TransGrid

Revised Revenue Proposal

2018/19 – 2022/23

1. Executive Summary

1.1 TransGrid's Revised Revenue Proposal 2018/19 – 2022/23

TransGrid is pleased to submit our revised revenue proposal to the Australian Energy Regulator (AER) which will reduce transmission costs for electricity consumers in NSW and the ACT. Our proposed investments and operational funding will allow us to maintain a safe and reliable electricity service to households and businesses and deliver greater price relief than proposed in our revenue proposal lodged in January 2017.

TransGrid acknowledges that electricity prices are currently of significant concern for Australians.

In preparing our revised proposal, we have not only paid heed to the AER's recent draft decision on our proposal, we have also responded to the views and expectations of our customers and the community.

With this in mind TransGrid is proposing to take additional steps in the next regulatory period designed specifically to lower prices even further than initially proposed.

This revised proposal represents the second consecutive period of real price reductions. Between the 2009/10 to 2013/14 and 2014/15 to 2017/18 regulatory periods we cut transmission prices by more than seven per cent. Our revised submission for the 2018/19 – 2022/23 regulatory period will further reduce transmission prices.

We will achieve this outcome for consumers by:

- closely aligning our operating expenditure forecasting method with the AER's method;
- accepting the AER's decision on the rate of return;
- accepting the AER's decision on the value of imputation credits;
- applying all of the AER's incentive schemes consistent with the AER's guidelines; and
- investing in our network to maintain a safe and reliable transmission service, including a modified proposal to reinforce the power supply to Inner Sydney to meet reliability standards.

TransGrid has been working closely with consumer and customer representatives through our advisory council and other engagement to ensure our proposal responds to community views. After carefully considering the draft decision and the AER's rationale, TransGrid now proposes revenue of $3,781 million for the five-year period. We have proposed capital expenditure targeted at maintaining an appropriate balance between risk and cost for customers. While our focus is on driving prices down, without investing where it is needed, consumers will become dissatisfied with the performance of the electricity system and significant economic disruption may result from loss of supply.

We thank the AER for giving due consideration to our proposal and recognise the substantial amount of work in preparing the draft decision. In this revised proposal we have incorporated corrections identified by the AER and updates for new information. We have also provided further information to support our proposal where requested by the AER.

1.2 Recent changes in the sector

Since the submission of our revenue proposal in January 2017, the energy sector has experienced an unprecedented rate of change, industry disruption and policy uncertainty. We recognise that the energy sector is undergoing a transition, and that demands on our network in the future will be greater than those of the past.

The foreshadowed integrated grid plan, prospective renewable energy zones and the Snowy 2.0 expansion may require us to build new networks within the next regulatory period to support the industry's transition to renewables. Working with the information currently available and recognising the uncertainty that still exists, TransGrid has proposed four new contingent projects that fit the most likely areas requiring investment under these new initiatives. This approach positions TransGrid to respond to emerging needs without cost to consumers until such costs and needs are certain and fully justified.

As the nation's Energy Ministers and the Energy Security Board have recognised, transmission networks will be critical to a successful transition from the ageing and increasingly obsolete fossil fuelled generation fleet to new era renewable generators. Networks will also have a role in addressing the challenges that will come with more distributed and intermittent patterns of both supply and demand. If the regulatory framework is applied with agility and rigour, investors will have both incentives and certainty to continue investing in the industry. Similarly, customers will pay no more than is necessary for the quality transmission services they require from our dynamic industry.

1.3 Reducing prices for electricity consumers

TransGrid has undertaken a comprehensive transformation program commencing in early 2015 and continuing through the privatisation process and into the present. Our approach to capital expenditure forecasting has been completely revised with a robust risk assessment of every capital project in the business. We benchmark competitively within our own industry and across comparator industries and we continually assess how we can do better.

In the revised proposal we have provided further information to support the proposed capital expenditure program and provided further detail on our risk assessment methodology. We have also modified our proposed solution for the Powering Sydney's Future project acknowledging both customer concern about reliability of supply and the AER's concerns around future uncertainty. We believe that reinforcing the electricity supply to the Sydney CBD is vital if we are to avoid an unacceptable risk of extended power interruptions.

We have closely aligned our operating expenditure forecasting method with the AER's method. Where appropriate we proposed some improvements to the method to improve accuracy of the forecast and ensure our forecast was compliant with requirements in the National Electricity Law and Rules. In the revised proposal we have accepted many of the AER's comments and adopted the AER's draft decision approach with updates from the AER's benchmarking report.

