Energy Transformation Taskforce

Market settlement

Implementation of five-minute settlement, uplift payments and Essential System Services settlement

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Energy Transformation Taskforce

David Malcolm Justice Centre
28 Barrack Street
Perth WA 6000
Locked Bag 11 Cloisters Square WA 6850

Main Switchboard: 08 6551 4600

www.energy.wa.gov.au

Enquiries about this report should be directed to:

Aditi Varma, Assistant Director- Future Market Design and Operations

Telephone: +61 (8) 6551 4756
Email: aditi.varma@energy.wa.gov.au

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1. Purpose

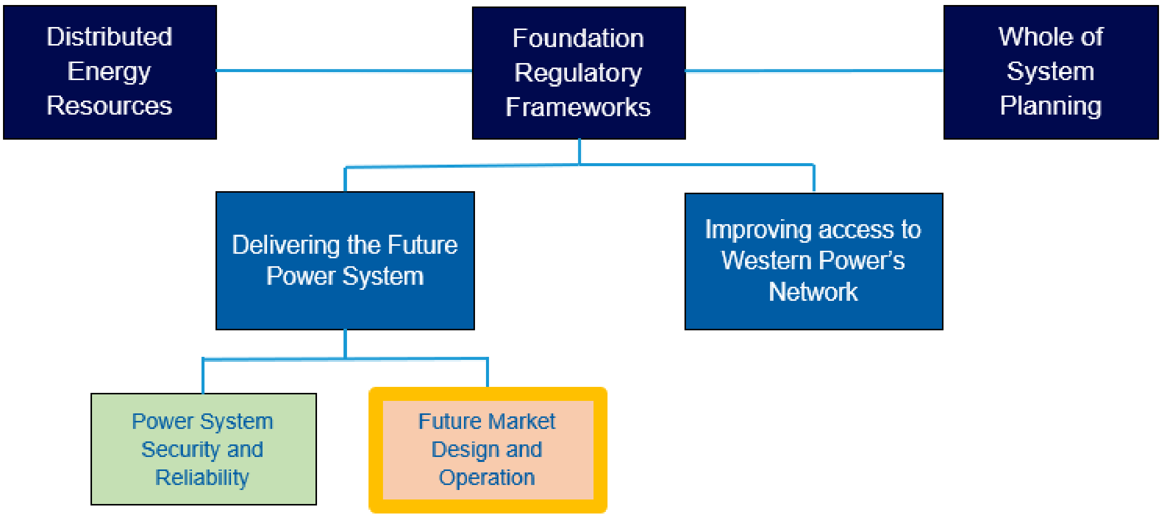
1.1 The Energy Transformation Strategy

This paper forms part of the work to deliver the Energy Transformation Strategy. This is the Western Australian Government's strategy to respond to the energy transformation underway and to plan for the future of our power system. The delivery of the Energy Transformation Strategy is being overseen by the Energy Transformation Taskforce (Taskforce), which was established on 20 May 2019. The Taskforce is being supported by the Energy Transformation Implementation Unit (ETIU), a dedicated unit within Energy Policy WA, a sub-department of the Department of Mines, Industry Regulation, and Safety.

More information on the Energy Transformation Strategy, the Taskforce, and ETIU can be found on the Energy Transformation website at www.wa.gov.au/organisation/energy-policy-wa

This paper is prepared as part of the Future Market Design and Operation project (highlighted in Figure 1) within the Foundation Regulatory Frameworks work stream of the Energy Transformation Strategy.

Figure 1: Energy Transformation Strategy work streams



The Future Market Design and Operation project is undertaking improvements to the design and functioning of the Wholesale Electricity Market (WEM). These include:

- modernising WEM arrangements to implement a security-constrained economic dispatch (SCED) market design that optimises the benefits of the introduction of constrained network access for Western Power's network; and
- implementing a new framework for acquiring and providing essential system services (ESS).

1.2 The purpose of this paper

This paper outlines the settlement approach and calculations to implement design decisions outlined in the previous Taskforce papers[1].

- The *Information Paper – Foundation Settings for Market Settlement*, which outlined that dispatch and settlement intervals will be aligned to both be five-minutes, with implementation of five-minute settlement at a future date following commencement of the new market arrangements. This paper outlines how and when five-minute settlement will be implemented.
- The *Information Paper – Foundation Market Parameters,* which outlined that 'constrained-on' payments will be retained in the new market. This paper outlines the purpose and design of these payments, referred to as 'uplift payments' in the new market.
- The *Information Paper – Frequency Control Essential System Services: Acquisition, cost recovery and governance,* which outlines the principles for design of ESS payment and cost recovery calculations. This paper outlines the detailed design of these calculations.

Settlement processes for Reserve Capacity Mechanism and other ESS (for example, locational ESS) will be provided in subsequent information papers.

[1] All papers are accessible through the Energy Transformation Strategy section of the Energy Policy WA website at www.energy.wa.gov.au

2. Implementation of five-minute settlement

2.1 Background

The *Information Paper – Foundation Settings for Market Settlement*, endorsed by the Taskforce in September 2019, included a design decision that dispatch and settlement intervals will be aligned to both be five-minutes at a future date, following commencement of new market arrangements.

The Information Paper outlined challenges associated with implementing five-minute settlement from commencement of the new market on 1 October 2022. This is because five-minute metered generation and consumption data will not be available for each generator and contestable metering installation[2] due to insufficient time to replace existing 30-minute meters prior to market start. A potential alternative of using a profiling method using SCADA data to allocate 30-minute metered data to five-minute intervals was also not considered feasible due to challenges with installing the required systems to profile SCADA data to five-minute values suitable for settlement.

The Taskforce recognised that the benefits of the new market may not be fully realised if the dispatch and settlement intervals remain misaligned. As such, further analysis has been undertaken to determine when five-minute settlement can best be implemented. This chapter outlines the Taskforce decisions to implement five-minute settlement.

2.2 Taskforce decision

Five-minute settlement will commence on 1 October 2025 when five-minute meters have been installed and five-minute meter data will be available for market settlement. This timeframe has been chosen to realise the benefits of implementing five-minute settlement as soon as possible while minimising the loss of residual asset life value of meters that need replacement. This timeframe also allows sufficient time to implement required regulatory amendments, infrastructure and system upgrades, and changes to Market Participants' systems. These changes are outlined below.

- **Metering infrastructure upgrades:** Western Power will replace 30,266 existing 30-minute meters to meters with five-minute capability. Another 5,067 existing meters will be reconfigured to enable their five-minute capability. Table 1 below outlines the number of meters by type of measurement that will be replaced or reconfigured. The cost of the metering upgrades will be recovered through Western Power's network charges under its access arrangement.
- **New meter data processing systems:** Western Power will implement a new metering back-office system to enable the processing and exchange of five-minute meter data.
- **Settlement system changes:** The Australian Energy Market Operator (AEMO) will upgrade and/or develop systems to enable five-minute meter data to be transferred, processed and stored.
- **Regulatory amendments**: Changes to the Electricity Industry (Metering) Code 2012 and associated documents will be progressed to mandate five-minute meters to be in place by 1 October 2025.

Market Participants may also need to upgrade their invoicing and metering systems to implement five-minute settlement by 1 October 2025.

[2] Non-contestable loads are currently not interval metered and are included in the Notional Wholesale Meter.

Table 1: Number of metering installations (generator and contestable load) by type and interval metering capability

Metering installation type	Megawatt hour (MWh) threshold (Annual throughput)[3]	Interval metered (30 mins)	Meters to be replaced with five-minute meters	Meters to be reconfigured to five minutes
1	Throughput>=1000 GWh	Y	14	0
2	100 GWh<= throughput <1000 GWh	Y	114	32
3	750 MWh<= throughput <100 GWh	Y	1,584	387
4	300 MWh<= throughput <750 MWh	Y	21,254	3,868
5	50 MWh<= throughput <300 MWh	Y	7,300	780
Total interval metering (Types 1-5)			**30,266**	**5,067**

Source: Western Power

During consultation, Market Participants expressed concern about five-minute settlement being implemented at the same time as the commencement of new market arrangements on 1 October 2022. Some participants indicated this would not allow them sufficient time to upgrade their systems and benefit from the learnings of five-minute settlement in the National Electricity Market (NEM)[4].

