Review of incentives schemes for networks

Final decision

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AUSTRALIAN ENERGY REGULATOR

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Contents

Summary

This is the final decision on our review of the incentive schemes that we apply to network service providers (NSPs) under the National Electricity Rules (NER), namely the Efficiency Benefit Sharing Scheme (EBSS), Capital Expenditure Sharing Scheme (CESS) and the Service Target Performance Incentives Scheme (STPIS). The EBSS and CESS were introduced in their current form in 2013, the distribution STPIS in 2008 and the transmission STPIS in 2007.

Most countries that regulate electricity NSPs, including Australia, have adopted incentive regulation. Incentive regulation rewards regulated NSPs for improving consumer outcomes by realising efficiency gains, reducing costs and improving service outcomes. If NSPs in the national electricity market spend less on operating and capital expenditure than forecast, they retain up to 30 per cent of the benefits. The incentive schemes supplement the regulatory framework to provide even incentives for efficiency through the regulatory control period. The strength of the incentives weaken over the regulatory control period without these incentive schemes.

The information revealed by our incentive schemes is used to set future revenue forecasts. The efficiency gains are shared between consumers and NSPs:

- NSPs retain 30% of all capital expenditure (capex) savings
- NSPs retain all operating expenditure (opex) savings for 6 years
- NSPs retain benefits of reliability improvements for 5 years (quantified using the value of customer reliability).

Consumers have reservations about incentive schemes

One reason for this review is that while incentive schemes aim to reward NSPs for promoting improved consumer outcomes, consumers have expressed concerns about the amount they pay for them. In aggregate, EBSS, CESS and STPIS payments have added up to 2 per cent to revenues over the past five years, which is equivalent to $1.2 billion.

The question for consumers is whether these incentive payments are worth it. In recent electricity distribution determination processes, consumers expressed concern about a lack of transparency about consumer benefits from the incentive schemes compared to the observed costs. Consumers have also questioned the extent to which NSPs are being rewarded for expenditure over-forecasting rather than efficient spending, particularly in the context of capital expenditure.

The schemes have improved efficiency with benefits for consumers

Our assessment of the available data shows that the incentive schemes have driven significant improvements in performance through efficiency gains, which reduces prices over time, and reduces outages. For electricity distribution:

- opex is down 30 per cent per customer since 2011/12
- capex is down around 50 per cent per customer since 2011/12
- these efficiency gains have contributed to the 35 per cent reduction in revenues per customer since 2014/15
- in 2021 we also had a record low frequency and duration of outages, with improvements of 20 to 30 per cent in those measures over the past 10 years.

While NSPs have been rewarded for the efficiency gains, the majority of benefits have gone to consumers. We therefore propose to retain the schemes with modifications.

Operating expenditure incentives are fit for purpose

Regulators and consumers have incomplete information about future opex. Our primary tool for addressing this is to use past expenditure outcomes as a starting point with incentives for NSPs to improve efficiency over time. The incentives reveal what can be achieved and are then used as the basis for forecasts.

The EBSS, introduced in its current form in 2013, is the mechanism which shares the benefits of operating cost reductions between consumers and NSPs. Our analysis shows that the scheme has contributed to improved efficiency and lower prices and is working as intended. The benefits to consumers are up to four times the benefits to NSPs.

Our revealed cost approach is supplemented by our use of a productivity factor in forecasts. The productivity factor means NSPs must beat their historic performance by more than 0.5 per cent per annum before they are rewarded with EBSS payments.

One of the issues raised by consumers is whether we should use benchmarking more aggressively in setting our expenditure forecasts. We use benchmarking to set operating expenditure forecasts when an NSP's performance is less than 75 per cent of the most efficient NSP. As we refine our benchmarking techniques there may be a case to revise the 75 per cent target so that benchmarking is applied at a point closer to the efficiency frontier. We will assess the appropriateness of the current 0.75 benchmark comparison point as part of our benchmarking development work.

Improvements to the CESS

For capex we also use a revealed cost approach. We have improved the way we use revealed costs in our forecasts by developing a replacement capital expenditure (repex) model and by refining other elements of our approach. As a result, the gap between our forecasts and actual expenditures has narrowed over time, from around 18 per cent for the first round of resets made after we introduced the CESS in 2013 to 7 per cent for current resets.

Nevertheless, applying a revealed cost approach to capex is more difficult than opex because of the often lumpy and sometimes non-recurrent nature of capex. While replacement capital expenditure and elements of IT expenditure are largely recurrent, augmentations are not, especially for large new transmission projects. This means the CESS does not have the same information revelation properties as the EBSS and some forecasting error is inevitable.

The current CESS applies a 30 per cent sharing ratio. NSPs retain 30 per cent of any underspending against our forecast, and the balance goes to consumers. In this final decision, we propose to improve outcomes for consumers by limiting CESS rewards for NSPs when outperformance is high, by improving transparency and potentially by limiting application of the CESS in the case of large transmission investments. In this final decision we have decided to amend the Capital Expenditure Incentive Guideline to vary the CESS and implement what we refer to as the Bright-Line Tiered Test. This will apply:

- a 30 per cent sharing ratio for any underspend up to 10 per cent of the forecast capital expenditure allowance in the previous regulatory control period
- a 20 per cent sharing ratio for any underspend that exceeds 10 per cent of the forecast capital expenditure allowance in the previous regulatory control period
- a 30 per cent sharing ratio for any overspend of the forecast capital expenditure allowance in the previous regulatory control period.

The approach has been designed to be asymmetric. Despite improvements in our assessment toolkit and stakeholder engagement, a level of information asymmetry between the AER, consumers and the NSPs remains. The risk of us over forecasting capex requirements and a NSP subsequently underspending its forecast allowance remains higher than us under forecasting and a NSP overspending its forecast allowance. Given this, applying the Bright-Line Tiered Test asymmetrically has the effect of providing an offset to potential asymmetry in forecast error.

For large transmission investments our final decision is to consider whether the CESS is fit for purpose on a case-by-case basis in the context of our consideration of contingent project proposals.

The changes to the CESS are supplemented by new transparency measures which will require NSPs to better explain the reasons for variations between opex and capex outcomes and forecasts. This will in turn assist stakeholders to better understand the extent to which genuine efficiency gains have driven expenditure outcomes, and the value of incentive payments.

Elements of the STPIS need reviewing

Transmission network service providers (TNSPs) are concerned about the Market Impact Component (MIC) of the transmission STPIS. Transmission outages can affect market outcomes, with the possibility of high spot market prices when there are significant transmission constraints. The MIC provides networks with incentives to manage outages in a way that limits market impacts.

The MIC sets performance targets based on historic data. However, high investment in variable renewable energy generation is creating greater and more widespread congestion, significantly increasing network constraints above historical averages. Transmission networks consider that they are being penalised for changes in the generation mix rather than their performance.

It is prudent to review the MIC component of the STPIS in light of increasing transmission congestion. In this final decision, we have decided to commence the review of the MIC towards the end of 2023, which would allow any revisions to be picked up in time for the next Queensland and South Australian transmission reset processes. As the Network Capability Incentive Parameter Action Plan (NCIPAP) is closely linked to the MIC, our position is to review the NCIPAP scheme alongside the MIC review.

Two other elements of our service standards incentives are the Demand Management Incentive Scheme (DMIS) and Demand Management Innovation Allowance (DMIA). These are relatively recent initiatives (introduced in 2017) and were considered as part of a STPIS review in 2018. To date the schemes have incentivised several projects and we are proposing to extend application of the schemes to export services. We are not proposing to further review the schemes at this point.

Consumer benefits resulting from this review

The data we have collected to date shows that the EBSS, CESS and STPIS have enhanced the expenditure efficiency of NSPs and improved service standards. However, the schemes are funded by consumers. The question is whether the benefits outweigh the costs. Consumers are concerned that incentive payments to NSPs are split between forecast error (or ‘gaming’ as the AER’s Consumer Challenge Panel (CCP) characterises it) and genuine improvements.

Some forecasting error is inevitable given the information asymmetry that exists between NSPs, consumers and the regulator. Nevertheless, our judgement is, based on our improving regulatory toolkit and the reducing gap between our forecasts and outturn expenditure over time, that consumers are significantly better off overall with the schemes than without them.

However, as outlined in this decision, we recognise that there remains scope for improvement. The initiatives in this review should improve outcomes for consumers by reducing the risk of forecasting errors. Specifically:

- The transparency measures adopted in this final decision will help consumers, and us, better scrutinise NSP proposals and in doing so create additional reputational incentives for NSPs to submit reasonable proposals

- Our review of benchmarking has the potential to bring opex under-performers closer to the efficiency frontier.
- The Bright-Line Tiered Test reduces incentives to overstate capex requirements and should contribute to more realistic capex proposals. Further, if capex is significantly less than forecast, CESS payments are lower than the current scheme.
- Flexibility to vary the CESS for transmission contingent projects reduces the risk that CESS payments are made for forecasting error or TNSPs are penalised for cost over-runs that are outside their control.

