Electricity Transmission Network Service Providers

Service Target Performance Incentive Scheme

Final Amendments

Explanatory Statement

April 2025

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1 Summary

The service target performance incentive scheme (STPIS) was introduced to provide incentives for transmission network service providers (TNSPs) to improve their service standards. It provides incentives for TNSPs to reduce the number and duration of outages, improve network capability, and reduce the market impact of planned outages. It complements incentives for TNSPs to improve efficiency over time through the efficiency benefit sharing scheme (EBSS) and the capital expenditure sharing scheme (CESS).

Among other things, the principles of the STPIS are that it should provide incentives for a TNSP to: [1]

(i) 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; and

(ii) improve and maintain the reliability of those elements of the transmission system that are most important to determining spot prices.

This promotes the efficient investment in, and efficient operation and use of, network services in the long term interests of consumers.

Since it was introduced, the STPIS has driven substantial improvements in service standards. The number and duration of transmission outages have progressively fallen. And the network capability component (NCC) has encouraged low-cost projects to improve existing network capacity by over 8000 MW.

In April 2023, we completed a review of incentive schemes that we apply to network service providers. During this review, stakeholders raised concerns about whether the market impact component (MIC) and the NCC remain fit for purpose, and about how performance targets are set in the service component (SC). We consider that while the STPIS remains an important regulatory tool to ensure TNSPs are operating their networks in the best interests of market participants and consumers, these concerns are credible.

Much of the reason why the STPIS is no longer working as intended is due to the current energy transition, which is changing the way electricity is generated and transported. When the STPIS was introduced in 2007, over 80% of electricity was generated using fossil fuels. Now renewables make up around 40% of output and 60% of generation capacity.[2] This move from more centrally located thermal generation to more geographically dispersed and weather dependent fuel sources creates new demands on the transmission network and has implications for how TNSPs manage their assets.

1 NER, cl 6A.7.4(b)(1).

2 Data is for 2023-24: see AER, *State of the Energy Market 2024*, pp. 35 and 36.

Changes to the STPIS are required to accommodate these developments. This Explanatory Statement sets out the reasons for the amendments we have made to the STPIS, and how we have taken stakeholder views into account.

1.1 Market Impact Component

In monitoring market outcomes after service standard incentives were introduced, we observed that planned outages scheduled during peak periods (for example in summer) could constrain off generators, forcing AEMO to dispatch more expensive alternatives. The market impact was often substantial. We were concerned that the increase in spot market prices would flow through to contract prices and ultimately retail prices paid by households and businesses. In response, we analysed metrics of the market impact of transmission congestion and developed the MIC.

However, there is consensus that the MIC is no longer fit for purpose. High investment in renewables, increased congestion on radial lines, and more outages associated with high transmission investment, has contributed to a significant increase in the number of MIC events over the past five years. Now TNSPs often face maximum penalties regardless of their actions.

Most stakeholders want to replace the current MIC with a more effective variant based on financial incentives to drive the conduct and behaviour of TNSPs in planning outages. The MIC is currently no longer fit for purpose, and not providing the correct incentives. Accordingly, we have suspended the MIC, and will establish a working group to recommend alternatives to the MIC. The working group will also consider what other mechanisms might be appropriate to achieve the objective of the MIC, for example, imposing conduct obligations. The working group will report its findings to the AER for consideration. We intend to establish the working group as soon as practicable in 2025, with the aim of it providing recommendations to the AER in mid to late 2026. The working group will include representatives of AEMO, the AEMC, TNSPs, generators and consumers.

Consistent with our proposed amendments, we will also improve transparency about the TNSPs' planned outage management performance by collecting new data and reporting annually. We will focus on how TNSPs use demand and supply forecasts to schedule and reschedule outages. We will also assess planned outages that occur at times of extreme spot market prices.

1.2 Network Capability Component

The NCC provides an incentive to a TNSP to reveal the capability of parts of its existing network and to identify and implement measures that would provide greater value to generators and consumers. Specifically:

- Generators benefit from increased network capability as they are less likely to be constrained from dispatching generation by network limits, leading to more efficient generator dispatch in the market.
- Consumers benefit from the resulting lower wholesale costs and efficient improvements in network capability to meet increases in peak demand.

Since the NCC was introduced, consumers have funded around $180 million in expenditure across the TNSPs. The NCC so far has delivered around 100 projects that have improved network capability by over 8000 MW.

Given outcomes to date, the need to optimise network capability, and widespread support from stakeholders, we will retain the NCC. However, the NCC in its current form is administratively complex and under-utilised. We have therefore amended the NCC to reduce the administrative complexity and refine the incentives it provides. This should encourage increased use of the NCC.

TNSPs will no longer be required to submit a network capability incentive parameter action plan (NCIPAP) as part of their revenue proposal. Instead, TNSPs will now be required to identify projects from their transmission annual planning report (TAPR) that they propose to include in the NCC for our approval each year. Our amendments will:

- eliminate duplication of process between the NCIPAP and TAPR, thereby reducing costs to TNSPs of participating in the scheme
- improve flexibility by allowing TNSPs to propose projects annually (rather than every five years as part of a regulatory reset process)
- provide more certainty about incentive payments by removing the risk that TNSPs can be worse off by proposing NCC projects.

We will retain AEMO's role in reviewing the projects TNSPs propose to be subject to the NCC. As the independent planner, AEMO is well placed to review existing line and plant ratings and the proposed capability improvements which underpin the estimated benefits of proposed projects. AEMO's review is an important cross check on the TNSPs' proposals given the substantial incentive payments on offer.

We will also consult on NCC proposals and provide stakeholders with the opportunity to identify, test, and scrutinise projects proposed by a TNSP. While the TAPR is the primary mechanism for identifying NCC projects, stakeholders will be able to propose projects if they have raised the option with a TNSP and the TNSP has not adequately engaged with the proposal as part of its TAPR development process.

1.3 Service Component

The SC provides incentives for TNSPs to reduce the number and duration of interruptions of supply to consumers. For the most part the incentives have worked well with significant improvements in performance over time.

TNSPs asked us to review the loss of supply event frequency parameter in the SC. This parameter provides incentives for TNSPs to restore services quickly when an outage occurs. TNSPs raised concerns that the scheme can result in unreasonable performance targets. In setting a target we currently round the annual average number of events to the nearest whole number. This means that targets can be zero even if there were loss of supply events in the previous regulatory control period. For example, if a TNSP experiences two loss of supply events over a five-year regulatory control period, the average annual number of events is 0.4. This is then rounded down to zero. Powerlink and Transgrid have been penalised by rounding.

We have amended the SC by removing rounding to set targets for the loss of supply frequency parameter as a fraction of events.

1.4 Next steps

We will establish a working group to develop alternative options to the MIC for the AER's consideration. We are aiming to establish the working group as soon as practicable in 2025.

The STPIS can only be applied at the time we make a revenue determination for a TNSP.[3] This means that version 5 of the STPIS will continue to apply until the start of each TNSP's next regulatory control period unless the National Electricity Rules (NER) are changed.

Consistent with our November 2024 Explanatory Statement on our proposed amendments we will also submit a rule change proposal to the AEMC to afford us the discretion to apply an amended STPIS during a regulatory control period, rather than only being able to do so as part of a revenue determination. TNSPs, ENA, EUAA, and AEMO supported this proposal.

Importantly, the rule change would enable all market participants, including consumers, to reap the benefits of improvements to the NCC and the SC sooner than would have otherwise been the case. We have established that the MIC is no longer fit for purpose. The rule change would also allow for its immediate and simultaneous suspension across all TNSPs.

2 Final amendments

We have amended the MIC, NCC and SC components of the STPIS.