The Taskforce has considered stakeholder concerns in its decision to defer implementation of five-minute settlement to 1 October 2025. During subsequent consultation, Market Participants expressed support for the deferred commencement date.

The Taskforce has endorsed the following design decision.

> Five-minute settlement will commence on 1 October 2025 using five-minute meter data.

2.3 Transitional arrangements

Between 1 October 2022 and 30 September 2025, 30-minute settlement will continue to be in place.

This means that:

- Western Power will continue to provide the 30-minute meter data to AEMO;[5]
- the settlement interval will continue to be 30-minutes, requiring energy volumes to be settled on a 30-minute basis, with a 30-minute settlement price (the calculation of the 30-minute settlement price is outlined in section •);
- specific settlement components such as uplift payments and ESS payments will be calculated at five-minute resolution, where relevant, and aggregated to 30-minute resolution; and

3 Electricity Industry (Metering) Code 2012, Appendix 1

4 For example, leveraging market settlement systems developed for the NEM. 5-minute settlement is scheduled to be implemented in the NEM from 1 July 2021.

5 However, meter data will need to be provided to AEMO at a greater frequency as opposed to the current monthly frequency to implement the previous Taskforce design decision of weekly settlement.

- the participant information reports published to individual market participants through AEMO's settlement systems will continue to be issued on the basis of 30-minute resolution.

2.3.1 30-minute settlement price for energy

A five-minute dispatch interval and a 30-minute settlement interval requires a settlement price to be calculated on a 30-minute basis. At market start, the settlement price for energy for a given 30-minute settlement interval will be the average of the six, five-minute market clearing prices for energy in that settlement interval.[6]

A volume-weighted settlement price[7] was also considered. However, volume-weighted prices would lead to higher market costs than averaging (as demand is correlated with energy price), would be more complex to implement, and would not provide improved incentives for efficient market participation.

To reduce the overall level of market costs and implementation complexity (and in the absence of broader market benefits), a time-weighted settlement price is preferred by the Taskforce.

The Taskforce has endorsed the following design decision.

> 30-minute settlement of energy at market start will use a time-weighted average of six five-minute energy market clearing prices to calculate a 30-minute settlement price for energy, and a Market Participant's 30-minute metered energy volumes.

6 For example, for the settlement interval 08:00-08:30 comprising the following six dispatch intervals 08:00-08:05, 08:05-08:10, 08:10-08:15, 08:15-08:20, 08:20-08:25, 08:25-08:30, the time-weighted settlement price would be the simple average of the market clearing prices over those six dispatch intervals.

7 The volume-weighted settlement price would weight the relevant five-minute market prices by the total five-minute loss adjusted SCADA generation.

3. Uplift payments

3.1 Background

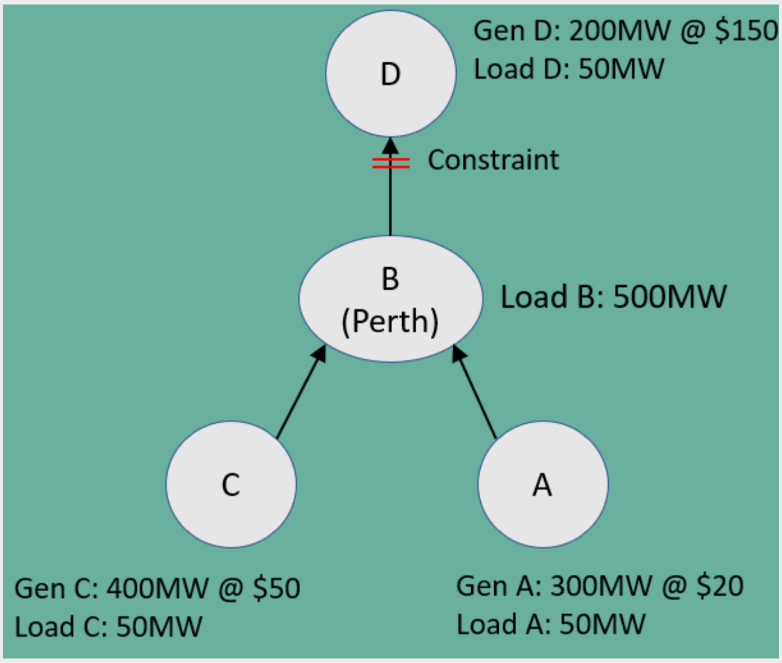
The *Information Paper – Foundation Market Parameters* outlined the design decision that a facility that is required to generate when its marginal offer price is higher than the market clearing price at the reference node in the presence of a network constraint, the facility should be made 'whole'. In the absence of some other mechanism, such a facility is not made whole because the payment it receives for its energy is less than the minimum price it was willing to receive to generate. This situation is called negative mispricing and can occur in markets with a single Reference Node price.

Mispricing is important because the WEM will be settled on a price calculated at the Reference Node, but generators will be dispatched using local prices. The magnitude and frequency of mispricing provides information on the level of congestion at specific locations on the transmission network. Where mispricing is large or too frequent, the network at that location may be more congested relative to other locations. Where generators located in a congested part of the network expect to be dispatched in ways where they cannot recover their true marginal costs, they will bid such that their likelihood of dispatch is reduced, or they are decommitted.[8] Prolonged instances of such bidding behaviour can lead to economically inefficient market outcomes.

The example below explains negative mispricing.

Example: Negative mispricing

The diagram to the right shows a Reference Node at location B, with generation in three locations: A, C, and D.



The total load to serve is 650megawatts (MW), with 500MW at the Reference Node. If there were no constraints, Generator C would be the marginal generator at all locations (i.e. serve the next increment of load at all locations A-D).

However, there is a network constraint that prevents energy from Generator C reaching the load at D. Generator D has to generate at $150/MW to meet some of the load in its location. The dispatch engine optimises dispatch outcomes in the presence of the constraint.

The market clearing price is set by the marginal cost to provide energy at location B. As the next increment of load at B would be served by Generator C at a cost of $50/MW, the market clearing price is $50/MW for all generators.

However, Generator D has a marginal offer price of $150/MW and therefore is out of pocket for $100/MW for its generation. This is negative mispricing.

8 An example of disorderly bidding behaviour is provided in Appendix B.

The Taskforce previously endorsed the decision to provide a 'constrained-on' payment to compensate (make whole) facilities dispatched under such circumstances. These payments will be referred to as uplift payments in the new market. This reflects that unlike in the current market the facility is not being dispatched out of merit, rather the facility is subject to negative mispricing due to the presence of a network constraint.

3.2 Taskforce decision

The following sections outline how the settlement system will determine when a facility is eligible for an uplift payment, and how the uplift price and uplift quantity (to determine the uplift payment) will be calculated.

3.2.1 Uplift trigger

The settlement system requires criteria to determine whether an uplift payment is to be paid. These two criteria – called the uplift trigger – are as follows.

1. The facility's marginal offer price is greater than the five-minute market clearing energy price; and
2. The facility's congestion rental contribution is greater than zero. This means that the network constraint is alleviated by the facility generating.

Both of these triggers must be true for a facility to be eligible for an uplift payment. These triggers will be visible through the facility's offers and dispatch engine outputs during market settlement to determine uplift payments.

Two other conditions will need to be confirmed to ensure the uplift trigger works as intended. These are that:

1. the facility is not in a binding ESS enablement minimum constraint for Contingency Reserve raise, Contingency Reserve lower, Regulation raise or Regulation lower; and
2. the facility is not in a binding down-ramp-rate constraint.