We also note that financial incentives are part of a broader regulatory package geared to improving consumer outcomes:

- Financial incentives are supplemented by reputational incentives established by the AER's Better Resets Handbook. The experience with the current NSW resets shows how the Better Resets program is driving increased consumer engagement and improved proposals.
- The incentive schemes are also supplemented by improvements to our capex and opex forecasting toolkit, with ongoing refinement of our opex benchmarking (for example our capitalisation work), our recent introduction of a 0.5 per cent per annum productivity factor for opex, our repex benchmarking work, and development of guidance notes (for example on asset management risk, Consumer Energy Resources and information technology).

Increased consumer engagement and improvements to our forecasting toolkit have contributed to convergence of forecast expenditure allowances and outturn expenditures over time.

Final decision

Having considered the submissions we received in response to the draft decision, the positions we have reached in this final decision are to:

- retain the EBSS as is
- amend the Capital Expenditure Incentive Guideline to vary the CESS to:
    - implement the Bright-Line Tiered Test, which applies a 30:70 sharing ratio for underspends of up to 10 per cent, a 20:80 sharing ratio for underspends exceeding 10 per cent, and asymmetric application of the scheme so that a 30:70 sharing ratio applies for all overspends
    - provide us with the flexibility to determine whether and how to apply the CESS to transmission contingent projects
    - allow us to establish a separate CESS for contingent projects (rather than necessarily including the contingent project in the total capex 'bucket')
- require NSPs to provide further information to better and more transparently explain the reasons for differences between our expenditure forecasts and the capital expenditure they have actually incurred as part of the Networks Information Requirements Review and the forthcoming regulatory information notices (RINs) that we will serve on SA Power Networks, Ergon Energy and Energex
- retain the distribution STPIS as is
- retain the service component of the transmission STPIS as is
- assess the appropriateness of the current 0.75 benchmark comparison point as part of our benchmarking development work
- undertake a review of the MIC of the transmission STPIS, and the related Network Capability Incentive Parameter Action Plan (NCIPAP) scheme, commencing in late 2023.

1. Background

In December 2021, we published a discussion paper which commenced our review of the incentive schemes we apply to network service providers (NSPs) under the National Electricity Rules (NER), namely:

- the Efficiency Benefit Sharing Scheme (EBSS)
- the Capital Expenditure Sharing Scheme (CESS)
- the Service Standards Performance Incentives Scheme (STPIS).

The EBSS and the CESS have been in place since 2013. The STPIS has been in place since 2008. We now have data to assess the effectiveness of the schemes and whether there is scope for improvement. We have also received consumer feedback on the EBSS and the CESS. In recent regulatory determinations for the Victorian and South Australian electricity distributors, consumers observed significant differences in expenditure forecasts and actual expenditure outcomes along with significant incentive rewards. Consumers are asking whether the incentive schemes are working as intended and providing value for money.

We received 16 submissions in response to our discussion paper from NSPs, retailers and consumer representatives. Following that, we published:

- a position paper in August 2022 and held a stakeholder forum, focusing on the CESS, to which we received a further nine submissions
- a draft decision in December 2022, to which we received a further 12 submissions.

This review is part of a broader program to incrementally improve our approach to regulation as reflected in the 'tilt' priorities outline in our Strategic Plan for 2020-25. Other elements of our program to improve network regulation include:

- our *Better Resets Handbook Toward Consumer Centric Network Proposals* (the Better Resets Handbook). This is designed to strengthen the reputational and procedural incentives on electricity networks in preparing their regulatory proposals and engaging with customers
- our review of incentive arrangements for export services
- refining our approach to benchmarking including the operating environment factors review we carried out in 2018 and the capitalisation review we are currently undertaking
- our 2022 review of rate of return parameters.

In addition, we report annually on electricity network performance and benchmarking outcomes. This year we are enhancing our reports with a new web-based electricity network performance dashboard, new export services performance reports, and timelier exploration of focus areas. These enhancements will provide additional transparency about network performance.

2. Efficiency Benefit Sharing Scheme

2.1 About the EBSS

How the EBSS works

The EBSS provides NSPs with incentives to undertake efficient opex during a regulatory control period. It allows NSPs to retain the benefit (or incurs the cost) of outperforming (underperforming) against opex forecasts for 6 years.

The scheme maintains incentive levels through the regulatory control period. Without the EBSS the NSP only retains efficiency gains for the balance of the regulatory control period, resulting in declining rewards for cost reductions as the regulatory control period progresses and low incentives in the final years. This can encourage NSPs to defer ongoing efficiency gains until early in the next regulatory control period.

The share of opex reductions retained by NSPs, in percentage terms, can be calculated by comparing the present value of six years of an opex reduction with the values of the opex reduction in perpetuity. At the time we released our Capital Expenditure Incentive Guideline 2013 we estimated the share of benefits from the EBSS going to consumers was around 70 per cent. We used this 30:70 ratio as the basis for setting the CESS sharing ratio. Since then, the value of the EBSS to NSPs has fallen and now the share going to consumers is around 80 per cent. The NSP's share of efficiency gains has fallen because of changes in rate of return parameters.

The rewards provided by the EBSS mean that NSPs have a strong incentive to reveal their true opex costs in forecasts. This information revelation property of the scheme helps us to more accurately forecast opex. The idea is we can observe expenditure outcomes and use them to set forecasts. In this way efficiencies are captured and carried forward as part of our revenue determinations. The available data suggests that consumers are benefiting. Opex costs have fallen on average by 30 per cent per customer since 2011/12 with corresponding reductions in revenues and prices.

Opex outcomes are typically used to set opex in year one of a regulatory period. We then forecast opex for the remaining years of the regulatory period by adjusting for factors such input price changes and output growth. We also forecast productivity improvements of 0.5 per cent each year. This is the revealed cost base-step-trend forecasting approach, which we describe in our *Expenditure forecast assessment guideline*.

We benchmark opex performance against other NSPs. If we find that an NSP is materially inefficient we typically adopt a lower opex forecast than the revealed actual opex costs. The size of the efficiency adjustment is determined by the benchmarking analysis.

Rule requirements

How the EBSS is currently applied is set out in the Efficiency Benefit Sharing Scheme Guideline.[1] Any changes we may make to the EBSS must be done so in a manner that will or is likely to contribute to the achievement of the National Electricity Objective (NEO).

In developing and implementing the EBSS, the NER require us to have regard to:[2]

- the need to provide NSPs with a continuous incentive to reduce opex

1 AER, *Better Regulation, Efficiency Benefit Sharing Scheme for Electricity Network Service Providers*, November 2013.

2 NER, cll. 6.5.8(c) and 6A.6.5(b).

- the desirability of both rewarding NSPs for efficiency gains and penalising them for efficiency losses
- any incentives that NSPs may have to capitalise expenditure
- the possible effects of the scheme on incentives for the implementation of non-network alternatives
- the benefits to electricity consumers likely to result from the scheme.

2.2 Final decision

Having now considered the submissions we have received from stakeholders, for the following reasons, the position we have reached in this final decision is to:

- retain the EBSS and its current design, which allows networks to retain efficiency gains for six years and delivers a sharing ratio (currently around 20:80) that changes as the rate of return parameters change
- improve transparency about opex outcomes.

We will also assess the appropriateness of the current 0.75 benchmark comparison as part of our benchmarking development work.

2.3 Stakeholder views

NSPs support retaining the EBSS. However, consumer representatives say we should be doing more:

- PIAC argues that incentive schemes should not reward NSPs that have average or low levels of productivity, that more emphasis should be placed on benchmarking, and that rule changes should be introduced to accommodate an increased emphasis on benchmarking.
- Similarly, the AEC suggested using benchmarking to drive opex efficiency of all networks closer to the efficiency frontier. In its response to our Discussion Paper the Network of Illawarra Consumers of Energy (NICE) favoured use of benchmarking over the current revealed cost incentive model, recognising that the rule changes would be required.
- The CCP and AEC suggest we consider menu regulation as previously adopted in the UK (where networks could choose a higher sharing ratio and lower expenditure target and vice versa).
- The AEC and CCP suggest we align the EBSS and CESS sharing ratios.

A summary of submissions is provided in Appendix A.

2.4 Discussion

Opex is largely recurrent and is for the most part well suited to a revealed cost incentive model. The data suggests the EBSS has contributed to significant efficiency gains and that consumers have benefited with lower prices.

However, consumer groups considered there is scope to improve opex forecasts and questioned the scale of EBSS payments to NSPs catching up to their more efficient counterparts. They also seek increased transparency about expenditure outcomes.

This section discusses questions raised by stakeholders:

- Should the AER place more emphasis on benchmarking?
- Should the AER apply menu regulation?
- Is there a case to align EBSS and CESS sharing ratios?