Market Impact Component

We have amended the STPIS to suspend the MIC. We will also:

- Explore developing an effective alternative to the MIC by:
  - establishing a working group with AEMO and key stakeholders to make recommendations for AER consideration on alternative incentives
  - considering a conduct obligation
  - consulting on a revised STPIS.
- Improve transparency by:
  - collecting new data from TNSPs on planned outage scheduling and rescheduling decisions
  - analysing planned outages that occur at the time of extreme spot market prices
  - reporting annually on the outage management performance of TNSPs, including data on the number of planned outages that occur at times of high spot market prices, the reasons for scheduling and rescheduling decisions taken at times of high price, and the outcomes of our analysis.

Network Capability Component

We have amended the NCC to no longer require TNSPs to submit a NCIPAP as part of their revenue proposal, but rather to require TNSPs to identify the projects in their TAPR that should be the subject of the NCC, for our approval, each year. Specifically:

- A TNSP can identify projects which:
  - are less than the RIT-T threshold (currently $8 million), and in aggregate (the total expenditure of all projects proposed for the NCC), less than 1 per cent of Maximum Allowed Revenue (MAR) in the relevant regulatory year
  - are selected on the basis of the ranking of projects in descending order of the likely benefits to consumers and on wholesale market outcomes
  - include project improvement targets.
- We must determine which projects identified by a TNSP are to be NCC projects, in consultation with stakeholders and AEMO.
- Approved NCC projects receive an incentive allowance of 1.5 times a priority project's proposed expenditure. Incentives are adjusted down by up to 1.5 times the amount of the proposed expenditure if improvement targets are not met. This means that TNSPs cannot be worse off by proposing NCC projects.
- A TNSP must provide us with information annually on progress of approved priority projects and costs incurred.

- We must publish progress of approved NCC projects, project costs incurred, and the incentive allowance paid to TNSPs (taking into account any reductions where project improvement targets are not met).

Service Component

We have amended the SC to remove rounding in setting targets for the loss of supply frequency parameter.

3 Background

3.1 STPIS review

In April 2023, we completed a review of the incentive schemes that we apply to regulated Network Service Providers (NSPs), which included the STPIS.[4] For the transmission STPIS, the final decision was to:

- review the MIC, which provides an incentive to TNSPs to minimise the impact of transmission outages on wholesale markets
- review the NCC, which provides incentive payments to TNSPs to undertake small, high net benefits projects, and
- retain the SC, which provides a reward or penalty based on the number of unplanned network outages and how quickly the TNSP restores them, as is.

In December 2023, we published an Issues Paper which identified shortcomings with the MIC and NCC – namely that the MIC is no longer fit for purpose and the NCC is administratively complex and under-utilised. We also broadened our review to cover target setting for elements of the SC. TNSPs were concerned that for the 'loss of supply event frequency' parameter in the SC targets have at times been set to zero, understating historic outcomes. This is an unintended consequence of the methodology used to set the performance target and can arbitrarily penalise TNSPs.

In November 2024, we published our proposed amendments to the STPIS and an Explanatory Statement. In December 2024, we held a public forum, and in February 2025 we received submissions in response to the proposed amendments.

This Explanatory Statement sets out our reasons, taking into account stakeholder feedback, for the amendments we have made to version 5 of the STPIS to prepare for version 6.

The STPIS can only be applied at the time we make a revenue determination for a TNSP.[5] This means that version 5 of the STPIS will continue to apply until the start of each TNSP's next regulatory control period unless the National Electricity Rules (NER) are changed.

3.2 Incentive regulation and the STPIS

We regulate TNSPs by setting revenue caps over a regulatory control period (typically five years). The revenue caps, amongst other things, reflect forecast expenditure requirements.

The regulatory framework set out in Chapter 6A of the NER provides incentives for TNSPs to spend less than the expenditure forecasts that we set in our revenue determinations. These incentives are strengthened by applying the EBSS and CESS. However, incentives to reduce expenditure run the risk of compromising service standards. This risk is addressed by providing countervailing incentives to maintain or improve service standards. These incentives complement minimum standards established by state based licencing

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4 AER, *Review of incentive schemes for networks, Final Decision*, April 2023.

5 NER, cl 6A.14.1(1)(iii).

requirements (e.g. jurisdictional planning standards such as N-1 network redundancy requirements).

Service standard incentives for TNSPs were first introduced in 2003 by the Australian Competition and Consumer Commission (ACCC).[6] The service standard incentives applied rewards and penalties for the number and duration of outages and formed the basis for the first version of the STPIS that we published in 2007.

In response to market outcomes, we have made important improvements to the STPIS since it was first introduced. In 2008 we included the MIC to provide TNSPs with financial rewards for scheduling planned outages at times that minimise the impact on the wholesale market. In 2015, we included penalties as well. In 2012, we introduced the NCC. The NCC provides incentives for TNSPs to undertake small capex projects that result in improvements to the existing transmission capacity.

3.3 Rule requirements

The NER requires us to develop and publish a transmission STPIS. The same framework that we applied to develop the STPIS applies to our review of the STPIS. Any changes we make to the STPIS must be done so in a manner that will or is likely to contribute to achieving the National Electricity Objective (NEO). We are also guided by the principles that the STPIS should amongst other things:[7]

- provide incentives for each TNSP 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
- result in a potential adjustment to the revenue that the TNSP may earn, from the provision of prescribed transmission services, in each regulatory year in respect of which the STPIS applies
- ensure that the maximum revenue increment or decrement as a result of the operation of the STPIS will fall within a range that is between 1 and 5 per cent of the maximum allowed revenue for the relevant regulatory year.

3.4 Stakeholder engagement

We received 12 submissions in response to our proposed amendments. We also held a stakeholder forum on 10 December 2024. In summary, stakeholders expressed:

- General support for better targeted incentive metrics given the MIC is not working as intended, and general support for the data collection and transparency measures we proposed.

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6 ACCC, Statement of principles for the regulation of transmission revenues: Service standards guidelines, 12 November 2003.

7 NER, cl 6A.7.4(b).

- Mixed support for suspending the MIC. While most TNSPs support suspension, other stakeholders support retaining the MIC until an alternative is developed.
- Limited support for introducing conduct obligations, on the basis that incentive mechanisms are likely to be more effective. The EUAA expressed support for conduct provisions as an interim measure while a new incentive scheme is developed.
- General support for our proposal to streamline the NCC by linking it to the TAPR. More specifically:
  - Some stakeholders want us to consult on NCC projects and to allow stakeholders to propose additional or alternative NCC projects.
  - There are mixed views on AEMO’s role in the NCC. Some generators want AEMO to review NCC projects. TNSPs argue that the review role is no longer necessary.
- General support for better aligning the incentive allowance and any reductions to the incentive allowance.
- General support for our proposed amendments to the SC.
- General support for a rule change to allow any new version of the STPIS to apply before the start of the next regulatory control period for each TNSP.

Appendix A provides a summary of submissions.

4 Market Impact Component

4.1 About the Market Impact Component

When established, the STPIS provided incentives to reduce the frequency and duration of interruptions to supply. However, it did not account for the market impact of outages. When transmission outages constrain off generators at times of peak demand, the impact on wholesale prices can be substantial.

The MIC aims to provide incentives for TNSPs to schedule planned outages at times which minimise the impact on spot market outcomes, which ultimately flow through to end consumers. Examples include encouraging TNSPs to schedule longer planned outages when seasonal demand is low (typically spring and autumn), shorter planned outages at times of the week and day when demand is low (such as weekends or overnight), and to alter practices where possible to allow for rapid return to service of equipment if market circumstances change.

The MIC works by identifying outages that require a network constraint to be invoked in AEMO's NEM Dispatch Engine (NEMDE).[8] Available AEMO data does not quantify the impact of constraints on regional wholesale prices. As a proxy for the impact, the MIC utilises published data on the marginal impact of network constraints.

The marginal impact of a constraint is calculated by considering the impact of relieving a constraint by a fraction of a MW. This constraint reduction allows the constrained off generators to be dispatched for that additional amount.

To measure the impact of constrained off generators, NEMDE calculates the change in the cost of dispatch, which in simple terms usually equates to the difference between the price bid in by the constrained off generators and the regional price (the marginal generator's bid). If, for example, generators behind the constraint bid -$1,000/MWh when the regional price is $100/MWh, then the marginal impact of the constraint is measured as $1,100/MWh.

