metering Code. This means the costs will be shared across network customers.

Uplift payments

Rebecca White presented on the purpose, eligibility criteria and calculation of uplift payments.

- In August 2019, the Taskforce endorsed the design decision to retain constrained-on payments in the new market.
- Constrained-on payments will now be called uplift payments
- The purpose of uplift payments is to make a generator 'whole' if they are negatively mispriced.
- An uplift payment will only be provided if the generator is dispatched due to a network constraint and the reference node price is less than its marginal offer price.
- In the new market, there are several circumstances when a generator may not be made whole for energy but will be made whole via other mechanisms for example the market for essential system services. In these cases, uplift payments are not required.

Rebecca White presented an example to illustrate a situation where an uplift payment would be paid. She also outlined the triggers for an uplift payment:

- The facility's congestion rental contributions > zero.
- The marginal offer price must exceed marginal clearing price.
- A generator will not be paid an uplift payment if it is dispatched due to an ESS constraint, otherwise the generator would be over-remunerated.
- Further is work required on the interaction between uplift payments and a facility that is subject to a locational ESS contract.

Rebecca White outlined how the price component of uplift payments would be calculated.

- The uplift payment price will equal the generator's marginal offer price minus the 30-minute settlement price. The 30-minute settlement price will be calculated as the time-weighted average of the six five-minute market clearing prices.

Jenny Laidlaw asked what if Gen D has different marginal offers for different intervals.

Sue Paul responded that uplift payments are calculated on a 5 min basis to accommodate offer prices that change from interval to interval.

Chayan Thanachayan questioned whether ramp rates would influence who is dispatched and the uplift payment calculation.

Sue Paul responded that SCED will determine which facility is dispatched and that ramp rates will be accounted in SCED.

Chayan Thanachayan asked how the payments would be recovered.

Sue Paul responded that payments will be recovered from loads as they are currently.

Rebecca White outlined how the quantity component of uplift payments would be calculated.

Two options were considered – either:

- make the quantity equal to the entire quantity facility is dispatched for in the five-minute dispatch interval; or
- or make the quantity equal to the quantity that was dispatched due to the constraint.

The first option was selected. Only paying for the tranche of generation dispatched due to the constraint would create a perverse incentive for disorderly bidding – it would also violate marginal cost pricing principles.

Wendy Ng asked whether short-run marginal cost (SRMC) pricing regulations will still apply in the new market.

Aditi Varma responded that some form of SRMC pricing regulation will be retained. However, these rules will need to be reformed to be fit for purpose in the context of the new ESS market.

Wendy Ng responded that SRMC has never been adequately defined. There appears to be a risk that if a generator bids at the cap and then is dispatched due to a constraint, then that facility could be accused of violating SRMC pricing.

Rebecca White responded that the project team will consider this issue and others under the market power mitigation project.

Kristian Myhre asked whether the approach to uplift payments is the same as that applied to constrained on payments.

Sue Paul responded that the approach is similar except for the triggers being different.

Manual overrides of SCED

Rebecca White outlined the conditions where SCED may require a manual override:

- The dispatch engine cannot solve for a feasible solution.
- In an emergency.

Any over-rides should last for a low number of intervals before a constraint equation is implemented.

Instances of manual over-rides will be monitored and addressed through market evolution if needed.

Jenny Laidlaw asked whether there is a risk that the dispatch engine may fail to recognise some instances where uplift payments are required, or if the dispatch engine produces spurious prices, and generators require payments to be made whole.

Rebecca White responded that there won’t be an opportunity for market participants to request the dispatch engine to be re-run. The project team expects these instances will be rare.

Greg Ruthven of AEMO noted that similar issues could arise as a result of SCADA glitches.

Wendy Ng noted that in the NEM, errors might not be recognised until long after dispatch.

Rebecca White responded that the accuracy of constraint equations and the procedures which define the processes for developing and updating constraint equations will be discussed in the upcoming 11 December constraints workshop.

Frequency ESS Settlement

Aditi Varma presented on Frequency ESS settlement.

The Taskforce has endorsed three types of Frequency ESS:

- Regulation;
- Contingency Reserve; and
- Rate of Change of Frequency service (RoCoF).

All of these will be procured through real-time markets. Taskforce has endorsed the application of the causer pays principle for ESS.

Aditi Varma outlined how ESS payments will be structured:

- If the ESS provider is providing the ESS under a supplementary mechanism, then the 5-minute payments will be calculated as the ESS performance factor x contracted MW x price
- Real time ESS market payments will be calculated as the ESS performance factor x enablement MW x five-minute ESS market clearing price.

