Network Market Impact Working Group

Network Market Impact Options Report

September 2026

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Summary

The purpose of this report is to set out the options and views considered by the Network Market Impact Working Group (the working group) for replacing the Market Impact Component (MIC) of the Service Target Performance Incentive Scheme (STPIS).

The working group was established by the AER to consider potential options in the absence of the MIC, to promote the efficient planning and management of network outages. This report records the working group process and views expressed by members of the working group. It is not an AER report and does not represent the views of the AER.

The working group:

- considered alternative options for an improved incentive mechanism to minimise the impact of network outages on market participants and consumers
- explored the introduction and considered the form of a conduct obligation on TNSPs to minimise the impact of network outages on wholesale prices
- considered data quality and implementation issues associated with the identified options
- provided views on the options for AER consideration.

In considering options to replace the MIC, the working group focused on planned network outages and the actions available to the TNSPs to minimise market impacts from those outages. This included considering how to identify planned outages that are likely to have a material market impact, and the outage planning and management practices that could reasonably be expected to mitigate those impacts.

The working group considered the following options in relation to planned transmission network outages:

- Option 1(a), (b) and (c): Improved transparency on outage planning and management
- Option 2: Outage notification incentive scheme
- Option 3: Outage scheduling incentive scheme
- Option 4: Material Market Impact (MMI) outage management incentive scheme
- Option 5: Conduct-based obligation
- Option 6: Combining options.

This report explains the options and draws on working group discussions to provide a qualitative summary of advantages and disadvantages of the options. This report also records the matters discussed and the views expressed during the working group process.

This report provides illustrative worked examples to show how options 2 (outage notification incentive) and 3 (outage scheduling incentive) could work, and:

- **Attachment B** sets out further details of how Option 4 could operate.
- **Attachment C** sets out further details of how Option 5 could operate; and
- **Attachment D** sets out further details of how Option 6 (a combined option) could operate.

The attachments are not intended to pre-empt detailed final scheme design of these options. They are included to make the options more concrete and to assist in assessing implementation issues.

Most working group participants expressed in-principle support for an incentive-based mechanism with financial rewards and penalties to encourage efficient outage planning and management, assessed on factors within a TNSP's control. Some participants supported a conduct-based obligation but either as a 'backstop' (if implementing an incentive scheme is not possible) or in conjunction with an incentive-based mechanism. Most participants expressed concern that a stand-alone conduct-based obligation may not be effective at aligning outage planning practices with beneficial consumer outcomes. However, some participants considered a conduct obligation could be used as a 'back stop' to an incentive-based mechanism.

Working group participants identified a number of implementation issues associated with incentive-based options:

- Narrowly based incentives (for example a notification or scheduling incentive) may not, by themselves, reduce the market impact of outages. For example, a notification incentive without a scheduling incentive could provide better notification outcomes but poorer scheduling outcomes on the market and vice versa.
- Participants discussed whether combining incentive schemes could improve market outcomes, while noting implementation issues, including how different components might be weighted.
- Participants questioned whether sufficient data are available to set evidence-based targets for the schemes or target the schemes to outages that matter (those likely to have a material market impact).

Participants also identified a number of implementation issues associated with a conduct-based obligation:

- A conduct obligation would require a Rule change and supporting framework, creating additional implementation, data capture, reporting and compliance effort that would need to be justified by clear consumer benefits.
- Implementing the obligation could shift TNSPs' focus from efficient outage planning to demonstrating regulatory compliance, particularly if it requires detailed documentation against broad information requirements for each relevant outage.
- The obligation may be difficult to apply predictably, as compliance would rely on ex-post judgement and would need to be targeted to matters within TNSP control, with clear carve-outs for safety, reliability, system security and operational practicality.

Discussions to date have provided considerable guidance in navigating the issues. Overall, the working group expressed a preference for an incentive-based approach to replace the Market Impact Component.

The working group recognised the limitations of existing data and noted that collection of information on outage planning, and management practices may enable the AER to further develop incentives in future. Participants noted that this information could inform the future development or refinement of a scheme.

This report is intended to inform the AER's consideration of a replacement for the MIC.

The report records the options discussed for replacing the suspended MIC, including options that could be developed or refined as further information becomes available.

1 Introduction

1.1 Purpose of this report

The purpose of this report is to set out the options and views considered by the Network Market Impact Working Group (the working group) to inform the AER's approach to replacing the MIC.

1.2 Background

The transmission Service Target Performance Incentive Scheme (STPIS) provides incentives to Transmission Network Service Providers (TNSPs) to provide greater transmission network reliability when network users place greatest value on reliability, as well as to improve and maintain the reliability of elements of the transmission network most important to determining spot prices.

On 17 April 2025, the AER published version 6 of the STPIS and an accompanying Explanatory Statement. Version 6 suspended the Market Impact Component (MIC) of the STPIS. The Explanatory Statement stated that in recent years, with changes in the generation mix and more regionally dispersed weather-dependent renewable generation, this component of the STPIS was no longer working as intended (see section 2.2 of the final Explanatory Statement). However, in view of the suspended MIC, the AER recognised the need to ensure that the TNSPs are planning and managing the operation of their networks to minimise the impact on wholesale prices.

The AER established a working group to consider alternative arrangements in the absence of the MIC. The working group was established to consider potential options, building on the findings of the STPIS Review, to promote the efficient planning and management of network outages.

This report records the working group process and views expressed but does not represent a consensus recommendation, though the working group has expressed support for an incentive-based approach to replace the MIC. The outcomes of the process will inform the AER's consideration of a replacement for the MIC.

1.2.1 Objectives of the working group

The objectives of the working group were to:

- consider alternative options for an improved incentive mechanism to minimise the impact of network outages on wholesale market prices.
- explore the introduction and consider the form of a conduct obligation on TNSPs to minimise the impact of network outages on wholesale market prices.
- provide views on preferred options for AER consideration.

The working group also considered the relevance of the recently published 'National Electricity Market wholesale market settings review' (Nelson Review) which recommended that:[1]

> Given the potential price impacts of network outages, the Panel advocates for stronger incentives for TNSPs to consider wholesale market effects in their planning. A revised, price-based mechanism could deliver clear, market-aligned signals or, alternatively, a conduct obligation could address market impacts without imposing excessive penalties. A targeted mechanism is essential to protect consumers and market outcomes while enabling essential works.

In considering these recommendations, the working group recognised that any incentive mechanism or conduct obligation should focus on impacts arising from foreseeable risks and matters reasonably within a TNSP's control.

The terms of reference of the Network Market Impact Working Group are provided in **Attachment A**.

The working group process considered the following:

- the problem to be addressed
- the behaviour that an option might seek to encourage
- which options, including incentive-based options and a conduct obligation, might address the problem; and
- how the options should be assessed.

The working group process and matters discussed are outlined in Table 1.

Table 1: Network Market Impact Working Group process

Meeting	Key areas of discussion
Meeting #1: 28 October 2025	Role and expectations of the working group; proposed framework for evaluation of options to replace the MIC.
Meeting #2: 25 November 2025	Policy objective to be addressed by a replacement to the MIC; and discussion of an incentive approach directly linking network outages to a threshold spot price.
Meeting #3: 27 January 2026	AEMO presentation on Network Outage Scheduler (NOS) data; discussion on outage coordination; intra-day timing of an outage; and proposed EUAA incentive-based approach.
Meeting #4: 24 February 2026	AEMO update on correlation between outages and spot prices; identifying outages that have a material market impact and identifying efficient outage management practices; discussion on proposed straw-person incentive scheme and a proposed incentive framework, developed by an adviser to ElectraNet, to avoid foreseeable market risks and to mitigate unforeseeable

[1] National Electricity Market wholesale market settings review, Final Report, December 2025, p.120

Meeting	Key areas of discussion
	market risks in the form of a risk based ex-ante incentive framework.
Meeting #5: 31 March 2026	Further discussion on outage management practices and the straw-person incentive option from meeting #4.
Meeting #6: 28 April 2026	Discussion on straw-person conduct obligation, consideration of constraints with a propensity to bind to identify material market impacts from planned outages.
Meeting #7: 26 May 2026	Discussion on ElectraNet's proposed incentive scheme, Powerlink's proposed incentive scheme and CEC [2]response to the form of conduct obligation.
Meeting #8: 30 June 2026	Further discussion on criteria to assess options and next steps for finalising the Network Market Impact Working Group Report.
Meeting #9: 4 August 2026	Discussion on key feedback provided by members on the Draft Network Impact Working Group Report.
Meeting #10: 25 August 2026	Further discussion on key feedback and process for finalising the Network Market Impact Working Group Report.

In summary, the working group process covered the problem that needs to be addressed; the challenges of linking outages to spot prices and a consideration of other forward-looking measures as a proxy for market impacts; outage management practices that may be employed by TNSPs to mitigate the market impacts from outages; the need for advance notification of outages and the need for improved information transparency on outages; options to address the problem that encompass incentive-based mechanisms and a form of conduct obligation; and criteria to assess the options.

1.3 Structure of this report

This report is structured as follows:

- Section 2 identifies the problem.
- Section 3 sets out the approach to identifying material market impacts that regulatory options seek to address.
- Section 4 sets out the TNSP outage planning and management practices that should be considered to mitigate market impacts from outages.
- Section 5 sets out the identified options to address the problem.
- Section 6 assesses the options against the agreed criteria.

[2] Clean Energy Council (CEC) represented its generator members on this working group and CEC views in this document represent those of its generator members only.

1.4 Next steps

This Network Market Impact Options Report is intended to inform the AER's consideration of a replacement for the MIC of the STPIS.

The objective of an incentive scheme is to encourage TNSPs to have regard to market impacts when planning and managing a planned outage. Participants discussed whether this could be achieved through an incentive scheme which rewards or penalises TNSPs for outperforming or underperforming, respectively, against a target metric. A conduct obligation was discussed as an alternative approach by specifying the objectives and matters that a TNSP must have regard to in planning and managing an outage. The proposed conduct obligation would impose a prohibition on specific behaviour and establish a requirement for a TNSP to demonstrate that it has satisfied the conduct that is required. A reporting only obligation was also discussed.

Implementation will depend on the legal pathway for each option. 'Network Outage Scheduler' and reporting improvements may require AEMO process or system changes. The incentive schemes discussed by the working group may be achieved under existing rule settings but may also require Rule changes along with revisions to the STPIS. A conduct obligation would require a Rule change.

2 Identifying the problem

A planned transmission network element outage may result in a network constraint being invoked in AEMO's National Electricity Market dispatch engine which may:

- constrain generators or storage from dispatch
- force dispatch of higher-cost generation
- materially increase wholesale spot prices and consequently influence forward contract prices.

Participants discussed high levels of system normal congestion in today's NEM, and in attributing a causal link between a particular network outage and an increase in spot price. Network outages may contribute to market costs and spot prices alongside a complex interplay of other factors such as rebidding, deviation from demand forecast, variable output from renewable energy resources, changes to generator behaviour, Distributed Energy Resource or Battery Energy Storage availability and system security requirements such as maintaining system strength.

The MIC was intended to incentivise TNSPs to minimise the market disruption caused by outages.[3] However, as the market has moved towards higher levels of dispersed variable renewable generation, the AER concluded that the MIC was no longer working as intended. In particular, the MIC came to be increasingly sensitive to participant bidding strategies and therefore did not provide a reliable measure of the economic costs of congestion. It also overstated the impact of congestion because higher levels of dispersed renewable generation were often replaced with other low-priced generation elsewhere in the system. These weaknesses in the MIC design were known at the outset but became more material with the changed structure of the network and generation sector.

In considering the impact of network outages on congestion costs, the working group recognised that the MIC no longer provides TNSPs with financial incentives to schedule and manage outages by reference to likely market conditions. This is further complicated because TNSPs and other market participants do not have visibility of power purchasing agreements (PPAs) that are also impacted by outages. A TNSP does not incur the market costs of an outage, including the system costs of constraining off low-price generation and the resulting effect on consumers through higher wholesale prices or inability to access PPAs. The MIC, when it worked, provided a proxy incentive and penalty consistent with the 'direction of travel' of the system cost impact. By contrast, a TNSP does incur the direct costs of rescheduling an outage or adopting more expensive outage management practices, such as live-asset work or after-hours work. Participants observed that the absence of the MIC or another market-facing mechanism may give TNSPs an incentive to avoid incurring higher outage-related costs, even when the outage may have a material adverse market impact.

The working group discussed instances in which planned outages may have contributed to high-price events in the wholesale market. However, it is not always clear how much a

[3] The MIC supported the STPIS principles to provide greater reliability of the transmission system that is owned, controlled or operated by it at all times when Transmission Network Users place greatest value on the reliability of the transmission system improve and maintain the reliability of those elements of the transmission system that are most important to determining spot prices.

planned outage contributed to a high price event where other factors, such as unplanned coal generator outages or a sudden reduction in variable weather-dependent generation output, also contributed. It may therefore be difficult to determine whether the TNSP could reasonably have foreseen the relevant market conditions when the outage was scheduled. Some participants considered that forward-looking indicators and foreseeable market risks should inform outage timing and management.

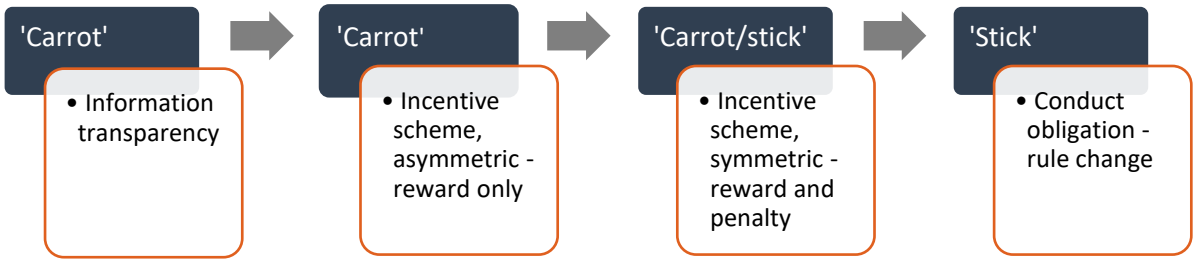
With the high penetration of weather-dependent renewable generation in the market, it is now more difficult to schedule outages with confidence that they will avoid high-price periods. Participants discussed whether a replacement for the MIC could encourage improved outage planning and management, while recognising the limits of TNSP foresight and controllability.

The objective of the replacement mechanism should be to ensure outage planning decisions are made holistically, considering foreseeable market impacts alongside broader network, operational and consumer outcomes. Participants discussed and generally supported that a replacement mechanism should focus on matters within TNSP control, including:

- identifying outages that may have a material market impact
- considering reasonably available market and system information
- coordinating with AEMO and neighbouring TNSPs
- assessing efficient mitigation options; and
- documenting the reasons for proceeding, deferring, modifying or recalling an outage.

In identifying a replacement for the MIC, the working group has explored the spectrum of regulatory approaches outlined in Figure 1.

Figure 1: Regulatory approaches



The spectrum of options covering these regulatory approaches has been considered in this report.

The working group considered the implications of taking no further action following suspension of the MIC, including that TNSPs no longer have the MIC as a quasi-market-facing incentive relating to outage timing, coordination, recall and mitigation.

3 Material market impacts

3.1 Definition of market harm

In considering a replacement for the MIC, the working group first identified the market harms that can result from outages. These include increased congestion leading to increased spot and contract prices, increased ancillary service prices, inefficient dispatch outcomes, increased risks to reliability, and increased costs to consumers.

The MIC provision in the NER and the previous MIC both reference spot prices. Given this, the working group considered whether market harm could be identified by reference to spot prices, including wholesale and ancillary service prices. As discussed below, participants identified limitations with that approach because spot prices are affected by multiple factors outside TNSP control. Of relevance, the Nelson review recommended consideration of wholesale market impacts, which broadens the scope from spot prices to include contract prices that broadly represent expected spot prices. The working group therefore considered leading indicators for likely market impact of outages, including regional reserve adequacy, the propensity for outage constraints to bind, outage notification practices, affected firm capacity, and price separation between regions. Participants noted that these measures serve different purposes and should not all be interpreted as direct indicators for market harm. For example, reserve adequacy, binding constraints and price separation may act as screening indicators of potential market exposure, while outage notification reflects outage management practices. A binding constraint does not, in itself, demonstrate that material market harm has occurred.

Participants discussed identifying harm, either directly or through leading indicators, as a first step in designing regulatory measures to improve outcomes. The regulatory measures (whether incentives or other measures) should be targeted at mitigating market harm that is reasonably foreseeable and sufficiently within a TNSPs control. The relevance of targets and outcome measures would depend on the design of the option.

In the context of a conduct obligation, the working group considered whether an obligation should be directly based on harms identified (increased spot and contract prices, increased ancillary service prices, inefficient dispatch outcomes, congestion, reduced reliability, and increased costs to consumers). Though TNSPs considered this approach too broad as it places a substantial emphasis on assessment of spot price (and FCAS price) forecasting, a role which TNSPs have little experience of; or natural exposure to and emphasised the importance of any replacement scheme focusing on foreseeable risks and actions within TNSP control.

3.2 Identifying material market impact outages

Network congestion from outages does not always lead to market harm in the form of elevated spot prices. This issue arose under the previous MIC, where an increase in the number and distribution of generators meant that the majority of the MIC ($10/MWh) events

had little or no correlation with spot prices[4]. The AER identified this design weakness as a reason for suspending the MIC.

In this context, the working group considered whether it would be desirable to target outages that are likely to lead to material market impacts (MMI). The ability to target outages has implications for the design and implementation of the regulatory approach.

AEMO stated that an incentive scheme should not apply to all planned network outages as the majority have minimal market impact. To identify the market impact of outages, AEMO reviewed market data to assess whether there is a correlation between network outages and spot prices. AEMO examined market data and concluded that it is challenging to identify, with high confidence, a direct link between a specific network outage and a change to the spot price, especially as the market is now experiencing high levels of congestion under system normal conditions. This difficulty in measuring the market impact attributed to outages reflects the fact that spot price outcome is determined by the interaction of participant bids, demand and system normal and outage constraints, including interconnector flows between regions and variation in semi-scheduled generation or unscheduled generation.

While EUAA agreed with AEMO's view with respect to the centralised market, the EUAA reminded working group participants that the complexities of the market mean many outages prevent consumers and/or retailers from accessing electricity through PPAs and associated renewable energy certification.

The working group discussed whether some network outages can amplify the impact of variations in other inputs to price outcomes. The working group also noted that forecast prices are not available until less than two days prior to dispatch, but other measures such as levels of reserve may be a leading indicator that an outage may have a material impact on spot prices. This led to consideration of whether attribution difficulties could be addressed through a practical MMI filter rather than a pure spot-price trigger. Participants discussed whether ex ante classification could identify the outages that warrant heightened scrutiny, while ex post assessment could be used to test and refine that classification over time.

Working group discussions indicated that it is difficult for AER, AEMO or TNSPs to accurately attribute future price outcomes to a single outage at the point of scheduling. Instead, the objective is to identify outages that warrant heightened planning, reassessment, mitigation and reporting.