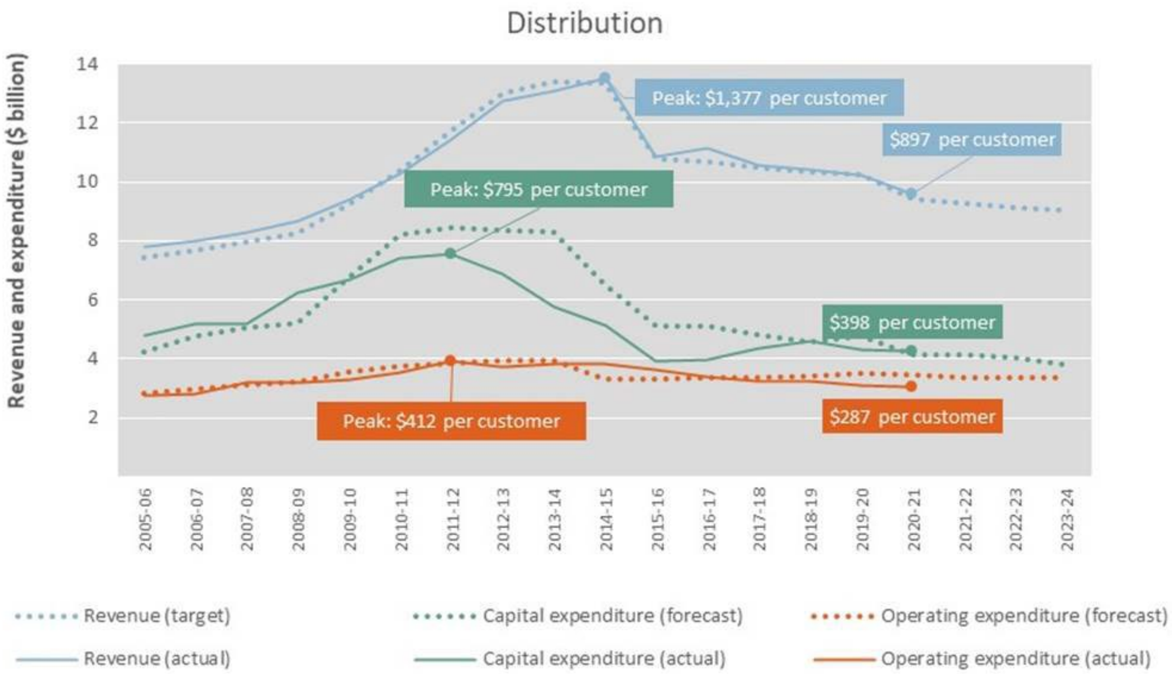
Benchmarking

The EBSS is a revealed cost model. We set opex forecasts, provide financial incentives for NSPs to reduce costs and then use the revealed costs as the basis for future opex forecasts.

While revealed cost is our primary forecasting tool, we recognise that not all NSPs respond to the EBSS in the way intended. For this reason, we introduced benchmarking in 2013 and applied it to several resets including Ausgrid and Evoenergy in 2015, and Power and Water Corporation in 2018. Benchmarking also influenced opex proposals submitted by networks such as Jemena and AusNet Services.

The EBSS combined with benchmarking has driven opex down significantly. Since 2012 total opex costs have trended down, opex per customer has fallen and measures of opex productivity have improved. The opex reductions translated into lower electricity distribution costs per customer as shown in Figure 1. Opex per customer fell from $412 in 2011/12 to $287 in 2020/21, a reduction of 30 per cent in real terms. Opex costs fell for electricity transmission customers as well, from $68 per customer in 2015/16 to $57 in 2020/21, a 16 per cent real reduction.

Figure 1: Revenue and expenditure, electricity distributors, $m 2020



Source: AER analysis

We should see further improvements in opex performance with the recent introduction of productivity forecasts. We now forecast productivity growth of 0.5 per cent per annum for electricity distributors, or 2.5 per cent over a five-year period. This anticipates future productivity gains and is based on an assessment of utility wide performance over an extended period.

A question raised by consumer submissions is whether we should apply benchmarking more aggressively in setting opex forecasts. Our current approach is to use a benchmarking comparison point of 0.75 to determine material inefficiency. This means that we use revealed costs if an NSP's benchmarked opex efficiency is 75 per cent or more than the most efficient NSP. If an NSP falls below this comparison point, we use benchmarking to make an efficiency adjustment to revealed opex.[3]

We err on the side of caution before departing from our revealed cost approach given the different circumstances facing each network. We take differences between networks into account in our benchmarking assessments, for example:

- our econometric modelling adjusts for network density
- our operating environment factors adjust for differences in vegetation management requirements
- we are reviewing capitalisation policies with a view to adjusting benchmarking results for different policies.

The judgement for the AER is whether benchmarking accuracy has improved enough to revise the 0.75 comparison point. Our final decision is to review whether it is appropriate to set a higher comparison point given the refinements we have made to our benchmarking modelling, operating environment factors and capitalisation policies. We will do this as part of our benchmarking development work.

Menu regulation

The CCP and AEC submissions encouraged us to consider menu regulation as previously adopted in the UK by Ofgem. Ofgem's approach was to establish its own forecast, and then allow the networks to choose between more ambitious expenditure forecasts and higher incentives, or less ambitious forecasts and lower incentives.

The CCP saw the approach as a potential way to differentiate between efficiency gains and gaming by the NSPs. Gaming occurs when NSPs overstate their expenditure requirements in order to receive incentive payments.

In practice, menu regulation is only effective as the regulator's initial forecasts. Information asymmetry challenges persisted with the scheme and ultimately Ofgem moved to different approaches, including more reliance on benchmarking, and differential sharing ratios depending on the robustness of forecasts[4].

Ofgem applies a confidence-dependent incentive rate, with 50% provided for high confidence costs and 15% for lower confidence costs. Ofgem considers factors such as historical costs, benchmarks and evidence of competitive tendering when determining whether costs are high confidence. In addition, NSPs are penalised 10% of the value of poorly justified lower confidence costs. Ofgem's approach aims to reward NSPs that reveal detailed cost information, do not overstate expenditure forecasts and achieve genuine efficiency improvements.

The AER has not opted for menu regulation because:

- The EBSS already has strong information revelation properties and combined with benchmarking has been successful in driving opex efficiency gains.
- Outcomes in the UK led Ofgem to move away from menu regulation.

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3 After taking into account operating environment factors.

4 RIIO-ED2 Final Determination Overview Document, Ofgem, November 2022

EBSS and CESS sharing ratios

As noted above, the benefits of NSP cost reductions are shared between consumers and NSPs. At the time we released our Capital Expenditure Incentive Guideline 2013 we estimated the share of benefits from the EBSS going to consumers was around 70 per cent. We used this 30:70 ratio as the basis for setting the CESS sharing ratio.

Since then, the value of the EBSS to NSPs has fallen and by 2020 the share going to consumers increased to around 80 per cent. The NSP's share of efficiency gains has fallen because of changes in rate of return parameters. We can expect some further changes in the sharing ratio as those rate of return parameters evolve in future.

The change in the EBSS sharing ratio creates an imbalance between CESS and EBSS incentives. The EBSS sharing ratio is now materially lower than the 30:70 ratio applied to the CESS. The imbalance may distort incentives by encouraging cost shifting from opex to capex or increasing management effort to cut capex compared to opex.

Two submissions in response to the draft decision asked us to consider aligning the sharing ratios. The AEC proposed increasing the EBSS sharing ratio to 30:70 in line with the CESS. The CCP also proposed alignment, though it incorrectly stated that this would require a reduction in the EBSS sharing ratio. At current rates of return, EBSS and CESS alignment would require an increase in the EBSS sharing ratio or a reduction in the CESS sharing ratio.

Our final decision is to retain the current approach of allowing networks to retain the benefits of opex reductions, relative to forecast opex, for six years. This is because:

- NSPs have continued to reduce opex with the lower EBSS sharing ratios.
- As noted in several submissions, there is limited discretion for NSPs to re-allocate costs between opex and capex as most expenses fall clearly into one category or another. Consistent with our position paper and draft decision, we do not see evidence that differences between the EBSS and CESS sharing ratios have distorted expenditure decisions.
- When reporting on opex and capex outcomes, NSPs must use the cost allocation methodology prescribed at the time the CESS was first introduced. This consistency allows stakeholders to meaningfully compare opex and capex over time.

In response to consumer group suggestions, the AER will improve transparency about opex outcomes and the balance between capex and opex spending. Along with the AER's annual network performance reports, this information should assist stakeholders assess these issues further in future.

3 Capital Expenditure Sharing Scheme

3.1 About the CESS

How the CESS works

The CESS, introduced in 2013, provides NSPs with an incentive to undertake efficient capex during each year of a regulatory control period. It achieves this by rewarding NSPs that outperform their capex allowance, and penalising NSPs that spend more than their capex allowance. The CESS also provides a mechanism to share efficiency gains and losses between NSPs and network users.