The MIC identifies all the constraints that cause a marginal impact of $10/MWh or more in a dispatch interval. The AER sets a comparison point based on performance over the previous seven years. TNSPs receive financial incentives of up to one per cent of their MAR if there are fewer $10/MWh events in a year than the comparison point and are penalised by up to one per cent of the MAR if there are more $10/MWh events than the comparison point.

TNSPs can propose to us to exclude events from the performance results. There are 13 possible reasons for exclusions listed in the STPIS, including force majeure events and events which are caused by a fault or event on a non-prescribed third-party asset.

4.1.1 Issues identified

There is a consensus that the MIC is currently not working as intended.

[8] The NEM dispatch engine (NEMDE) is the software developed and used by AEMO to ensure the central dispatch process maximises value of trade subject to the various constraints.

Early in the MIC's operation, all TNSPs received rewards for improving performance. Powerlink, for example, received rewards averaging around 1 per cent of MAR between 2013 and 2018. For some TNSPs, however, the number of $10/MWh events at times exceeded the performance target from 2015. Under version 4 of the STPIS (introduced in 2012) the TNSPs were not penalised, but often received no rewards. For example, ElectraNet did not receive a reward between 2015 and 2018. Nor did Transgrid between 2015 and 2017.

Version 5 of the STPIS (which applied between 2017 and 2019 at the start of each TNSP's new regulatory control period) allowed for penalties of up to 1 per cent of MAR. Increases in $10/MWh events resulted in MIC penalties, with all TNSPs except for TasNetworks eventually incurring maximum penalties. Maximum penalties were incurred by:

- AusNet Services in 2021 and 2022
- ElectraNet from 2020 until 2023 in addition to incurring penalties ever since version 5 of the STPIS took effect
- Powerlink from 2019 to 2023
- Transgrid from 2020 until 2023.

Factors outside the control of TNSPs have driven the substantial increase in the number of $10/MWh events and the associated penalties that they have consequentially incurred. If a TNSP knows it is likely to incur maximum penalties under the MIC irrespective of what it does, the incentive to better manage outages is significantly diminished. This appears to be the case for AusNet, ElectraNet, Powerlink and Transgrid.

The main reason why the MIC no longer works as intended is because of the fundamental shift in generation and the transmission network driven by the energy transition. This has increased the number of binding transmission constraints and substantially increased the number of $10/MWh events experienced by TNSPs. The number of $10/MWh events for:

- Powerlink, increased from under 1,000 per annum in 2018 to over 13,000 per annum in 2019 and remains high
- ElectraNet, increased from 96 events in 2014 to over 10,000 in 2015, then fell in 2017 but increased again in 2018, 2021 and 2022 to reach the highest level recorded in 2022 at 15,742
- Transgrid, increased from 1,252 in 2019 to over 14,000 in 2020
- AusNet Services, has fluctuated, but stepped up in 2021 to 3,756 and 2022 to 6,355.

Only TasNetworks has experienced relative stability in the number of $10/MWh events.

Since performance targets are based on historic performance, TNSPs submit that they are being penalised for changes in the generation mix instead of their management of outages.

Other factors have also contributed to the increase in $10/MWh events:

- More planned outages are required with increased investment in new transmission lines, upgrades to existing transmission infrastructure, and connection of new generators. For example, the number of planned outages scheduled by Powerlink and ElectraNet increased four-fold and three-fold respectively between 2016 and 2023.[9]

- Scheduling outages is more challenging. Historically, TNSPs could rely on low demand and prices in spring and autumn to schedule substantial outages. However, we now see higher prices during these periods, especially during evening peak periods.
- Average Regional Reference Prices (RRP)[10] increased from 2021 onwards and were particularly high in 2022. This means that any given scheduled outage is more likely to coincide with high prices.

4.2 Final amendments

For the reasons set out below, we have amended the STPIS to suspend the MIC. We will also explore developing an effective alternative and improve transparency by:

- establishing a working group with AEMO and key stakeholders to develop potential alternative options to the MIC for the AER's consideration
- considering a conduct obligation
- consulting on and revising the STPIS
- collecting new data from TNSPs on planned outage scheduling and rescheduling decisions
- analysing planned outages that occur at the time of extreme spot market prices
- reporting annually on the outage management performance of TNSPs, including data on the number of planned outages that occur at times of high spot market prices, the reasons for scheduling and rescheduling decisions taken at times of high price, and the outcomes of our analysis.

4.3 Reasons for amendments

4.3.1 Improving the MIC

There is a consensus that the MIC is not working as intended. The EUAA captured stakeholder sentiment as follows:

> EUAA is opposed to the current situation that unintentionally penalises TNSPs due to an outdated process that uses historical averages when the network was significantly different and less congested. In effect, the MIC has become a congestion tax on TNSPs.[11]

Notwithstanding this view, stakeholders still want to see planned outages taken at times of least disruption to the market. Most stakeholders see an improved MIC or alternative

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9 AEMO, NEM Constraint Report 2023 summary data, April 2024.

10 Regional reference price provides a reference from which the spot prices are determined within each region.

11 EUAA submission, 5 April 2024.

incentives as the best way of achieving this. The JEC, for example, states “an MIC founded on financial sanctions rather than reporting remains most appropriate”.[12]

There are different views on what should replace the MIC:

- The CEC, ENGIE, and EnergyAustralia propose replacing the MIC with incentives to improve notification of outages. These stakeholders proposed suggestions for how a notification incentive scheme could work.
- The ENA expressed caution about setting or incentivising outage notification targets. They are concerned about a loss of flexibility to respond to new information.
- AEMO points to both benefits and risks of incentivising longer lead times. Longer lead times can improve co-ordination of generator and transmission outages. The offsetting risk is that longer lead times may make TNSPs “less responsive to shifting outages according to market conditions”.[13]

In the Issues Paper we explored possible options for improving the MIC through better targeting, for example by only rewarding or penalising TNSPs for events that have a material impact on spot prices. Submissions and further analysis by us showed that our suggestions were unlikely to be effective.

However, the objective of better targeting the MIC remains valid and is supported by stakeholders. Similarly, there may be merits in adopting incentives based on notifications of outages. We propose additional work to identify a workable alternative to the current MIC.

4.3.2 A working group

In response to stakeholder views, we have decided to establish a working group to develop alternatives to the MIC, including exploring the possibility of a conduct obligation. The working group will make a recommendation to the AER for our consideration.

We aim to establish the working group as soon as practicable in 2025, with a view to it providing recommendations to the AER by mid to late 2026. A terms of reference will also be developed. The working group will include representatives of AEMO, the AEMC, TNSPs, generators and consumers.

We intend to amend and update the STPIS with our preferred alternative as soon as practicable after we have considered the working group’s recommendations.

4.3.3 Suspending the MIC

All stakeholders support developing an alternative and our proposal to improve transparency by collecting more information. However, some stakeholders are of the view that we should retain the MIC until an alternative is developed on the basis that the MIC still has some impact.[14]

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12 JEC submission, 4 February 2025.

13 AEMO submission, 3 February 2025, p. 3.

14 AEMO, CEC, EnergyAustralia, ENGIE and the JEC.

While stakeholders agree that the MIC is not fit for purpose, it may still be having some impact. MIC annual compliance data (used to determine annual rewards/penalties) shows that while ElectraNet, Powerlink and Transgrid continued to incur maximum penalties in 2023, ElectraNet and Powerlink improved their performance in 2024. Only Transgrid incurred the maximum penalty in 2024. Figures 1 to 5 show these MIC results including 2024 provisional data.[15]

The improved performance of ElectraNet and Powerlink in 2024 lends some support to retaining the MIC until an alternative is developed. However, our position remains to suspend the MIC on the basis that:

- Our analysis demonstrates the MIC is poorly targeted. Most of the $10/MWh events we use to set incentive payments and penalties do not affect spot prices.
- All stakeholders agree with our conclusion that the current MIC is not working as intended and is not fit for purpose.
- While the results for ElectraNet and Powerlink improved in 2024, all TNSPs except TasNetworks have experienced multiple years of maximum penalties since 2019, ranging from two years for Ausgrid to five years for Transgrid.
- The 2024 improvements for ElectraNet and Powerlink may be a one-off and not indicative of any forthcoming trend, and it is not clear whether the actions of TNSPs or external factors drove these results.