Appendix A provides more information on ESS enablement minimum constraints and binding down-ramp-rate constraints.

Additionally, where the facility is receiving a payment through another mechanism to make it whole, it will not be eligible for an uplift payment. For example, a higher-cost facility that is dispatched for energy due to a frequency ESS constraint will not receive an uplift payment as it receives compensation through the ESS market (potentially also including a contractual payment for availability under the ESS supplementary mechanism for procurement). There may also be off-market contracted mechanisms, for example a Network Control Service, where a facility would be recovering its running costs through that contract.

Appendix A outlines calculations for the uplift trigger and uplift payment.

The Taskforce has endorsed the following design decision.

> An uplift payment will be paid to a facility for the relevant five-minute dispatch interval if the facility:
>
> - has a marginal offer price that is greater than the five-minute market clearing energy price; and
> - has a congestion rental contribution greater than zero.
>
> An uplift payment will not be paid to a facility that meets these criteria if:
>
> - the facility is in a binding ESS enablement minimum or down-ramp rate constraint; and/or
> - it is receiving payment for a contracted service for the relevant binding network constraint.

3.2.2 Uplift price

The uplift price is used in the uplift payment calculation. While 30-minute settlement is in place between 1 October 2022 and 30 September 2025, the uplift price will be the difference between the 30-minute settlement price for energy and the facility's marginal offer price for the five-minute interval where it is eligible for an uplift payment. Together, the uplift price and the energy price will add to the facility's marginal offer price to make the facility 'whole'. The use of a 'pseudo-nodal' price, rather than the facility's marginal offer price was also considered, but is not preferred because of its potential to over-compensate a facility for its running costs. This is discussed in Appendix B.

Once five-minute settlement is implemented from 1 October 2025, the settlement price for energy will equal the five-minute market clearing price for energy as calculated in the dispatch engine.

The Taskforce has endorsed the following design decision.

> The uplift price to determine a facility's uplift payment for a five-minute dispatch interval where the uplift trigger applies, will be the facility's marginal offer price for that interval less the 30-minute settlement price for energy.

3.2.3 Uplift quantity

The uplift quantity is the generation quantity eligible for an uplift payment. A facility will receive an uplift payment for the entire quantity generated for the five-minute dispatch interval where the uplift trigger applies. Application of the uplift payment only to the quantity in the marginal offer tranche was considered. However, this approach has the potential to contribute to disorderly bidding and impose higher costs on the market. This is discussed in the context of an example of disorderly bidding provided in Appendix B.

While 30-minute settlement is in place between 1 October 2022 and 30 September 2025, the uplift quantity will be derived by profiling the 30-minute metered generation quantity into five-minute intervals using SCADA five-minute generation values.

Once five-minute settlement is implemented from 1 October 2025, the five-minute metered generation quantities will be used to determine the five-minute uplift quantity.

The Taskforce has endorsed the following design decision.

> The uplift quantity to determine a facility’s uplift payment for a five-minute dispatch interval where the uplift trigger applies, will be that facility’s entire generation quantity in that five-minute dispatch interval.

3.2.4 Cost-recovery for uplift payments

The cost of uplift payments will be recovered from Market Customers. This is consistent with the current mechanism where the cost of constrained on and off payments is recovered from Market Customers.

Importantly, the magnitude and frequency of uplift payments provides information regarding the direct economic costs of congestion on the network. This is useful information for the network operator when planning network reinforcement or augmentation and for the Economic Regulation Authority in assessing investment decisions.

If these costs were directly borne by the network operator, it may receive a stronger incentive to minimise these costs. However, in the short-term, the cost of uplift payments is not expected to be large, and the benefits of a more direct incentive are likely to be outweighed by the administrative burden of allocating the costs to Western Power through the market settlement system. Regardless, amendments to the Electricity Networks Access Code 2004 (Access Code) will be pursued to ensure this market cost is taken into account by Western Power when applying the net benefit test to its network augmentation proposals. Further discussion on appropriate incentives for Western Power to resolve network congestion is outlined in section 5.4.

The Taskforce has endorsed the following design decision.

> The cost of uplift payments will be recovered from Market Customers.

4. Manual overrides of SCED

4.1 Background

A manual override of SCED occurs when AEMO manually intervenes within a dispatch interval to override market dispatch outcomes produced by the dispatch engine (i.e. intervening with manual dispatch). AEMO may need to manually intervene in dispatch to resolve infeasible dispatch solutions, or in an emergency situation.

Manual overrides of SCED are expected to be rare occurrences under the new market arrangements where energy and frequency control ESS[9] will be co-optimised and cleared every five minutes using a SCED algorithm that factors in network constraints. The shortening of the dispatch interval to five minutes will reduce the need to intervene in automated dispatch to address changes such as load or intermittent generation forecast changing materially. Where emergency situations occur, AEMO will be required to promptly create or recreate constraint equations to minimise any manual dispatch. For these reasons, manual overrides are expected to occur only for a low number of dispatch intervals.

Manual overrides may lead to facilities being dispatched in an unanticipated manner (or 'out-of-SCED-merit'). Where a facility is dispatched upwards out-of-SCED-merit and settled at the Reference Node price, it may be unable to recover its running costs.

Due to the infrequent nature of these occurrences, the Taskforce considers there is limited value in developing a complex compensation mechanism to apply from market start. The incidence of such occurrences will be monitored to determine if a compensation mechanism needs to be developed.

4.2 Taskforce decision

The Taskforce has endorsed the following design decision.

> The frequency and duration of manual SCED overrides will be monitored, with compensation mechanisms to be developed in future if required.

9 Contingency Reserve, Regulation and Rate of Change of Frequency (RoCoF) control.

5. Frequency Control ESS settlement

5.1 Types of Frequency Control ESS

The Information Papers on *Frequency Control Technical Arrangements* and *Frequency Control: Acquisition, Cost Recovery and Governance*[10] defined the new frequency control ESS, a framework for their acquisition, and high-level cost-recovery principles. Frequency control ESS are summarised in Table 2.

Table 2: Summary of Frequency Control ESS

Frequency Control ESS	Risk being covered	Service description
Regulation (raise and lower)	Upward/downward deviation from load forecast during a dispatch interval (assuming linear ramping) that causes the frequency to drop below (requiring a regulation raise service) or go above 50 Hz (i.e. requiring a Regulation lower service).	Reserve MW to respond upwards during dispatch interval when load is greater than generation (Regulation raise) and downwards when load is less than generation (Regulation lower). The need for the service arises as a result of generation and load varying within interval from target/forecast.
Contingency Reserve (raise and lower)	Loss of generation (Contingency Reserve raise) or large load (Contingency Reserve lower).	Reserve MW to respond to loss of generation/load to restore frequency to acceptable level.
Rate of Change of Frequency (RoCoF) Control service	If frequency changes too fast, it can cause problems for automatic detection of frequency changes, and potentially result in damage or trip-off of generators and other system components. The new RoCoF Control service has two functions: 1. to ensure RoCoF is restricted to below a certain maximum level; and 2. potentially allow trade-off between the quantity of Contingency Reserve required and the quantity of inertia in the power system.	The quantity of RoCoF Control service required is a function of: • contingency size; • Contingency Reserve quantity; and • total inertia on the power system.

This chapter outlines how providers of frequency control ESS (referred to as ESS throughout this section) will be paid and how the costs of these services will be recovered.

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10 Both information papers are available at: http://www.wa.gov.au/government/document-collections/taskforce-publications

5.2 Payments to ESS providers

5.2.1 Background

All frequency control ESS will be acquired through real-time ESS markets. Participation in ESS markets will be open to all facilities available and capable to provide one or more types of ESS. The co-optimisation algorithm in the market-clearing engine will output a market-clearing price for energy and each ESS. ESS providers will be paid for the services they provide according to the specific market-clearing price relevant to that market.