Similar to opex and the operation of the EBSS, without a CESS, a NSP faces incentives under the regulatory regime to achieve capex efficiencies that will decline over a regulatory control period. If a NSP makes an efficiency gain in the first year of a five-year regulatory control period, any benefit will last for four more years before any actual capex is rolled into the regulatory asset base (RAB). However, in the final year, the benefit will be close to zero. This may lead to inefficient capex decisions including inefficient substitution of opex for capex towards the end of a regulatory control period.

The CESS complements the rewards a NSP would already receive for an efficiency gain so the total benefit of an efficiency gain to a NSP will be the same in each year. The CESS also currently provides symmetric incentives in that the reward for an efficiency gain is equal to the penalty for an efficiency loss of the same quantum. The CESS was first implemented with a 30 per cent sharing ratio, which at the time, balanced the incentives between the CESS and the EBSS.

Rule requirements

How the CESS is currently applied is set out in the Capital Expenditure Incentive Guidelines.[5] The same framework that we applied to develop the Capital Expenditure Incentive Guidelines also applies to reviewing the CESS. In summary, any changes we may make to the CESS must be:

- done so in a manner that will or is likely to contribute to the achievement of the NEO
- consistent with the capital expenditure incentive objective, taking into account the capital expenditure criteria, the capital expenditure factors and the capital expenditure sharing scheme principles.[6]

We must take into account:

- that NSPs should be rewarded or penalised for improvements or declines in the efficiency of capex
- that any rewards and penalties should be commensurate with the efficiencies or inefficiencies in capex, but rewards and penalties do not need to be the same
- the interaction of the CESS with any other incentives the NSP has to undertake efficient capex or opex
- the capital expenditure objectives, and if relevant, the operating expenditure objectives.

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5 AER, *Better Regulation, Capital Expenditure Incentive Guideline for Electricity Network Service Providers*, November 2013.

6 NEL, s 16(1)(a); NER, cll 6.4A, 6.5.7, 6.5.8A, 6A.5A, 6A.6.7(c) and 6A.6.5A.

3.2 Final decision

Having considered the submissions we received from stakeholders in response to the draft decision, for the following reasons, the position we have reached in this final decision is the same as that in the draft decision. Namely, to:

- amend the Capital Expenditure Incentive Guideline to vary the CESS to:
  - implement the Bright-Line Tiered Test, which applies a 30:70 sharing ratio for underspends of up to 10 per cent, a 20:80 sharing ratio for underspends exceeding 10 per cent, and asymmetric application of the scheme so that a 30:70 sharing ratio applies for all overspends
  - provide us with the flexibility to determine whether and how to apply the CESS to transmission contingent projects
  - allow us to establish a separate CESS for contingent projects (rather than necessarily including the contingent project in the total capex 'bucket')
- require NSPs to provide further information to better and transparently explain the reasons for differences between our expenditure forecasts and the capital expenditure they have actually incurred as part of the Networks Information Requirements Review and the forthcoming regulatory information notices (RINs) that we will serve on SA Power Networks, Ergon Energy and Energex.

3.3 Stakeholder views

Consumer concerns

The CCP considered that the Bright-Line Tiered Test is a positive, albeit modest, development for consumers. However, the CCP continued to re-iterate its scepticism about the benefits of the incentive schemes and stated that we have not adequately addressed their concerns about whether the schemes have delivered better outcomes for consumers. Similar concerns were expressed by PIAC, the AEC, and in response to the position paper, Mr David Havyatt and Red Energy.

PIAC focussed on incentive payments for NSPs with average or below average performance and efficiency. PIAC argued that incentive schemes should not reward NSPs that have average or low levels of productivity, that more emphasis should be placed on benchmarking and that rule changes should be introduced to accommodate an increased emphasis on benchmarking.

The AEC is concerned about regulated supply costs and engaged Boardroom Economics to review our draft decision. Boardroom Economics recommended that we use benchmarking to drive NSPs closer to the opex efficiency frontier, align EBSS and CESS incentives, and review the case for totex in an Australian context.

Bright-Line Tiered Test

NSPs do not support changing the CESS on the basis that they consider the case to do so has not yet been made. However, were we to vary the CESS, from the perspective of minimising regulatory burden and maintaining simplicity, NSPs have expressed a preference for us to implement the Bright-Line Tiered Test. NSPs argued that there should be a 'high bar' for changes to regulatory arrangements to promote stability, the evidence does not support the proposed changes and that the tiered test is not costless because it blunts incentives to achieve large efficiencies.

The AEC does not support the Bright-Line Tiered test on the basis that it considers it will not incentivise more accurate forecasts.

As we noted above, the CCP considered the Bright-Line Tiered test a positive development for consumers, albeit a modest one. In response to the discussion paper, the CCP proposed diminishing incentives the higher the capex underspend. Their view was that gaming is more likely the higher the underspends. The Bright-Line Tiered test is consistent with the CCP's initial submission, though with a less aggressive reduction in incentive rates. The CCP's proposal was to progressively reduce CESS payments to zero when the gap between forecast and outcome reaches 10 per cent.

Asymmetric application of the CESS

The Bright-Line Tiered Test is asymmetric in nature because the tiered sharing ratio only applies to underspends. All overspends will remain subject to the existing 30:70 sharing ratio.

NSPs do not support this asymmetric approach because:

- existing regulatory mechanisms such as ex post reviews and increased consumer engagement address information asymmetry concerns
- it runs counter to our preference for symmetry expressed when developing the CESS in 2013
- information asymmetry as evidenced by the accuracy of forecasts is falling over time
- the energy transition is increasing the risk of higher capex requirements than anticipated.

Conversely, despite considering that the Bright-Line Tiered Test will result in only modest benefits for consumers, the CCP supported it being asymmetric. PIAC did not directly comment on asymmetry but expressed concern that the Bright-Line Tiered Test would lower the penalty that NSPs incur if they over-spend their allowance.

CESS: Large transmission projects

In the draft decision, we proposed providing ourselves with the flexibility to decide whether to apply the CESS to large transmission projects, and whether to apply a lower sharing rate than the standard 30 per cent.

The ENA, TNSPs and the CCP support the flexibility proposed. The CCP suggests we outline the criteria that the AER will apply when making our decisions.

A summary of submissions is set out in Appendix A of this final decision.

3.4 Discussion

Case to refine incentives

In the position paper, we stated that there are two principal competing considerations concerning the CESS. First, by its design, the CESS has the potential to reward a NSP for an underspend that is not the result of genuine efficiency gains. It is important to recognise that capex is generally less recurrent than opex, and accordingly, the benefit of the information we can derive from past capex about future capex is more limited. Second, since its introduction in 2013, the data we have collected so far strongly suggests that the CESS has worked well to provide incentives for NSPs to incur efficient capex.

The key question before us now is whether CESS rewards for underspends that are not genuine efficiency gains outweighs the incentives the CESS has provided to date for NSPs to incur efficient capex. Or more pointedly, whether the CESS remains fit for purpose. This is the crux of the issue that arises between the competing views of NSPs and consumer groups about the CESS.

At the outset, it is important to recognise that this question can only be considered in the context of the regulatory regime that is prescribed in the NEL and the NER. This regulatory regime assumes that a forecast capex allowance that we determine in a regulatory determination, taking into account all the information available at the time, is the efficient and prudent amount of capex for a NSP to incur during a regulatory control period. The CESS works well if all underspends represent genuine efficiency gains. However, the extent to which an underspend that results in a reward payment to a NSP under the CESS genuinely reflects an efficiency gain, or is the result of forecast error, or in recent times a deferral due to the Covid-19 impact, can be difficult to ascertain.

This is due to the information asymmetry that exists between us, consumers and the NSPs. However, the level of information asymmetry between us and the NSPs inevitably reduces over time as we progressively better understand how each NSP operates in practice. That said, we recognise that forecast capex that we determine is efficient for a NSP to incur can never be a fully accurate representation of what a NSP might need to incur during a regulatory control period. Nor can such an allowance ever be said to be completely devoid of any forecast error. In practice, this means that the CESS will reward a NSP for an underspend irrespective of whether that underspend is the result of genuine efficiency gains or forecast error on our part. If a NSP is rewarded because of forecast error, this erodes the benefits of the CESS for consumers. At one extreme, if the forecast errors are large enough, consumers may be worse off because of the CESS: the quantum of the CESS payments to an NSP may exceed the efficiency gains made.

The extent to which forecasting errors are a problem, must be viewed in light of improving overall accuracy of our forecasts over time and the reduction of the information asymmetry between us and the NSPs. Lower forecast error is the corollary of more accurate forecasts. This has been the result of our significant investment in the regulatory tools over the years that we use to assess and determine an NSP’s capex and opex forecasts, which are now well-developed. This includes:

- applying our replacement capex (repex) model to forecast replacement costs by asset category based on the age profile of assets, revealed replacement rates and revealed unit costs which allows us to benchmark and compare unit costs and replacement rates across NSPs
- using revealed unit costs to forecast connections and augmentation expenditure
- adjusting CESS payments for deferrals that we identify
- similar to opex, applying a base, step and trend approach for IT and vehicles
- subjecting particular capex projects to detailed engineering reviews
- our guidance notes on Consumer Energy Resources Integration expenditure, actionable integrated system plan projects and replacement modelling for transmission that emphasises the need for economic risk-based planning
- relying on market tested outcomes for major projects where possible (for example, for Transgrid’s component of the South Australia to New South Wales interconnector, we used tendered costs as the basis for our forecast).