The current MIC will apply to each TNSP until the start of each TNSP's next regulatory control period or until the commencement of a rule change, allowing the AER to apply any new version of the STPIS to TNSPs at an earlier time, whichever comes first. We anticipate that mid 2026 would be the earliest such a rule change could take effect.[16] We would seek to introduce the MIC's replacement as soon as practicable. However, this would require a consultation on a revised STPIS in accordance with the transmission consultation procedures.

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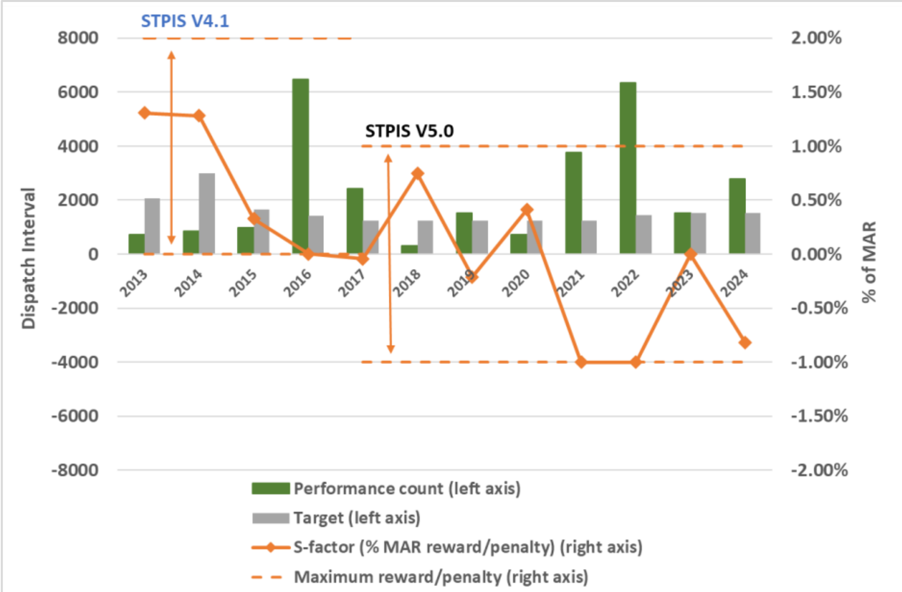
15 This data is yet to be validated by the AER

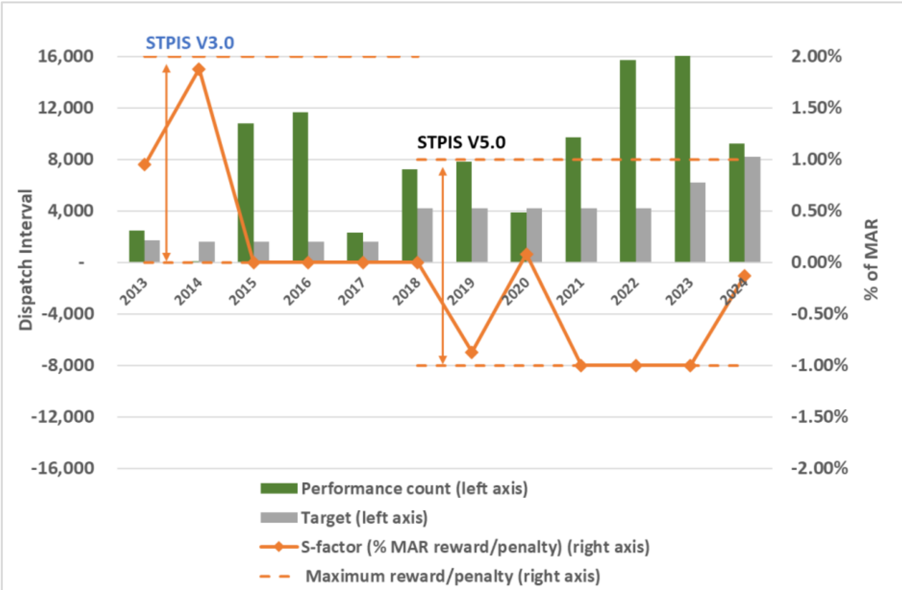
16 Noting that Directlink's next revenue determination takes effect from 1 July 2025, so the MIC suspension will take effect from that date for Directlink.