The working group expressed mixed views on whether to apply a regulatory regime to all outages or a subset of outages. In considering whether planned outages can be narrowed down to those that are likely to have an MMI (for the purpose of developing an incentive mechanism or conduct obligation) the working group considered the following approaches:

- the nomination of outages of network assets that are likely to have an MMI

[4] The previous MIC did not measure spot price impact. It measured whether constraints to manage network outages bound and an MIC event occurred if the marginal cost of the constraint was greater than $10/MWh. This became a significant limitation, because any generator caught behind a constraint is incentivised to bid to very low prices, which then triggered a MIC event, this is even if the generator that is constrained has the same SRMC as another generator (such as two solar farms).

- ex-post assessment of outages to determine MMI outages based on pre-defined criteria (e.g., spot price increase above predefined threshold or the propensity of binding outage constraints).

Nominating MMI transmission outage elements

Some working group participants suggested that MMI outages could be identified by reference to pre-determined elements on a TNSP's network where an outage has the potential to have an MMI. This could be operationalised through a published register of transmission elements where planned outages automatically trigger enhanced planning, reporting or conduct requirements. The register could be proposed by TNSPs, consumers and retailers, reviewed by AEMO and the AER, and updated periodically to capture changes to the network and generation in the vicinity and changing market conditions. Alternatively, there could be an agreed 'methodology' for TNSPs to use to periodically determine their list of MMI network elements. The CEC submitted that consumers or market participants should also be able to nominate an outage for inclusion on the register.

The working group considered that TNSPs may be best placed to identify assets on their networks that have a high likelihood of an MMI from an outage. However, to provide oversight and improve consistency, the working group queried whether AEMO should have a role in reviewing TNSP nominations. VicGrid raised the question as to what role VicGrid should play in identifying assets that would have a high likelihood of an MMI from an outage in Victoria. VicGrid considered that given its role in planning the network, it would appear reasonable for it to be involved in this aspect of decision making. The proposed reporting framework may also inform future identification of transmission elements likely to be associated with MMI outages.

Applying criteria for determining MMI outage constraints

The working group considered whether a TNSP's discretion to identify outages likely to cause an MMI should be subject to guidance. Participants discussed whether guidance would be useful during any transitional period. Participants noted that, without guidance, TNSP classifications may not be comparable and collected data may not be consistent. Any guidance could identify the main indicators of a likely MMI outage, while remaining flexible enough to capture emerging constraints, new generation and storage patterns and changes in AEMO operating practice. Participants suggested that transmission elements associated with a potential MMI could be identified in advance by having regard to:

- identifying transmission elements via AEMO constraint datasets that regularly bind in dispatch
- reviewing 'Projected Assessment of System Adequacy' to identify periods of elevated reliability risk, binding network constraints and changes in modelled interconnector flows and capability associated with planned network outage conditions
- reviewing historical constraint shadow price data to identify assets where the aggregate market cost from past outages exceeds a defined constraint shadow cost threshold (e.g., a binding outage duration multiplied by a shadow price per MWh).

In general, the working group recognised that while these approaches may support more granular identification of MMIs over time, they require historical data and further development. In the interim, a simpler starting point, such as AEMO's existing High Impact

Outage list supplemented as required, could provide a practical and readily available basis for identifying MMI outages, with refinement as better data becomes available.

Binding constraints

AEMO sought views on whether binding constraints associated with transmission outages could be used as a proxy for the outages' market impact. To inform the discussion, AEMO conducted an ex-post analysis to assess the propensity for certain outage constraints to bind when they are invoked. The hypothesis being that some outage constraints tend to bind most of the time once they are invoked, and others bind only a small proportion of the time when they are invoked. The assumption is that an outage constraint that binds most of the time would be causing a bigger market impact than an outage constraint that is in place but rarely binding. The propensity of an outage to bind could potentially be used as a proxy measure for the market impact of an outage. AEMO's analysis was based on a limited sample. Further work would need to be undertaken to advance this methodology of identifying transmission elements likely to have a material market impact.

This approach to determining which network outages have a material market impact (MMI) requires an assessment of historical data. At a high level, participants discussed another metric - whether constraints that have the largest market impact reduce the availability of a large proportion of firm capacity. For example, where the constraint impacts assets such as interconnectors or transmission flow paths to a REZ (that provides access to a diversified supply of generation including storage in that region) or to large quantities of dispatchable generation (such as batteries and gas fired generation).

Specifically, participants discussed whether a constraint that reduces firm generation may be more likely to bind during high-price periods. By contrast, where a constraint primarily limits weather-dependent generation, the spot price may be lower because other weather-dependent generators elsewhere in the system may also be producing at high output levels. On that basis, a constraint that limits a relatively small volume of intermittent weather-dependent generation may be less likely to have a material market impact. A threshold based on the proportion of firm capacity reduced by a constraint was discussed as a possible means of identifying constraints with the potential for an MMI, although this approach would need further review to determine whether it is sufficient by itself to narrow the scope of MMI outages.

To progress this approach, AEMO considered that the AER and working group should develop a consistent approach across TNSPs for determining which outages are likely to have a material market impact. A practical starting point could be to use existing information and experience to identify an initial set of higher-risk network elements, with the methodology refined over time through reporting and ex-post assessment.

Use of Projected Assessment of System Adequacy (PASA)

The Medium Term (MT) PASA provides an indication of the forecast supply-demand balance and system adequacy in the market well in advance of a planned outage. The working group discussed using regional reserve as a proxy measure for expected spot prices. ElectraNet suggested that MT PASA could be used to assess expected reserve, where a reserve threshold for considering whether to proceed with an outage could be the sum of the capacity of several of the largest generators in a region.

However, MT PASA does not calculate a regional reserve margin, and regional reserve levels are only calculated in the ST PASA and pre-dispatch timeframes and not in the MT PASA timeframe which is the period expected to be more relevant to network outage planning. While, AEMO does publish regional scheduled PASA availability and demand information, the difference between these figures should not be interpreted as a 'reserve margin' as this simple calculation would not fully account for network constraints, interconnector support, VRE conditions and other factors reflected in the reliability modelling. The published daily demand values are also reporting outputs and are not the demand traces used directly in the MT PASA reliability assessments.

However, AEMO considered that MT PASA does provide useful information on the impact of network outages on interconnector transfer capability, in the presence of planned network outages, which may be useful for the purpose of scheduling outages four months in advance. AEMO noted that some consideration may need to be given to whether this information is accessible in a form that can be interpreted and used by TNSPs for this purpose. MT PASA also calculates a daily 'Loss of Load Probability'(LOLP), reported as the highest half-hourly LOLP for each day, which AEMO considered is a useful relative reliability-risk indicator that could be used for outage scheduling. Loss of Load Probability measures the probability of loss of load under a certain set of assumptions, rather than the amount of reserve available.

The MT PASA analysis also reports binding network constraints (including their probability of binding and hours binding), which can be linked through the constraint set and NOS to understand which outage-related constraints affect generators or interconnectors and how frequently they bind in the MT PASA simulations.

There was also a question as to how reliable MT PASA is as a measure of market conditions. MT PASA provides demand and forecasts of available capacity (supply) conditions well in advance of a scheduled outage but cannot forecast market prices. That said, the working group considered that MT PASA provides relevant information on forecast supply-demand, reliability and network conditions that may indicate periods of tight conditions and should be considered by a TNSP in planning the timing of an outage, alongside other available market information. The MT PASA timeframe for planning an outage also allows participants and consumers to enact their own risk mitigation strategies, irrespective of the market outcomes. This is discussed further in Section 4.

Working group discussion also recognised that the planning timeframe is itself material to consumer outcomes. Providing sufficient advance notice (for example, greater than three to four months) was considered to influence contract market outcomes, and therefore retail prices, potentially more than responding to any individual spot price outcome. On this basis, certainty of outage timing has value to consumers independent of the spot price impact of a given outage.

Figure 2 outlines the information used by AEMO about demand and supply conditions that may inform a TNSP's view of likely market conditions. The discussion focused primarily on information available at the time of scheduling, rather than on how updated information should be considered closer to the outage date.

Figure 2: Projected Assessment of System Adequacy (PASA)



Reserve adequacy

To identify and manage the impact of weather-dependent renewable generation on regional reserves, AEMO also applies a Forecast Uncertainty Measure (FUM), which quantifies the expected range of forecast errors for weather-dependent generation and expresses that uncertainty in MW terms. In other words, the FUM measures the portion of non-firm renewable generation capacity that cannot be relied upon when estimating regional reserves. However, the FUM as a key input into reserves is only calculated on a rolling basis 72 hours ahead of time. Beyond that time there is a fixed figure to allow for worst-case uncertainty that does not depend on forecast weather conditions.

The working group considered whether a threshold regional reserve could be used to determine a likely occurrence of an MMI and whether an outage should be rescheduled. Accordingly, the working group considered whether a reserve margin threshold could instead be adopted as a practical ‘rule of thumb’ in determining whether an outage should proceed. In effect, the threshold reserve margin value would operate as a proxy for tight supply conditions, and therefore for the likelihood of elevated wholesale prices. However, AEMO confirmed that a regional reserve level is only available in the short term PASA timeframe and is not an available metric four months in advance, at the proposed time of outage scheduling.

A minimum regional reserve threshold, if made available, could be used for the decision to proceed with an outage, or it could be treated as one input into broader criteria. A broader assessment could consider whether, based on information reasonably available at the time, the outage is likely to have a material market impact and whether there is a reasonably practicable and materially better alternative. With a broader assessment, reserve information would prompt closer scrutiny where it indicates tight supply conditions, taking into account the affected network element, constraint location, available alternatives, AEMO advice, system security and the practicability and cost of mitigation.

Targeting low demand periods to avoid likely MMIs

While it is becoming more difficult to identify low demand periods, the working group considered whether it is optimal to plan an outage during the day to avoid morning and evening peaks. TNSPs noted that scheduling a network outage during the day when there is low system demand (e.g., low system demand due to high rooftop solar output), may not always be optimal. This is because AEMO may cancel an outage or advise a TNSP that an outage is unlikely to proceed for system security purposes arising from minimum system demand.

As a way of managing the system security risks of taking outages during low demand periods, the working group discussed using grid scale batteries to provide network support control ancillary services (NSCAS). The procurement of these services could allow an outage to occur in the middle of the day.

In considering procuring NSCAS as a system security risk mitigation measure, the relevant test is whether the mitigation would reduce total system and consumer costs. The cost of procuring NSCAS or other mitigation should be assessed against the expected market benefit. Some participants considered that an incentive scheme should not reward high-cost mitigation without regard to the expected market benefit.

AEMO does not currently include scheduled loads in forecasting minimum system demand (e.g., large scale battery charging loads), which can result in an overly cautious approach. AEMO advised that it is reviewing the exclusion of scheduled loads in its estimation of minimum system demand. To the extent that these loads are included in estimates of minimum system loads, this may provide more opportunities for outages to be taken in the middle of the day.[5]

Use of a defined constraint shadow cost

A shadow cost is an estimate of the MMI of an outage by using historical data on the estimated cost of a constraint. EnergyAustralia suggested this approach relies on reviewing historical marginal costs of constraints from outages to estimate a $/MWh impact of the constraint which multiplied by the duration of the outage gives an estimated total cost. However, both are coarse measures of an MMI as they are only an estimate, and the outage may only be one factor explaining shadow costs. In addition, this approach also may have the same limitations as the MIC as a measure of the economic impacts of transmission congestion on the market.

Ex-post assessment of MMI outages

This approach seeks to determine outages which have led to MMIs on an ex-post basis using a predetermined metric. This metric could be based on a spot price threshold. Because this approach identifies MMI events on an ex-post basis it may not be suitable for purposes of implementing an incentive-based mechanism. It requires TNSPs to predict when an MMI event may occur. As noted by TNSPs, accurately predicting events is not easy and TNSPs may not be well placed to make such forecasts.

If spot prices are used as a measure of market impact, there is also a question about what threshold should be adopted. As an example, a threshold value of $300/MWh could be adopted as cap contracts typically reflect this value. However, the working group did not express a view on either the level or methodology for determining such a threshold.

While an ex-post metric has limitations for purposes of an incentive scheme, participants discussed whether it could assist in understanding TNSP performance. It can assist in identifying which network elements, constraints, reserve conditions and outage types are most associated with material market impacts and thereby support validation of the

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5 AEMO advised that prior to September 2026, AEMO included scheduled pumps but not bidirectional unit (BDU) loading in forecast and actual minimum system load (MSL) thresholds. Since spring 2025, there has been a large increase in utility-scale BDU capacity, and AEMO will be reflecting typical BDU market behaviour in MSL thresholds from September 2026. As BDUs typically charge during MSL conditions, incorporating BDUs improves MSL thresholds, which may enable more outages to proceed in the middle of the day. More information on AEMO's MSL management approach can be found on AEMO's website: https://www.aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/managing-distributed-energy-resources-in-operations/managing-minimum-system-load.

identification of likely MMI for future baseline development. Participants discussed whether monitoring and reporting using ex post metrics could provide transparency and assist in assessing the effectiveness of the replacement scheme.

In discussing use of ex-post metrics, the working group observed that AEMO identifies 'High Impact Outages' as part of its system management responsibility, notably the obligation to publish potential for occurrence of significant impact on power system security.[6] This process currently acts as an operational and planning horizon safeguard, allowing AEMO to apply additional scrutiny to proposed outages with the most severe potential system or market impacts. However, while the definition of high impact outages include the circumstances where "during the outage there is potential for energy and frequency control ancillary service prices to approach the Market Price Cap or Market Price Floor", the process is primarily directed at system security and reliability outcomes. Whereas outages that may lead to MMIs are likely to encompass a broader scope of outages to those captured through the High Impact Outage process.

6 NER cl. 4.3.1(m)

4 TNSP outage planning and management practices

The working group considered principles most relevant to management of planned network outages. This paper draws on the discussion and material presented to the working group to suggest the following principles of good practice. TNSPs should identify whether the event is one requiring heightened scrutiny in terms of an MMI, and if so:

- have regard to relevant PASA, reserve, forecast and other market information reasonably available at the time the outage is scheduled
- consider whether there is a reasonably practicable and materially better alternative timing, duration, cancellation, coordination or outage-management approach
- provide at least four months' notification of the outage
- consider outage-management practices capable of avoiding or materially reducing the likelihood or extent of an outage if a material adverse wholesale market impact is likely
- minimise event duration, and time to recall the outage if required, so far as reasonably practicable, consistent with safety, power system security, reliability and prudent asset management.

This section outlines the working group's consideration of outage planning and management practices that could avoid or materially reduce the likelihood or severity of material adverse market impacts arising from planned outages.

The CEC and EUAA participants observed that TNSPs do not always have incentives to minimise the market impact of network outages. TNSPs have incentives to minimise their operational costs, which do not always reflect overall efficient system or consumer costs. In other words, by reducing their own costs, the TNSPs may increase the impact of outages on market participants and/or consumers. Participants discussed the need to balance the costs of an outage for spot and contract market participants; and the network costs incurred by the TNSP.

TNSPs also noted that outage planning and management decisions are multi-faceted, requiring consideration of safety, reliability, system security, asset condition, deliverability and consumer impacts. They also noted that TNSPs do not have visibility of market participants' contractual arrangements to manage outage-related risk, even though this could inform decisions to reprioritise or re-sequence outages as conditions change. The objective should therefore be efficient, holistic outage planning that balances foreseeable market impacts with broader network, operational and consumer outcomes. VicGrid also commented on whether we should weigh the costs of outages against the benefits (or indeed the costs of deferred benefits) where augmentations are the reason for the outages.

Many of the outage planning and management practices identified by the working group are common to incentive-based mechanisms and conduct obligations. They could also inform transparency measures. This chapter summarises the outage planning and management practices discussed by the working group. The practices are relevant to the outages

identified as having the potential for an MMI. For this subset of outages early notification, reassessment as information changes, coordination, recall, efficient mitigation, clear record keeping and transparent reporting are all likely components of effective planning and management practice.

Advance notice

Some working group members emphasised the importance of certainty of timing in minimising market impacts of planned outages. This also allows market participants and consumers who hold PPAs with renewable generators to efficiently manage risks associated with network outages. They noted that this could be supported by requiring TNSPs to provide an adequate level of advance notice of outages.

The discussions focused on controllability and the importance of distinguishing factors within a TNSP's control. TNSP participants expressed concerns that advance notice will reduce flexibility, delay consumer benefits and increase capital and operating expenditure and risk incentivising padding of outage durations to mitigate project delay risks. In particular early notification cannot take into account unforeseen circumstances, such as adverse weather, supply chain issues, last-minute contractor availability, and changes to third party requests. There were also differing views from participants as to what constituted unforeseen circumstances and what areas should be considered as under TNSP control. Locking in outages under these circumstances can result in increased costs to both TNSPs and market participants. There are circumstances where rescheduling will be appropriate, where the additional TNSP costs are likely to be lower than the expected avoided market costs as a result of re-scheduling.

Some participants supported incentivising TNSPs to select planned outage times that minimise the risk of market impact or rescheduling. This would, for example, entail TNSPs selecting outages during off peak periods, at times when reserves are high, and there are no clashing outages. TNSP participants did not oppose this view but noted that it was already becoming increasingly difficult to find appropriate times for outages given increasing occurrences of minimal system load as well as high demand periods.

Participants discussed the risk that a mechanism could reward firmness for its own sake. Some participants considered that a mechanism should not reward TNSPs for poor selection of outage timing, or for ignoring market developments. Participants noted that four months' notice may assist market participants because it allows market participants to manage risk, but it should not discourage a TNSP from deferring, modifying or recalling an outage where new information indicates pursuing an outage will cause material market impacts. The TNSP's decision should be based on an assessment of costs and benefits of the available options based on the information available to the TNSP at the time. The decision can also undermine confidence if not undertaken transparently as it may create uncertainty - whether an outage is taken or not can add risk to the market. One way to mitigate this is to provide information on the criteria that a TNSP would test when considering whether to defer, modify or recall an outage. This provides both certainty to the market and flexibility to respond to material changes in market conditions, which the market knows of in advance and can build into the risk management practices of market participants. TNSP participants noted the risk that an obligation to repeatedly re-assess and document decision making in this regard would materially increase operating costs which may not always bring a commensurate increase in consumer benefits.

AEMO's Congestion Information Resource (CIR) Guidelines require TNSPs to provide at least four months' notice of planned transmission outages that are high impact or have historically (or are likely to) cause congestion in the Network Outage Schedule (NOS). Consistent with the CIR Guidelines, the Clean Energy Council (CEC) and Energy Users' Association of Australia (EUAA) proposed a mechanism which incentivises TNSPs to give market participants at least four months' notice to allow them to manage market risks. The advance outage notification option is explored in further detail in section 5.