Our Better Resets Handbook further supplements these tools. The Better Resets Handbook provides reputational incentives for NSPs to improve their processes and regulatory proposals by establishing principles for good regulatory proposals and better consultation with consumers. In particular, the Better Resets Handbook sets out our clear expectations on the process, and what constitutes and is required, of a proper proposed capex forecast. Meeting these expectations is part of reducing the level of information asymmetry that exists between the NSPs and us.

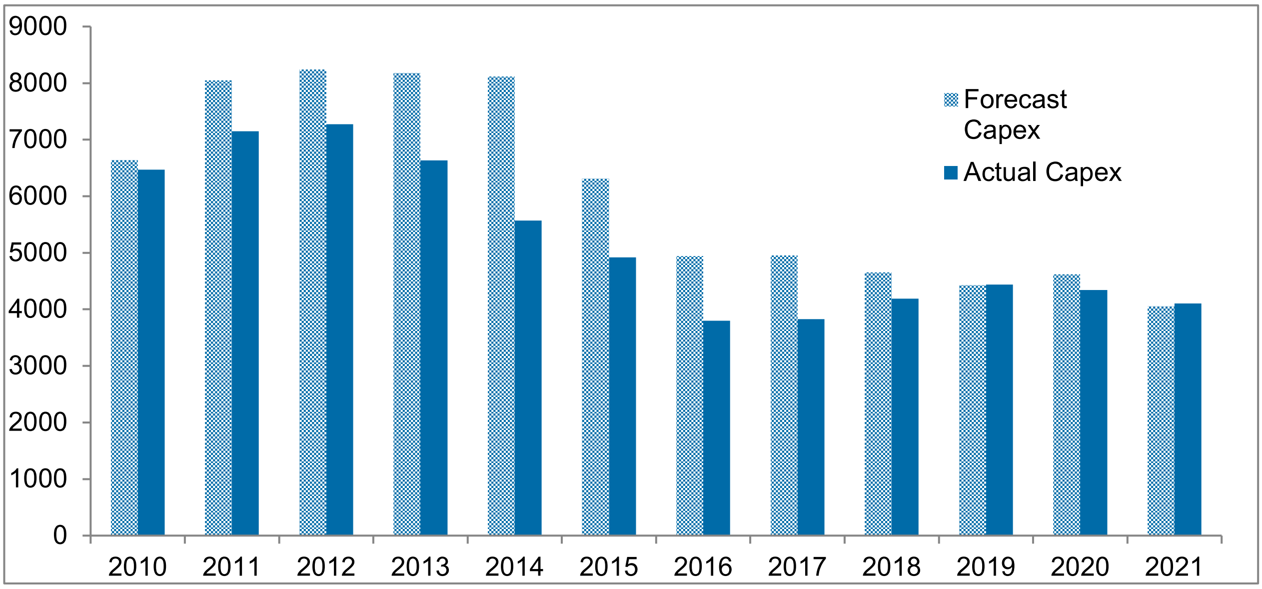
The improvements in the accuracy of our forecasts over time is shown in Figures 2 and 3.

Figure 2 shows forecast and actual aggregate electricity distribution capex by year from 2011 to 2021. Capex peaked in 2012, fell substantially over the next four years to 2016 and has been relatively stable since then. Forecast error fell over the period and has averaged at 5 per cent over the four years from 2018 to 2021.

Figure 3 compares the level of aggregate distribution and aggregate transmission capex under or overspending over the last two full regulatory control periods, and the current regulatory control period.[7] It shows that NSPs underspending relative to our forecasts reduced significantly over the three regulatory control periods. For distribution network service providers (DNSPs), the average underspend has fallen from around 18 per cent in the first regulatory control period to around 7 per cent now.

For TNSPs, an underspend of some 28 per cent in the first regulatory control period in is now an overspend of around 5 per cent. This is despite transmission being generally harder to forecast because it is less recurrent and has more project 'lumpiness' with significant major projects including new interconnectors.

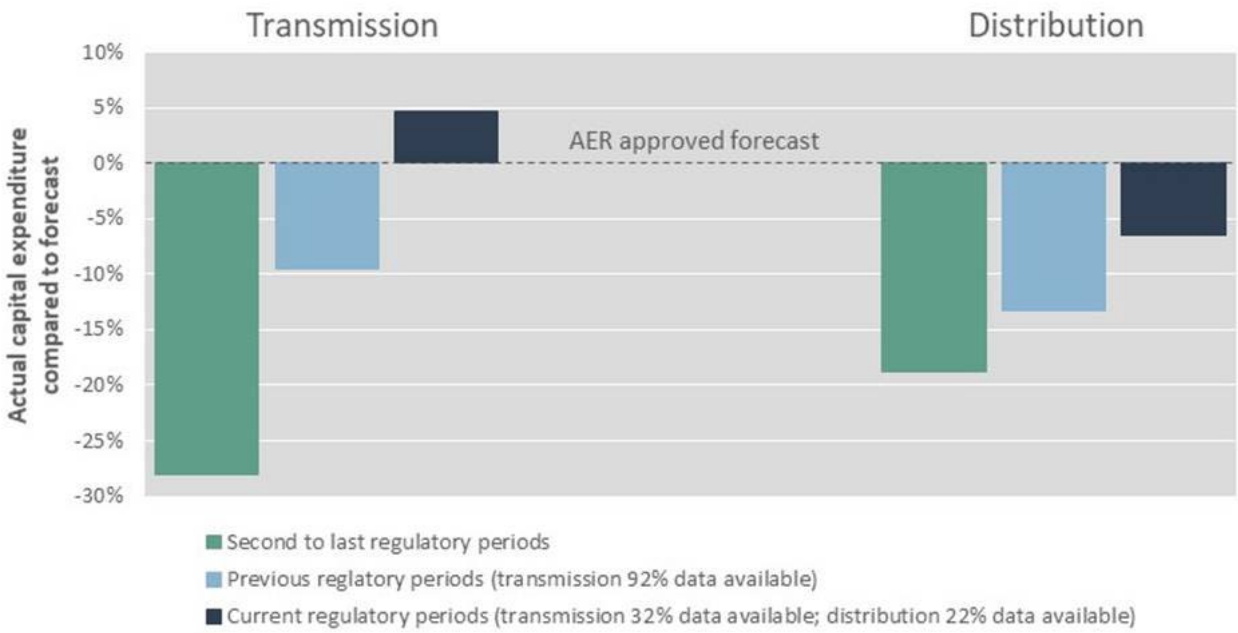
Figure 2: Forecast and actual electricity capital expenditure by year ($m 2021)



Source: AER data

7 For DNSPs, the current regulatory control period is 2021-25 for VIC, QLD and SA, and 2020-24 for NSW and ACT. The previous regulatory control period is 2016-20 for VIC, QLD and SA, and 2015-19 for NSW and ACT. The second to last regulatory control period is 2011-15 for VIC, QLD and SA, and 2010-14 for NSW and ACT.

Figure 3: Actual capital expenditure compared to forecast



Source: AER data

However, whilst the accuracy of our forecasts has improved over time, this improvement has not been equally realised for each NSP. This can be seen in Table 1, which sets out each DNSP's underspending:

- in the last full regulatory control period (column 2)
- compared to our final decision for the previous regulatory control period (column 3)
- compared to how much the DNSP proposed in the following regulatory control period (column 4).

Table 1: Capital expenditure compared to AER forecast by distribution network

DNSP	Underspend in previous regulatory control period	Final decision compared to actuals in previous regulatory control period	Initial proposal compared to actuals in previous regulatory control period
AusNet Services	-15%	-18%	-14%
CitiPower	-32%	3%	49%
Jemena	-23%	9%	7%
Powercor	-14%	0%	24%
United Energy	-22%	17%	58%
SA Power Networks	-16%	-5%	2%
TasNetworks	7%		29%
Evoenergy	2%	-8%	-3%
Ausgrid	-16%	-5%	6%
Endeavour Energy	-6%	9%	8%
Essential Energy	-16%	-6%	-5%
Energex	-12%	-21%	-20%
Ergon Energy	-3%	-24%	-8%
All distribution networks	-13%	-18%	-14%

Notably, there is a wide disparity between DNSPs in their initial proposals. Column 4 shows that some networks proposed a significant step up in capex compared to what they actually incurred in the previous regulatory control period, and similarly that our final decision was significantly lower than some of the networks' initial proposals (column 4).

For example, some of the Victorian electricity DNSPs underspent in the previous regulatory period and then requested a step up in capex, while AusNet Services underspent its capex in the previous regulatory period and then proposed a further step down in spending. AusNet Services went through the NewReg trial and consulted with its customers in forming its regulatory proposal. The end outcome was positive for consumers on its network.