Figure 1: AusNet Services STPIS Outcomes



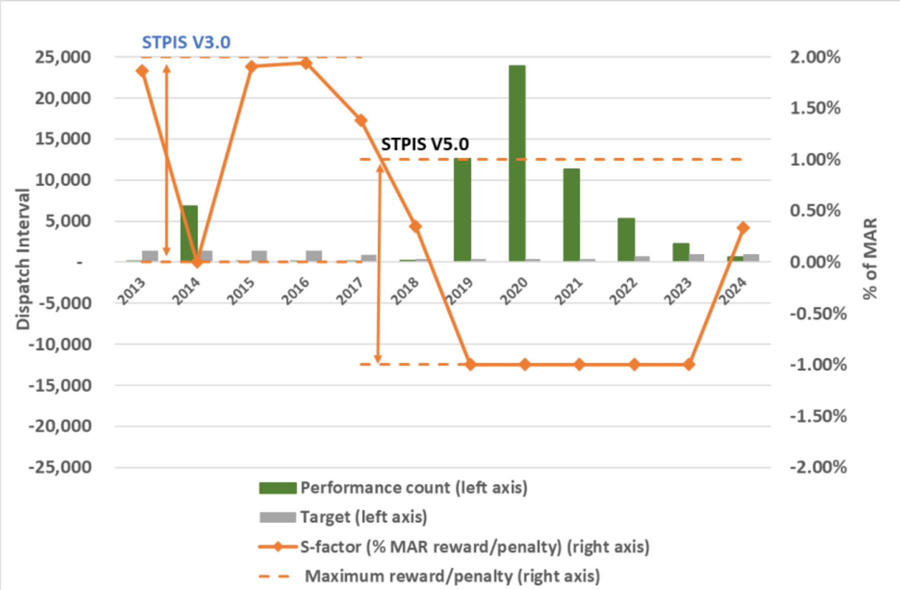
Source: AER analysis

Figure 2: ElectraNet STPIS Outcomes



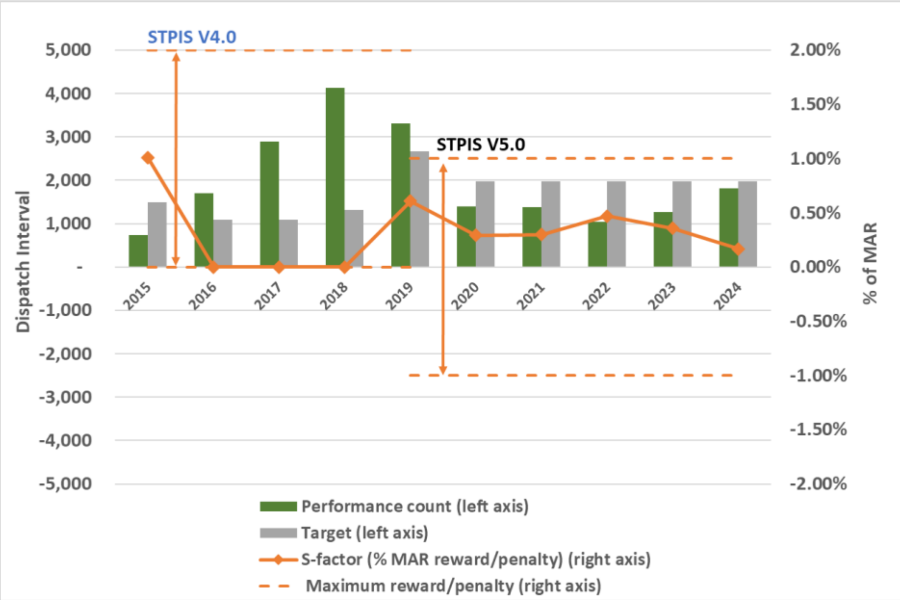
Source: AER analysis

Figure 3: Powerlink STPIS Outcomes



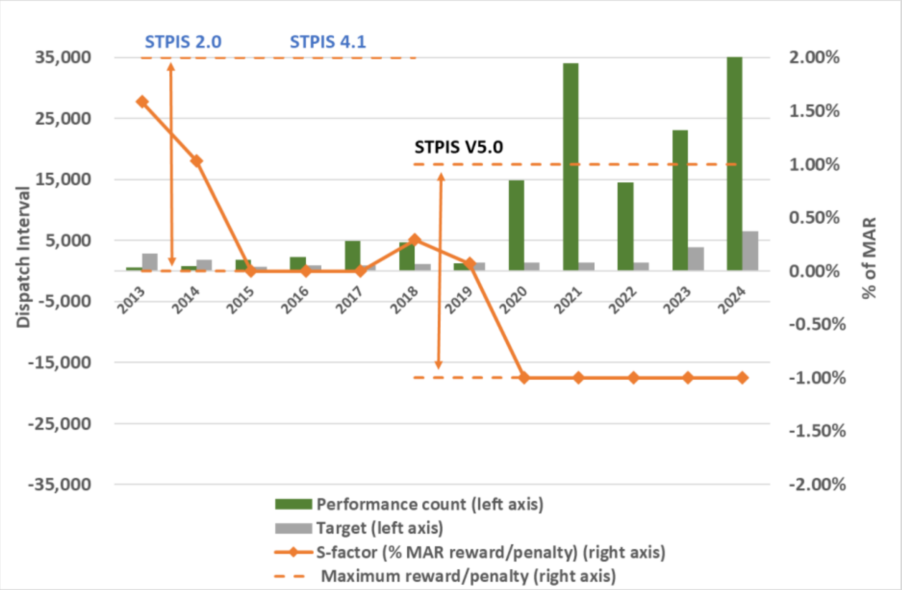
Source: AER analysis

Figure 4: TasNetworks STPIS Outcomes



Source: AER analysis

Figure 5: Transgrid STPIS Outcomes



Source: AER analysis

4.3.4 Conduct obligation

When we published our proposed amendments, we sought views from stakeholders about whether a conduct obligation should be introduced and imposed on TNSPs. There was limited support for a conduct obligation. The CEC did not support a conduct obligation on the grounds that it would be less effective than incentives, while TNSPs want further assessment of data to establish the need for a conduct obligation The EUAA supported conduct obligations, but only as an interim measure pending redevelopment of the MIC. EnergyAustralia was similarly open to conduct obligations, but in addition to an incentive.

We remain open to the possibility of imposing a conduct obligation. We will consider the relative merits of a conduct obligation in addition to alternative incentives developed by the working group when it delivers its recommendations for our consideration.

4.3.5 Transparency and reporting

We proposed, as part of our proposed amendments, to collect and report on additional data. Submissions supported our proposals.

Our decision is to collect data on planned outage management decisions made by TNSPs either voluntarily or by issuing a regulatory information notice or order. We will analyse planned outage events that contribute to extreme spot prices and publish this information in reports annually.

When scheduling outages TNSPs should have regard to demand and supply forecasts and avoid scheduling outages that could lead to high wholesale prices. Further, TNSPs should have regard to subsequent changes in demand and supply forecasts and consider rescheduling planned outages where the subsequent changes are likely to result in high wholesale prices.

As part of our data collection, we will require TNSPs to report on all planned outages that occur when spot market prices are high. When planned outages are taken at extreme spot market prices, we will analyse and report on the TNSP's actions. We will consider what constitutes high prices and extreme prices as part of our ongoing analysis.

We will require the TNSPs to explain:

- how they took into account demand and supply forecasts in scheduling the planned outage
- how they took into account changes in demand and supply forecasts in considering whether to reschedule the planned outage
- why they did not reschedule a planned outage when forecasts showed tight demand and supply conditions.

Our annual reports will include:

- spot market prices at the time planned outages are taken
- the information we collect on outage management practices and decisions
- the findings of our analysis
- to the extent possible, an overall assessment of the TNSP's outage management practices and performance.

5 Network Capability Component

5.1 About the Network Capability Component

The NCC provides incentives for TNSPs to increase the capability of existing assets. The intention of the NCC is to encourage incremental or small improvements to the existing network rather than pursuing additional large augmentations and expansions of the network. Cost effective improvements in network capacity benefit generators and consumers.

Version 5 of the STPIS required a TNSP to consult with AEMO and submit a network capability incentive parameter action plan (NCIPAP) as part of its revenue proposal. In summary, in a NCIPAP, a TNSP was required to:

- identify the key network capability limitations on each transmission circuit or load injection point on its network
- identify projects to address the identified limitations
- for each proposed project, specify a project improvement target
- ensure the total annual proposed expenditure does not exceed one per cent of the average annual MAR proposed by the TNSP in its revenue proposal.

A TNSP received an annual network capability incentive allowance equal to 1.5 times the average annual cost of the NCC projects. If a TNSP did not achieve a project's improvement targets, then it could incur a penalty of up to 3.5 per cent of the average annual MAR. Reductions in the incentive allowance could apply if project costs were higher than forecast, or if the project did not deliver the estimated benefits.

5.2 Final amendments

We have amended the NCC to no longer require a TNSP to submit a NCIPAP as part of its revenue proposal, but rather to require a TNSP to identify the projects in its TAPR that should be the subject of the NCC, for our approval, each year. Specifically:

- A TNSP can identify projects which are:
  - less than the RIT-T threshold (currently $8 million), and in aggregate (the total expenditure of all projects proposed for the NCC), less than 1 per cent of maximum allowed revenue (MAR) in the relevant regulatory year
  - selected on the basis of the ranking of projects in descending order of the likely benefits to consumers and on wholesale market outcomes
  - inclusive of project improvement targets.
- We must determine which projects identified by a TNSP are to be NCC projects, in consultation with stakeholders and AEMO.
- Approved NCC projects receive an incentive allowance of 1.5 times a priority project's proposed expenditure. Incentives are adjusted down by up to 1.5 times of proposed expenditure, if improvement targets are not met. This means that TNSPs cannot be worse off by proposing NCC projects.

- A TNSP must provide us with information annually on progress of approved priority projects and costs incurred.
- We must publish progress of approved NCC projects, project costs incurred, and the incentive allowance paid to TNSPs (taking into account any reductions where project improvement targets are not met).

5.3 Reasons for amendments

The original rationale for the NCC was to encourage TNSPs to undertake low-cost improvements in network capacity, instead of high-cost capital augmentations. This rationale is as applicable today as it was when the NCC was introduced in 2012.[17]

However, our data shows that TNSPs are proposing fewer NCC projects, and the total value of projects is low. Given the data, stakeholders have raised concerns about whether the NCC continues to provide appropriate incentives to improve network capacity.[18]

To address this decline, our proposed amendments aim to encourage increased use of the NCC by:

- streamlining processes for identifying and approving projects
- improving flexibility by allowing TNSPs to propose projects annually (rather than every five years as part of a regulatory reset process)
- amending incentive payments to remove the risk that TNSPs can be worse off by proposing NCC projects.

In response to our proposed amendments, stakeholders expressed views on:

- removing the NCIPAP and instead relying on the TAPR process
- involving AEMO as part of assessing proposed priority projects
- our consultation process
- better aligning the incentive allowance and any reductions to the incentive allowance
- transparency about the costs and delivery of priority projects
- how the NCC is currently applied.