Due to the relatively small size and level of market concentration in the WEM, the Taskforce endorsed a decision to trigger a supplementary mechanism to procure required ESS, when necessary. The supplementary mechanism would be triggered as required to provide certainty for investment by the required types of ESS capacity providers if the desired quantity (or type) of capacity does not manifest, and/or to address market power issues if there is evidence of inefficient pricing outcomes in the real-time ESS market(s). Facilities that are contracted to be available for ESS provision in the supplementary procurement mechanism will receive a payment as specified in the contract. Further information on the operational aspects of the supplementary procurement mechanism, including any penalties that may be applied for non-performance on contractual obligations, will be covered in a future information paper.

5.2.2 Taskforce decision

An ESS provider will receive the following payment(s):

- **A real-time market payment.** This will be calculated by multiplying the enablement quantity by the market-clearing price determined in the dispatch engine. ESS payments will be calculated on a five-minute basis using the five-minute market clearing ESS price and the ESS quantity the provider was enabled for during that five-minute dispatch interval. Five-minute settlement for ESS is possible as both the ESS market clearing price and the ESS enablement quantities are available at five-minute resolution from dispatch engine outputs. Payments will be aggregated for 30-minute settlement.
- **Supplementary contract payment.** This will apply if the ESS provider is contracted through the supplementary procurement mechanism. The payment will be the contracted price and quantity.

The Taskforce has endorsed the following design decisions:

> - ESS payments will be the sum of the real-time market payment and any applicable supplementary procurement mechanism payment.
> - ESS payments will be calculated on a five-minute basis and aggregated to 30-minutes for settlement.

5.3 ESS cost recovery

5.3.1 Cost recovery principles

Causer-pays cost recovery incentivises the parties that contribute to the need for the service to take actions that decrease their share of costs by improving their contribution to the need to procure ESS.

This results in the desirable outcomes of improved performance to support system security, and the overall costs of ESS reducing to its lowest economic value.

The Taskforce previously endorsed the causer-pays principle for ESS cost recovery. The operationalisation of this principle is outlined in Table 3 below.

Table 3: ESS cost recovery

Type of ESS	Cost recovery principles
Regulation	The costs of frequency regulation services in each interval will be recovered from the causers of frequency deviation according to their contribution to the requirement, as follows: – Intermittent generators according to their deviation from forecast. – Scheduled generators according to deviation from dispatch. – Loads according to their volatility.
Contingency Reserve	The costs of Contingency Reserve in each interval will be recovered from the causers of frequency deviation (or a proxy), according to their contribution to the requirement. – The full runway method will continue to be used for cost allocation of Contingency Reserve for generation contingencies (i.e., Contingency Reserve raise). The largest network contingency will be included in the runway cost allocation, with the cost allocated to the generators associated with the network contingency. – Interval-by-interval values will be used for scheduled and intermittent generation and facilities behind a network constraint. – Total generation of generators associated with intermittent loads will be included in the runway calculation, except where a generator trip would not affect the total withdrawal or injection at the meter. – The cost of Contingency Reserve for load contingencies (i.e., Contingency Reserve lower) will be recovered from loads according to their share of consumption in the trading interval.
RoCoF control service	The costs of the RoCoF Control service will be shared between generators (based on their RoCoF ride-through capability) and loads (including as a proxy for network).

5.3.2 Regulation

Regulation raise and lower is required due to:

- scheduled generators deviating from their dispatch target;[11]
- intermittent generators deviating from their forecasted end of interval quantity. The inherent volatility of intermittent generators means that deviation from forecast is much more likely compared to scheduled generators; and
- load volatility.

5.3.3 Taskforce decision – Regulation

A generation facility's or load's contribution to the requirement for Regulation is its intra-interval variation from its dispatch targets or demand forecast. A greater deviation from the dispatch target

[11] Note that some departures from dispatch targets are legitimate deviations as a result of the generator responding to system frequency changes (e.g., droop response), and these will be excluded from the cost-allocation methodology.

or forecast increases the Regulation requirement. Both generation facilities and loads are causers for the Regulation requirement.

A reasonable approach to allocate the cost of Regulation to generation facilities and loads would properly take into account the extent of their contribution to the intra-interval variation from dispatch targets or demand forecasts. The approach applied in the NEM estimates four-second deviations using very granular SCADA, Automatic Generation Control and system frequency data. Calculating the contribution factor at a four-second resolution, however, may not produce the most accurate results because of the potential to over-estimate a facility's deviation. This method is also relatively complex to implement, and some loads may not have SCADA readings available at that resolution.

However, it is desirable to calculate the contribution factors at a granularity level that achieves a balance between reasonably estimating the facility's contribution to causing the Regulation requirement and is simple and practical to implement.

While further work is undertaken to determine contribution factors, the Taskforce considers it reasonable to allocate the cost of Regulation service to intermittent generators and loads, based on their share of 30-minute metered generation and consumption. While this is a less granular method of calculating their contribution to the Regulation requirement than that used in the NEM,[12] this method is consistent with the current approach to allocate the costs of the existing Load Following Ancillary Service.

The Taskforce has endorsed the following design decision.

> The cost of Regulation service will be allocated to intermittent generators and loads based on their share of 30-minute metered generation and consumption.

5.3.4 Contingency Reserve raise

Contingency Reserve raise is required to cover the risk of a material decrease in power system frequency due to:

- a generation facility tripping (generation contingency); or
- network components failing (network contingency), leading to a loss of generation behind the network contingency.

The risk being covered is the loss of generation *at a given point in time* that causes the frequency to drop. Hence, the risk being covered by the Contingency Reserve raise service can be characterised as a risk expressed in MW capacity, rather than a MWh risk.

The full runway method of cost allocation will be retained to allocate Contingency Reserve raise costs to generators. Costs will be allocated on a five-minute basis using the MW quantity energy and frequency control ESS (Regulation and Contingency reserve) cleared by the dispatch engine for all generation facilities above 10MW.[13]

[12] Including scheduled generators in this approach to cost-recovery would be unreasonable because by virtue of the current generation mix, it would result in these generators paying for the majority of the Regulation service, even though they currently contribute the least, when compared to intermittent generators.

[13] Retaining the 10 MW minimum threshold is consistent with the current approach, where the lowest generation capacity to which Spinning Reserve cost is allocated is 10 MW.

Treatment of generators with intermittent loads

Generation serving intermittent loads will be allocated Contingency Reserve raise costs unless they can provide evidence that their co-located load trips at the same time as the generation which serves them.

The risk contribution of a generator serving an intermittent load will be calculated using its total generation (as using net exported generation will under-estimate the risk set by their entire generation unit). An intermittent load's risk contribution is most accurately estimated by its five-minute SCADA reading and this reading will be used for cost-allocation. A five-minute enablement quantity is not available for an intermittent load facility as it does not participate in ESS.

Treatment of network contingencies

Credible network contingencies[14] will be an input into the scheduling and dispatch process to ensure adequate Contingency Reserve raise is scheduled to cover the risk of a network component tripping risking the loss of available generation capacity associated with that component. Therefore, the network contribution needs to be included in the runway cost allocation.

When it comes to cost recovery, there are different ways in which network contingencies can be treated in the runway cost allocation:

1. all credible network contingencies can be ranked, such that each network contingency is treated as an individual facility risk; or
2. only designated network contingencies can be ranked (for example, all network contingencies greater than the largest generator (e.g. ~300MW); or
3. only the largest network contingency can be included.

Given that the network can be considered a single facility, including multiple network contingencies in the runway (i.e. options 1 and 2) means that the network contribution is counted multiple times despite being one facility. For this reason, only the largest network contingency will be included for cost recovery purposes, with all tranches of the runway cost shares allocated to that network contingency.