Longer scheduled outage windows

Recognising the limitations of the preceding outage management practice of providing advance notice of outages, the working group considered the case for scheduling longer outage windows combined with the ability to rapidly recall the outage (where possible), if there are unexpected adverse market impacts, to increase certainty to the market as well as providing flexibility for the TNSP to manage the market impact of the outage. Participants noted that longer outage windows may increase costs for TNSPs due to having contractors on standby but may result in a lower market impact than shorter outages that do not have the flexibility to avoid likely high market demand periods. Participants noted that increased costs would occur if a planned outage of shorter duration was subsequently cancelled or recalled by AEMO due to security or reliability concerns. As such longer scheduled outage windows can allow TNSPs to limit outages to periods of lower market impact risk (within the nominated outage window) and reduce the likelihood of outage overruns or AEMO recalling or cancelling outages.

TNSP participants also noted that requiring longer outage windows would further reduce the feasible windows for taking outages. Powerlink also noted that extending outage durations may simply shift other outages into inherently higher-risk periods (for example summer), potentially offsetting any market impact benefits achieved through greater outage flexibility. Transgrid stated that extending the notified duration of planned outages to preserve flexibility for later re-scheduling is not a practical solution. Transgrid considered that given the significant volume of planned outages required to deliver the capital works program over coming years, including ISP projects and customer connections, and the limited windows available to undertake those outages, this approach would be difficult to implement in practice. Participants also observed that, under current arrangements, outages are generally only recalled where reliability or power system security risks arise, rather than solely in response to elevated spot prices, highlighting a potential change in operational practice that would need to be considered if outage recall were used as a market impact mitigation measure.

Some members of the working group were concerned that this may increase uncertainty about the timing of an outage and increase hedging costs for market participants – although this can be mitigated by requiring the TNSP to provide transparent assessment criteria for whether to go ahead with the outage or not. The EUAA noted that an increased outage window would allow flexibility for TNSPs and allow participants and consumers to manage their risks: hedging costs are generally higher when minimal notification is provided, not when the period of outage is notified as longer. This approach may also increase risks that an outage window will occur during a period when there may be system security issues with a correspondingly higher risk that the outage can't proceed unless it can be recalled in a timely manner. This approach will also exacerbate the current issue of limited available

windows for outages as well as reduce the accuracy of AEMO's forward market information such as PASA.

Outage coordination

The working group recognised that there is scope to improve coordination of planned outages both for associated works within the TNSP's network and between TNSPs. For example, on interconnectors, and within a TNSP many network elements affect flows between its network and another TNSP's network. Without coordination, outages of individual elements not taken together result in more individual instances of outages than if multiple outages occurred concurrently.

AEMO advised that there are some limits to TNSP coordination, as AEMO's 'clash list' restricts simultaneous outages on certain network elements for system security reasons. Though, after the South Australia Interconnector Tripping Remedial Action Scheme was introduced in early 2024, most network elements on the South Australia – Victoria interconnector are no longer on the clash list, creating greater opportunities for coordination.

Participants generally supported outage coordination within and across TNSPs as an efficient way to mitigate the impact of an outage but noted that information asymmetry may require an intermediary. There was some debate about whether AEMO could play this role. The discussion focused on what roles are appropriate for AEMO. In particular participants discussed a role for AEMO in informing system security, outage coordination and MMI classification where relevant. Some participants considered that AEMO should not be responsible for wholesale market cost optimisation through the outage approval process. Without an intermediary there may be an option to require reporting from TNSPs to confirm that coordination was explored to address this asymmetry. AEMO's noted that the information is already available for TNSPs to coordinate their outages to minimise market impact, but TNSPs need an incentive to undertake the additional work required to coordinate. AEMO commented that it does not see a clear rationale for a role in coordination of outage timing across TNSPs.

Live line and substation work

The working group considered the role of live line work in good outage management practices. Live line and substation work refers to TNSPs performing maintenance, repairs, or inspections while network elements remain energised. Live line and substation work can provide significant benefits by reducing the need for network outages and mitigating associated customer and market impacts where the work is suitable to be performed live. However, its application depends on the nature of the work, network configuration, safety requirements, availability of specialised resources and equipment, and technical feasibility, and should not be assumed to be an available option in all circumstances. Members of the working group highlighted the benefits of live line work, noting that it is within a TNSP's control and can help reduce the impact of outages.

However, the application of live line and substation work varies across TNSPs. Powerlink maintains both live line and live substation crews and routinely uses live work practices, where suitable, to avoid outages of plant, including where outages could affect customers or create market impacts. ElectraNet also supports the use of live line work to minimise network outages, while other TNSPs currently do not widely apply this practice. It is also not suitable for all high-voltage work. Further the specialised contractors and equipment required can add

significantly to costs. Given the costs of live line works, ElectraNet developed an incentive mechanism where TNSPs are rewarded for controllable actions, such as live line works, that reduce market impacts. For completeness, AEMO noted the minor reduction in system security associated with suppression of auto reclose for most live line works.

Daily outages or rapid recall of outages

Maintenance outages that take more than one day to complete can be taken as one outage over the period or, as a daily outage where the equipment is switched out and isolated at the start of the day and then switched back in at the end of the day. A hybrid is to take the outage for the entire period but have the outage able to be recalled at short notice. A daily outage or hybrid outage is likely to have lower market impacts. It also has the advantage of being able to not go ahead at the time when the market forecast is different from that expected. Daily outage (or one with quick recall) is also more likely to gain AEMO approval, as AEMO has increased confidence in the demand and VRE forecast (the FUM is much reduced 24 hours ahead). However, daily recall adds to TNSP costs – both the switching costs and the cost of shortening the working days for the maintenance activity - so should only be used in circumstances where it materially reduces MMI. TNSP participants also noted that there were instances of work where daily outages or rapid recall were not feasible from a technical or safety perspective.

The CEC suggested that outages with the potential for a MMI should have a defined maximum recall time period. Their preference is for outages to be temporarily suspended, rather than having a daily outage. To facilitate this – as with a daily outage approach - a TNSP would incorporate additional days in the advised planned outage time period to allow for temporary suspension. TNSPs noted that recall times are currently provided via NOS and shortening them may not always be possible (e.g. removing oil from a transformer for intrusive maintenance could have a recall time of several days).

In considering when to adopt daily outages or rapid recalls, TNSPs should identify whether it is technically feasible, the minimum recall time, additional costs (including switching and additional maintenance costs), and the circumstances in which the cancellation (for daily) or recall would be used.

Contingency outage date

Another outage management practice considered by the working group is reporting both a primary and contingency (secondary) transmission outage date. The purpose of a contingency outage date is to provide the TNSP with flexibility to reschedule the outage to a secondary date, if market conditions are likely to be worse than expected and to recognise that transmission outages are dependent on factors that can change at short notice.

The contingency date would not be a firm outage booking but would provide external parties with advance notice of the fallback outage date (if required). This would enhance certainty and transparency so that impacted stakeholders could plan for both possibilities.

AEMO indicated that it does not support a scheme that incentivises TNSPs to nominate multiple outage windows for the same outage. AEMO’s PASA and outage management systems are not set up for this, and it would not be manageable with existing systems. Nominating a primary and secondary outage window in advance would require double the amount of work for AEMO in terms of PASA, as each outage window would need to be

treated as if it was going ahead until it is cancelled. This would be confusing for market participants, create a lot of uncertainty in outage windows that are already full, and potentially offer little benefit in terms of market prices.

The working group considered whether booking a contingency outage date should apply on a case-by-case basis, rather than to all planned outages. Participants also discussed whether contingency days should be coordinated between TNSPs and AEMO. For example, where an outage on a major network element is planned over several weeks and there is a risk it may be suspended, both AEMO and the TNSP could determine whether a contingency date is required.

The TNSP participants considered that additional contingency days may also increase planning complexity and significant outage planning cost. TNSPs and AEMO would need to assess whether the network can be operated securely both with and without the contingency outage proceeding, and whether the same contingency plans remain valid in each case. This complexity would be greater where multiple outages rely on the same contingency outage date, as this would increase the number of outage combinations requiring assessment.

On this basis there may be a case to apply contingency dates on a case-by-case basis only. There is a recognition that a general requirement for backup dates may overbook scarce outage windows resulting in more outages being undertaken at a time of market disruption.

Procurement of network control ancillary services

As discussed in section 3, the working group discussed the possibility of TNSPs procuring Network Control Ancillary Services (NSCAS) to mitigate system security concerns related to outages during periods of minimum system load conditions. This is because low market impact periods may coincide with very low demand periods where AEMO has system security concerns. For example, battery providers could be contracted to increase demand and then allow network outages to be scheduled during low demand periods. This would mitigate AEMO concerns related to minimum system load and the procurement of NSCAS could allow the outage to proceed while at the same time enabling a TNSP to avoid an MMI from the outage.

The AEMC is also considering a rule change request to establish a new reserve market to manage system security issues during periods of low operational demand.[7] The establishment of this market may also mitigate AEMO concerns regarding the scheduling of outages during low operational demand periods.

NSCAS or other market-facing mitigation was discussed as an option to be considered for MMI outages, not a standing requirement. Participants discussed whether the relevant test should be whether the expected market and consumer benefit of the mitigation is likely to justify the costs.

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[7] AEMC recently initiated its assessment of a rule change request from the Clean Energy Council to establish of a new reserve market to manage system security issues during periods of low operational demand. The proposed reserves would be targeted to the procurement of reserves to manage the possibility of contingencies occurring during low operational demand periods. See link to the rule change request - https://www.aemc.gov.au/rule-changes/minimum-system-load-reserve-service.

5 Options identified in the working group process

In considering the available tools to promote good outage management practices, the following approaches were considered by the working group:

- **Improved transparency** that provides enhanced market information about when outages are being scheduled, and improved transparency about TNSP performance in managing the impact of planned outages.
- **An incentive-based mechanism** on TNSPs by providing a financial reward/penalty to encourage efficient outage planning and management behaviour to minimise foreseeable material impacts from planned outages.
- **A conduct-based obligation** that involves amending the Rules to introduce an obligation for TNSPs to have regard to likely market conditions in planning and managing an outage.

Participants discussed that these options could be applied separately or in combination.

5.1 Improved transparency of outage planning and management

The working group considered options to improve transparency about the TNSP outage management practices. The discussion covered two issues. One is information the TNSPs should provide to the AER and market participants. The second is AEMO's systems for recording information about planned outages, including notification and rescheduling of outages.

This section discusses the options for improving transparency. By way of context, this section first considers existing information provided by AEMO.

5.1.1 Congestion Information Resource and Network Outage Scheduler

The NER requires AEMO to publish the Congestion Information Resource (CIR). This requires, among other things, TNSPs to provide information on planned network outages that are likely to materially affect network constraints in relation to a transmission system. The information for the purposes of the CIR:

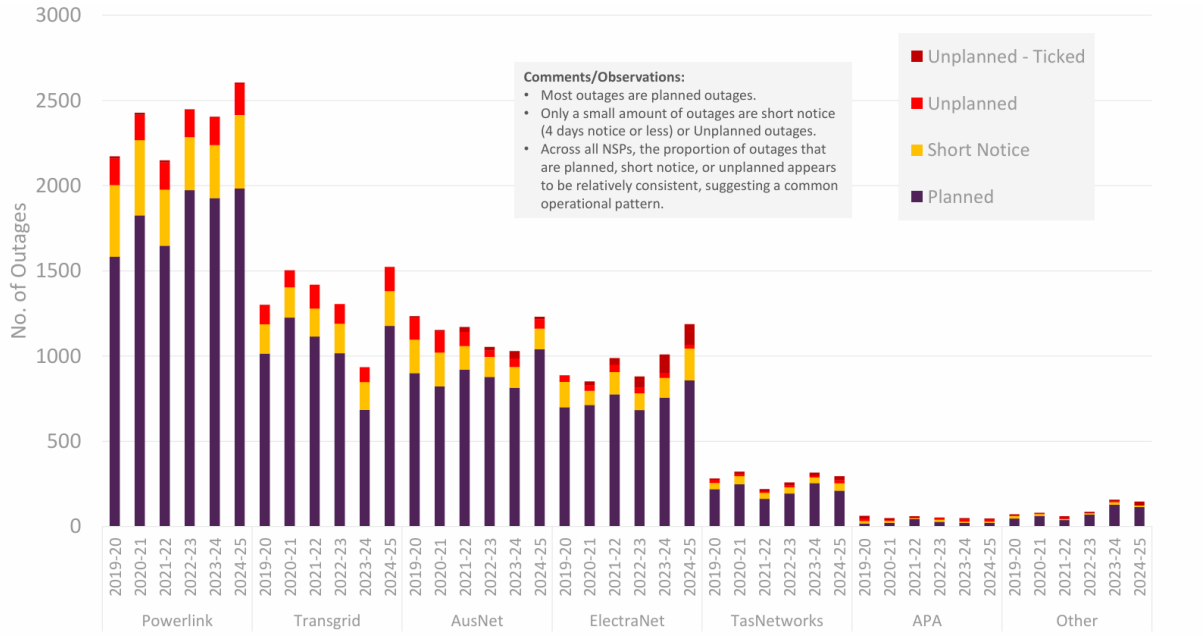
- must represent TNSP’s current intentions and best estimates regarding planned network events at the time the information is made available
- does not bind the TNSP to comply with an advised outage program; and
- may be subject to change due to unforeseen circumstances outside the control of the TNSP.

As part of the CIR, AEMO publishes a Network Outage Scheduler (NOS). AEMO updated the CIR and requires, for the purposes of the NOS, that a TNSP notify a planned outage that

is high impact or has historically (or is likely to) cause congestion in at least four months before the date of the planned outage. AEMO has also committed to collecting information on a TNSP reason for rescheduling an outage.

AEMO publishes network outage statistics on an annual basis (refer to Figure 3). These statistics also include, amongst others, the average lead time for outages for each TNSP.[8]

Figure 3: Network outages by TNSP



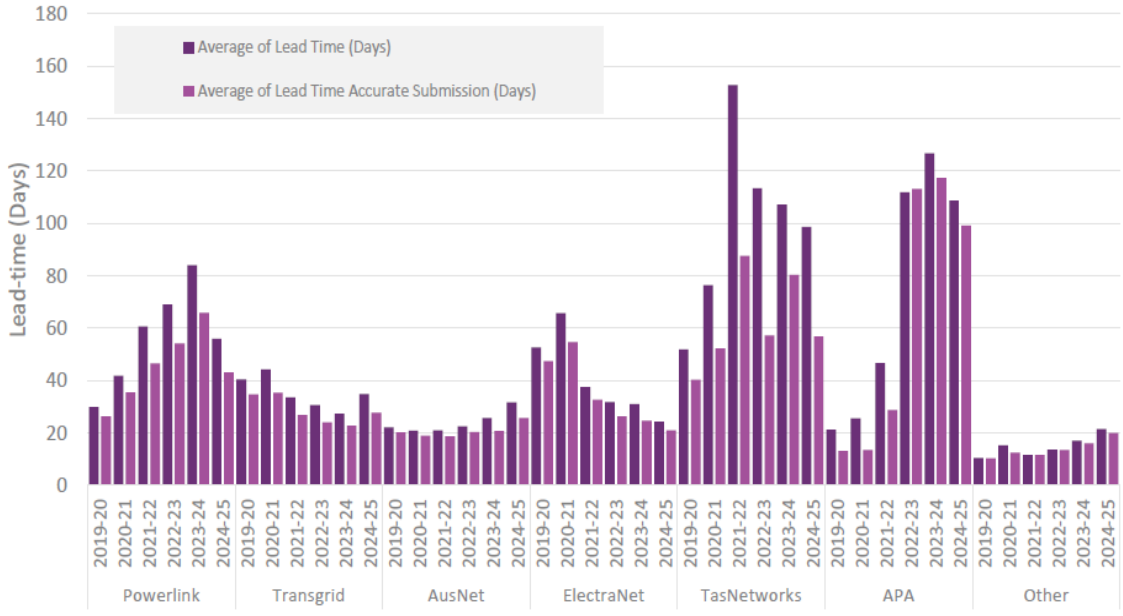
Source: AEMO

Note: Powerlink's reported network outages also include 110kV network outages in the DNSP network.

Figure 3 indicates that most network outages are planned, and the number of planned outages has increased in recent years. The increase in outages is in part driven by increased renewable generation connections. The average lead time for the notification of outages by a TNSP is also set out in Figure 4.

8 Refer to AEMO website: 'Network Outage Submission Statistics: FY 2019-25 – https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/2025/network-outage-submission-statistics-for-financial-years-2019-2025.pdf?rev=5f290aecce86416ca2a073b7fb2e8996&sc_lang=en

Figure 4: Average lead time of TNSP outages



Source: AEMO

AEMO assesses the timing of scheduled outages as conditions and forecasts change and up to seven days before the outage and again on the day of the outage. AEMO may withhold permission for a TNSP to proceed with an outage if:

- a system security issue is identified that cannot be resolved
- a lack of reserve level two or level three is forecast during the outage; or
- the outage would require AEMO to issue a 'market direction'.

Consistent with its role and functions, AEMO considers system security and reliability when assessing scheduled outages. It does not intervene on outage timing on the basis of wholesale market costs. The working group discussed whether that distinction supported a separate AER-led framework directed to market-impact incentives, transparency and TNSP performance assessment.

Participants considered that there may be scope to improve transparency about outage notifications in the NOS. In particular, the NOS could be enhanced to:

- identify whether an outage has been rescheduled, and link the rescheduled outage to the original outage rather than recording it as a new outage;
- record who cancelled an outage and the reason for the cancellation; and
- record the reasons for any rescheduled outage.

5.1.2 Improved transparency - options

The working group discussed three options for improving transparency on how planned outages are managed:

- improvements to NOS to provide more transparent information on outage timing

- collection of data to identify which planned outages have a material impact on the market
- TNSP reporting on management of outages that have a material impact.

These transparency measures could be implemented as a stand-alone measure or in conjunction with incentive and conduct-based measures.

Option 1(a) NOS enhancements

The CEC and EUAA expressed concern about inadequate notification of outages. They have expressed concern that the timing of outage notifications in the NOS is not sufficiently clear, or outages logged in NOS provide less than four months' notice, with many scheduled on short notice. In part this may reflect the outage notification practices of the TNSPs, but it may also reflect increasingly weather-dependent impacts of outages, and the limitations of NOS itself. However, there was no consensus on whether any lack of notification reflects poor TNSP practices, factors outside the TNSP's control, or limitations of the NOS system.

Some participants considered that TNSPs should identify good time periods for outages, for example, identifying periods with anticipated lower overall market risk, and at times of the day which minimise impact (for example, not during evening peaks). However, the information available to TNSPs four months ahead of an outage is incomplete. After notification of an outage, new developments may affect the impact of the outage, for example unplanned network or generation outages not listed at the time the outage was notified, and weather events. As ElectraNet pointed out, the latter is now having a more significant impact on the market, with the uncertainty in weather taken into account by AEMO through the FUM.

AEMO is responsible for NOS enhancement. Participants noted that AEMO has taken steps to improve outage notification. AEMO now clarifies in the Congestion Information Resource Guidelines that TNSPs are to provide no less than four months' notice and has acknowledged that there is a case for providing more information on reasons for outage rescheduling.