On Regulation cost-recovery:

- Under 30-minute settlement regulation raise and lower costs will be allocated to intermittent generators and loads based on their share of 30-minute metered generation and consumption.
- 5-minute settlement will enable a more accurate causer pays approach. Under five-minute settlement, costs will be allocated to scheduled generators based on deviation from dispatch targets; intermittent generators based on their deviation from forecasts; and loads based on their inter-interval variation in consumption.

Aditi Varma outlined how Contingency Raise costs will be recovered.

- The full runway method will be retained and expanded to include network contingencies.
- The project team is still debating how to apply causer pays principle for network contingencies because both networks and generators are involved. Ultimately the goal is to ensure costs are allocated to those parties that can control them via changes in behaviour.

Patrick Peake of Perth Energy asked if Western Power would be made to pay for historic decisions that increased the size of the contingency?

Aditi Varma said the project team has not decided yet on how costs will be recovered for network contingencies and is looking at approaches taken in other markets.

Sue Paul noted that in New Zealand the owner of the interconnector pays the cost but that this is supported by network regulations that require the network operator to account for market outcomes of their investment decisions.

Patrick Peake said that the Western Power is gaining revenue and putting the contingency reserve costs on others, and noted that the issue should not be repeated, for example in the Eastern Goldfields.

Glenn Carruthers of Western Power noted that Western Power has built the network in accordance with its planning criteria.

Aditi Varma noted that the current framework does not provide adequate guidance on how the network planning criteria should interact with market costs.

Wendy Ng asked whether there will be an early transition to the new method, considering the situation where the network contingency sets the contingency reserve requirement exists currently.

Aditi Varma that Energy Policy WA is working on the North Country issue currently. Interim solutions are available, but the project team is seeking to apply a more rigorous approach that will be in place work from 2022 and will supersede any interim approaches.

Jenny Laidlaw suggested that a real time solver could aid the situation. For example, a dynamic frequency contingency model could be used.

Aditi Varma acknowledged the need for a dynamic model and said this is being developed as part of

Geoff Glazier of Merz Consulting noted that the dispatch engine will flag generators causing increased contingency raise requirements to solve for the most economic dispatch.

Aditi Varma outlined how contingency lower costs will be recovered.

- Contingency lower costs would be recovered from loads according to their 30-minute metered consumption quantities prior to 2025 and then their 5-minute meter data from 2025.

Aditi Varma outlined how RoCoF regulations costs will be recovered.

- The need for RoCoF services is caused by everyone on the system.
- Causer pays scheme incentivises entities to improve their performance to RoCoF standard and reduce/remove exposure to costs of service.
- Proposed transitional period from market start:
    - AEMO determines a max forecast RoCoF level which if all generators/loads/network components can ride-through, no RoCoF service would be required.
    - Only paid for by participants with ride-through capability lower than the maximum level.
    - RoCoF cost allocation to generators and loads will be based on metered generation and consumption.
- Transitional application of causer pays principle will encourage compliance with the standard. Over time, as generators, loads and network components are better able to ride-through RoCoF requirements, overall system performance will improve, and the costs of the service will reduce to its lowest economically efficient value. In this situation, only the distribution loads will be left paying the costs, which essentially means that the system may start from a causer-pays regime but will ultimately become a beneficiary-pays regime. There will be an option to reactivate the standard if performance deteriorates.

Wendy Ng noted that generators will be forced to provide RoCoF, whereas participation in ESS is currently voluntary.

Aditi Varma responded that RoCoF is implicitly provided by some generators when they are dispatched for energy.

Glenn Carruthers said that RoCoF is a symptom and not the problem. The problem could be a lack of inertia and that there is a risk that the cost recovery rules penalise generators providing inertia. If the cause of RoCoF is reduced inertia, then penalise participants who do not provide inertia. Generators could then make investments to avoid these costs.

Aditi Varma responded that it is arguably the large generators providing inertia that also set the safe limit.

Geoff Glazier said that the dispatch process will incentivise generators to provide inertia, but the market operator will require data on facilities' capabilities.

Glenn Carruthers raised a concern that RoCoF costs will increase, putting pressure on facilities that are required by the system to reduce the need for RoCoF services.

Aditi Varma said the system will evolve to a beneficiary pays scheme.

Peter Huxtable asked what costs will be allocated to loads.

Aditi Varma said that there will be a three-way allocation and noted that similar to generators and network, large loads may be able to take measures to reduce their RoCoF cost. For contestable customers, this may be possible through negotiating with their retailers that have a direct interaction with the market.

The Project team will return in the new year with more detail on RoCoF safe limits and how facilities can demonstrate their ability to meet the standard.

Non-frequency ESS settlement

Aditi Varma outlined how non frequency ESS costs will be recovered.

- System restart services will be recovered from loads.

Non-cooptimised ESS, such as locational ESS, costs will be covered in a forthcoming paper.