The cost attributable to the network contingency needs to be allocated to the entity best placed to minimise these costs. However, the increased requirement for Contingency Reserve raise is an indirect cost attributable to the network operator. This is because the network operator will not typically have direct control over generators wishing to connect in parts of the network,[15] where once they are operating, they will raise the contingency reserve raise risk. The cost of this increased risk is difficult to predict and quantify for the network operator in its annual planning processes because it emerges from dispatch processes, not from the condition of the network. The network operator may therefore have a perverse incentive to over-estimate this risk in its network pricing strategy, which may lead to higher network charges for all network users, rather than being directly borne by the generator(s) that increased the contingency reserve raise risk by locating in the relevant part of the network.

For these reasons, the Taskforce considers that the cost of Contingency Reserve raise emerging from network contingencies should be borne by the generators associated with that network

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[14] The size of a network contingency is given by the sum of the cleared generation of the facilities that would trip if the contingency manifested.

[15] Western Power is obligated under Clause 2.7 of the Access Code to facilitate the connection of new facilities to its network.

contingency. The method for allocating this cost will be detailed through rule drafting, which will be subject of further consultation with stakeholders.

Importantly, a signal to reinforce or augment the network still needs to be sent to the network operator to ensure that its contribution to setting the Contingency Reserve raise risk is reduced. Further discussion on this matter is outlined in section 5.4.

5.3.5 Taskforce decision – Contingency Reserve raise

The Taskforce has endorsed the following design decisions.

- The runway method will be used to allocate the cost of Contingency Reserve raise to generators. The largest network contingency will be included in the runway model and allocated to the associated generators.
- Costs will be allocated on a five-minute basis using dispatch engine outputs (or five-minute SCADA data in the case of intermittent loads).
- Generators serving intermittent loads will be liable for Contingency Reserve raise costs unless they can provide evidence that the load trips at the same time as the serving generation.

5.3.6 Taskforce decision – Contingency Reserve lower

Contingency Reserve lower is required to cover the risk of a material increase in frequency due to a loss of load. Therefore, loads are the causer of a Contingency Reserve lower requirement.

Contingency Reserve lower costs will be recovered from loads based on their share of consumption in the trading interval. This is consistent with the current cost allocation method for Load Rejection Reserve.

Between 1 October 2022 to 30 September 2025, Contingency Reserve lower costs will be allocated on a 30-minute basis, based on the load's 30-minute metered consumption quantity.

Cost allocation on a five-minute basis is relatively more difficult to implement due to the absence of five-minute metering for loads. A methodology to profile 30-minute consumption quantities using SCADA data (where available) to five-minute load volumes, would need to be developed. This may involve complex implementation in addition to SCADA equipment not being available at all load sites. For these reasons, costs will be allocated to loads on a 30-minute basis until five-minute meters and five-minute settlement is implemented.

The Taskforce has endorsed the following design decision.

> The cost of Contingency Reserve lower will be allocated to loads based on their 30-minute metered consumption.

5.3.7 Rate of change of frequency (RoCoF) Control

RoCoF Control is a new ESS that performs the following two functions:

- Primarily, to restrict the RoCoF to below a certain level; the amount of RoCoF Control service scheduled to meet this purpose is referred to as the minimum RoCoF requirement.

- Secondarily, to provide a substitute for Contingency Reserve raise; the more inertia there is in the power system at any given point in time, the less contingency reserve raise is required. There is a trade-off between the two services; the amount of RoCoF Control service scheduled to meet this requirement is referred to as the additional RoCoF requirement.

This new service is required because, as the amount of synchronous generation on the power system reduces, the expected RoCoF when a contingency event occurs will increase. Such events are expected to happen infrequently in the near term, but with greater occurrence over time.[16]

When RoCoF is high, there are implications for various parties. An AEMO-commissioned international review[17] (citing Irish references) found:

- generators may face cascade tripping, wear and tear, safety concerns, and catastrophic damage to generating units;[18]
- network components are affected; when RoCoF is too high, frequency can move outside of the allowed range before mitigating measures such as automatic under-frequency load-shedding have time to respond, leading to cascading outages and frequency collapse; and
- the impact on loads is inconclusive.

The capability of generators, loads, and network components to ‘ride-through’ high RoCoF events without tripping off varies.

AEMO will determine a safe RoCoF limit through appropriate technical studies and include it in the Frequency Operating Standard and the dynamic frequency contingency model used in dispatch. Initially, it may be prudent to set the limits conservatively, and explore relaxing them as experience is gained and confidence improves.[19] However, because the RoCoF Control service by its nature requires (higher marginal-cost) synchronous generators to run instead of cheaper intermittent renewable generators, setting limits conservatively has the potential to add significant costs.[20]

The causer-pays approach to cost recovery is a key part of uncovering true capability of different facilities, incentivising them to improve their ride-through capability, and expanding the secure operation zone. As the secure operation zone expands, the requirement for a RoCoF Control service reduces, implying the cost of providing the service will also reduce. This is a desirable outcome as it both improves overall system security and reduces the costs of the service to its lowest economically efficient value.

In advance of market start, AEMO will conduct modelling to determine an upper RoCoF ride-through limit, above which no RoCoF Control service would be required (i.e. the maximum RoCoF if only primary frequency response was available). In other words, AEMO will need to determine the maximum RoCoF in the absence of a RoCoF Control service across the range of expected system conditions.

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16 Essential System Services Framework Review (ESSFR) (July 2019). The ESSFR modelled RoCoF in 2023, noting that, if relying on Contingency Reserve response no faster than 1 second, RoCoF of ~ 3Hz/second could be experienced under some circumstances.

17 DGA Consulting, International Review of Frequency Control, AEMO, October 2016, available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/2016/FPSS---International-Review-of-Frequency-Control.pdf

18 This was assessed to be “highly unlikely” on the basis that units can be expected to undergo more severe network fault events without catastrophic failure.

19 This has been the approach in Ireland, as they have gradually raised the bar for intermittent renewable penetration.

20 Some inertia can be provided by any synchronous machine, not just a synchronous generator; for example, the service could also be provided by renewable generators that install a synchronous condenser or by a network synchronous condenser.

Generators and network as causer

Generation and network facilities are important drivers for the requirement for a RoCoF Control service. To incentivise generators and network facilities to improve their ride-through capability and reduce their exposure to the costs of the RoCoF Control service, it is reasonable to allocate a proportion of the costs to them.

Loads as causer

The contribution of loads to the RoCoF Control service requirement is less clear. While loads face a high RoCoF any time they are tripped off in an uncontrollable manner, there is no explicit evidence that loads (particularly large industrial loads) will not suffer damage in a high RoCoF event that does not result in a blackout, or exacerbate the situation by tripping off (which helps if frequency is falling, but hinders if frequency is rising) or behaving in some other abnormal way. However, large industrial loads that are generally contestable may be able to identify and improve their ride-through capability through their contractual relationship with retailers (for example, an innovative retailer may be able to assist reducing electricity bills by improving the load's ride-through settings, and demonstrating compliance with the RoCoF safe limit). Large loads should therefore also receive an incentive to improve their ride-through capability and reduce their exposure to the costs of the RoCoF Control service. For these reasons, it is reasonable to allocate a proportion of the costs to them.

Smaller loads, such as residential loads, however, may ultimately become the only remaining reason for the service. However, these loads are also the beneficiaries of the power system, and as such it is reasonable for the costs of the RoCoF Control service to ultimately be borne by the beneficiary. Synergy, as the retailer for these loads, could be required to work with Western Power to determine how best to improve the performance of smaller loads to assist with relaxing the RoCoF safe limit.

5.3.8 Taskforce decision – RoCoF

Minimum RoCoF Control Requirement

The approach to allocating the Minimum RoCoF Control Requirement cost is to split the total RoCoF Control service in a dispatch interval in three parts and allocate as follows:

1. Generators in the RoCoF ride-through band would be required to fund one-third of the minimum RoCoF Control requirement cost. This one-third share would be allocated to generators in proportion to their share of generation. As generators demonstrate their ability to ride-through safely, their exposure to the costs of the service would reduce.
2. All loads, initially, with a mechanism requiring AEMO to investigate the true ride-through capability of loads to be used as input into future safe limit reviews. The loads' one-third share would be allocated to individual loads in proportion to their share of consumption. As loads demonstrate their ability to ride-through safely, their exposure to the costs of the service would reduce.
3. To Western Power, based on its network ride-through capability. Western Power would fund one-third of the Minimum RoCoF Control Requirement cost if its network is unable to ride-through the RoCoF safe-limit. If Western Power were to amend its network settings to improve its ride-through capability, then the Minimum RoCoF Control Requirement cost would be split two ways between generators in the RoCoF ride-through band and loads.