Working group discussions identified that there is further scope for AEMO to enhance transparency of the NOS. These enhancements could include:

- identifying whether an outage has been rescheduled or suspended, linking the rescheduled or suspended outage to the initial outage, and ensuring that it is not recorded as a new outage
- recording who cancelled an outage and the reason for the cancellation
- recording the reasons for a rescheduled outage.

This information could assist market participants to manage their risks. It could also form the basis for AER reporting. AER reporting would improve transparency about TNSP performance and inform current and future incentive schemes. Reporting could cover the original scheduled date and time of planned outages, any revised dates and times, the party initiating cancellation or rescheduling, the reason for cancellation or rescheduling, the relevant network element and constraint. Some TNSPs noted that implementing this approach may require changes to TNSP outage management systems and associated interfaces with NOS and emphasised the importance of demonstrating that the incremental

benefits of enhanced reporting are proportionate to the costs of implementing and maintaining those system changes.

Option 1(b) Planned outages that have a material market impact

NOS shows when outages are taken and flags a subset of outages that have historically bound or are expected to bind and are considered to be 'high impact outages', where 'high impact' refers, among other things, to the potential for the market price to approach the price cap or price floor during the outage. Participants discussed whether applying a filter to identify outages with an MMI could allow further scrutiny of outage events. For example, it may help market participants to better understand which network elements and which outage timing have higher market impact.

There is likely to be some overlap between a 'high impact outage' and an outage that is likely to have a material market impact.[9] However, AEMO considered that the High Impact Outage list is not a reliable indicator of the likelihood an outage causing MMI where no further network contingency has occurred. Further, the HIO measure of market price that approaches price cap or floor is outside of the range intended for MMI. This is especially so prior to a further network contingency. AEMO noted that the HIO system security criteria consider the post contingency actions to resecure the network such as AEMO direction, load shedding or State separation, all of which can cause extreme prices.

The working group, as discussed in section 3, discussed possible ways of identifying planned outages that have an MMI. Options include:

- Continuing to collect data used for the current MIC. The MIC identifies outage events that cause a threshold price separation between constrained off generators and the relevant regional reference price.
- Matching regional reference prices to the time of outages. This allows high price events to be identified but does not show a causal link between the outage and the high price event.
- Identifying the network elements that are likely to be most critical to market outcomes.

The limitation of the current MIC data is that many or most $10 marginal constraint cost events do not cause significant market impact, because the metric only considers the marginal value of a constraint (not only the spot price). For this reason, identifying the planned outages that take place at times of high prices could be a better filter. As an example, the AER could collect and report on all planned outages that took place when prices were over $300/MWh. However, this would identify correlation rather than causation and would not show whether the outage caused or contributed to the high price.

Option 1(c) Ex-post assessment of high impact outages

This option would provide information on planned outages identified as likely to have a material market impact. The AER would collect information and report on TNSP outage

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[9] The primary purpose for AEMO to publish 'High Impact Outages' is to flag planned outages that can significantly impact power system security following a critical contingency event during the outage (NER cl. 4.3.1 (m)). Note that a planned outage that can significantly impact system security without a contingency loss of another element will not be approved under the present outage planning guidelines.

management practices for the identified outages. It would assess the TNSP's decisions against principles of good outage management practices. The list below provides an example considered by the working group of such principles. It asks whether the TNSP:

- identified the event as one requiring heightened scrutiny
- had regard to relevant PASA, reserve, forecast and other market information reasonably available at the relevant time
- considered whether there was a reasonably practicable and materially better alternative timing, duration, cancellation, coordination or outage-management approach
- considered coordination with related planned network events, common flow paths and interconnectors, where reasonably practicable
- reassessed the event before its scheduled date and upon any material change in market conditions or other relevant circumstances; and
- documented the basis for the final timing, duration and outage-management approach.

The principles could be the same as principles adopted for purposes of an incentive scheme or compliance obligation.

With this option the AER would collect information using its regulatory information orders (RIOs) and publish reports periodically, say annually. The reports would be publicly available, allowing stakeholders to better understand outage planning practices and scrutinise TNSP performance. Participants discussed whether the data should be collected in a consistent format across TNSPs so that the AER can compare performance, identify recurring constraint and outage patterns, and test candidate metrics for a future scheme. VicGrid commented that the ex-post assessment of high impact outages appears reasonable and should be considered further to inform prudent outage planning and management.

Some working group members considered that this type of information could be used to inform an incentive-based approach in future.

5.2 Incentive-based options

The working group discussed incentive-based approaches directed to good outage planning and management practices as identified in section 4. The working group identified several elements of good practice including:

- Providing adequate notice of outages.
- Selecting outage times that are likely to minimise market impact.
- Adopting practices that avoid or minimise material market impact, for example live line or out-of-hours work or active coordination with other TNSPs.
- Reviewing information that becomes available after the outage is notified and modifying future outage timing or practices as appropriate.

These elements overlap with the principles of good outage planning and management practice outlined in section 4, that should apply to improved transparency in the section above and the conduct obligation in section 5.

Participants discussed whether good outage planning and management practices could be incentivised with financial rewards and penalties. Rewards are provided when TNSPs perform well and penalties when they underperform. One approach discussed was to set a specific target with rewards for outperforming against the target and penalties for underperforming. A variant is to set multiple targets with weightings attached to each target. Another approach discussed was to provide a more qualitative ex-post assessment of a TNSP's performance against specified principles.

The working group identified the following incentive-based mechanisms:

- outage notification incentive scheme
- outage scheduling incentive scheme
- MMI outage management incentive scheme; and
- a combination of these mechanisms.

These are discussed below (starting with option 2 on the basis that transparency with reporting is option 1).

5.2.1 Option 2: Outage notification incentive scheme

The CEC, EUAA, ElectraNet and Powerlink proposed incentives to promote greater predictability of planned outages. These participants considered that an outage notification incentive scheme would provide market participants with greater certainty as to the timing of an outage and allow users to better manage market risks (e.g., by enabling participants to hedge price risk). This mechanism would also allow generators to schedule their own outages for maintenance at the same time as network outages.

There were mixed views as to whether the outage notification scheme should focus on all planned outages or only outages that have the potential for an MMI, but many have major impacts on holders of PPAs on specific transmission lines. However, participants also recognised that outages on many parts of the network have little impact on market outcomes or market participants. It may be appropriate to limit the scheme to outages on more significant parts of the transmission network. This issue is discussed in section 3.

The scheme would set a notification target for each TNSP, with rewards for performance and penalties for not meeting targets. Examples of a target include the number of hours, or the percentage of outages, notified at least four months in advance. Incentives could be scaled for the level of over (or under) performance up to certain caps. Some participants suggested that the incentives (penalty) could be graduated based on the lateness of an outage notification relative to the target, where the penalty could increase the later a notification is provided relative to the target. Powerlink (refer to Box 3) also proposed that a target also be set for late rescheduling of an outage (in this case less than four months). Box 1 provides an example provided by ElectraNet of an example of an outage notification mechanism.

Box 1: Example: Outage notification incentive mechanism – notification target (no. hours)

- Example: 100 hours total across all MMI outages in a year, with a performance target of 80%.
- Scenario: AEMO cancelled/postponed 20 hours of outage, TNSP cancelled/postponed 10 hours. Rest delivered adhering to the four months' notice requirement.
- Payment: 80 hours 'TNSP controllable outage' 70 hours delivered 87.5% performance score:
- Incentive = (87.5-80)/(100-80)*1% of Maximum Allowable Revenue (MAR) = 0.375% of MAR
- If the TNSP cancelled/postponed 20 hours instead of 10 hours 60 hours delivered 75% performance score:
- Incentive under asymmetric scheme = $0 (because performance score < target)
- Incentive under symmetric scheme = (80-75)/(80 - 0)*-1% of MAR = -0.0625% of MAR

Ex post reporting

- TNSPs to apply for hours exemption where:
- System security criteria necessary for the outage to proceed is not met (as mentioned in the AER brief discussion paper)
- Customer initiated changes to outage scheduling
- Adverse weather conditions which prevent safe works proceeding
- Identification of urgent defects which prevent safe works proceeding or otherwise pose safety, environmental or bushfire risk if not addressed promptly (note that the Service Component already penalises outages with <24 hours' notice)
- Latent site conditions requiring late engineering or other changes to the work
- Supply chain delays
- Where one or more of the above exemptions apply, the outage is treated in the same manner as AEMO cancelled/postponed outages – i.e. its hours are removed from both the numerator and denominator of the performance score

Source: ElectraNet

Note: The approach also relies on identifying MMIs for the purpose of setting a target and assessing performance.

Box 2 provides an example of a points-based incentive scheme as proposed by the CEC

Box 2: Outage Planning and Management Points Scheme

Under the scheme:

- planned network outages would only include outages on a Potential Market Impact list. The criteria for inclusion in this list should be consulted upon, but CEC submits it should include the following quantitative criteria:
    - 10-15% expected impact on a network flow path's transfer capability
    - 10-15% expected generator(s) output capability
- Each planned network outage included in the "Potential Market Impact Outage" list would be allocated a notional number of Outage Planning and Management Points (**Points**).
- A planned "Potential Market Impact Outage" that was submitted by a TNSP with 4 months' notice (122 Days) would incur no Points deduction

- Where a planned "Potential Market Impact Outage" was submitted with less than 4 months' notice, the proposed framework would deduct Points at a progressively increasing rate as the notice period for planned outage reduces prior to their start date.

The rate at which the Points would taper off needs to be determined through consultation with industry and the NMIWG. However, it is likely that:

- initially the rate at which points would be lost would be very small where the TNSP submitted its notice of the planned outage into the NOS close to 4 months prior to its start date
- the rate at which points would be lost would increase materially the closer the planned outage is notified to its start date.

Source: CEC

The working group discussed how the target could be set. TNSPs suggested targets based on past performance, while the CEC suggested establishing new benchmarks. Some participants speculated that a limitation of using past TNSP performance is that historical performance may not reflect good practice. However, alternative targets may also be difficult to substantiate given the limitations of existing NOS data. Transgrid noted that the setting of arbitrary performance targets that are not based on historical data, risks diluting the incentive, given the possibility of inadvertently setting a target that is unduly difficult to achieve in practice.

In addition, in setting a benchmark, outages on many parts of the network have little impact on market outcomes or market participants. Regional feeder lines, for example, may connect only a few small renewable generators, noting that these small generators may have PPAs with end users. The working group discussed whether a notification incentive scheme should be limited to outages on more significant parts of the transmission network.

Participants also noted that a notification incentive should exclude cancellation or rescheduling of outages driven by factors genuinely outside the TNSP's control. Participants expressed differing views as to what should or should not be considered as within a TNSP's control and considered such could be set out in an AER guideline. A scheme would need to clearly specify which outages should be excluded. Adjustments to NOS may be required to accurately record such exclusions. Alternatively, EUAA proposed that a percentage of outages be excluded from a notification scheme to account for outages that are cancelled or rescheduled for factors outside the TNSP's control.

The working group discussed the implications of just having notification incentives, recognising that it could have unintended consequences. Participants identified the following possible limitations if the option operated without supplementary measures:

- does not address the objective of scheduling outages at times that limit the impact of the outage on the market
- may reduce the incentive for a TNSP to reconsider outage timing in light of new information (such as unplanned outages of major generators, or options to co-ordinate outages)
- may incentivise a TNSP to schedule more outages than are necessary which may reduce the certainty of outage timing that this mechanism seeks to promote.

Working group participants recognised that a notification incentive may not be the sole replacement for the MIC but noted it could form part of a multi-pronged incentive scheme. It improves certainty but does not by itself ensure that outages are scheduled, coordinated, recalled or mitigated in a way that minimises material market impacts.

The working group considered supplementary measures to improve outage management, focusing on avoiding scheduling outages where there is a foreseeable risk of material market impacts. The CEC considered that a notification incentive scheme should allow TNSPs to temporarily suspend outages during periods where there is a high risk of material market impacts. That said, the working group did not develop a detailed position on how this could work, or how TNSPs should respond to new information emerging after the initial notification. A key issue here is the role weather plays in the impact of outages.

With increasing renewable generation, weather conditions increasingly determine reserve adequacy on the day. At times TNSPs can face competing objectives when new information becomes available: maintain an outage to meet notification objectives or re-schedule when the market impact is expected to be low. To some extent it may be possible to deal with the issue by specifying circumstances where TNSPs should not go ahead with an outage. The working group discussed exempting TNSPs from penalties where AEMO directs them not to take an outage. This could be broadened to not penalising TNSPs if they re-schedule because of an unanticipated high market impact of an outage (unforeseen at the time of the original notification).

An incentive scheme should distinguish between information reasonably available when the outage is first scheduled and information that becomes available closer to the outage date. Some participants considered that TNSPs should not be penalised merely because market conditions change but should reassess MMI outages against predefined transparent criteria.

ElectraNet's advisor encouraged the working group to consider an incentive mechanism that distinguishes between foreseeable risks and unforeseeable risks. The approach would encourage TNSPs to identify foreseeable market risks of tight market conditions (e.g., use of MT PASA), and schedule accordingly. It would also incentivise TNSPs to adopt works practices (e.g., after hours work) to minimise the impact of unforeseeable risks such as weather-dependent supply shortfalls, generator trips or interconnector failures. This approach shares some of the attributes of Option 2 and Option 3 (see below).

The CEC proposed that an incentive scheme could have regard to foreseeable risks of market conditions at the time of scheduling the initial outage, where these foreseeable risks include:

- low expected reserve conditions
- clashing outages
- seasonal peak demand (summer/winter)
- historical correlations of network congestion.

The CEC proposed that the AER should work with AEMO and industry participants to provide guidance on when there would be a foreseeable risk of market impacts, and this should be reviewed and updated every 6 months. This might specify particular transmission elements or interconnectors (which could be revised as the network changes).

5.2.2 Option 3: Outage scheduling incentive scheme

The working group, as discussed above, considered incentivising TNSPs to identify and act on foreseeable market risks. When scheduling outages TNSPs should use available demand and supply forecasts to inform outage timing. MT PASA is an available tool when scheduling an outage, four months out, providing forecasts of demand and supply conditions. MT PASA modelling uses AEMO demand forecasts, historical weather-based demand and VRE traces, participant-submitted generation availability, probabilistic forced outages and applicable network constraints, including planned network outages.

The working group considered expanding the notification incentive to include a scheduling incentive or as a standalone incentive. An incentive could be framed around selection of outage dates and times when forward indicators show lower reliability or supply-adequacy risk. MT PASA could provide some of this information, although it does not currently forecast and publish a regional reserve metric. AEMO confirmed that a regional reserve level is only available in the short term PASA timeframe and is not an available metric four months in advance, at the proposed time of outage scheduling. AEMO advised that the MT PASA provides the LOLP as the highest half-hourly probability of loss of load for each day under the LOLP Run's high-demand and low VRE assumptions.

MT PASA also provides other metrics that could be useful for TNSPs in scheduling outages. These include outage-related binding constraints and their probability of binding and hours binding, together with modelled interconnector flows and calculated import/export limits in the presence of planned outages, as well as identifying the generators and interconnectors affected by certain constraints.

Another metric proposed was selection of outage timing when available reserves are higher than the output of say the two largest generators in the relevant region. An incentive as proposed could work as follows:

- The number of outages is recorded along with the number (or percentage) that are scheduled when reserves are higher than the nominated level.
- A target is set for the number or percentage of outages scheduled when reserves are higher than the nominated level.
- TNSPs receive financial rewards when they outperform against the target and penalties when they underperform.
- The rewards or penalties could be scaled according to the level of out (or under) performance up to a cap.

As noted above, MT PASA does not explicitly identify reserves, so a reserve-based incentive would first require an agreed methodology. A simple availability minus demand indicator could be derived from existing published information, but publication of a standardised MT PASA reserve measure would require further methodology development and potentially changes to MT PASA outputs. The CEC also suggested that AEMO should more clearly signal the impact of outage constraints on the reported available supply within region and interconnector capacity to make it easier for TNSPs to schedule outages.

As with a notification incentive, the question is how to set the target (the number or percentage of outages that are scheduled when reserves are higher than the nominated level). One possibility is historic performance, though as the data has not been collected this may not be an option. Until TNSPs have used MT PASA metrics for the purpose of outage scheduling consistently and until the AER has tested how those inputs correlate with actual outage outcomes, participants noted that any performance target may be difficult to substantiate or link to matters within TNSP control.

As with a notification incentive, outages on many parts of the network have little impact on market outcomes or market participants. It may be appropriate to limit the scheme to outages on more significant parts of the transmission network. This issue is discussed in section 3.

Powerlink provided an example of how an incentive mechanism based on a proposed reserve adequacy measure informed by MT PASA could run in conjunction with a notification incentive. This type of combined approach is discussed further under Option 6. The example attaches weightings to each component of the scheme. The example is set out in Box 3.

Box 3: Example of outage planning metric

Planning performance category	Weighting
Late outage scheduling (<four months)	+-50% of MAR
Reserve adequacy at time of scheduling	+-25% of MAR
Late reschedule (<four months)	+-25% of MAR

Scenario: Total assessable outages of 90 and 4 late outage notifications, resulting in performance of 86/90 = 95.6%

Target = 92% based on historical performance

Incentive: (0.956-0.92)/(1-0.92) * 0.50 = 0.225%

Source: Powerlink

Note: The weights will reflect a (%) contribution of each incentive component of the scheme, and the overall weighted incentive will be applied to the MAR to determine the reward/penalty.

5.2.3 Option 4: MMI outage management incentive scheme

Option 4 focuses on these additional elements: incentives to improve management of outages when an MMI is likely. The option provided in this report draws on input on the ‘straw-person’ proposal considered by the working group.

Notification and selection of outage timing are two key elements of good outage management principles. However, this option captures additional elements, including coordination of outages, re-scheduling in light of material new developments, and use of higher cost works when reserve conditions are tight (such as live line, daily outages or quick recall and after-hours work).

The option would establish principles of good outage management (focusing on MMI events), assess TNSP performance against an outage management plan, and provide financial

incentives. The scheme would provide additional revenues to the TNSPs to cover the additional costs required for the outage management plan. There is also the option of additional revenue if the TNSPs perform well against the identified principles as reflected in the plan and if the TNSP does not deliver the plan or do not justify departures from the plan, this revenue would not be retained.

This option does not make TNSPs responsible for wholesale price outcomes outside their control. Participants discussed whether price and reserve outcomes could be collected and reported, but primarily to test the MMI classification and help assess TNSP performance.

The working group discussed how principles of good outage planning and management could be implemented. The discussion focused on how the TNSPs could develop such principles. The CEC, for example, supported encouraging TNSPs to implement an efficient, effective and transparent outage planning and management framework to mitigate market risks associated with network outages that may have an MMI. This option could include 'proceeding criteria' to assess whether an outage should proceed. These criteria could include considerations such as interconnector capability; weather conditions; minimum system load considerations; other concurrent outages; availability of mitigation measures; and AEMO advice.