A summary of submissions is set out in Appendix A of this Explanatory Statement.

5.3.1 Using the TAPR to streamline the NCC

Our final amendments remove the requirement for TNSPs to prepare a NCIPAP. Instead, a TNSP will now be required to submit an application to us annually that identifies which

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17 AER, Explanatory Statement, proposed amendments, Service Target Performance Incentive Scheme, October 2024, p. 29.

18 AER, Submission responses to Transmission STPIS Review, Issues Paper, December 2023.

projects in its TAPR should be considered projects for the purposes of the NCC. A TNSP's application must:

- explain how the project would result in a material benefit and the key assumptions underpinning the benefit assessment
- specify the capacity of the transmission circuits and/or injection points which the project is seeking to improve, along with the estimated improvement in capacity
- specify the total forecast operational and capital cost of each project identified
- specify the proposed improvement target for each project
- rank projects in descending order based on the likely net benefits of the project.

These amendments streamline the NCC process. TNSPs must identify network limitations, projects to address those limitations, and the estimated costs and benefits of the proposed projects as part of their TAPR. Relying on the TAPR and removing the NCIPAP eliminates duplication of process.

Further, by allowing TNSPs to identify projects annually from their most recent TAPR, our amendments allow TNSPs to respond to current developments. As such, we will assess and approve proposed projects on an annual basis, whereby the incentive allowance will be up to 1.5 per cent of a TNSP's annual maximum allowed revenue for the relevant regulatory year.

Stakeholders generally support our proposed amendments to annually approve projects identified in the TAPR.[19]

5.3.2 Role of AEMO

AEMO currently reviews TNSPs' NCIPAP proposals. We will retain AEMO's role in reviewing proposed projects and ability to propose projects that have not been identified by a TNSP.

There are mixed views on AEMO's role. Some stakeholders consider that AEMO has the right skill set to assess projects and their role should be retained.[20] However, the ENA submits that AEMO's role increases the regulatory and administrative costs of operating the scheme.[21] The CEC is open to removing AEMO's role provided that AEMO can still propose projects that have not been identified by the TNSPs, and that TNSPs are required to consult with AEMO in identifying viable projects.[22]

As the independent planner, AEMO is well placed to examine existing line and plant ratings and the proposed capability improvements and assess the veracity of estimated benefits of proposed projects. AEMO's review of proposals should give stakeholders confidence that the TNSPs' assessment of project benefits is reasonable. We see this as an important cross

19 ENA, TNSPs, CEC, DCCEEW, AEMO, EUAA, and JEC supported identifying NCC projects from the annual TAPR.

20 EnergyAustralia, AEMO and ENGIE support an ongoing role for AEMO

21 ENA, Submission on draft STPIS amendments, February 2025.

22 CEC, Submission on draft STPIS amendments, February 2025.

check on the TNSPs' proposals given the substantial incentive payments on offer. AEMO supports having an ongoing role.[23]

The CEC proposed an independent expert review of all line ratings and the potential for alternative technologies to improve network capability. We have not accepted this proposal on the basis that AEMO will examine the existing and proposed circuit and connection point ratings as part of its review of NCC project proposals. As discussed below, we will also consult on the TNSPs' proposals to enable stakeholders, including market participants to scrutinise proposed projects, including key assumptions that underpin the estimated benefits of these projects. As part of their annual NCC proposals, we expect that TNSPs will provide the methodologies and assumptions used to estimate existing and improved circuit and plant ratings as a result of a proposed project.

5.3.3 Consultation process

We will consult on the TNSPs' NCC proposals and take submissions into account in determining which projects should be approved.

Some stakeholders commented on our consultation process, arguing that interested parties should be able to propose projects not identified by TNSPs. Their concern is that interested parties have limited scope to propose projects given that TNSPs are not required to consult on their TAPR. For example, the CEC submitted that:[24]

> Given the regulatory regime still provides incentives for TNSPs to dedicate their resources to the implementation of projects above the RIT-T threshold, and there is no obligation on the TNSPs to identify and progress projects under the NCC scheme, it is important that all stakeholders are able to propose NCC projects to the TNSP and there is more transparency around the TNSP's consideration of priority projects under the NCC scheme, to ensure that low cost but high value NCC projects continue to be undertaken.

Our consultation process will give stakeholders the opportunity to identify, test, and scrutinise projects proposed by a TNSP. This opportunity is consistent with consultation on NCIPAP as part of the revenue determination process.

While the TAPR is the primary mechanism for identifying NCC projects, stakeholders will also be able to raise network limitations and possible solutions with TNSPs and propose projects as part of our consultation process if a TNSP has not adequately engaged with stakeholder proposals raised during the TAPR development process.

5.3.4 Incentive arrangements

Version 5 of the STPIS applies an incentive allowance of 1.5 times the proposed expenditure. It also applies a reduction to the incentive allowance of up to 3.5 per cent of

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[23] AEMO, Submission on draft STPIS amendments, February 2025

[24] CEC, Submission on draft STPIS amendments, February 2025

MAR if we determine that the project's improvement target was not achieved. This creates the potential for substantial net penalties if targets are not met.[25]

Our proposed amendments addressed the potential for substantial net penalties by aligning the basis for incentive payments and incentive reductions. The incentive allowance and reductions to the incentive allowance were both set at 1.5 times the project's costs. Stakeholders generally supported this.

However, there remains a question about whether actual or proposed costs should be used to set incentive payments. Our proposed amendments used proposed costs to determine incentive payments, and then actual costs for any reductions in incentive payments (where project targets are not achieved). This followed the approach in Version 5 of the STPIS. This left some risk of net penalties (the incentive reduction exceeding the incentive payment) if actual costs ended up being higher than proposed costs.

Further, views on whether the incentive allowance should be based on actual or proposed expenditure were mixed. Transgrid submitted that basing the incentive reduction on actual expenditure may encourage a TNSP to delay the project or reduce its scope in preference to going overbudget. The EUAA supported using proposed expenditure as this would mean no net impact on the TNSP if the target is not achieved.[26] By contrast AusNet supported applying revenue reductions on actual expenditure.[27]

Having considered stakeholder views, our position now is to base incentive payments and incentive reductions on proposed expenditure for two reasons.

Firstly, when incentive payments and reductions are both based on proposed costs TNSPs can be no worse off by proposing NCC projects. As noted above, our proposed amendments left some risk of net penalties (the incentive reduction exceeding the incentive payment). Removing the risk of net penalties should encourage increased take up of the NCC.

Secondly, using proposed expenditure is likely to strengthen incentives for TNSPs to efficiently deliver NCC projects. Incentive payments based on proposed costs remain constant even if TNSPs deliver projects at lower cost than proposed. By contrast, if actual costs are used to set incentive payments, cost reductions result in lower incentive payments. This may deter TNSPs from pursuing efficiencies.

5.3.5 When should incentive adjustments apply?

Clause 5.3(d) in the STPIS states that an NCC project improvement target is not achieved if:

(1) the target has been achieved through network augmentation or replacement of existing assets and a TNSP has incurred a capital cost that is greater than its proposed cost on a priority project; or

(2) despite achieving the priority improvement target, there is a material change such that the project no longer provides a material benefit.

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25 The maximum allowed value of NCC projects is one per cent of MAR. With an initial incentive allowance of 1.5 times project costs, this gives a maximum initial incentive allowance of 1.5 per cent of MAR. At 3.5 per cent, the maximum penalty exceeds the maximum incentive allowance by more than two times.

26 EUAA, Submission on draft STPIS amendments, February 2025, p. 3.

27 AusNet, Submission on draft STPIS amendments, February 2025, p.3.

If the project's improvement targets are not met, we may reduce incentive payments to the TNSP.

Transgrid submitted that clause 5.3(d) of the STPIS does not specify the criteria by which NCC penalties can be waived by the AER.[28] Transgrid suggested that we specify in the STPIS that reductions to the incentive allowance should only apply if both clause 5.3(d)(1) and 5.3(d)(2) apply. In other words, Transgrid argues that any reductions to the incentive allowance should be waived if only one of the clauses is breached.