Our experience in making the final decisions for Victorian DNSPs suggests that we have the tools available to provide reasonable capex forecasts. However, the Victorian experience also highlights variability in the quality of proposals and the level of consumer engagement undertaken in developing the proposals.

In this context, the purpose of the CESS is to provide a NSP with an incentive by rewarding a NSP for being even more efficient in incurring capex than our forecast assumes, and conversely, a penalty if a NSP is not as efficient as our forecast assumes. In other words, the CESS encourages a NSP to underspend against our approved forecast.

Incentives to outperform forecasts are consistent with the CESS principles and the capex incentive objective in the NER. The CESS principles provide that a NSP should be commensurately rewarded or penalised for improvements or declines in efficiency of capex whilst allowing for such rewards or penalties to differ.[8] The capex incentive objective is aimed at only including prudent and

8 NER, cll 6.5.8A(c) and 6.5.8A(d).

efficient capex (that which reasonably reflects the capex criteria) in the Regulatory Asset Base (RAB).[9]

As noted above, the key question for us is whether benefits to consumers from improvements in efficiency offset CESS payments. While we consider that our incentive schemes have provided significant net benefits for consumers, we also consider that there is scope to improve the CESS and to further improve our forecasts. Recent expenditure outcomes in Victoria and South Australia have revealed that more can be done to reduce the level of forecast error, and in turn, the possibility of a NSP being rewarded for non-genuine efficiency gains.

There are several ways we can reduce forecast error. As discussed above, we have invested in our expenditure assessment toolkit, and we have improved engagement between NSPs and consumers through our Better Resets Handbook. A further initiative from this review is to improve transparency about regulatory outcomes. We discuss this further in section 5 of this final decision. We are also implementing the Bright-Line Tiered Test.

Applying lower sharing ratio when an underspend is more than 10 per cent may improve the proposals submitted by NSPs. This is because applying a lower sharing ratio in those circumstances could reduce CESS payments a NSP would otherwise benefit from under the current CESS, thereby reducing incentives to overstate capex requirements.

The improved capex forecasts that flow from these initiatives are in the long-term interests of consumers.

Finally, in response to the draft decision, the CCP submitted that throughout this review we have not adequately addressed their concerns about whether consumers benefit from incentive schemes. Whether consumers are better off with us applying the Bright-Line Tiered Test, or incentive schemes at all, is a question that goes to the design of the overall regulatory regime in Chapters 6 and 6A of the NER. It is not possible to precisely identify the extent to which a NSP may have gamed the process in outperforming its allowance. What can, however, be said is that the data shows significant reductions in opex and capex and convergence between our forecasts and outturn expenditures over time. Our judgement based on the data is that consumers have and will continue to benefit in net terms from the CESS and EBSS.

Bright-Line Tiered Test

In the position paper and the draft decision, we presented several options about how the CESS may be varied. For reasons of predictability, certainty, simplicity and minimising regulatory burden, the position we reached in the draft decision was to vary the CESS to implement the Bright-Line Tiered Test. The Bright-Line Tiered Test applies:

- a 30 per cent sharing ratio for any underspend up to 10 per cent of the forecast capital expenditure allowance in the previous regulatory control period
- a 20 per cent sharing ratio for any underspend that exceeds 10 per cent of the forecast capital expenditure allowance in the previous regulatory control period
- a 30 per cent sharing ratio for any overspend of the forecast capital expenditure allowance in the previous regulatory control period.

As discussed above, whilst the NSPs do not consider we have yet made the case for change, were we to vary the CESS, most NSPs support us implementing the Bright-Line Tiered Test. The CCP considers that the Bright-Line Tiered Test is a positive development for consumers, albeit modest. Having regard to these views, the position we reached in the draft decision to implement the Bright-Line Tiered Test has not changed in this final decision.

[9] NER, cll 6.4A(a) and 6.5.8A(b).

Asymmetric application of the CESS

The design of the Bright-Line Tiered Test is asymmetric. The 20 per cent sharing ratio will not be applied to any overspend in excess of 10 per cent of the forecast capex allowance. The NSPs do not support us asymmetrically applying the CESS, whereas the consumer representatives do.

Our reasons to apply the CESS asymmetrically are:

- Consumers are concerned that the CESS encourages NSPs to over-state their forecast capex requirements. Despite improvements in our assessment toolkit and stakeholder engagement, a level of information asymmetry between us, consumers and the NSPs remains. Therefore, the risk of over forecasting capex requirements remains higher than under forecasting. Given this, applying the Bright-Line Tiered Test asymmetrically has the effect of providing an offset to potential asymmetry in forecast error.
- Generally, the level of information asymmetry that exists between NSPs, consumers and us is greater in setting capex forecasts than it is in setting opex forecasts. This arises because capex is generally less recurrent than opex (particularly in transmission). Accordingly, we consider it appropriate to have symmetry in the EBSS and asymmetry in the CESS.
- The approach proposed is consistent with the overall design of the regulatory regime that is prescribed in the NER. For example, the NER already allows for us to undertake an ex-post review to exclude overspends that we consider are not efficient. The ex-post review is itself asymmetric, as there is no ability for us to undertake an ex-post review of an underspend. Similarly pass throughs are available to NSPs for material new requirements and obligations. While notionally symmetric, pass throughs are typically applied when there are additional cost pressures.

CESS: Large transmission projects

The position we have reached in this final decision is to provide ourselves with the flexibility to decide whether, or how, the CESS should be applied to transmission contingent projects. We may also determine whether to apply a separate CESS for contingent projects (rather than necessarily including the contingent project in the total capex ‘bucket’). This is necessary if we are to apply a different CESS sharing rate for contingent projects compared to other capex.

The factors we will consider in deciding whether and how to apply the CESS to a transmission contingent project are set out in the Capital Expenditure Incentive Guideline. They are:

- the TNSP’s CESS and capital expenditure proposals
- benefits to consumers from the exemption
- the size of the project
- the degree of capital expenditure forecasting risk[10]
- stakeholder views.

This will add to existing flexibility that the NER provides for us to specify how we may apply the CESS to a DNSP or a TNSP in a framework and approach paper prior to the commencement of a regulatory control period.[11] Whilst our default position is to apply the CESS without variation, it remains open for a DNSP, a TNSP or another interested stakeholder, to make a submission to us about why this should not be the case.

10 Taking into account, for example, the extent to which a project is already outsourced and subject to contract terms.

11 NER, cll 6.8.1(b)(2)(v) and 6A.10.1A(b)(3).

4 Service Target Performance Incentive Scheme

4.2 About the STPIS

How the STPIS works

The STPIS provides NSPs with incentives to maintain and improve network performance by rewarding NSPs that outperform service performance targets and penalising NSPs that underperform service performance targets. This balances the incentives in the EBSS and CESS to reduce expenditures. The objective is to drive expenditure reductions through efficiency gains rather than at the expense of service levels to customers. There are separate service performance schemes for electricity DNSPs and electricity TNSPs. There are no schemes for gas networks.

For electricity DNSPs, the focus is the frequency and duration of interruptions to supply. Reliability is measured by a combination of System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI) and Momentary Average Interruption Frequency Index (MAIFI). This is measured for each segment of the network — CBD, urban and rural.

Reliability targets are typically based on the level of reliability achieved by a NSP over a recent period. These targets are then updated every 5 years as part of the regulatory determination process.

The rewards for improving reliability (and the penalties for declines in reliability) are based on the value that customers place on improved reliability. We undertook a review of the value of customer reliability in 2019 and use the outcome in setting the STPIS targets.

TNSPs typically have higher levels of redundancy and reliability than DNSPs. In this context, the focus of the STPIS for TNSPs focuses on the impact of outages. This scheme has three components:[12]

- *Service component.* The service component provides a reward or penalty of plus or minus 1.25 per cent of the maximum allowed revenue based on the number of unplanned network outages and how quickly unplanned outages are restored.
- *Network capacity component.* The network capability component provides incentive payments to transmission NSPs to undertake small, high net benefits projects. These projects are expected to have a short payback period and deliver improvements in the capability of the transmission network at times when it is most needed.
- *Market impact component.* The market impact component provides an incentive to TNSPs to minimise the impact of transmission outages that affect wholesale market outcomes. The market impact component measures performance against the market impact parameter, which is the number of dispatch intervals where an outage on the transmission network results in a network outage constraint[13] with a marginal value greater than $10/MWh (known as the ‘MIC count’).[14]

12 AER, *Final – Service Target Performance Incentive Scheme,* October 2015, cl. 2.2(a).

13 Network outage constraints are constraint sets that are applied in AEMO's market systems to manage power flows during outages so that the power system remains secure during an outage.