The proposal is for the TNSPs to establish an outage management plan which identifies:

- the TNSP's process for assessing whether planned outages are expected to have a material market impact
- proposed mitigation steps for each material market impact outage; and
- the expected efficient costs of those mitigation steps.

The mitigation measures could include, amongst other things, recall or partial recall arrangements, live line work and coordination steps.

Under this proposal, the AER would assess and approve the outage management plan and set an ex-ante allowance. The ex-ante allowance would be based on the additional costs required to mitigate MMIs. The proposed allowance reflected the working group's recognition that mitigation measures are often more costly than current practices, and this disincentivises TNSPs from considering their impact on the market. VicGrid commented that care needs to be taken not to incentivise practices that should already be priced into the TNSPs' cost structures. In particular incentivising "after-hours" work is now quite common in most industries and while more expensive than standard hours it should not be considered unusual to the extent that it requires an additional incentive. ElectraNet considered that this approach was more akin to cost-of-service regulation as opposed to an efficient incentive scheme.

Powerlink commented that in determining works that could be potentially undertaken to mitigate market impacts, different outages on the same plant will require different mitigation measures depending on the work being performed, for example:

- Insulator replacements on a transmission line may be suitable for live works on most towers and have daily recall for those towers not suitable for live line methods.

- Whereas a circuit breaker replacement for the same transmission line may be unsuitable for live works, require a significant increase in complexity and staging to implement temporary bypass to enable a recall time (instead of having no recall).

Therefore, depending on the work being performed, mitigating market impacts will often require bespoke solutions for each individual outage in the outage management plan. Such bespoke, fit for purpose solutions may not be considered favourably by the AER, increasing the risk that the associated expenditure will not be approved for cost recovery (and if not approved, the works will need to be replanned to more traditional methods).

If the TNSP delivers the approved plan, it would receive the allowance. The allowance may include a margin above the efficient costs as an incentive to develop innovative work practices to reduce the market impact of the network outages. If the TNSP underspends but broadly delivers the plan, it would retain the underspend. If the TNSP does not deliver the plan, the revenue would not be retained or a proportion of revenue would not be retained, unless the TNSP can provide a reasonable explanation for departures from the plan.

The allowance would not pay TNSPs merely for proposing higher-cost outage management practices. Under the proposal, it would fund mitigation assessed as efficient where the expected market benefit is likely to justify the cost, and to be retained only where the TNSP delivers the approved plan or reasonably explains departures.

The proposal discussed at the working group was for revenue uplifts (with no penalties), but there were different views amongst working group members about the merits of this. Some working group members considered that any incentive scheme should be symmetrical with both financial rewards and penalties depending on performance. Participants expressed different views on this. Some participants noted that a symmetrical approach would be desirable in principle, but it may be difficult to implement in practice for an outage management scheme. A symmetric scheme requires a baseline or benchmark. At present, sufficiently reliable and available information for setting a baseline is not available.

Some participants considered that a symmetrical scheme could be considered in future if a robust baseline can be established. It may be possible to use information from the asymmetric (revenue uplift only) scheme to develop a robust baseline for a new or revised scheme.

Participants discussed including a defined review point (say after two or three years). The review could consider whether TNSPs are effective in identifying MMI events, whether the mitigation measures are effective, and whether TNSP reporting is comparable. As noted above, a review could consider whether a future symmetrical incentive can be introduced without arbitrary outcomes.

Material Market Impact outages

The scheme would be targeted at planned outages expected to have a material market impact (MMI). The scheme would not apply equally to all planned outages. If the scheme applies too broadly, it may become administratively burdensome and less effective.

A planned outage may have MMI where it is reasonably likely to materially affect wholesale market outcomes. Relevant considerations may include whether the outage affects interconnector capability, major transmission flow paths access to dispatchable generation,

REZ access, constraints that historically bind during high regional reference price periods and reserve conditions.

Outage Management Plan

The outage management plan would be central to the scheme. Under the proposal, the plan would identify, for the relevant period, planned outages expected to have MMI and how the TNSP proposes to manage those outages. The plan could explain how the TNSP identifies MMI outages, what mitigation options it considered, why the proposed mitigation is efficient, and how the AER will later assess delivery and learn from the outcomes. For example, for a MMI network element, a TNSP might articulate in their plan that the outage recall time will be reduced from 5 days to 1 day in the case of certain ‘tight’ network conditions arising during the outage. If this situation arises, and the TNSP reduces the outage recall time, they would receive the agreed uplift payment.

The TNSPs would record the reasons for their MMI assessments, and the steps taken to manage the impact of them. This transparency would allow the AER and market participants to assess the TNSPs' actions against their plan. The outage management plan would operate as the reference point for the scheme.

Transparency measures

The proposal contemplated quarterly public reporting by TNSPs on every planned outage and include, amongst other things, planned outages undertaken, planned outages deferred, cancelled or modified, whether proceeding criteria were met, mitigation measures, whether the market impact was reasonably foreseeable and reasons for deviation from the plan. Confidential reporting to the AER may be required for sensitive operational information, security information, or commercially sensitive mitigation contracts.

A simplified worked example of this option is set out in **Attachment B**.

5.3 Option 5: Conduct-based obligation

The working group considered establishing a conduct obligation. This could be introduced to supplement an incentive mechanism or be a stand-alone Rule provision that places an obligation on TNSPs to promote efficient, effective and transparent planning and outage management practices. The CEC supports an obligation to supplement an incentive reward/penalty scheme, but only if it is determined to be a civil penalty provision.

Participants discussed whether a conduct obligation could set a minimum standard for serious failures to consider or appropriately manage foreseeable market impacts. A worked example of this option is set out in **Attachment C**. The attachment explains how the conduct obligation could be structured around a core rule obligation, an AER guideline, reassessment, record keeping, carve-outs and targeted transparency measures.

The stated objective of the proposed conduct obligation as set out in the ‘straw-person’ proposal is to require a TNSP, in planning and managing planned network outages, to avoid causing material adverse effects on the NEM where a reasonably practicable and materially better alternative is available. The proposal was intended to address the concern that TNSPs do not presently bear the market cost of poorly planned and managed planned outages.

Participants discussed whether the obligation should be assessed by reference to information reasonably available to the TNSP at the relevant time. It should not operate as a hindsight obligation based solely on ex post wholesale price outcomes.

Proposed form of conduct obligation

The key features of the proposed form of conduct obligation include:

- A broad approach to the main forms of market harm.
- Identifying the matters to which a TNSP might be required to consider if the objective is to avoid material adverse wholesale market impact.
- Identifying the situations and circumstances that should not be covered by a conduct obligation.
- Record keeping and reporting requirements.

Under the proposal, the Rules would state the core legal standard and the main elements of the framework, while a Guideline, developed by the AER, would provide the detailed criteria, thresholds and methodology needed to apply that standard in practice.

The CEC expressed a preference for the Guideline to not be developed in accordance with the transmission consultation procedure, which takes 9 months, as this would not be nimble enough to respond to evolving network conditions during the transition in a timely fashion. CEC further suggested that the AER work with AEMO to identify (and include in the Guideline) transmission assets where planned outages could result in material market impacts. The CEC also suggested regular reviews to pick up changing market and network conditions.

Conduct to be addressed by an obligation

The conduct obligation discussed by the working group uses the concept of “material adverse wholesale market impact”. This concept is intended to capture, at a workable level of generality, the main forms of market harm that may arise where a planned network event (outage) is scheduled, managed or otherwise dealt with in a suboptimal way. The concept was discussed as potentially broad enough to capture:

- increases in spot prices
- increases in ancillary service prices
- transmission congestion that has a material adverse effect on wholesale market outcomes
- reduced reliability of important parts of the transmission system; and
- increased costs to consumers.

Based on feedback received during the working group process, including concern that TNSPs cannot reasonably be expected to forecast spot or ancillary service prices when planning outages, an alternative framing of material adverse wholesale market impact could focus on material and reasonably foreseeable risks of:

- adverse wholesale market impacts, including materially higher dispatch costs or adverse impacts on spot prices and ancillary service prices

- reduced reliability of important parts of the transmission system at times that are of most value to consumers; and

- the likelihood of increased costs to consumers.

The proposed purpose of the provision was to avoid or materially reduce a material and reasonably foreseeable risk of adverse wholesale market or consumer impact where a reasonably practicable and materially better alternative is available.

For discussion, the proposed obligation would prohibit a TNSP from scheduling or otherwise managing a planned network event where, on the information reasonably available to it at the relevant time, the event creates a material and reasonably foreseeable risk of adverse wholesale or consumer consequences, and there is a reasonably practicable alternative timing, duration, method or management approach that would avoid or materially reduce that risk. The assessment would be proportionate to the nature and timing of the event and reviewed when materially new information becomes available. It would not require a quantitative forecast of spot or ancillary service prices. The invocation or expected binding of a constraint would not of itself constitute an adverse market impact but may be relevant to the extent that it indicates a material risk of adverse market or consumer consequences.

Matters relevant to planning and managing an outage

The proposed conduct obligation was directed to the practical matters most relevant to the planning and management of planned network outages. Those matters could include:

- medium-term PASA, short-term PASA, reserve information, pre-dispatch information, AEMO forecasts, AEMO advice and other reasonably available market information;
- forecast demand, generator availability, VRE output, interconnector capability, minimum system load, reserve conditions and other concurrent outages;
- alternative timing, outage windows, duration, recall arrangements, daily suspension or other contingencies;
- coordination with AEMO, neighbouring TNSPs and related planned outages on common flow paths or interconnectors;
- advanced notification of outages;
- outage management practices that could avoid or reduce the likelihood or extent of a material market impact, including live-line work, after-hours work, shorter outage windows, resequencing, additional resourcing, NSCAS or other mitigation measures; and
- whether the expected market benefit of a mitigation measure is likely to justify its efficient cost.

The proposal included carve-outs where proceeding with the planned network event in the manner proposed is necessary for safety, power system security or reliability, or where changing the event would materially prejudice the carrying out of the works; or result in non-compliance with applicable legal or Rules requirements.

Record keeping and reporting

It also proposed a record-keeping and record-retention requirement, so that the relevant reasoning remains available for later review and makes clear that nothing in the proposed provision requires a TNSP to fail to comply with a direction of AEMO.

ElectraNet, supported by other TNSPs provided feedback that:

- The proposed code of conduct obligation presents a conflict in objectives with the four months' notice scheme proposal, as it mandates flexibility in the scheduling of outages (in contrast to the four months' notice scheme promoting certainty in scheduling an outage).
- The obligation includes a requirement to consider a "vast array of information and forecasts", as well as documenting how TNSPs have considered all the information in reaching a determination. Further, there is the potential for conflicting information amongst the sources, but currently no guidance on how to deal with potential conflicts.
- There is no indication that the obligation will be proportionate to the scale of impact of outage, i.e. the full obligation could be triggered for any instance of *material adverse wholesale market impact*, as well as for any 'material change in market conditions'.
- The proposal does not consider the costs of ageing asset risk and cumulative deferral risk, or whether the benefits of timely works outweigh the costs of market impact.
- A key criticism of the previous MIC was linking the incentive to spot market outcomes which were out of TNSP control. While this proposal doesn't strictly tie compliance to spot market outcomes, it departs from the view that a replacement for the MIC be focussed on foreseeable impacts (those that can reasonably be identified using publicly available system information at the time an outage is scheduled or confirmed) and places a substantial emphasis on assessment of spot price (and FCAS price) forecasting – a role which TNSPs have no experience or natural exposure to.
- This approach shifts away from outcome-based efficiency incentives towards process compliance.
- The proposed obligations are likely to require an operating cost step change to service; however, given the timing of revenue proposals, TNSPs may not be able to include, or at least properly assess, the required amount in forthcoming revenue proposals.
- ElectraNet's concerns identified matters for consideration in the design of any obligation.

Those concerns related to whether any obligation should be targeted and focused on MMI outages, reasonable information sources, proportionate record keeping and clear carve-outs, rather than a broad process obligation that requires TNSPs to forecast spot prices or document every possible market variable for every outage.

They also raised the question whether the conduct obligation should not be framed as a broad hindsight-based process obligation. If pursued, it should be targeted to MMI outages, assessed by reference to information reasonably available at the time, and supported by clear carve-outs for safety, reliability, AEMO directions, asset risk, legal obligations and operational practicality.

5.4 Option 6: A combination of measures

For completeness it is worth noting that options could be combined. For example, combining notification, scheduling and outage management incentives should be more effective in minimising the market impact of outages than just one of the incentive schemes. Implementation though would be more complex.

Similarly, there is also the possibility of a hybrid approach that is an incentive-based mechanism coupled with a conduct obligation. As noted above, the CEC supported one or more incentive-based schemes (at least Option 2 and, a scheme which incentivises avoiding scheduling outages where there could be a foreseeable risk of material market impacts, if added to Option 2); and a conduct obligation with a civil penalty provision as a back-up to the incentive approach.

In considering a targeted incentive-based approach, participants discussed whether a conduct obligation could complement a replacement to the MIC, in circumstances where an incentive scheme provides a ‘bonus’ only mechanism. Under this hybrid approach, the conduct obligation could operate alongside the incentive-based mechanism. The working group also discussed how incentive schemes could be combined, and Powerlink provided an example of how weightings could be applied.

Options 1 to 3 were each assessed above on a standalone basis. However, TNSP participants proposed these mechanisms as components of a single integrated scheme, such as those submitted by Powerlink and ElectraNet, rather than as mutually exclusive alternatives. Assessed individually, each option displays a gap that is, in most cases, directly addressed by another component. These TNSPs considered that combining these measures therefore mitigates most of the weaknesses identified in the standalone assessments as set out below.

Notification and scheduling are complementary, not competing. The principal criticism of the notification incentive (Option 2) is that it improves certainty but does not ensure outages are scheduled to minimise market impact and may even reward "firmness for its own sake." The principal criticism of the scheduling incentive (Option 3) is the opposite: it improves timing but does not improve notification or the scope for participants to manage risk through contracting. Combined, each component supplies what the other lacks. A TNSP cannot score well simply by locking in a poorly timed outage, because the scheduling/reserve component tests timing against forecast conditions; equally, it cannot score well by optimising timing while providing inadequate notice.

Transparency underpins and disciplines the incentive components. Option 1 (transparency) is assessed as providing only reputational incentives that are weaker than a financial mechanism. However, its value increases materially when combined with Options 2 and 3: consistent reporting on notification, rescheduling and outage timing provides the data needed to set and refine evidence-based targets, and to verify performance. In combination, transparency ceases to be a standalone substitute for incentives and instead becomes the reporting layer that makes the incentive components measurable and auditable.

The combined scheme resolves the target-setting concern. A recurring concern with Options 2 and 3 individually is the limited historical data available to set non-arbitrary targets. The transparency component (Option 1), applied during an initial reporting-only or shadow period, directly addresses this by generating the baseline dataset required before financial incentives commence. This staged approach – reporting first, then asymmetric (reward-only) incentives, then symmetric incentives – mirrors the way other STPIS parameters have been introduced and therefore actually allows targets to be evidence-based rather than arbitrary.

The combined scheme can be targeted to MMI outages. Each component can apply to the same defined set of MMI outages (for example, drawing on AEMO's High Impact Outage

list as an initial basis). This ensures the scheme concentrates effort on the outages that genuinely affect market outcomes and avoids the dilution risk identified for the standalone options, where effort might be spread across a large number of low-impact events.

Residual limitations. Combining the measures increases design and administrative complexity relative to any single component and requires agreement on how the components are weighted. Powerlink's example (Box 2) illustrates one approach to weighting the components within a single ±1% of MAR envelope. These are design questions capable of resolution, rather than fundamental barriers, and are materially less complex than the alternatives requiring an ex-post management-plan assessment (Option 4) or a new rule-based obligation (Option 5).

On this basis, the combined incentive scheme (Options 1 to 3) addresses the effectiveness limitations identified for each component in isolation, while remaining implementable within the existing STPIS framework and without a rule change (refer to **Attachment D**). The working group's discussion indicated majority in principle support for an incentive-based mechanism of this kind.

Other combined options

An alternative combined incentive approach briefly discussed by the working group considered an ex-ante framework focused on foreseeable market risk. This approach was developed by an adviser engaged by ElectraNet. This combined approach could include incentives incorporating:

- A minimum advance notice period for an outage
- Inclusion of primary and secondary outage windows
- Formal AEMO coordination gate as to whether outage should proceed (considers both impact on energy and ancillary services prices)
- MT PASA consideration of reserve adequacy to test the timing of the planned outage
- Timeliness of completing works when reserve adequacy is sufficient.

This approach would also recognise that a TNSP may have to employ higher cost works to include flexible outage management practices to manage unforeseeable risks. This approach would also allow short-term recall and outage postponement but limited deferral of an outage. The objective of this approach links reward and penalties to a planning discipline. This approach was not discussed in depth, but it includes elements that are covered by the incentive options covered in this report. The key difference from the other options is that AEMO could have a role in determining whether an outage should proceed. Though as discussed in this report, AEMO is focused on system security and not on the market impact of outages.

6 Assessing options against criteria

Having identified options to improve planning and management practices, the question is how well the options perform. This section records the criteria discussed by the working group for assessing the options.

The working group agreed with the following criteria for assessing the identified options:

- **Material impact** – the option is targeted to material market impacts to promote the efficient operation of the market.
- **Simple/workable** – the option is administratively simple to implement.
- **Measurable** – input 'parameter' and outcomes are objectively measurable.
- **Stable** – input 'parameter values' are stable over time.
- **Controllable** – to ensure the option is effective, the TNSPs ability to limit market impacts needs to be within the control of the TNSP.
- **Sustainable** – the option is fit for purpose over time.

It was proposed that these criteria can be categorised into two broader groupings in terms of '**effectiveness'** and **'implementation'**.

The working group's discussion on effectiveness focused on the impact of options in mitigating the market impact of outages and the scope for market participants to manage the impact of outages through contracting (risk management). The effectiveness criteria reflect this discussion and the 'material impact' criterion.

The working group's discussion on implementation reflects discussion on whether the option is clear, predictable and stable, the behaviours incentivised are in the TNSP's control, the basis for setting performance targets is robust, and the option is simple to administer (for TNSPs and the regulator). Again, the implementation criteria reflect this discussion and the 'simple', 'stable' 'controllable' 'workable' and 'sustainable' criterion.

No agreement was reached on performance targets for the incentive schemes, so for purposes of this evaluation the criterion is whether the target could be evidence based, for example based on past performance, as distinct from arbitrary targets. Selection of incentive targets goes to the criteria of 'stable' and 'sustainable'.

6.1 Summary of advantages and disadvantages of options

To assist the working group, this section attempts to distil the working group's comments to provide a qualitative summary of advantages and disadvantages of the options against the criteria. This assessment is summarised in Table 2.