While 30-minute settlement is in place between 1 October 2022 and 30 September 2025, the generator and load share of the Minimum RoCoF Control Requirement will be allocated based on 30-minute metered generation and consumption values. Once five-minute settlement is implemented, cost recovery will occur on a five-minute basis.

Additional RoCoF Control Requirement

The additional RoCoF Control Requirement portion is effectively a substitute for Contingency Reserve raise, and will therefore be included in the runway method allocation of costs for the Contingency Reserve raise service.

The Taskforce has endorsed the following design decisions.

> - The cost of the minimum RoCoF Control requirement will be allocated equally (i.e. one third each) between generators, loads, and the network with ride-through capability less than the maximum forecast RoCoF level, with generation and loads allocated the costs on a 30-minute basis.
> - The cost of the additional RoCoF Control requirement will be included in the runway method calculation for Contingency Reserve raise.

5.4 Incentivising network investment to minimise market costs

As discussed in sections 3.2.4 and 5.3.4, market operational costs such as uplift payments and Contingency Reserve raise costs provide useful information to inform a net benefits test for network reinforcement and/or augmentation. These costs can be allocated to the network operator, Western Power, to provide direct financial incentives to minimise these costs. However, as previously discussed in those sections, Western Power's existing regulatory framework does not provide sufficient clarity to require the consideration of these market costs in its net benefit test for network augmentation. Without this clarity, action from the network operator to reduce these costs is not assured, and the risk of unintended consequences is material.

For these reasons, the Taskforce considers it reasonable in the short-term to pursue amendments to the Access Code to require Western Power to take into account market-related costs, including the operational costs of uplift payments and Contingency Reserve raise, in its net benefit test for network augmentation. Western Power's annual planning processes will also need to be improved to require modelling and analysis that provides information on network congestion and the potential for network contingency risk at different locations on the network. Western Power's review of its Technical Rules, anticipated to be undertaken throughout 2020, will also include consideration of how network planning processes can be improved to reduce network contingency risk. [21]

Additionally, the framework for locational ESS, currently under development by the Taskforce, is expected to set out processes that will enable Western Power (and/or AEMO) to perform "market-testing" to determine if alternatives exist that can enable Western Power to reinforce its network at a cheaper cost than the operational costs of catering for a large contingency risk, or to manage network congestion. An information paper outlining this framework is planned for release in February 2020.

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[21] Other jurisdictions (e.g., Ofgem in the United Kingdom) include normal and/or infrequent loss of infeed risk in network asset planning. This is the risk of active power infeed loss at different locations on the network that can cause frequency deviations.

Experience from other jurisdictions indicates incentives-based regulation can provide a sharper, more positive signal to network operators to resolve network issues that increase operational costs in the market. For example, the efficiency benefit sharing scheme in the NEM incentivises electricity network businesses to spend efficiently on network augmentations and share the benefits of efficiencies with consumers. In the United Kingdom, the national grid transmission system operator is incentivised to spend efficiently by retaining a share of the saved revenue.

In the South West Interconnected System, a material shift will be needed in the manner in which the network operator is regulated to allow for the development of such transmission efficiency incentive schemes. Although this work is not contemplated as part of the Energy Transformation Strategy, the Taskforce anticipates that this work could be required in future.

5.4.1 Taskforce decision

The Taskforce has endorsed the following design decision.

> Changes to the Access Code will be progressed to include the consideration of market costs in the net benefit test for network augmentation proposals.

6. System Restart ESS

6.1 System restart

System Restart services are required to allow parts of the power system to be re-energised by black start-equipped generation capacity following a full (or partial) black out. Unlike other generators, black start-equipped generators can be started up without requiring a supply of energy from the network. There is currently no market for System Restart services as this is procured by AEMO based on a System Restart Standard outlined in the WEM Rules. The costs of the service are recovered from Market Customers based on their metered consumption in a settlement period.

Although the efficiency of the procurement process will be assessed through further work in the locational ESS workstream (e.g., to examine locational market power concerns), the cost-recovery process for System Restart is not expected to change.

6.1.1 Taskforce decision

AEMO will make settlement payments to System Restart providers as required by their individual contracts. The payment generally comprises a fixed payment and arrangements for non-performance. The specific payment arrangements will vary according to the terms of the contract.

System Restart service costs will continue to be recovered from market customers based on their metered consumption over the settlement period.

The Taskforce has endorsed the following design decision.

> The existing approach to settling System Restart services will be retained:
>
> - System Restart providers will be paid on a contractual basis.
> - Costs will be recovered from Market Customers based on their metered consumption in a settlement period.

Appendix A

Uplift trigger

The Uplift Trigger for facility *f* in dispatch interval *DI* is defined as:

$$IsMisPriced^{*}_{f,DI} = \begin{cases} 1\ if & \sum_{\forall n \in NC^{*}_{f} \cap DI} w_n^f MV_n > 0 \\ & \sum_{\forall n \in NC_{f,ESS} \cap DI} w_n^f MV_n = 0 \\ & \cap\ MOP_{f,DI} > MCP_{DI}\ \cap \\ & f \neq binding\ ESS\ EnableMin\ or\ down\ ramp\ constraint \\ 0 & otherwise \end{cases}$$

Where:

- the set of network constraints are denoted as follows:
  - $NC \cap DI$ denotes the set of all network constraints (*NC*) applicable to all facilities being applied in dispatch interval *DI.*
  - $NC_{f,ESS}$ is a subset of the full set of network constraints *NC*. It denotes the subset of network constraints that are part of the non-frequency ESS contract facility *f* has entered-into with Western Power.
  - NC^{*}_{f} is a subset of the full set of network constraints *NC* which excludes $NC_{f,ESS}$. Note that both $NC_{f,ESS}$ and NC^{*}_{f} is indexed on facility *f.* This is because the non-frequency ESS contract is facility specific.
- w_n^f denotes facility f's constraint coefficient in constraint *n*.
- MV_n denotes the marginal value or shadow price of constraint *n*, which will be non-zero only if the constraint is binding.
  - $\sum_{\forall n \in NC \cap DI} w_n^f MV_n$ can be interpreted as facility *f*'s congestion rental contribution in dispatch interval *DI* if facility *f* was not in a non-frequency ESS contract. Hence, if there are no non-frequency ESS contracts, then the congestion rental component of the uplift trigger would be summed over all network constraints for all facilities.
  - $\sum_{\forall n \in NC^{*}_{f} \cap DI} w_n^f MV_n$ (the summation used in the uplift trigger above) can be interpreted as facility f's congestion rental contribution in dispatch interval *DI* in respect of all network constraints that are not part of the non-frequency ESS contract.
  - $\sum_{\forall n \in NC_{f,ESS} \cap DI} w_n^f MV_n$ is the congestion rental associated with the constraint equations that are part of the *NC* ESS contract. This additional condition is added to ensure that if *NC* ESS constraints are binding at the same time as non-*NC* ESS constraints, then the facility receives no uplift payments (to avoid double payment).
- $MOP_{f,DI}$ and MCP_{DI} respectively denote the facility marginal offer price and market clearing price in dispatch interval *DI*.