14 AER, *Final – Service Target Performance Incentive Scheme,* October 2015, Appendix C.

Rule requirements

As required by the NER, we have developed and published a distribution STPIS and a transmission STPIS.[15] The same framework that we applied to develop the distribution and transmission STPIS also applies to our review of the STPIS. In summary, any changes we may make to the STPIS must be done so in a manner that will or is likely to contribute to the achievement of the NEO, and for the distribution STPIS, take into account:[16]

- the need to ensure that benefits to consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for DNSPs
- any regulatory obligation or requirement to which the DNSP is subject
- the past performance of the distribution network
- any other incentives available to the DNSP under the Rules or a relevant distribution determination
- the need to ensure that the incentives are sufficient to offset any financial incentives the service provider may have to reduce costs at the expense of service levels
- the willingness of the customer or end user to pay for improved performance in the delivery of services.

For the transmission STPIS, we must be guided by the following principles that the STPIS should:[17]

- 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
- take into account the regulatory obligations or requirements with which TNSPs must comply
- take into account any other incentives provided for in the Rules that TNSPs have to minimise capital or operating expenditure
- take into account the age and ratings of the assets comprising the relevant transmission system.

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15 AER, *Electricity distribution network service providers: Service Target Performance Incentive Scheme – Version 2*, 14 November 2018; AER, *Electricity Transmission Network Service Provider Service Target Performance Incentive Scheme – Version 5*, 17 September 2015; NER, cll 6.6.2 and 6A.7.4.

16 NEL, s 16(1)(a); NER, cl 6.6.2(b).

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

4.3 Final decision

Having considered the submissions we received from stakeholders in response to the draft decision, for the following reasons, the position we have reached in this final decision is the same as that in the draft decision, namely to:

- retain the distribution STPIS as is
- retain the service component of the transmission STPIS as is
- undertake a review of the MIC of the transmission STPIS, and the related Network Capability Incentive Parameter Action Plan (NCIPAP) scheme, in the second half of 2023 in time for the next Queensland and South Australian transmission resets.

4.4 Stakeholder views

Submissions focused on transmission and the MIC component of the STPIS.

The current method sets future targets based on historic data. However, high investment in variable renewable energy generation is creating greater and more widespread congestion, significantly increasing network constraints above historical averages. TNSPs consider that they are being penalised for changes in the generation mix rather than their performance. They propose a review of the MIC component of the STPIS to consider target setting (use of historic averages) and the behaviour to be incentivised (scheduled verses dynamic responses to emerging congestion).

The TNSPs proposed an urgent review of the transmission STPIS on the basis that the method for setting performance targets is no longer fit for purpose. In its response to the draft decision, TasNetworks proposed that we complete the review in time for their upcoming 2024−29 regulatory control period.

4.5 Discussion

Transmission STPIS

All the TNSPs seek a review of the MIC component of the STPIS.

The MIC rewards TNSPs for minimising the market impact of outages, whether planned or unplanned. The MIC was established because TNSPs often scheduled planned outages at times of high demand when the outage would cause significant financial penalties for generators and other market participants. The scheme is working to incentivise management of network congestion as designed.

At the same time the data shows increasing congestion because of the transition to renewables. Increasing congestion risks penalising TNSPs for factors which are outside their control.

Targets for the MIC are set through the revenue determination process for each TNSP. The target is calculated by averaging the median 5 of the last 7 years of annual performance measure data.[18] TNSPs receive a reward or penalty of up to ±1 per cent of the maximum allowable revenue for the relevant calendar year. Because solar and wind generation investment is adding to congestion, historic performance measures are no longer an accurate indicator of likely future performance.

[18] The target will be calculated from the average of the 5 values remaining from the last 7 years of annual performance measure data, excluding the largest and smallest annual values.

In addition, several developments will affect regulation of TNSPs. These include the Energy Security Board's post-2025 Market Design, the Australian Energy Market Commission's investigation of system strength frameworks in the National Electricity Market, the outcomes of the Coordination of Generation and Transmission Investment review, and the implementation of actionable projects under the Australian Energy Market Operator's (AEMO) integrated system plan.

It is prudent to review the MIC of the STPIS in light of the increasing transmission congestion and the transmission reviews currently underway. The position we have reached in this final decision is to undertake a review of the MIC starting towards the end of 2023, in time for the next Queensland and South Australian transmission reset processes. While the review is unlikely to be completed in time for TasNetworks' reset, there may be scope to introduce the new MIC measures part way through the regulatory control period.

In the meantime, we have just released a guidance note on the MIC[19] and will continue to work with TNSPs on a case-by-case basis to determine appropriate performance targets within each revenue determination.

Submissions commented on one other transmission service standards issue, the Network Capability Incentive Parameter Action Plan (NCIPAP). The NCIPAP scheme incentivises opex and minor capex that results in:

- improved capability of those elements of the transmission system most important to determining spot prices, or
- improved capability of the transmission system at times when transmission network users place greatest value on the reliability of the transmission system.

The scheme is based on business case analysis and outcomes are generally considered project by project.

There is also a case to review the NCIPAP when we review the MIC. While the scheme has generated several projects and encouraged TNSPs to explore non-network initiatives to address transmission capability, circumstances have changed. AEMO and TNSPs now work more closely together on transmission planning including in developing options and undertaking cost-benefit assessments. Given the new planning arrangements there is a question about whether the NCIPAP is still required. We also note the scheme is administratively complex for all parties. Therefore, the position we have reached in this final decision is to review the NCIPAP scheme alongside the MIC review.

Distribution STPIS

Submissions generally consider that the distribution STPIS is fit for purpose, though the CCP recommended less reliance on incentive payments and more on penalties, while the DNSPs raised some implementation issues.

Over time, the STPIS has contributed to improvements in the number and duration of distribution outages with the scheme. Between 2006 and 2020, the average number of interruptions per

19 Guidance Note: Transmission Service Performance Incentive Scheme – Clarification of data period and exclusion definitions in the market impact component, April 2023

customer per year declined by 0.68, or 38 per cent. Similarly, between 2006 and 2020, the average duration of outages reduced by 26 minutes or 18 per cent.

The position we have reached in this final decision is to retain the distribution STPIS in its current form:

- the scheme has successfully contributed to improved service performance
- we reviewed the scheme in 2018 and the value of customer reliability in 2019
- we consider the approach of linking performance incentives to the value of customer reliability remains appropriate.

5 Improved transparency

Our review of the EBSS, the CESS and the STPIS has identified an opportunity for us to improve the transparency of, and the reasons for, differences between our expenditure forecasts and the actual expenditures incurred by NSPs during a regulatory control period. Improved transparency will better inform consumers and us about the extent to which any underspends incurred by a NSP reflect genuine efficiency gains.

A clear case exists for NSPs to be more transparent about the reasons for any differences between actual capex incurred and our approved forecasts in each regulatory control period. In addition to the criteria set out in the Better Resets Handbook about what we expect from a robust capex forecast in a regulatory proposal, there is also a clear case for NSPs to explain how actual capex outcomes in one regulatory control period relate to any proposed forecasts in a regulatory proposal for the following regulatory control period.

The position we have arrived at in this final decision is to require NSPs to explain:

- why actual expenditure incurred by a NSP departs from a forecast capex allowance we have determined in a given regulatory control period
- how any such departure is consistent with capex proposed in a regulatory proposal for the following regulatory control period
- if NSPs have achieved efficiencies, how
- where capex projects or programs have been deferred from one regulatory control period to the next, and the reasons for those deferrals
- the extent to which changes beyond the control of an NSP, including regulatory obligations, customer demand, and environmental issues may be relevant.

The CCP has proposed that the information should be provided as a ‘narrative’ to assist consumers understand differences between expenditure outcomes and forecasts. This approach is consistent with our Better Resets Handbook. The Better Resets Handbook establishes ‘early signal pathways’ for select NSPs, with extensive consumer consultation processes before NSPs lodge their revenue proposals. The Better Resets Handbook provides guidance on what information the NSPs should include as part of their early engagement. Amongst other things, the approach requires NSPs to explain differences in forecast expenditure and outcomes.

The transparency measures in this final decision build on the Better Resets Handbook by requiring all NSPs to participate and by better defining information requirements. The additional information or ‘narrative’ will help to empower consumers when they participate in NSP consultation processes, allowing them to more meaningfully scrutinise NSP proposals.

We place considerable weight on outcomes of NSP consumer engagement. If NSPs have run good consultation processes and consumers are supportive, we are more likely to accept a proposal. By contrast if consumers are not supportive, or the consultation process is inadequate, we are likely to scrutinise proposals more intensively.

We will revisit these matters as part of the Networks Information Requirements Review that we are currently conducting, which commenced on 23 March 2022,[20] and our consultation from March

[20] AER, *Network Information Requirements Review: Discussion paper*, March 2022.

2023 on the regulatory information notices (RINs) for the forthcoming regulatory proposals for SA Power Networks, Ergon Energy and Energex.

These consultation processes will provide us with an opportunity to engage with consumer groups to properly identify the information we should seek from NSPs to better understand and improve the transparency about differences between our expenditure forecasts and actual expenditures incurred. Our intention is for NSPs to provide a narrative, as recommended by the CCP, that explains differences between capex outcomes and forecasts in a way that is both comprehensive and accessible to stakeholders.