Table 2: Summary of options against the criteria

			Effectiveness			Implementation			
			Mitigating market impact	**Risk management**	**Measurable**	**Clear, predictable and stable?**	**In TNSP control?**	**Robust basis for setting performance target?**	**Simple to administer?**
Option 1: Transparency & Reporting	**Carrot:** Information transparency	**1a:** AEMO NOS scheduling data enhancements **1b:** Outage and price linkage **1c:** Ex-post assessment of HIO via RIOs	Reputational impacts may encourage improved outage management practices, though likely less effective than an incentive scheme or conduct obligation.	Transparency may improve outage notification practices but is likely less effective than direct incentives or obligations.	Reported information (notification timing, rescheduling and cancellation reasons) is objectively measurable and drawn from NOS and TNSP records. However, the effectiveness of the reputational incentive it creates is not itself directly measurable.	Reporting requirements would be prescribed and therefore clear and stable, provided the relevant instruments are not frequently amended.	Reporting obligations are within TNSP control.	Not applicable.	Straightforward to administer, subject to the nature of the information collected and reported.
Option 2: Outage Notification Incentive	**Carrot/Stick:** Incentive scheme, symmetric reward/penalty	Incentive scheme that rewards TNSPs for providing earlier and more reliable notification of significant planned outages to minimise foreseeable risks. CIR	Provides an indirect benefit. Better notification helps participants manage impacts but does not directly reduce the market impact of the outage itself.	Strong alignment with participant risk management through improved outage certainty and notice periods.	Highly measurable. Notification lead times are recorded objectively via NOS submission timestamps, and performance against a notification target can be calculated transparently and verified by the AER with minimal judgement.	Objective notification metrics could provide a clear and predictable framework. However, additional governance would be required to define which outages are subject to the incentive and to periodically review those criteria as experience is gained. The forward-looking list of relevant outages would provide	Primarily within TNSP control, subject to genuine changes in system conditions or circumstances.	Some challenges arise from the need for enhanced transparency, the use of historical NOS data, and the need to determine appropriate notification thresholds and targets.	Relatively simple to administer compared with broader incentive options.

		aligned to four months.				transparency and predictability for both TNSPs and market participants.			
Option 3: Scheduling Incentive	**Carrot/Stick:** Incentive scheme, symmetric reward/penalty	Incentivises TNSPs to use MT PASA data as a forward indicator of supply adequacy, reliability risk and network conditions, rewarding outages scheduled during periods of lower forecast system stress with the aim of reducing potential market impacts.	Aims to reduce outage-related market impacts by influencing when outages are scheduled and avoiding times of foreseeable system 'tightness'.	Provides limited benefit to notification certainty or participant planning compared with a notification incentive.	Largely measurable, depending on MT PASA metric used for outage scheduling. Outage timing relative to MT PASA metrics can be an objective observable input. AEMO has advised that MT PASA does not currently calculate or publish formal regional reserve margins, so an appropriate and consistent metric would need to be defined before it could be used for this purpose.	Yes, provided the selected forward supply-adequacy or reliability indicator is clearly defined and transparently available.	Scheduling decisions are generally within TNSP influence, although future market and system conditions are not.	MT PASA-based scheduling metrics have not previously been considered by the TNSPs, therefore limited historical data may be available to set a future target.	Can be designed to be simple to administer.
Option 4: MMI Outage Management Incentive	**Carrot/Stick:** Incentive scheme, reward/penalty	Incentivises enhanced planning and mitigation practices for MMI outages, recognising the additional effort and cost involved in reducing	Incentivises enhanced planning and mitigation of MMI outages, including greater flexibility as conditions change. Effectiveness depends on reliable identification of MMI outages, measurable performance criteria and outcomes that are substantially	Supports participants by reducing the likelihood or severity of material market impacts from outages. This benefit is offset by the risk of uncertainty about whether outages will proceed. The outcome would depend on how the plan is implemented and	Partially measurable. Mitigation costs and plan delivery can be quantified, but assessment of performance against the outage management plan relies substantially on ex-post qualitative judgement, reducing	Requires reliable ex-ante identification of MMI outages, with uncertainty around ex-post assessment and approval of mitigation expenditure. To be fully effective, this option requires that MMIs can be reasonably identified. This option requires the ex-ante	Planning and mitigation actions are largely within TNSP control, although expenditure approval and changing market conditions are not. The scheme would therefore need to distinguish between matters the TNSP could reasonably foresee and manage,	Performance targets are set in the management plan and would be reviewed by the AER. However, assessment of performance would be undertaken ex-post and is likely to involve a degree of judgement. At least initially, the approach could create some	The scheme is more complex to administer than options 1, 2 and 3. It requires development of a detailed plan and provision of detailed information by the TNSPs and a detailed assessment by

		market impacts.	within the TNSP's control.	whether it provides participants with timely and useful information without creating additional uncertainty.	the objectivity of the outcome measure.	development of actions to avoid or mitigate market impacts. This option also requires ex-post review of events which introduces inherent uncertainty in ex ante decision making, reducing clarity and predictability of the mechanism.	and outcomes arising from changing market or system conditions, or regulatory decisions, that are outside the TNSP's control.	uncertainty for the TNSPs about likely outcomes, potentially diluting the TNSPs' incentives.	the AER. Further, information on MMIs and expenditure in the outage management plan may need to evolve by updating the outage management plan, say every two years, to ensure it is sustainable over time.
Option 5: Conduct Obligation	**Stick:** Conduct obligation, rule change	Require TNSPs to take reasonable steps to minimise foreseeable material market impacts.	Broadly applies across outage planning and delivery and could influence a wide range of outage management practices to minimise market harm.	Could support both improved outage management and improved notification practices. As notification would be one of the measures targeted, this option should improve participants' ability to manage the impact of outages through contracting, to the extent that the mechanism does not also contemplate late reassessment of outages.	Not measurable. Compliance turns on whether the TNSP "ought reasonably to have known" of a likely impact and whether a "materially better" alternative existed – predictive, counterfactual assessments that are inherently judgement-based rather than objectively measurable.	The principles underlying a conduct provision may be clearly stated, but this would require considerable effort to define the relevant obligations, information requirements, applicable outages and supporting guidance. The option will be less predictable for TNSPs than a notification or scheduling incentive scheme because assessment of performance would be undertaken ex-post.	A conduct obligation would be within a TNSP's control because the core obligations, possibly supplemented by a guideline, would relate to matters within the TNSP's control. The obligation would specify circumstances in which events are outside a TNSP's control.	No formal performance target. Compliance would be assessed qualitatively ex-post. As with the MMI outage management incentive, the 'performance targets' are principles based. The assessment of performance would be undertaken ex-post and is likely to involve a degree of judgement resulting in uncertainty regarding AER assessments of performance.	The scheme would be more complex to administer than option 1 (transparency), option 2 (notification incentive) and option 3 (scheduling incentive). At times it will involve provision of detailed information by the TNSPs and a detailed assessment by the AER.

Option 6: Hybrid / 'Multi-Criteria Approach'	**Carrot/Stick:** Combination of incentive scheme and information transparency	Combine elements of the options above, akin to the sub-elements of the STPIS Service Component.	Can combine complementary strengths to address market impacts, including notification, scheduling, outage management and compliance backstop measures.	May better address both market impact mitigation and participant risk management than any single option.	May require careful calibration to avoid overlapping or conflicting incentives.	Limited working group discussion to date means further design work on a settled approach would be required.	As noted, the scheme would need to distinguish between matters the TNSP could reasonably foresee and manage, and outcomes arising from changing market or system conditions, or regulatory decisions, that are outside the TNSP's control.	There may be initial challenges in capturing reliable data to set performance targets and outcomes. A staged approach would allow implementation and refinement as better data become available.	More complex to design, administer and explain to stakeholders. Any initial replacement scheme should be simple, and complexity added on later to address gaps that have appeared.

Option 1(a), (b) and (c): Improved transparency on outage planning and management

The transparency option requires TNSPs to report on their performance against defined metrics including outage notification, outage scheduling, and outage management when an MMI is expected. The results would be published by the AER, possibly with an AER evaluation of performance.

Improving transparency should create reputational incentives to plan and manage outages well, including advanced notification. These reputational incentives are likely to be strongest when TNSPs can be compared and performance ranked.

How effective reputational incentives are in furthering the two effectiveness criteria is a matter of judgement, and central to whether this option is sufficient on its own.

This option may be relatively easy to implement. TNSPs need to report on performance, but no financial incentives apply, so questions of target setting and clarity and predictability of targets do not apply. However, the criterion of TNSP control is relevant. While reporting against principles of good outage planning and management would be clear, there may be some ambiguity about how stakeholders will interpret published data and the extent to which TNSPs are seen as responsible for factors outside their control.

The assessment of the transparency option can be summarised as follows:

- ***Effectiveness*:**
    - *Mitigating market impact*: Transparency, and the resulting impact on reputations, should provide some incentives for good outage management practices, though the option is probably less powerful than either a well-designed incentive scheme or a conduct provision.
    - *Risk management*: Again, transparency should provide reputational incentive for improved notification, though transparency is likely to be less effective than a well-designed incentive scheme or clear obligation.
    - *Measurable:* Reported information (notification timing, rescheduling, cancellation reasons) is objectively measurable and drawn from NOS and TNSP records. However, the effectiveness of the reputational incentive it creates is not itself directly measurable.

- ***Implementation:***
    - *Clear, predictable and stable?* Information to be reported on would be specified in information instruments, so would be clear and stable (provided the instruments are amended infrequently).
    - *In TNSPs control?* Reporting of outage information is in the TNSPs control.
    - *Basis for setting performance target is robust?* As there is no performance target with the transparency option, this criterion is not relevant.
    - *Simple to administer?* Administration of a transparency measure should be relatively easier to administer, subject to the nature of the information that is collected and reported.

Option 2: Outage notification incentive scheme

The case for improving notification of outages is based on risk management. Earlier notification may assist market participants to better manage their financial exposure to

outage-related market outcomes by providing additional time to adjust positions, obtain hedge contracts or otherwise manage risk. For example, a firm generator such as a gas plant constrained off by an outage may be able to meet financial contractual obligations by contracting with a third party. The benefits are most marked for smaller players who do not have the capacity to manage risks internally in the way large retailers can.

The option rates well against the risk management criterion but has limitations. Notification does not reduce the underlying physical or market impact of an outage; rather, it may provide participants with an opportunity to better manage their exposure to those impacts. Though the EUAA noted that the upward pressure on contracting prices is mitigated by long notification periods and certainty of outages as informed by PASA. The effectiveness of this opportunity depends on the availability and cost of suitable contracting arrangements, which may not be accessible or economical for all participants (e.g., not all participants can contract away the impact of outages as there is a cost to contracting, and the costs of contracting may become higher because of the scheme). This is particularly the case for outages that reduce the ability to trade across an interconnector – the ability to trade this away at a reasonable cost is limited if the region already has high market concentration.

By itself the option may not provide effective incentives to limit the impact on spot markets of outages.

If a clear notification target is set, and exemptions are provided for factors outside the TNSP's control, a notification incentive performs well against the criteria of clear and predictable targets and TNSP control.

Transgrid supported using historical data to set targets. However, consistent with all the options, initial target setting is difficult because there is limited relevant data. Further, incentives should be targeted at outages that could have a material impact on market participants. At this point the working group has not identified robust metrics for identifying MMIs to provide consumer benefits. The working group discussed starting with HIO list and reviewing and updating it over time based on experience as material adverse wholesale market impacts are identified. This approach would provide forward-looking transparency to market participants by identifying, in advance, outages that are expected to have the greatest potential to affect market outcomes. However, in attempting to identify MMIs there is the risk that the list may be either overly inclusive, resulting in TNSPs being rewarded for providing notification of outages that have little impact, or overly narrow resulting in insufficient incentives for outages that subsequently prove to have a material impact. Though, the EUAA considered that while some notified outages may not have a material impact, they may have significant impact to PPA holders through the ability to seek alternatives early.

In August 2025, AEMO amended the CIR, to clarify that, TNSPs must provide at least four months' notice of planned outages that are high impact or have historically (or are likely to) cause congestion. This is stated to be without limitation to the TNSP's obligation under NER which is to submit the current intentions on network outages that materially affect transfer capabilities for the next 13 months into NOS before starting. The working group has not discussed the effectiveness of the updated CIR measures, noting this has been recently amended.

The assessment of the notification incentive option can be summarised as follows:

- ***Effectiveness*:**
  - *Mitigating market impact*: Limited effectiveness as the option only incentivises notification, so may be less effective in mitigating market impact.
  - *Risk management*: The option should be effective in improving the scope for participants to manage the impact of outages through contracting, though with some limitations as not all market participants can reduce risk in this way.
  - *Measurable:* Highly measurable. Notification lead times are recorded objectively via NOS submission timestamps, and performance against a notification target can be calculated transparently and verified by the AER with minimal judgement.

- ***Implementation*:**
  - *Clear, predictable and stable?* Yes, if the target is clearly specified and is stable over the reset period. However, additional governance would be required to define which outages are subject to the incentive and to periodically review those criteria as experience is gained. The forward-looking list of relevant outages would provide transparency and predictability for both TNSPs and market participants.
  - *In TNSP' control?* This option is within the TNSP's control, though this would need to recognise that there are some circumstances where a notified outage may not proceed.
  - *Basis for setting performance target is robust?* Available information may not enable performance targets to be set given concerns over reliability of historical data, though target setting may improve over time based on updated historical performance.
  - *Simple to implement?* This option is relatively simple to implement as it is focused on assessing performance against a simple metric.

Option 3: Outage Scheduling incentive

Scheduling planned outages at times that limit the market impact of the outages is a core element of good practice. The option discussed by the working group is to use MT PASA metrics to identify and schedule outages at times when projected 'system tightness' is low. The option rates well in effectiveness in reducing the market impact of outages. Other elements of good planning and management, such as TNSPs' management of outages when an MMI is likely, can easily be covered by this incentive.

A scheduling incentive does not address notification so is not likely to be effective in improving scope for participants to manage the impact of outages through contracting and gets a low score against the risk management criterion. However, to the extent it is successful in reducing the market impact of outages, it should reduce the cost of risk management contracts for market participants.

If well designed, it should be predictable and within the control of TNSPs. As with a notification incentive it does not initially rate well against the target setting criterion but may perform strongly in this regard as the relevant dataset grows. As MT PASA does not currently calculate or publish a formal regional reserve margin, historical data for the proposed reserve-based metric is not readily available to set an initial target. TNSPs have

suggested an initial reporting-only or shadow period to establish an evidence-based baseline before financial incentives apply to address the lack of historical data, this also needs to recognise that the MT PASA currently does not allow for reserves to be determined.

MT PASA information may assist in identifying periods of tighter supply, elevated reliability risk or network limitations. As with the notification incentive, ideally outages that have little or no market impact should be filtered out. The risk is that the scheme rewards TNSPs for scheduling outages based on MT PASA indicators where those for outages would have had limited market impact. Given that most outages are not likely to have an impact, a lack of filtering could dilute or render the scheme ineffective for the relatively few outages that do have a major impact.

The assessment of the scheduling incentive option can be summarised as follows:

- ***Effectiveness*:**
    - *Mitigating market impact:* This option should incentivise TNSPs to initially schedule outages to avoid or minimise market impacts. However, while it provides more certainty on the timing of an outage, it does not re-consider outage timing in response to updated information.
    - *Risk management:* Not effective to the extent that the option (by itself) does not incentivise notification.
    - *Measurable:* Largely measurable, provided appropriate metrics are available through the MT PASA analysis for this purpose. These metrics should be objective and observable.

- ***Implementation*:**
    - *Clear, predictable and stable?* Yes, as the target measure should be clearly specified and be stable over the regulatory period
    - *In TNSP's control?* Scheduling that is based on available market information is within the control of the TNSP. Forecast levels of reserve four months out is not currently available.
    - *Basis for setting performance target is robust?* Available information may not be available at this time to set robust targets given concerns over historical notification information and that forecast reserve information is not currently available. Although, an initial reporting-only period would largely address this concern.
    - *Simple to implement?* The option can be designed to be simple to administer.

Option 4: MMI outage management incentive

This option would require TNSPs to develop a periodic outage management plan incorporating principles of good outage management (focusing on MMI outages). TNSP performance would then be assessed against the outage management plan, with financial incentives by including a margin above costs for good performance. The scheme would provide additional revenues to each TNSP to implement the plan, but the additional revenue (or part of the additional revenue) would not be retained if a TNSP did not deliver the plan or did not justify departures from the plan.

However, consistent with all the incentive-based options, target setting is difficult because there is limited relevant data. Further, incentives should be targeted at outages that could have a material impact on market participants to provide consumer benefits.

The option has the advantage of focusing on the ongoing management of outages after the initial scheduling of the outage and using an outage management plan to guide how those outages are identified, assessed, managed and reassessed including measures to avoid or mitigate the impact of outages on market participants. However, the issue with developing a metric or approach for identifying MMI outages remains a challenge to all options intending to target MMI outages. As with the notification and scheduling incentive schemes the option, depending on its design, may only cover a subset of good outage planning and management practices.

Transgrid and ElectraNet do not support this option on the basis that:

- The proposal would create significant administrative complexity by requiring TNSPs to prepare detailed outage management plans for each MMI outage, including estimating the cost of mitigation measures and assessing those costs against expected market benefits. These plans would then need to be assessed by the AER, potentially involving multiple rounds of review and feedback. This is likely to increase operating costs significantly and extend project lead times.

- The assessment of TNSP performance under this option appears to involve a high degree of discretion, particularly in determining how effectively outage management plans have been delivered. This may create uncertainty and inconsistency around the AER's expectations and weaken the effectiveness of the incentive framework.

- The re-assessment, cancellation and re-scheduling aspects of this option also appear to conflict with Option 2, similar to the issues identified in relation to Option 1c.

Transgrid suggested an alternative approach in the form of an incentive scheme based on the proportion of MMI outages avoided through in-service (e.g. live line) work, to address the abovementioned shortcomings of this option.

The assessment of the MMI outage management incentive option can be summarised as follows:

- ***Effectiveness*:**
    - Mitigating market impact: This option should be effective in mitigating market impact as it provides additional efficient allowances and financial incentives by including a margin above costs for good practices. The option focuses on practices to limit market impact when an MMI is expected. Its effectiveness would depend on how MMI outages are identified, how performance is measured, and whether the relevant practices are foreseeable, and within the TNSP's reasonable control. This option may also include 'proceeding criteria' (an outage will only proceed if criteria are met and will not proceed if criteria are not met to account for changes in the market conditions). However, care would be needed in designing any proceeding criteria, as a fixed proceed or cancel threshold may not provide certainty in all circumstances, particularly

where conditions are close to the threshold or where the consequences of rescheduling depend on outage location, work stage, recall capability or broader operational impacts. This provides incentives for efficient and market focused scheduling and re-scheduling. This option provides more flexibility for the TNSP to respond to expected changes in market conditions than the scheduling incentive (option 3), but risks increasing hedging complexity and costs for market participants. The uncertainty introduced by the ex-post review may also introduce conservatism in decision making which could reduce the ability of the mechanism to materially mitigate the market impact.