The use of the above trigger may lead to a facility being paid an uplift payment unnecessarily. For example:

- If an ESS provider is dispatched for energy at its enablement minimum level[22] when a network constraint is binding, then the above trigger would allow the facility to receive an uplift payment. In this scenario, the reason the facility is being dispatched may be because the ESS constraint is binding (otherwise it would be dispatched down to zero). Under such a scenario, the participant should revise its bids by setting its reserve offers to zero. If after doing so, the congestion rental component in the uplift trigger is still non-zero, then it would indicate that the facility genuinely qualifies for an uplift payment. Hence, a facility should not be eligible for uplift payments when it appears in a binding ESS enablement minimum constraint for Contingency Reserve raise, Contingency Reserve lower, Regulation raise or Regulation lower ESS[23].
- A facility behind a constraint may not be marginal in its location, in which case the uplift trigger above would denote it is eligible to receive an uplift payment even though it is not out of pocket.

  For example, if a generator (Generator A) is behind a binding network constraint and the next MW of load at that location is provided by another generator who is also behind the same constraint (Generator B) but is more expensive than Generator A's marginal offer price.[24] This scenario could arise if:

  - Generator A is up-ramp rate constrained; or
  - Generator A is on outage or has insufficient capacity to meet its load; or
  - Generator A's next offer tranche is more expensive than Generator B's offer tranche that is dispatched to meet the next increment of load at A.

Here, Generator A's marginal offer could be less than the market clearing price, however Generator A's pseudo-nodal price will be set by Generator B's marginal offer price, and hence its congestion contribution will be non-zero. Therefore, an additional condition for an uplift payment to apply would be that the relevant generator's marginal offer price must be greater than the market clearing price.

- If a facility is in a binding network constraint and a binding down ramp rate constraint, it cannot set its pseudo-nodal price; it is only being dispatched because it cannot ramp down quickly enough to a cheaper tranche or to zero. In such a scenario the facility should not receive an uplift payment.
- A facility may have a non-frequency ESS contract with Western Power. Under such a scenario, the facility may be negatively mispriced with respect to certain network constraints; however, their contract with Western Power is the mechanism by which they are made whole when these constraints bind. Hence, any facility with a non-frequency ESS contract with Western Power should not be eligible to receive an uplift payment when the specific constraints that are part of the non-frequency ESS contract bind.

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[22] Refer to *Information Paper – ESS Scheduling and Dispatch* for more details on how constraints relating to ESS dispatch.

[23] The Contingency Reserve and Regulation trapeziums will be implemented via separate constraint sets. Hence, the dispatch engine will be able to indicate whether the enablement minimum constraint is binding for any of Contingency Reserve raise, Contingency Reserve lower, Regulation raise or Regulation lower ESS.

[24] That is, the offer price associated with the last offer tranche cleared.

Given the above, the uplift trigger for facility *f* in dispatch interval *DI* ($IsMisPriced_{f,DI}$) will apply (i.e. equal 1) if:

- the facility's congestion rental contributions are greater than zero ($w_n^f MV_n > 0$) in respect of all network constraints which are not part of the facility's non-frequency ESS contract with Western Power;
- the facility's marginal offer price in the dispatch interval is greater than the market clearing price in that interval ($MOP_{f,DI} > MCP_{DI}$); and
- the facility does not appear in a binding ESS enablement minimum constraint for Contingency Reserve raise, Contingency Reserve lower, Regulation raise or Regulation lower ESS or a binding down ramp rate constraint.

A facility will be eligible to receive an uplift payment if all the conditions above apply.

Uplift payment

The uplift payment for facility *f* in dispatch interval *DI* (in settlement interval *SI*) is defined as:

$$UpliftPayment_{f,DI} = MLF_f \times \left(UpliftPrice_{f,DI} \times MQ_{f,DI}\right)$$

$$= IsMisPriced_{f,DI} \times MLF_f \times (MOP_{DI} - SP_{SI}) \times MQ_{f,DI}$$

Where MLF_f is the marginal loss factor for facility *f*.

Appendix B

Alternative for uplift price

An alternative for the uplift price considered by the Taskforce was the facility local price calculated by the dispatch engine (i.e. the 'pseudo-nodal' price). Particularly, a hub and spoke model defines a facility's local price to be the sum of the market clearing price (at the Reference Node) and the facility's congestion rental contributions; the latter can be interpreted as a nodal price difference which reflects the impact of network congestion on the locational marginal price.

The pseudo-nodal price equals the facility marginal offer price, if the facility is marginal in its location. However, this will not always be the case. For example, when there is more than one facility operating behind a constraint, the local price as shown by the pseudo-nodal price could be set by the other generator behind the same constraint. In this case, the uplift trigger could still show the non-marginal facility in that location as eligible for uplift payment because the local price is higher than the Reference Node price, even though the facility's own marginal offer price may be lower than the pseudo-nodal price. In this situation, using the pseudo-nodal price may lead to that facility potentially being over-compensated for its running costs. The purpose of the uplift payment mechanism is to make a facility whole and ensure they recover their running costs. As such, the pseudo-nodal price is not considered an appropriate proxy for the purposes of the uplift payment mechanism.

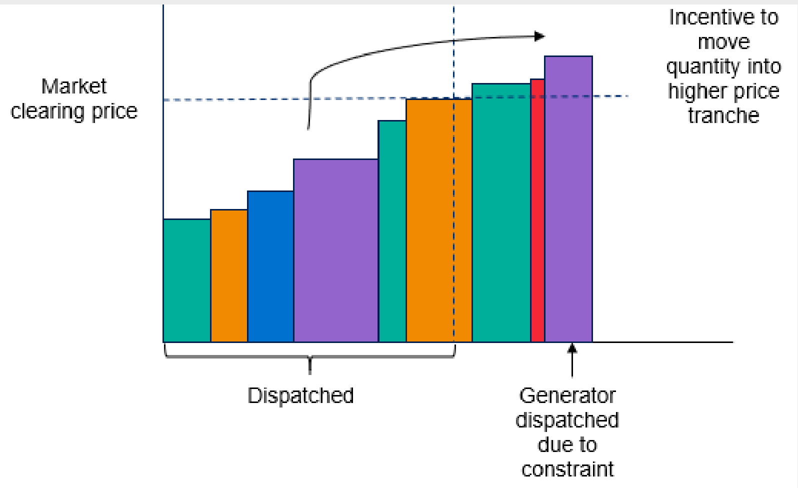
Alternative for uplift quantity

An alternative for the uplift quantity eligible for an uplift payment is to qualify the generation quantity associated with the facility's offer tranches where its marginal offer price is greater than the market clearing price (or the marginal offer tranche). This option is likely to lead to disorderly bidding. Based on pre-dispatch information, a generator may expect to receive an uplift payment for some of its generation from a given facility for a given dispatch interval. It may have an incentive to move other lower cost generation tranches for that facility to the higher cost tranche in an attempt to maximise its ability to fully recover its running costs. This may lead to inefficient market outcomes, including potentially raising the market clearing price. Disorderly bidding is further explained in the example below.

Example: Disorderly bidding

In this example, the purple bars show a single facility with two differently priced offer tranches. The generator has an incentive to move the quantity from the lower priced tranche (left) to the higher priced tranche (right) to increase its uplift payment.

This will shuffle the other generators to the left, and potentially increase the market clearing price.



This incentive is removed if the uplift payment is paid for the entire generation quantity for that facility for the given five-minute dispatch interval.