To this end, we propose to include a requirement in the RINs for a NSP to provide detailed information on the factors that have materially impacted the level of actual expenditure incurred in comparison to the forecast expenditure allowance that we approved for a regulatory control period. We will also be requiring the detailed information to address any relevant underlying circumstances, and any changes in the assumptions that were made and underpinned the forecast expenditure allowance. Finally, we are also considering staging these requests for information. For example, to require SA Power Networks, Ergon Energy and Energex to provide by:

- 31 January 2024, detailed information for the first three regulatory years of the 2020-25 regulatory control period
- 31 October 2027, detailed information for each regulatory year of the 2020-25 regulatory control period and the first two regulatory years of the 2025-30 regulatory control period.

6 Final decision

For the reasons discussed above, the positions we have reached in this final decision are to:

- retain the EBSS as is
- amend the Capital Expenditure Incentive Guideline to vary the CESS to:
  - implement the Bright-Line Tiered Test, which applies a 30:70 sharing ratio for underspends of up to 10 per cent, a 20:80 sharing ratio for underspends exceeding 10 per cent, and asymmetric application of the scheme so that a 30:70 sharing ratio applies for all overspends
  - provide us with the flexibility to determine whether and how to apply the CESS to transmission contingent projects
  - allow us to establish a separate CESS for contingent projects (rather than necessarily including the contingent project in the total capex 'bucket')
- require NSPs to provide further information to better explain the reasons for differences between our expenditure forecasts and the actual expenditures as part of the Networks Information Requirements Review and the forthcoming regulatory information notices (RINs) that we will serve on SA Power Networks, Ergon Energy and Energex
- retain the distribution STPIS as is
- retain the service component of the transmission STPIS as is
- assess the appropriateness of the current 0.75 benchmark comparison point as part of our benchmarking development work
- undertake a review of the MIC of the transmission STPIS, and the related Network Capability Incentive Parameter Action Plan (NCIPAP) scheme, commencing in late 2023.

In terms of timing, we will apply the new measures at the start of the next NSW, ACT and Tasmanian regulatory control periods and then at the start of future regulatory control periods for other NSPs. We propose to apply any future changes to the STPIS and related schemes in 2024 and apply them to the next transmission resets in SA and Queensland.

APPENDIX A: Summary of stakeholder submissions in response to the Draft Decision

Stakeholder	Key points
Australian Energy Council Boardroom Economics	1. Retailers are concerned about regulated supply costs and that the benefit to networks of the incentive framework is excessive and leads to consumers paying more than necessary for their energy supply. 2. Boardroom Economics recommended we: ▪ use additional regulatory tools, such as menu regulation (adopted by OFGEM) to incentivise more accurate expenditure forecasts ▪ use benchmarking to drive opex efficiency of all networks closer to the efficiency frontier ▪ abandon the bright line step down in capex incentive strength for large underspends on the basis that it does not incentivise more accurate forecasts ▪ equalise incentives for capex and opex by setting the EBSS strength at 30 per cent and consider the use of totex in an Australian context ▪ use the proposed transparency requirements to compare NSP forecasts and actual costs, rather than AER allowances and actual costs.
Ausgrid	1. Supported the ENA's submission. 2. The Bright-Line Tiered Test should be applied symmetrically because forecast error is equally likely to be below as above actual requirement. The CESS should not be applied asymmetrically. There are measures to address forecast error such as ex post assessments.
AusNet Services	1. Supported the ENA's submission. 2. The CESS should not be applied asymmetrically because information asymmetry as evidenced by the accuracy of forecasts is falling over time, there is increased consumer engagement, and the energy transition is increasing the risk of higher capex requirements than anticipated. 3. Supported the proposed transparency measures in principle, noting that the measures may impose additional costs on NSPs. The benefits of additional requirements should be balanced against the costs.
Citipower, Powercor & United Energy	1. Supported the ENA's submission. 2. CPU has initiated improvements to its tracking of actual spending compared to forecasts as a first step in implementing the new transparency measures. 3. Asymmetric application of the CESS is not appropriate because there is a higher likelihood that NSPs will over rather than under spend in future because of the risk of new government initiatives in the context of the carbon transition. 4. Similarly lack of trust in forecasts when under-spending is more than 10% applies equally to underspending. Over-spending of more than 10% means it is likely that something material has changed, for example forecasting assumptions or the macro environment.
Consumer Challenge Panel	1. Overall, the draft decision does not address consumer concerns about the EBSS, CESS and STPIS. The CCP questions whether the schemes have delivered better outcomes for consumers. A primary concern is that incentives reward gaming as well as genuine efficiency. The CCP wants the AER to be more ambitious in addressing gaming risks. 2. The proposed asymmetry of the CESS between the treatment of under- and overspends is a positive, albeit modest, development for consumers. 3. The CCP recommended we: ▪ Adjust (reduce) the EBSS so that the sharing arrangements under the two schemes remains aligned following its proposed amendment to the CESS.

Stakeholder	Key points
	▪ Better explain how the AER will use the transparency narrative, and how it will respond to an inadequate narrative. ▪ Outline the criteria that it will apply when assessing whether a TNSP is provided access to an incentive scheme. ▪ Explain how its proposal responds to the concerns raised by consumers and the CCP.
Energy Networks Australia	1. Supported retaining EBSS, CESS and STPIS noting the efficiency benefits to date and improved service quality. 2. Supported the proposed transparency measures: ▪ the CCP's focus on the narrative to explain the gap between forecast capex and outcomes rather than further detailed data collection ▪ consultation on the transparency measures as part of the Network Information Requirements Review. 3. Supported flexibility in applying the CESS to large transmission projects. 4. Supported a review of the MIC component of the Transmission STPIS and recommends completing the review in time to apply to TasNetworks' next regulatory period (2024 to 2029). 5. Does not support changes to the CESS: ▪ there should be a 'high bar' for changes to regulatory arrangement to promote stability ▪ evidence does not support the proposed changes ▪ of the potential variable CESS rate options proposed, the bright-line tiered test performs well from the perspective of minimising regulatory burden and maintaining simplicity ▪ while simple and relatively easy to administer, the tiered test proposed is not costless because it blunts incentives to achieve large efficiencies. 6. Does not support the CESS being applied asymmetrically: ▪ it is unnecessary given ex-post reviews and evidence of improved AER forecast accuracy ▪ it runs counter to the AER's preference for symmetry expressed when developing the CESS in 2013.
Essential Energy	1. Supported the ENA's submission. 2. Rigorous review processes and increased stakeholder engagement by NSPs reduces the risk of unrealistic capex forecasts being approved. Further, weather extremes and the fast-evolving energy landscape increase the risk of overspends. Together these factors mean asymmetric application of the CESS is not appropriate. 3. Supported additional transparency and seeks a consultation process as part of the Network Information Requirements Review to determine whether additional measures proposed are practical and meet the intended outcomes. 4. Comfortable with the CESS being applied in the upcoming regulatory control period.
Evoenergy	1. Is receptive to applying the new arrangements to the upcoming regulatory period. 2. Noted uncertainty of capex in the context of the energy transition in the ACT 3. Preferred a symmetric application of the CESS.
Marinus Link	1. Supported the current incentives framework noting the significant efficiency gains made to date.

Stakeholder	Key points
	2. The case for the bright-line tiered test has not been made and it may deter genuine efficiencies. Marinuslink recommends a cautious approach to any changes. 3. Supported flexibly applying the CESS for major transmission projects because: ▪ for Marinuslink there is a high risk of forecasting error ▪ large projects may result in higher costs for consumers as more risks are transferred to contractors. 4. Marinuslink will address application of the CESS in its revenue proposal considering whether it will be able to respond to incentives as intended
Public Interest Advocacy Centre	1. The draft decision does little to address over-compensation for average or below average performance and efficiency. 2. Incentive schemes should not reward NSPs that have average or low levels of productivity. To help address this more emphasis should be placed on benchmarking with rule changes to accommodate those changes. 3. The CESS should only apply if NSPs can prove efficiency gains. 4. The bright-line tiered test lowers the penalty that NSPs would incur if they over-spend their allowance (if a symmetric approach is adopted). 5. Questioned the merits of retaining incentive schemes that are overly generous to networks and of little demonstrated benefit to consumers.
SA Power Networks	1. Supported retaining the EBSS, CESS and STPIS. 2. Considered the case for changing the CESS has not been made but is comfortable with the bright-line tiered test on the basis that it is unlikely to dampen SAPN's capital efficiency drive and that it provides clear signals on how the CESS will operate. 3. Does not support asymmetric application of the CESS on the basis that existing regulatory mechanisms such as ex post reviews address information asymmetry concerns. 4. Supported the proposed transparency measures and encourage the AER to consult on implementation of the measures, for example through the Network Information Requirements Review.
TasNetworks	1. Supported flexible application of the CESS to contingent projects. 2. Supported a review of the MIC of the STPIS as soon as possible so the revised scheme can be applied to TasNetworks' upcoming 2024-29 regulatory control period.