- *Risk management:* The effectiveness of this option depends on the outage management plan (and the principles embedded in it). If notification requirements form part of an outage management plan the option should be effective in improving notification outcomes. However, this would depend on how the plan is implemented and whether it provides participants with timely and useful information without creating additional uncertainty about whether outages will proceed.
- *Measurable:* Partially measurable. Mitigation costs and plan delivery can be quantified, but assessment of performance against the outage management plan relies substantially on ex-post qualitative judgement, reducing the objectivity of the outcome measure. Additionally, the longer ahead of time the plan is submitted/published the less likely it is to reflect operational requirements or the costs of implementation.

- ***Implementation*:**
  - *Clear, predictable and stable?* To be fully effective, this option requires that MMIs can be reasonably identified ex-ante to inform an outage management plan to 'set targets,' and actions to avoid or mitigate market impacts. As noted by TNSPs, identifying MMIs ahead of time may be difficult. But reporting should highlight where MMI outages were not included in the scheme to provide a feedback loop. This is similar to how a 'reporting only' period in options 2 and 3 could gradually develop an appropriate baseline This option also requires ex-post review of events which introduces inherent uncertainty in ex ante decision making, reducing clarity and predictability of the mechanism.
  - *Basis for setting performance target is robust?* Performance outcomes are set in the management plan and would be reviewed by the AER. However, assessment of performance would be undertaken ex-post and is likely to involve a degree of judgement. At least initially, the approach could create some uncertainty for the TNSPs about likely outcomes, potentially diluting the TNSPs' incentives to implement good outage planning and management practices. This suggests a degree of discretion should be applied by the AER to minimise undesirable financial penalties, or a staging approach may be needed to learn from and fine-tune the scheme.
  - *In the TNSP's control?* The MMI outage management incentive is within the TNSPs control, with this element decreasing in effectiveness with increasing AER discretion in the ex-post review process. The scheme would therefore need to distinguish between matters the TNSP could reasonably foresee and manage, and outcomes arising from changing market or system conditions, or regulatory decisions, that are outside the TNSP's control.

- *Simple to administer?* The scheme is more complex to administer than options 1, 2 and 3. It requires development of a detailed plan and provision of detailed information by the TNSPs and a detailed assessment by the AER. Further, information on MMIs and expenditure in the outage management plan may need to evolve by updating the outage management plan, say every two years, to ensure it is sustainable over time.

Option 5: Conduct-based obligation

A conduct obligation should be effective in promoting good outage management practices. The threat of action, combined with transparency about TNSP practices, should provide incentives for TNSPs to adopt the principles of good outage planning and management. Further, as with the transparency and incentive scheme options, the information collected as part of the AER's monitoring of conduct could be used to provide further opportunities to enhance incentive schemes.

The CEC submitted that a conduct provision has limitations. In particular, time delays involved in taking enforcement action could also delay the impact of the obligation on TNSP practices.

The outcomes of the AER's assessment of TNSP performance would be ex-post with the outcomes not known until the assessment has been made. While a conduct obligation would set out principles of good practice, the principles are necessarily relatively high level and may be subject to some interpretation.

A key disadvantage of a conduct obligation is that it is not readily implementable given the need to undertake a rule change process for an entirely new requirement, and then subsequently develop an AER guideline, including, further work to define the obligation, the events to which it applies, and the framework for assessing compliance. The principles of good practice set out in a conduct provision can be monitored, reported on, and acted on where appropriate but this would require a new, material administrative burden placed on both TNSPs and the AER.

The assessment of the conduct-based option can be summarised as follows:

- ***Effectiveness*:**
  - *Mitigating market impact:* This option may be effective in mitigating the market impact of outages, in that it covers a broad range of outage management practices but only if the threat of action is real. This is balanced against the risk that a conduct obligation directs TNSP effort towards demonstrating compliance with administrative criteria, rather than towards the outcomes of most concern. Because the obligation applies to a broad range of matters rather than remaining focused on MMI outages, effort may be diluted across many low-impact events instead of concentrated on the outages that genuinely affect market outcomes.
  - *Risk management*: As notification would be one of the measures targeted, this option should improve the scope for participants to manage the impact of outages through contracting to the extent that this mechanism does not also contemplate late re-assessment of outages.

- *Measurable.* Not measurable. Compliance turns on whether the TNSP "ought reasonably to have known" of a likely impact and whether a "materially better" alternative existed – predictive, counterfactual assessments that are inherently judgement-based rather than objectively measurable.

- ***Implementation*:**
  - *Clear, predictable and stable?* The principles underlying a conduct provision may be clearly stated, but this would require considerable effort to define the relevant obligations, information requirements, applicable outages and supporting guidance. The option will be less predictable for TNSPs than a notification or scheduling incentive scheme because assessment of performance would be undertaken ex-post. A principles-based conduct obligation is likely to be sustainable over time.
  - *In TNSP's control?* A conduct obligation would be within a TNSPs control as the core obligations (possibly supplemented by a guideline) are within a TNSP's control. A conduct obligation would specify circumstances where 'events' are outside a TNSPs control.
  - *Basis for setting performance target is robust?* As with the MMI outage management incentive, the performance targets are principles based. The assessment of performance would be undertaken ex-post and is likely to involve a degree of judgement.
  - *Simple to implement?* The scheme may be more complex to administer than option 1 (transparency), option 2 (notification incentive) and option 3 (scheduling incentive). At times it will involve provision of detailed information by the TNSPs and a detailed assessment by the AER.

Glossary

Term	Definition
AER	Australian Energy Regulator.
AEMO	Australian Energy Market Operator.
AEMC	Australian Energy Market Commission.
CIR	Congestion Information Resource.
Conduct obligation	a rule-based obligation requiring TNSPs to have regard to specified matters and avoid or minimise material market impacts where a reasonably practicable and materially better alternative is available.
Forecast uncertainty measure	AEMO measure of forecast uncertainty for weather-dependent generation, expressed in MW terms.
MAR	Maximum allowed revenue.
Material market impact (MMI)	a reasonably likely material effect on wholesale market outcomes arising from a planned network outage, assessed by reference to matters such as interconnector capability, major flow paths, dispatchable or firm capacity, REZ access, reserve conditions, binding constraints, price separation and affected load or generation.
MIC	Market Impact Component of the STPIS.
MT PASA	Medium-term Projected Assessment of System Adequacy.
NOS	Network Outage Schedule.
NSCAS	Network Support and Control Ancillary Services.
Outage Management Plan	the planning document under Option 4 that identifies MMI outages, mitigation measures, proceeding criteria, recall arrangements, costs and reporting commitments.
PASA	Projected Assessment of System Adequacy.
PPA	Power purchasing agreement
REZ	Renewable Energy Zone.
ST PASA	Short-term Projected Assessment of System Adequacy.
STPIS	Service Target Performance Incentive Scheme.
Incentive-only scheme	the asymmetric incentive, outage management scheme and straw-person scheme discussed by the working group, under which a TNSP may retain an allowance or receive a reward where it delivers an approved Outage Management Plan or reasonably explains departures.
TNSP	Transmission Network Service Provider.
VRE	Variable renewable energy.

Attachment A: Network Impact Working Group – Terms of Reference

1. Background

The Service Target Performance Incentive Scheme (STPIS) is an important regulatory mechanism that provides incentives for transmission network service providers (TNSPs) to:

- schedule outages at times which minimise the impact on wholesale market outcomes: the market impact component (MIC)
- undertake low-cost projects which improve the capability of the existing network: the network capability component (NCC) and
- reduce the number and duration of unplanned outages: the service component (SC).

1.1. The Transmission STPIS review

In April 2023, the AER completed a review of all of the incentive schemes that it applies to network service providers. The review found that whilst the SC remains fit for purpose, the MIC and NCC were not working as intended. The AER committed to commencing a review of the transmission STPIS at the end of 2023.

On 17 April 2025, the AER published STPIS version 6, incorporating the final amendments, and an accompanying Explanatory Statement.

Our final amendments implemented in version 6 of the STPIS:

- suspend the MIC and explore developing an effective alternative by establishing a working group with AEMO and key stakeholders
- amend the NCC to make it a more streamlined process and improve incentives; and
- amend the loss of supply event frequency parameter of the SC.

The AER suspended the MIC of the STPIS as there is consensus that in recent years, with changes in the generation mix and more regionally dispersed renewable generation, this component of the STPIS is no longer working as intended (see section 2.2 of the final Explanatory Statement).

However, we recognised the need to ensure that the TNSPs are operating their networks to minimise the impact on wholesale prices. As discussed in our Explanatory Statement, we have established a working group to consider alternative incentive arrangements in the absence of the MIC and to consider an approach for developing a conduct obligation. The establishment of a working group provides the opportunity to further consider potential options that build on the findings of the STPIS Review to promote the efficient management of network outages. The considerations of the working group also align with the recommendation from the recent 'National Electricity Market wholesale market settings review' to consider stronger incentives for TNSPs to consider wholesale market effects from outage planning.

2. Objectives and role of the working group

The Network Market Impact Working Group (NMIWG) will:

- consider alternative options for an improved incentive mechanism that minimise the impact of network outages on wholesale market prices.
- explore the introduction and consider the form of a conduct obligation on TNSPs to minimise the impact of network outages on wholesale market prices.
- provide views on a preferred solution(s) for AER consideration.

Participation is expected to include:

.1. sharing information between NMIWG members

.2. collection and provision of data by members and analysis of data, and testing ideas

.3. providing feedback and insights on identified options

.4. providing input and advice on any working group papers

.5. providing advice on data quality; and

.6. any implementation issues associated with identified options.

- To assist the NMIWG, the AER will prepare and circulate before the inaugural meeting of the NMIWG:
  - a refresh of the alternative options that were canvassed and consulted on during the recent transmission STPIS Review; and
  - other potential approaches identified by AER staff that may warrant exploration by the NMIWG.

3. Key Deliverables and timing

The key deliverables are outlined below.

3.1. Market Impact Options Report

- The NMIWG's task will be to provide input and feedback for the purposes of considering alternative incentive-based options to the MIC and a form of conduct obligation. This input and feedback will be considered by the AER to develop a 'Market Impact Options Report' (referred to as the Report). The NMIWG is also expected to provide feedback on data quality and implementation issues associated with identified options.
- The Report will be distributed to the NMIWG for feedback, including on any preferred option or options.
- The Report is expected to be completed by no later than quarter 4 in 2025-26. This Report may be published on the AER's website.
- The AER will be informed by the views of the NMIWG. If the AER identifies a preferred alternative option to replace the MIC, this will form the basis of further stakeholder consultation for the purposes of a future STPIS Review.

The AER will also consider any views of the NMIWG on the form of any conduct obligation for the purposes of any potential changes to the National Electricity Rules.

4. Governance

The NMIWG will provide important feedback and advice to the AER on the development of an alternative MIC and form of a conduct obligation. While the AER will be informed by the outcomes of the NMIWG, the AER is responsible for making decisions on any proposed

preferred approach on incentives that will be part of a future STPIS, and this will be made clear in any public reporting on this process.

NMIWG meetings will be separated between meetings focused on an alternative to the MIC and the form of a potential conduct obligation and the sequencing of these meetings will be determined during the process.

Where there is a general consensus among members, this will be recorded by the Secretariat.

- The NMIWG will operate under the guidance of this Terms of Reference document and will remain in existence until the Report is completed.

5. Chair and Secretariat services

The NMIWG is to be chaired by the AER. The Secretariat function will be filled by the AER. This includes:

- the distribution of the agenda and relevant meeting papers
- recording and distribution of action items and the meeting schedule.

The AER will distribute the agenda one week prior to each meeting and distribute action items in advance of each meeting.

6. Membership

6.1. Membership

Membership of the NMIWG is limited to a reasonable size to allow for the efficient and focused sharing of information and discussion. The NMIWG will include representatives of the AER, AEMO, AEMC, TNSPs, generators and consumers.

A single representative for each member organisation should be nominated to attend all meetings. If the nominated representative is unable to attend a meeting, they may send a proxy in their place, who should be informed of relevant details in advance.

The total number of non-AER members is 15. Membership of the NMIWG is detailed in Table 1 below.

Table 1: Network Market Impact Working Group Members

Organisation	Representative	Membership
Australian Energy Regulator		
Australian Energy Market Operator		2 Members
Australian Energy Market Commission		2 Members
VicGrid		1 Member
TNSPs	ElectraNet AusNet Services Powerlink	4 Members

Organisation	Representative	Membership
	Transgrid	
Generators	Clean Energy Council Shell Iberdrola EnergyAustralia	4 Members
Users	EUAA ECA	2 Members

6.2. Knowledge and skill requirements

The AER expects NMIWG members to have:

- sound knowledge of the operation of the National Electricity Market
- an understanding of the AER's role in relation to:

incentive-based regulation

compliance and enforcement.

6.3. Provision of data

NMIWG members should endeavour to meet any reasonable requests for data relevant to objectives of the NMIWG.

In the event that a member of the NMIWG identifies information or data that is considered to be confidential, the NMIWG member must not disclose this information or data outside the NMIWG.

7. Meetings

NMIWG meetings will be conducted on-line. The NMIWG will meet monthly for 1–2 hours but the timing of meetings may vary depending on need.

Additional out-of-session meetings or workshops may be scheduled with the agreement of the Chair and group consensus.

8. Expenses

The AER is not responsible for any expenses incurred by NMIWG members.

Attachment B: MMI outage management incentive scheme

This attachment sets out a simplified incentive scheme for planned outages that are reasonably expected to have a material market impact. It is intended to sit as an annexure to the Network Market Impact Options Report.

1. Purpose

The Incentive scheme would operate as an interim mechanism for planned outages that are reasonably expected to have a material market impact.

The scheme would not seek to prevent TNSPs from undertaking necessary planned outages. Planned outages are required for maintenance, augmentation, connection works, system security and the safe operation of the transmission network.

2. What the scheme does

The scheme should be kept simple. It would have four core elements:

- identify planned outages that are reasonably expected to have a material market impact
- require each TNSP to prepare an Outage Management Plan for those outages
- allow the TNSP to receive or retain an allowance if it broadly delivers the approved plan, or provides a reasonable explanation for any material departure; and
- require reporting of outcomes so the AER can assess performance, mitigation costs, market outcomes and the potential baseline for a future symmetrical incentive.

3. Material market impact outage filter

The scheme should not apply to all planned outages. It should apply only to planned outages that are reasonably expected to have a material market impact.

A planned outage may have a material market impact where it materially affects, or is reasonably expected to materially affect, one or more of the following:

- interconnector capability
- major transmission flow paths
- access to dispatchable or firm capacity
- REZ access or access to diversified generation
- regional price separation

- reserve conditions or forecast demand
- constraints that historically bind during high-price periods
- market concentration or access to competitive supply; or
- AEMO-identified system or market risks.

The filter should be practical. It should not require an exhaustive market modelling exercise for every planned outage. It should be capable of being refined over time as the AER, AEMO, TNSPs and market participants obtain better information about which outages have material market consequences.

4. Outage Management Plan

Each TNSP would prepare an Outage Management Plan for the relevant period (this could be on an annual basis). Under the proposal, the plan would identify the material market impact outages expected during that period and how the TNSP proposes to manage those outages.

The plan should identify:

- the planned outages expected to have a material market impact
- the proposed mitigation measures
- any recall, suspension or shorter-window arrangements
- the inclusion of proceeding criteria (an outage will only proceed if criteria are met - to account for changes in the market conditions and also provide certainty to participants - and will not proceed if they are not)
- coordination with outages of other relevant TNSP equipment and, where relevant, neighbouring TNSPs
- any proposed NSCAS or other market-facing mitigation measure
- the expected efficient costs of mitigation; and
- the reporting commitments that will allow the AER to assess outcomes and develop a future baseline.

5. Financial treatment

The AER would assess the Outage Management Plan and approve an allowance for efficient mitigation measures. The allowance may include a small margin above the efficient costs as an incentive to develop innovative work practices to reduce the market impact of the network outages.

The TNSP would retain the allowance if it broadly delivers the approved plan or provides a reasonable explanation for any material departure. Broad delivery should mean substantial

delivery, not perfect delivery. A TNSP should not lose the allowance merely because circumstances changed or because a reasonable departure from the plan was required.

If the TNSP materially fails to deliver the approved plan without reasonable explanation, it would not retain the allowance or would retain only part of it. This is why the scheme is not simply a bonus scheme. The incentive is conditional on the TNSP delivering, or reasonably explaining departures from, the approved outage management approach.

The scheme should also preserve consumer benefit discipline. Mitigation costs should be approved only where they are prudent and efficient, and where the expected market benefit of mitigation is likely to justify the cost.

The inclusion of a margin above efficient costs, and how that margin aligns with beneficial consumer outcomes, will be a core consideration for this mechanism. Absent a margin, this mechanism acts more as a cost-of-service regulatory mechanism, where TNSPs are only allowed recovery of efficient operating costs, rather than an incentive to optimise outcomes within the TNSP's control. Further, any uncertainty introduced via the ex-post review will likely drive conservatism in applying this mechanism as TNSP's risk losing the allowance, with no related upside, given it would only be cost recovery-based.

6. Transparency and learning

The reporting framework should be detailed enough to allow the AER, market participants and consumers to understand how TNSPs are identifying, planning, managing and reviewing material market impact outages.

Reporting should cover, at a minimum, whether the outage was classified as a material market impact outage, the basis for that classification, whether the outage proceeded as planned, whether proceeding criteria were met, mitigation measures adopted, recall or suspension arrangements, reasons for any material departure from the plan, relevant market conditions and lessons learned. Reporting should also highlight where an outage occurred that contributed to a material market impact, but the outage was not considered in the scheme to provide a feedback loop to enhance the classification process.

The reporting framework should distinguish between information suitable for public reporting and information that should be provided confidentially to the AER. Public reporting should support market transparency and accountability. Confidential reporting may be appropriate for operational, security-sensitive, commercially sensitive or cost information.

Attachment C: Conduct-based obligation

This attachment outlines a possible conduct obligation for planned network outages that are likely to have a material market impact.

The attachment is not intended to be a complete form of conduct obligation. It sets out the core policy design, the role of the obligation, the matters a TNSP would be expected to consider, and the way the obligation could be supported by an AER guideline and transparency measures.

1. Purpose of the conduct obligation

The purpose of the conduct obligation is to require TNSPs, when planning and managing planned network outages, to have proper regard to foreseeable material market impacts where a reasonably practicable and materially better alternative is available.

The obligation would not prevent TNSPs from undertaking necessary planned outages. Planned outages remain necessary for maintenance, augmentation, connection works, system security, reliability, safety and prudent asset management.

The obligation would instead address a narrower concern: a planned outage may be timed, coordinated or managed in a way that materially affects the wholesale market, even though the TNSP does not bear the full market cost of that decision.

Participants discussed whether the obligation should be assessed by reference to information reasonably available to the TNSP at the relevant time. It should not operate as a hindsight assessment of spot price outcomes after the event.

2. Relationship with incentive schemes

The conduct obligation should be understood as a backstop or complement to the incentive scheme.

The conduct obligation would establish a minimum standard of conduct for TNSPs when planning and managing higher-impact outages.