Appendix C

ESS payment

The payment to participant *p* for their facilities ($\forall f \; registered\ to\ p$) for ESS product *s* in dispatch interval *DI* is given by:

$$ESSTA_{s,p,DI} = \sum\nolimits_{\forall f \in p} \left\{ \begin{matrix} \pi_{s,DI} \times \frac{ESSCleared_{s,f,DI} \times PF_{s,f}}{12} \\ + IncSup_{s,f} \times Sup\_\pi_{s,f} \times \frac{AvQty_{s,f} \times PF_{s,f}}{12} \end{matrix} \right\},$$

Where:

- $\pi_{s,DI}$ is the real-time (co-optimised) price of ESS product *s* in dispatch interval *DI.*
- $ESSCleared_{s,f,DI}$ is the MW quantity enabled for ESS product *s* and facility *f* in dispatch interval *DI*. This quantity is divided by 12 to account for the five-minute dispatch interval.
- $Sup\_\pi_{s,f}$ and $AvQty_{s,f}$ are respectively the availability price and availability quantity pertaining to the supplementary contract to procure ESS product *s* from facility *f*.
- $0 < PF_{s,f} \leq 1$ [25] denotes the performance factor for ESS product *s* and facility *f* and will be an input into the dispatch engine.[26]
- $IncSup_{s,f}$ denotes whether or not a supplementary procurement contract exists for ESS product *s* and facility *f*:
  - $IncSup_{s,f} = \begin{cases} 1 & if\ supplementary\ procurement\ contract\ exists\ for\ product\ s\ and\ facility\ f \\ 0 & Otherwise \end{cases}$

The payment to participant *p* for ESS products *s* in settlement interval *SI* is calculated by summing the ESS payments ($ESSTA_{s,p,DI}$) for over the relevant dispatch intervals *DI* as follows:

$$ESSTA_{s,p,SI} = \sum_{\forall DI \in SI} ESSTA_{s,p,DI}$$

ESS cost recovery

Regulation Reserve raise and lower

At market start, the existing approach to regulation ESS will be retained (unless a methodology to calculate contribution factors for different facilities can be developed).

Denote:

- $ESSTA_{\boldsymbol{Regulation},SI}$ to be the total regulation ESS payments made to providers in settlement interval *SI*.

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25 $PF_{s,f}$ is a parameter used to reflect the varying response capabilities of facilities providing ESS.

26 For Contingency Reserve raise, $PF_{s,f}$ will be calculated by AEMO's frequency response model (which iterates with the dispatch engine to set the performance factors, the primary requirement and the RoCoF requirement).

- $ESSTA_{\boldsymbol{Regulation},SI} = ESSTA_{\boldsymbol{RegUp},SI} + ESSTA_{\boldsymbol{RegDown},SI}$, where $ESSTA_{\boldsymbol{RegUp},SI}$ and $ESSTA_{\boldsymbol{RegDown},SI}$ respectively denote the total regulation raise and lower payments made to providers in settlement interval *SI* (calculated in accordance with section 0).

The total regulation cost allocated to participant *p* in settlement interval *SI* is denoted by:

- $RegCost_{p,SI} =$
- $ESSTA_{\boldsymbol{Regulation},SI} \times \frac{\sum_{\substack{i \in Intermittent \\ Generators \\ registered\ to\ p}} MeteredGen_{i,SI} + \sum_{\substack{i \in NMIs \\ registered \\ to\ p}} MeteredConsumption_{i,SI}}{\sum_{\substack{j \in \forall\ Intermittent \\ Generators}} MeteredGen_{j,SI} + \sum_{j \in \forall NMIs} MeteredConsumption_{j,SI}}.$

Contingency Reserve raise

Contingency reserve raise costs will be allocated to causers of contingencies using the runway method.

Denote:

- $ContRaiseReq_{DI}$ as the Contingency Reserve raise requirement identified by the dispatch engine in dispatch interval *DI*.
- $\{Cont_{(1)}, Cont_{(2)}, Cont_{(3)}, \ldots, Cont_{(n)}\}$ to be the ranked list (from highest to lowest) of contingencies identified by the dispatch engine with contribute to $ContRaiseReq_{DI}$. Particularly:
  - $Cont_{(i)}$ can either denote the cleared energy and ESS (in dispatch interval *DI*) from facilities above the de-minimis (10MW) or the total generation at risk (in dispatch interval *DI)* if the largest network contingency manifested.
  - $Cont_{(1)}$= $ContRaiseReq_{DI}$, as the largest contingency sets the contingency raise requirement.

The MW share of the contingency raise requirement allocated to $Cont_{(i)}$ can be expressed as:

$$MWShare_{(i)} = \begin{cases} \sum_{j=i}^{n-1} \frac{Cont_{(j)} - Cont_{(j+1)}}{j} + \frac{Cont_{(n)}}{n}, & \forall \leq i \neq n \\ \frac{Cont_{(n)}}{n}, & i = n. \end{cases}$$

Note $\sum_{i=1}^{n} MWShare_{(i)} = ContRaiseReq_{DI}$.

The Contingency Reserve raise cost allocated to $Cont_{(i)}$(in dispatch interval *DI)* can be written as follows:

$$\boldsymbol{ContRaiseCost_{(i),DI} = ESSTA_{ContRaise,DI}} \times \frac{\boldsymbol{MWShare_{(i)}}}{\boldsymbol{ContRaiseReq_{DI}}},$$

Where, $ESSTA_{ContRaise,DI}$ denotes the total Contingency Reserve raise payments made to providers in dispatch interval *DI* (calculated in accordance with section 0).

The total Contingency Reserve raise cost allocated in the settlement interval *SI* is the sum of the costs allocated in the relevant dispatch intervals.

$$ContRaiseCost_{(i),SI} = \sum_{\forall DI \in SI} ContRaiseCost_{(i),DI}$$

The costs above are set out at the contingency (or facility) level. The Contingency Reserve raise costs allocated to a participant would be calculated by summing the costs of all facilities associated with that participant:

$$ContRaiseCost_{p,SI} = \sum_{\substack{\forall f \in facilities \\ registered\ to\ p}} ContRaiseCost_{(f),SI}.$$

Contingency Reserve lower

The contingency lower cost allocated to participant *p* in settlement interval *SI* is denoted:

$$ContLowerCost_{p,SI} = ESSTA_{ContLower,SI} \times \left(\frac{\sum_{i \in NMIs\ registered\ to\ p} MeteredConsumption_{i,SI}}{\sum_{j \in \forall NMIs} MeteredConsumption_{j,SI}} \right),$$

Where:

- $ESSTA_{ContLower,SI}$ denotes the total contingency lower payments made to providers in settlement interval *SI*.
- Metered consumption denotes negative metered schedules over a given settlement interval.

RoCoF Control

This section sets out cost recovery formulae for the minimum RoCoF control requirement. The additional RoCoF control requirement (which is a substitute for contingency raise ESS will be allocated using the runway method).

Denote:

- $ESSTA_{\boldsymbol{RoCoF},SI}$ to be the total minimum RoCoF control payments made to providers in settlement interval *SI* (calculated in accordance with section 0).
- Let $\{G_1, G_2, \ldots., G_g\}$ and $\{L_1, L_2, \ldots., L_l\}$ denote respectively the set of generating facilities and loads with ride-through capability less than the forecast maximum RoCoF requirement.

The cost allocated to generating facility G_i in settlement interval *SI* is denoted by:

1. $RoCoF_{G_{i,SI}} = \frac{ESSTA_{\boldsymbol{RoCoF},SI}}{3} \times \frac{MeteredGen_{G_i SI}}{\sum_{k \in \{G_1, G_2, \ldots, G_g\}} MeteredGen_{k,SI}}.$

The cost allocated to load L_i in settlement interval *SI* is denoted by:

2. $RoCoF_{L_{i,SI}} = \frac{ESSTA_{\boldsymbol{RoCoF},SI}}{3} \times \frac{MeteredConsumption_{L_i,SI}}{\sum_{k \in \{L_1, L_2, \ldots, L_l\}} MeteredConsumption_{k,SI}}.$

The cost allocated to the network owner in settlement interval SI is denoted by:

3. $RoCoF_{NO,SI} = \frac{ESSTA_{\boldsymbol{RoCoF},SI}}{3}.$

Note:

- If the network owner provides evidence that its network components have a ride-through capability greater than the forecast maximum RoCoF control requirement, then its cost share would be zero.
- Consequently, the $ESSTA_{RoCoF,SI}$ cost component in equations 1 and 2 above, would be divided by two (instead of three), as the cost would now be shared amongst two parties instead of three.