We have decided not to amend clause 5.3(c) as proposed by Transgrid as the two limbs capture different factors. However, in determining whether to apply a reduction to the incentive allowance, consistent with past practice, we may consider whether the project is expected to provide material benefits taking into account any project cost overruns.

5.3.6 Improved transparency

The CEC submits that there should be more transparency about NCC projects, including information on the progress of approved projects and project costs.[29]

We agree that there should be greater transparency about approved projects and completed projects. Having regard to submissions, we have decided to publish information on an annual basis, setting out:

- progress in undertaking NCC projects
- for completed projects, what improvements in network capacity have been achieved, and how this compares to the identified improvement targets
- actual costs incurred on each approved project.

28 Transgrid, Submission on draft STPIS amendments, February 202, pp.10-11

29 CEC, Submission, February 2025

6 Service Component

6.1 About the Service Component

The SC provides incentives to a TNSP to maintain the reliability of its network. It does this by providing a reward or penalty of ± 1.25% of MAR, based on the number of unplanned network outages and how quickly these outages are restored. The parameters used for the SC are either determined within the STPIS or are proposed by a TNSP in a revenue proposal.[30]

TNSPs have expressed concern about the loss of supply event frequency parameter in the SC, which provides incentives for TNSPs to improve their response times when unplanned outages occur. This parameter accounts for 30 per cent of the SC. It measures the number of unplanned outages per year that take longer to rectify than system minute thresholds set out in the STPIS.

System minute thresholds represent reasonable times for a TNSP to respond to outages, which have been set using historical data and stakeholder feedback. We have updated these with each version of the STPIS. The system minute thresholds have reduced over time.

The TNSP's performance over a regulatory control period is used to set the target number of unplanned outage events. TNSPs receive financial rewards if they outperform, and penalties if they underperform, against their target.

6.2 Final amendments

For the reasons set out below, we have amended the SC to remove rounding to set targets for the loss of supply frequency parameter as a fraction of events.

For example, if a TNSP had 2 loss of supply events in the previous regulatory control period, the annual target would be 0.4. If the TNSP then has no events in a year they receive a financial reward, but if they have one or more events, they incur a penalty.

6.3 Reasons for amendments

While TNSPs support retaining the SC, there is concern about how performance targets for the loss of supply event frequency parameter are set.

In administering the SC, we:

- count the total number of loss of supply events over the previous regulatory period
- derive an annual average number of events (by dividing the total number of events in the previous regulatory period by the number of years in the regulatory period)
- round the annual average number of events to the nearest whole number.

The last step has resulted in zero targets even through the TNSP experienced loss of supply events in the previous regulatory control period. For example, if a TNSP experiences two

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30 Page 5, STPIS version 5 (corrected)

loss of supply events in five years, the average annual number of events is 0.4. This is then rounded down to zero.

TNSPs have expressed concerns that the SC is asymmetric when the target is zero. This is currently the case for Transgrid and Powerlink. When the target is zero, any loss of supply event incurs a penalty, but rewards are not possible. The best a TNSP can do is to avoid a penalty. We recognised that rounding the average number of events to the nearest whole number can arbitrarily penalise TNSPs. Our proposed amendments addressed this by removing rounding so that the targets can be fractions of an event. All stakeholders, other than Transgrid, supported our proposed amendments.

Transgrid submitted that in the circumstances of a zero target, and where the TNSP does not experience a loss of supply event during the regulatory control period, the TNSP should receive the full reward.[31] Transgrid reasoned that when the target is set at zero, the SC will be a penalty only scheme. If there is no further scope for improving reliability, a reward is not possible, and a TNSP needs to maintain this performance otherwise a penalty will be incurred. Transgrid goes on to state that this asymmetry is at odds with clause 6A.7.4(b) of the NER, where the principles of the STPIS should provide incentives to the TNSP to provide greater reliability.

We do not agree that a TNSP should receive a reward where the target is set to zero and the TNSP does not experience a loss of supply event. In this circumstance, the TNSP has already been rewarded under the STPIS for achieving a zero target (subject to the rounding issue that we have addressed in our final amendments). If the loss of supply performance deteriorates, the TNSP will receive a non-zero target in the next regulatory control period and will have an opportunity to improve performance and receive a reward at that time. In this way the STPIS is consistent with the principles of maintaining and improving reliability of those elements of the transmission system most important to determining spot prices.[32]

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31 Transgrid, Submission to draft STPIS amendments, February 2025, p. 3.

32 NER, cl 6A.7.4(b)(1)(ii).

7 Timing of applying an amended STPIS

We can only decide to apply version 6 of the STPIS to a TNSP at the time we make a revenue determination for a TNSP.[33] This means that version 5 of the STPIS will continue to apply until the start of each TNSP's next regulatory control period unless the National Electricity Rules are amended.

The commencement date for the next regulatory control period for each TNSP is set out in Table 1.

Table 1: Commencement date of the next regulatory control period for each TNSP

TNSP	Commencement of next regulatory control period
Directlink	1 July 2025[34]
AusNet	1 April 2027
Powerlink	1 July 2027
Transgrid	1 July 2028
ElectraNet	1 July 2028
Murraylink	1 July 2028

We consider that version 6 of the STPIS should apply as soon as possible to allow implementation of the revised NCC and SC. Therefore, we will submit a rule change proposal to the AEMC for its consideration. The purpose of that rule change proposal is to afford us the discretion to apply any new version of the STPIS before the next regulatory control period. Absent such a rule change, we can only apply version 6 of the STPIS at the start of each TNSP's next regulatory control period. TNSPs, ENA, EUAA, and AEMO supported this proposal.

Our intention is to lodge a rule change proposal with the AEMC in mid-2025.

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[33] NER, cl 6A.14.1(1)(iii).

[34] Noting that Directlink's next revenue determination takes effect from 1 July 2025, so the MIC suspension will take effect from that date for Directlink.

Glossary

Term	Definition
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
capex	capital expenditure
CESS	capital expenditure sharing scheme
EBSS	efficiency benefit sharing scheme
MAR	maximum allowed revenue
MIC	market impact component
NCC	network capability component
NCIPAP	network capability incentive parameter action plan
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
opex	operating expenditure
SC	service component
STPIS	service target performance incentive scheme
TNSP	Transmission Network Service Provider

Appendix A Summary of stakeholder submissions

The following summarises input that stakeholders provided on the MIC, NCC, SC and the timing of implementing an amended STPIS.

Market Impact Component

Issue	Stakeholder submissions
Suspension of the MIC	CS Energy, ENA and TNSPs support suspension of the MIC as soon as possible. Their view is that the AER should gain an improved understanding of the operation of networks and conduct detailed analysis before designing a replacement. EUAA supports suspension of the MIC on the basis that an alternative is developed. The alternative needs to be amended to include semi-scheduled generation, and trunk and radial lines.
	ENGIE, CEC, DCCEEW, EnergyAustralia, AEMO and JEC do not support suspension of the MIC without a replacement mechanism. Their preference is to either retain an amended version of the MIC, or retain the MIC while an alternative is developed. AEMO considers there are still benefits in Tasmania, that penalties may fall after the next resets, and that there is a case to retain the current MIC until an alternative is introduced. AEMO is concerned that introducing a new scheme may be a lengthy and difficult process, and is concerned about the lack of incentives in the interim.
Introduce a conduct obligation	CS Energy, AusNet and Powerlink do not support introducing new conduct obligations. EnergyAustralia considers introducing new conduct obligations could be done in addition to STPIS refinements rather than instead of them. EUAA support AER's proposal to implement a code of conduct rule change to ensure that TNSPs consider the cost to consumers of their planned outages.
AER to annually report each TNSP's outage performance	CEC and JEC do not believe annual reporting is sufficient to maintain and improve outage management performance. They do not think that reputational incentives on TNSPs to improve are enough on their own. CS Energy, ENA and TNSPs considers that the proposed collection of information, analysis of network events and transparency reporting would provide TNSPs sufficient incentive to schedule outages at times least costly to the market.