The conduct obligation is suited to serious or clear failures to consider reasonably available information, reassess an outage, coordinate with relevant parties, or adopt a reasonably practicable and materially better alternative.

3. Why a conduct obligation may be needed

The suspension of the MIC has left a gap in the framework. TNSPs do not currently face a dedicated market-facing discipline directed to the wholesale market consequences of outage timing, coordination, recall and mitigation.

A conduct obligation can require TNSPs to have regard to specified information, consider reasonably practicable alternatives, reassess outages as circumstances change, and retain records of their reasoning.

The obligation should not make TNSPs responsible for wholesale market outcomes outside their control. It should focus on whether the TNSP made a reasonable and properly informed decision, having regard to the information available at the time.

4. Core design

The conduct obligation would apply to planned network outages that are likely to have a material adverse wholesale market impact, as determined by reference to criteria or thresholds in an AER guideline.

The obligation would prohibit a TNSP from scheduling, managing, coordinating, postponing, cancelling or rescheduling a planned network outage in circumstances where there are material and foreseeable risks of:

- adverse wholesale market impacts, including materially higher dispatch costs or adverse impacts on spot prices and ancillary service prices)
- reduced reliability of important parts of the transmission system at times that are of most value to consumers; and
- the likelihood of increased costs to consumers.

The obligation should be framed as a firmer standard than a mere reasonable endeavours obligation. A reasonable endeavours formulation may be too soft, because it may only require evidence that the TNSP turned its mind to the issue. The obligation should require the TNSP to consider whether a materially better and reasonably practicable alternative is available. One possibility might be to restrict the obligation to MMIs to avoid introducing additional complexity and increased operating costs for a large number of outages which have no material market impact.

However, the obligation should not be absolute. It should be subject to clear carve-outs for safety, power system security, reliability, AEMO directions, legal obligations, asset condition risk, defect risk and other operational circumstances identified in the guideline.

5. Material adverse wholesale market impact

The Rules should define the concept of material adverse wholesale market impact at a high level. The detailed criteria, thresholds, indicators and examples should sit in an AER guideline.

This hybrid model was discussed as potentially preferable to hard-coding detailed thresholds in the Rules. The subject matter is technical, changing and likely to require refinement as the AER, AEMO, TNSPs and market participants gain more experience with MMI outage identification. The trade-off with this approach is reducing clarity, predictability and transparency compared to setting defined criteria in the NER.

A material adverse wholesale market impact may include one or more of the following effects:

- increased wholesale spot prices;

- increased ancillary service prices;
- inefficient dispatch outcomes or binding constraints;
- reduced reliability of transmission elements that are important to determining spot prices;
- reduced reliability at times when users place greatest value on reliability; or
- increased costs to consumers through adverse effects in the NEM.

The obligation should not depend solely on a single ex post price threshold. Price thresholds may assist as indicators or reporting triggers, but they may be both under-inclusive and over-inclusive if used as the sole legal test.

6. Matters the TNSP should consider

In planning and managing a likely MMI outage, a TNSP should be required to have regard to the AER guideline and to reasonably available market, operational and system information.

The matters to be considered should include:

- medium-term PASA, short-term PASA, reserve information, pre-dispatch information, AEMO forecasts, AEMO advice and other reasonably available market information;
- forecast demand, generator availability, VRE output, interconnector capability, minimum system load, reserve conditions and other concurrent outages;
- alternative timing, outage windows, duration, recall arrangements, daily suspension or other contingencies;
- coordination with AEMO, neighbouring TNSPs and related planned outages on common flow paths or interconnectors;
- outage management practices that could avoid or reduce the likelihood or extent of a material market impact, including live-line work, after-hours work, shorter outage windows, resequencing, additional resourcing, NSCAS or other mitigation measures; and
- whether the expected market benefit of a mitigation measure is likely to justify its efficient cost.

The obligation should not require TNSPs to undertake exhaustive market modelling for every planned outage. It should require a practical and proportionate assessment, directed to outages that may have material market consequences.

7. Reassessment and record-keeping

The obligation should extend beyond the initial scheduling decision. Market conditions can change materially between the time an outage is first notified and the time it is due to proceed.

A TNSP should therefore be required to reassess a likely MMI outage sufficiently before its scheduled date and upon any material change in market conditions or other relevant circumstances.

The reassessment should consider whether the outage should proceed as planned, be postponed, rescheduled, cancelled, shortened, placed on recall, temporarily suspended or otherwise modified.

The TNSP should make and retain written records of:

- the information considered
- the alternatives considered
- the mitigation measures considered and adopted
- the reasons for proceeding, rescheduling, modifying or cancelling the outage
- why any reasonably practicable alternative was not adopted; and
- why the TNSP considered that proceeding would not breach the conduct obligation.

The records should be retained for a defined period, for example five years. This would support compliance oversight, transparency, learning and any future incentive design.

8. Carve-outs and safeguards

The obligation should include clear carve-outs so that it does not interfere with safety, power system security, reliability, AEMO directions or necessary network works.

The obligation should not apply where proceeding with the outage in the manner proposed is necessary to maintain or restore safety, power system security or reliability.

The obligation should also not require deferral, rescheduling, resequencing, cancellation or modification where doing so would:

- materially prejudice the safe, timely or effective carrying out of the works
- materially increase asset condition risk or defect risk
- prevent compliance with a legal obligation, jurisdictional electricity legislation, the Rules or an AEMO direction; or
- give rise to other operational circumstances identified in the AER guideline.

Participants discussed the importance of these safeguards. They make clear that the obligation is not a prohibition on outages with market effects. It is a requirement to consider and adopt a reasonably practicable and materially better alternative where one is available and, where doing so is consistent with safety, reliability, system security and prudent asset management.

9. Role of the AER guideline

The conduct obligation should be supported by a Planned Outage Market Impact Guideline made by the AER under the transmission consultation procedures.

The guideline would specify the criteria, thresholds, principles, methodologies, indicators and examples relevant to determining whether a planned network outage is likely to have a material adverse wholesale market impact.

The guideline may distinguish between different classes of planned outages, network elements, regions, interconnectors, flow paths, market conditions and system conditions.

The guideline may also specify how forecast information, reserve information, outage interactions, AEMO advice and other market data should be taken into account, and how reassessment should occur as circumstances change.

The guideline should be flexible enough to evolve as the NEM changes. It should also be sufficiently clear to give TNSPs, AEMO, market participants and the AER a common framework for identifying and assessing likely MMI outages.

10. Transparency measures

Participants discussed whether the conduct obligation could be supported by targeted transparency measures. Transparency would also support incentive scheme development.

Public reporting should be balanced against confidentiality, system security and operational sensitivity. Some information may be suitable for public disclosure, while more detailed operational or cost information may need to be provided confidentially to the AER.

11. Enforcement and consequences

The conduct obligation should be framed so that it is capable of being enforced.

A contravention may require proof that the TNSP knew, or ought reasonably to have known, that the outage was likely to have a material adverse wholesale market impact, and that a reasonably practicable and materially better alternative was available at the time.

That inquiry is likely to involve predictive judgments, counterfactual analysis, operational evidence and competing considerations including safety, reliability, asset condition, contractor availability and system security.

Participants expressed different views on the implications of those enforcement difficulties. They indicate that the obligation should be clear, supported by a guideline, and reinforced by record-keeping and transparency. Some participants considered that its practical value may lie in shaping TNSP conduct in the shadow of enforcement, rather than in frequent litigation.

If pursued, the obligation could be framed for possible prescription as a civil penalty provision.

12. Indicative rule structure

The rule package could have the following structure:

- a Chapter 10 definition of Planned Outage Market Impact Guideline

- a Chapter 10 definition of material adverse wholesale market impact
- a Chapter 5 conduct obligation applying to planned network events likely to have a material adverse wholesale market impact
- requirements to consider specified information, alternatives, coordination, mitigation measures and duration
- a reassessment obligation
- record-keeping and record-retention requirements
- carve-outs for safety, system security, reliability, asset risk, legal obligations, AEMO directions and other specified circumstances
- a guideline-making clause requiring the AER to develop and maintain the Planned Outage Market Impact Guideline; and
- optional transparency amendments through the Transmission Annual Planning Report and/or congestion information resource.

13. Conclusion

The obligation should be targeted, practical and supported by a guideline. It should focus on matters within TNSP control: the information considered, alternatives assessed, coordination undertaken, mitigation measures considered, reassessment conducted and reasons recorded.

The obligation should not make TNSPs responsible for wholesale market outcomes outside their control. Nor should it prevent necessary planned outages. Its role is to ensure that, where a reasonably practicable and materially better alternative is available, TNSPs have a clear obligation to consider and adopt it unless there is a sound operational, safety, reliability, system security or AEMO-related reason not to do so.

Some participants discussed the conduct obligation as a possible backstop or complement to an incentive-based mechanism.

Attachment D: Combined outage planning incentive scheme

This attachment sets out a simplified combined incentive scheme for planned outages that are reasonably expected to have a material market impact. It is intended to sit as an annexure to the Network Market Impact Options Report.

1. Purpose

The combined outage planning incentive scheme would operate as a staged mechanism for planned outages that are reasonably expected to have a material market impact.

The scheme is intended to encourage TNSPs to plan and manage outages in a way that:

- provides sufficient advance notice to market participants;
- schedules outages having regard to forecast market and system conditions;
- supports coordination with AEMO and, where relevant, neighbouring TNSPs;
- focuses effort on outages that are most likely to matter for consumers and market participants; and
- avoids making TNSPs responsible for wholesale market outcomes outside their control.

The scheme would not prevent TNSPs from undertaking necessary planned outages. Planned outages remain required for maintenance, augmentation, connection works, system security, reliability, safety and prudent asset management.

The scheme would instead provide a financial incentive for TNSPs to meet objective outage planning and scheduling criteria, while recognising circumstances outside the TNSP's reasonable control.

2. What the scheme does

The scheme should be kept practical, measurable and capable of staged implementation. It would have five core elements:

1. identify planned outages that are reasonably expected to have a material market impact;
2. assess those outages against a small number of objective planning criteria;
3. exclude outage hours where specified exemption circumstances apply;
4. calculate performance using a transparent metric based on non-compliant outage hours; and
5. apply a reward or penalty, bounded by the revenue at risk under the STPIS.

The combined scheme brings together the key elements of Options 1, 2 and 3. Transparency provides the data layer. The notification incentive provides certainty to market participants. The scheduling incentive encourages TNSPs to consider forecast system conditions when selecting outage timing.

Assessed separately, these options each have limitations. Combined, the components are complementary. The notification component addresses market participant risk management, the reserve/scheduling component addresses foreseeable market conditions, and the transparency component provides the reporting and data needed to verify performance and set future targets.

3. Material market impact outage filter

The scheme would not apply to all planned outages. It would apply only to planned outages that are reasonably expected to have a material market impact.

For an initial implementation period, the scheme could use AEMO's existing High Impact Outage list as a practical starting point for identifying in-scope outages. This approach would avoid the need to develop a new bespoke MMI classification process before the scheme commences.

Over time, the MMI filter could be refined using additional information, including:

- AEMO's analysis of constraints with a propensity to bind during outages;
- historical constraint binding frequency;
- historical shadow price or market impact data;
- regional reserve conditions;
- interconnector and major flow path significance; and
- reported outcomes from the initial implementation period.

This staged approach would allow the scheme to commence using a practical and available filter, while preserving the ability to refine the scope as better information becomes available.

4. Assessment criteria

For each planned outage on an in-scope MMI element, performance would be assessed against a three-gate test.

The gates would be:

1. **Advance notification**
   The outage is submitted to the Network Outage Scheduler at least 120 calendar days before the planned commencement date.

2. **AEMO outage assessment**
   AEMO has provided a Medium Term Likely to Proceed status, or equivalent medium-term assessment outcome, within an agreed timeframe. If AEMO does not assess the

outage within the agreed timeframe, this gate would be deemed satisfied for the purpose of the scheme, unless the delay was caused by the TNSP.

3. **Forecast reserve adequacy**
   At the time of outage submission, forecast reserve conditions for the relevant region and outage period exceed an agreed threshold.

For the reserve adequacy gate, an indicative reserve surplus could be derived from published MT PASA information, such as aggregate PASA availability less forecast regional demand. AEMO publishing a standardised reserve measure would improve transparency and consistency, but the underlying data required for an indicative measure is already available from MT PASA outputs.

The reserve threshold would need to be developed through consultation and tested during an initial reporting-only period. It could be expressed as a fixed MW threshold, a percentage of forecast demand, or a threshold based on the capacity of the largest credible generation contingencies in the relevant region.

5. Non-compliance metric

The scheme would measure performance by reference to the proportion of in-scope outage hours that fail one or more of the assessment criteria, after applying exemptions.

The performance metric would be:

- Non-compliance rate = Non-compliant MMI outage hours / TNSP-controllable MMI outage hours

Where:

- Non-compliant MMI outage hours are outage hours on in-scope MMI elements where one or more gates are not met and no exemption applies.
- TNSP-controllable MMI outage hours are total MMI outage hours less exempt outage hours.

This percentage-based approach normalises for differences in the volume of MMI outage work across years and across TNSPs. It avoids penalising a TNSP simply because it has a larger planned works programme, while still maintaining incentives to minimise the proportion of MMI outage hours that are poorly planned or insufficiently supported by forecast market conditions.

6. Exemptions

The scheme would exclude outage hours from the non-compliance calculation where the outage outcome is materially affected by circumstances outside the TNSP's reasonable control.

Potential exemption categories include:

- AEMO cancellation, deferral or refusal to provide permission to proceed;
- customer-initiated changes to outage timing;

- adverse weather or unsafe site conditions;
- urgent defects or safety-related works;
- latent site conditions requiring late engineering or work method changes;
- supply chain delays;
- contractor availability changes outside the TNSP's control;
- AEMO directions or system security requirements;
- legal, environmental or jurisdictional obligations; and
- circumstances where proceeding, deferring or modifying the outage would materially increase safety, reliability, system security or asset condition risk.

Exemptions should be supported by evidence and assessed as part of the annual compliance process. Exempt outage hours would be removed from both the numerator and denominator of the non-compliance rate.

7. Financial treatment

The scheme would apply a financial reward or penalty based on performance against an ex-ante target.

The target would be set as a target non-compliance rate, based on historical data or data collected during an initial reporting-only period.

The incentive rate would be calculated as:

Incentive rate = revenue at risk / target non-compliance rate

The annual incentive outcome would then be calculated as:

Incentive = (target non-compliance rate – actual non-compliance rate) x incentive rate

The incentive would be bounded by the revenue at risk under the STPIS.

For example, if the revenue at risk is ±1 per cent of MAR and the target non-compliance rate is 10 per cent:

- if the actual non-compliance rate is 5 per cent, the TNSP would receive a reward of +0.5 per cent of MAR;
- if the actual non-compliance rate is 10 per cent, the TNSP would receive no reward or penalty;
- if the actual non-compliance rate is 15 per cent, the TNSP would receive a penalty of -0.5 per cent of MAR; and
- if the actual non-compliance rate is 20 per cent or higher, the penalty would be capped at -1 per cent of MAR.

This approach is intended to be transparent and similar in structure to other STPIS parameters, where a target is set and rewards or penalties are applied for outperformance or underperformance.

8. Staged implementation

The scheme could be implemented in phases.

Initial reporting-only phase

During the initial phase, TNSPs would report performance against the three-gate test, but no financial reward or penalty would apply. This would allow:

- testing of the MMI outage filter;
- testing of the reserve adequacy threshold;
- collection of baseline performance data;
- identification of data quality issues;
- development of exemption evidence standards; and
- assessment of the administrative burden.

Reward-only phase

Following the reporting-only phase, the scheme could commence as an asymmetric reward-only incentive. This would recognise that the scheme is new, the data may still be developing, and the behavioural response is not yet proven.

Symmetric phase

Once a baseline has been established and the scheme has been tested, it could transition to a symmetric reward and penalty mechanism. This would provide stronger incentives while reducing the risk of arbitrary outcomes during the early years of implementation.

This staged approach reflects the historical development of the MIC and allows targets to be evidence-based rather than arbitrary.

9. Reporting and transparency

The scheme would require periodic reporting to support performance assessment and market transparency.

Reporting could include:

- the list of planned outages on in-scope MMI elements;
- the date each outage was first submitted to NOS;
- whether the outage satisfied the 120-day notice gate;
- whether AEMO provided MTLTP or equivalent medium-term assessment;

- the reserve adequacy assessment at the time of submission;
- whether any exemption was claimed;
- the basis for any exemption;
- whether the outage proceeded as planned, was deferred, modified, cancelled or rescheduled; and
- the resulting non-compliance calculation.

Public reporting should be balanced against operational, system security and commercially sensitive information. Summary information could be published, while more detailed evidence supporting exemptions could be provided confidentially to the AER.

10. Relationship to other options

The combined scheme is intended to address the limitations identified when Options 1, 2 and 3 are assessed in isolation.

A notification incentive improves certainty for market participants but does not, by itself, ensure that outages are scheduled at sensible times. A scheduling incentive encourages TNSPs to consider foreseeable market conditions but does not, by itself, provide sufficient certainty for market participants to manage risk. Transparency alone provides reputational incentives but does not create a direct financial reward or penalty.

Combining these components addresses these limitations. The notification component supports market participant risk management. The reserve/scheduling component discourages outages from being scheduled at times of foreseeable system tightness. The transparency component provides the information required to verify performance, set targets and refine the scheme over time.

The combined scheme also avoids a number of limitations associated with other options. Unlike an outage management plan allowance, it does not rely primarily on ex ante funding of mitigation costs or ex post assessment of whether a plan was delivered. Unlike a conduct obligation, it does not require a new rule-based compliance framework or broad ex post assessment of whether a TNSP should have identified a materially better alternative.

11. Residual issues

The combined scheme would still require design work before implementation. Key issues include:

- the initial MMI outage filter;
- whether AEMO’s HIO list is a suitable starting point;
- the reserve adequacy methodology;
- the initial target non-compliance rate;
- the appropriate revenue at risk;

- the exemption categories and evidence requirements;
- the treatment of AEMO delays in providing medium-term outage assessment outcomes;
- whether performance should be assessed annually or over a longer averaging period; and
- the required NOS and MT PASA data archiving arrangements.

These are material design issues, but they are capable of resolution through an initial reporting-only phase and consultation with AEMO, TNSPs and market participants.

12. Conclusion

The combined outage planning incentive scheme provides a practical and staged approach to replacing the suspended MIC.

It focuses on objective and measurable behaviours that are largely within TNSP control: giving adequate notice, scheduling outages having regard to forecast reserve conditions, and maintaining transparent records of compliance and exemptions.

By combining notification, scheduling and transparency measures, the scheme addresses the main limitations of each option when assessed in isolation. It also provides a clearer and more measurable alternative to a conduct obligation, while remaining capable of implementation through the STPIS framework.

The scheme is therefore suitable for further development through baseline data collection, AEMO engagement and detailed design of the MMI outage filter, reserve threshold and exemption framework.