<table>
<tr><td rowspan="2">Stakeholder input of alternatives</td><td>Minimum 4 months’ notice of planned outages

CEC have proposed in their submission and at the AER public forum[35] an alternative incentive scheme focusing on adequate advance notice of planned outages. TNSPs are required to submit information of their planned network outages for the next 13 months into the Network Outage Schedule (NOS). CEC’s view is for TNSPs to give at least 4 months’ notice of planned outages in the NOS, with penalty levels increasing as the notice period decreases, with the exception of unforeseen circumstances.

ENGIE, EnergyAustralia and EUAA submissions supported CEC’s proposed incentive.

ENA and TNSPs do not support the minimum 4 months’ notice for all planned outages as it does not account for the variability and complexity of outage planning.

While ENA recognises the importance of addressing outage impacts, it is concerned that a mandatory 4-month notice period would reduce the flexibility needed to manage a rapidly evolving energy system effectively. Instead, ENA recommends a collaborative, evidence-based approach that prioritises the long-term interests of consumers by balancing certainty with flexibility in outage planning.

From Powerlink's experience, outage planning is a complex, multi-variable problem. Given its highly contextual nature, the development of an appropriate outage reporting mechanism requires a contemporary and holistic understanding of how and why outages are planned and managed. Powerlink also does not recommend the direct use of the data presented by CEC in the public forum (i.e. NOS), and the potential application of conduct provisions without further validation of the underlying power system context and assumption, such as:
data source limitation of AEMO's Network Outage Scheduler (NOS) - there is a limited ability to capture full network outage planning considerations and context relating to the work; and
the notification period registered - it is impact by the changes in a number of fields that relate more directly to supporting engineering due diligence of outages by TNSPs and AEMO, rather than being indicative of the notification period to a market participant.</td></tr>
<tr><td>Amend the materiality threshold

AEMO’s and EnergyAustralia’s views are the $10/MWh metric is no longer a suitable indicator of when a planned outage is likely to have resulted in a material impact on spot prices. They have suggested for AER to change the materiality price threshold from $10/MWh.</td></tr>
</table>

[35] CEC - Presenting at AER STPIS Public Forum, 10 December 2024

Network Capability Component

Issue	Stakeholder submissions
Replace NCIPAP with the TAPR	ENA, TNSPs, CEC, DCCEEW, AEMO, EUAA, ENGIE and JEC support linking the NCC to the annual TNSP TAPR process. Stakeholders also recommended more transparency through publication of the decision-making process – i.e., which projects have been approved, progress of the projects, etc. EUAA submitted that care needs to be taken in linking the NCC to the TAPR so that NCC projects provide a real improvement in network capability, and not just an improvement through end-of-life replacement (as new infrastructure is almost always more efficient than old infrastructure.
Role of AEMO	AEMO, ENGIE and EnergyAustralia considered that AEMO is well equipped to review NCC projects. CS Energy, CEC and Transgrid argue that AEMO's role is unnecessary, and the AER should remove AEMO's formal consultative role (i.e., AER should be the sole assessor of NCC projects). ENA supported the removal of AEMO from the formal priority project consideration to reduce the regulatory and administrative costs of operating the scheme. CEC proposed that instead of AEMO involvement, within 6-12 months prior to the commencement of the amended NCC scheme, TNSPs should be required to appoint an independent expert to undertake a study which: • audits line ratings of their network • examines how specified alternative transmission technologies could improve network capability (and by how much) at different locations where there is already high congestion, or where there is likely to be high congestion in the near future • recommends technologies and locations for low cost but high value projects; and • TNSPs should be required to publish this study and the AER to approve these studies. EUAA is seeking clarity on the roles of AER and AEMO, including assessment of the NCC project presented in the TAPR to test that it is a real NCC project.
Balancing Incentives	Stakeholders (DCCEEW) supported alignment between the incentive allowance and any reductions to the incentive allowance. TNSPs suggest using proposed costs as the basis for incentive payments, rather than actual project cost. ENA considered that both the reward and penalty should be based on the priority project estimated cost. The ENA stated that aligning both rewards and penalties to estimated cost maintains the scheme's symmetry while providing clarity and transparency to

	stakeholders. The EUAA also supported using proposed expenditure as aligning both rewards and penalties to estimated cost maintains the scheme's symmetry while providing clarity and transparency to stakeholders. Transgrid submitted that if the reduction in the incentive allowance is based on actual expenditure, this may bias a TNSP towards implementing a project late or with incomplete scope in preference to overbudget. Ausnet supported applying revenue reductions based on actual expenditure. The EUAA questioned whether the incentive need to be larger e.g. 2x the cost rather than the proposed 1.5x in order to incentivise TNSP's to perform these projects in addition to their ISP commitments.
Improved transparency	Stakeholders also recommended more transparency through publication of the decision-making process – i.e., which projects have been approved, progress of the projects, etc. The CEC submitted that there should be transparency for all stakeholders in relation to the identification and progression of NCC projects (which the current framework lacks). The CEC also submitted, amongst other things, that information on the progress of approved projects, including costs, and information about the removal of approved projects or addition of new projects, which the TNSP is required to report to the AER should also be made available to stakeholders on a timely basis.
Clarification of the operation of the NCC	Transgrid submitted that cl.5.3(d) of the STPIS does not precisely specify the criteria by which NCC penalties can be waived by the AER. Specifically, which combinations of cl.5.3(d)(1)-(4) need to be satisfied to be exempt from a penalty. Transgrid suggested that the AER add text to the STPIS that satisfying either one of the clauses 5.3(d)(1) – 5.3(d)(2) is sufficient to waive the penalty.
Stakeholder input	ENGIE submitted that it agrees with CEC on allowing market participants to be able to identify and recommend projects to TNSPs. CEC, ENGIE, AusNet and EnergyAustralia highlighted that the TNSPs are not required to consult on the TAPR, unlike the NCIPAP. They suggested that there should also be an opportunity for stakeholders to propose NCC projects in the TAPR. EnergyAustralia submitted that in line with CEC proposals, the AER should consider allowing any stakeholder to propose candidate projects, with requirement on the relevant TNSP to publish its reasons for accepting or rejecting their inclusion. EnergyAustralia commented that the existing TAPR process lacks transparency and there appear to be no obligations on TNSPs to consult. It may be the case that AEMO can be designated as a channel to elicit and guide input from wider stakeholders on opportunities for and the scope of high value projects. We would also encourage closer scrutiny of the congestion information resource and congestion outcomes to inform candidate low-cost investment options.

	EnergyAustralia recommended that TNSPs, with AER guidance, develop a structured process to evaluate all proposed network capability projects. The AER's explanatory statement suggests that projects be ranked according to payback period, whereas other metrics may be more suitable. The JEC submitted that robust requirements for acquiring and using consumer input on the ranking of options is introduced.

Service Component

Issue	Stakeholder submissions
Target setting	All stakeholders that have responded to the SC proposed amendments support amending the loss of supply frequency parameter to remove rounding. Transgrid encourages the AER to adopt the following changes: • In the event of a zero target, a zero energy not supplied (ENS) count results in full reward rather than zero. • Under this recommendation, a count of one or more continues to result in the maximum penalty under a zero target (as is presently the case).

Implementation

Issue	Stakeholder submissions
Timing of the amended STPIS	ENA, TNSPs, AEMO, Powerlink and EUAA support a rule change to implement the amended STPIS as soon as possible. ENA supports the AER's proposal to submit an expedited rule change to adopt amended incentive schemes as changes are made from time to time. The proposed rule change would allow TNSPs to opt into incentive schemes that are amended during a regulatory period. Adoption of the new arrangements and treatment of any existing NCIPAP projects and revenue would need to be agreed with the AER on a bilateral basis.