We adopted the AER's guideline approach for the rate of return and whilst we maintain our approach to the estimation of the market risk premium is consistent with the guideline we have accepted the value in the AER's draft decision. We have also accepted the AER's decision on the value of dividend imputation credits, whilst noting a reliable estimate for the utilisation method can be calculated using the ATO tax statistics method without the need for further adjustments or assumptions.

We have adopted all of the AER's incentive schemes without adjustment in our revenue proposal but accept the AER's interpretation of the STPIS scheme in their draft decision and have reflected their interpretation in the revised proposal. We have identified improvements needed in both our calculation and the AER's for CESS to achieve the objectives of the scheme. We have not applied the AER's retrospective adjustments to the EBSS scheme in our revised proposal.

Chapter 2 sets out an overview of the proposal, summarising what we have accepted in the AER's draft decision and where we have made changes.

1.4 Consumer consultation

TransGrid understands consumer engagement has fundamental importance to both our business and the development of the industry; particularly in this time of change for the industry. Customers have told us their foremost concerns are for reliable service and lower prices. We have consulted intensively with consumer groups and other stakeholders on our revenue requirements for the next regulatory period and we are confident that our proposal is aligned with customer expectations. Our proposal is focused on delivering real price reductions in the next regulatory period and maintaining the safety and reliability of the electricity service we provide.

An example of TransGrid's willingness to collaborate with consumers is our approach to the Powering Sydney's Future (PSF) project. Customers urged us to "find a solution" with the AER. Accordingly, we proposed that we modify the PSF project to be undertaken in two stages and only look for approval in the next period for stage one. This ensures we meet our reliability requirements, whilst minimising the upfront costs of the project and offering a more agile solution. Should demand not grow as forecast, or should more cost-effective demand management solutions come to market during the interim, it may be that we are able to delay the second stage further, which will deliver savings for customers. This proposal was unanimously endorsed by the TransGrid Advisory Council and has been adopted in our revised proposal.

2. Introduction and Context

2.1 TransGrid's Revised Revenue Proposal

TransGrid is pleased to submit its revised revenue proposal. The AER has agreed with just over 91% of the revenue proposed by TransGrid, and it is our shared opinion that TransGrid and the AER are not substantially in disagreement. This proposal focuses on the remaining points of difference, which are predominantly:

- The appropriate level of capital expenditure
- Calculation of the efficiency benefit sharing scheme.

We are also pleased the AER has an open mind on our most substantive points of difference, and has invited us to submit further information to support our position on the capital expenditure needs for the NSW and ACT network.

Whilst working within the requirements of the National Electricity Rules (Rules), TransGrid has focused this revised proposal on the substantive issues and looked to reach agreement wherever possible. Revenue proposals are complex and detailed documents that require rigorous justification to support material revenue requirements. The AER's decision underpins the financial viability of our business and its ability to operate efficiently within a technical and increasingly highly regulated environment of reliability, safety, security and environmental obligations. Once the AER's decision is made, TransGrid must get on with the business of providing a safe and reliable electricity supply to the people of NSW and the ACT, irrespective of the economic and regulatory context within which it finds itself.

This chapter provides an overview of our revised proposal, the key rationale for our position, what has changed since we submitted our revenue proposal in January this year, and what these changes mean for the business, customers and stakeholders. For those who then want to dive into the detail, we invite you to read on. For many, we hope this chapter gives you the key information you need to understand TransGrid's priorities and perspectives for this upcoming regulatory period.

2.2 Overview of the Revised Proposal

The table below provides an overview of TransGrid's revised proposal and some high level context and rationale for our approach. The table follows the order of the chapters in the remainder of this document and starts with capital expenditure, the component for which TransGrid and the AER have the greatest difference of opinion.

Table 2.1: Overview of revised proposal

($June 2018)	Revenue Proposal	Draft Decision	Revised Proposal
Revenue Allowance	**$3,973m**	**$3,627m**	**$3,781m**
Capital Expenditure	$1,612m	$992m	$1,534m
Rationale	TransGrid maintains that the AER has made a number of errors in both the analysis and interpretation of the detailed engineering based risk analysis and network planning fundamentals underpinning TransGrid's revenue proposal. We have offered further workshops with the AER to resolve these differences. We have prepared substantial further information to address errors in the AER and its consultant's analysis. In an effort to bridge the gap with the AER, we have proposed a modified Powering Sydney's Future (PSF) project which lowers the upfront capital cost by $120 million. This will immediately lower the price impact for customers in the next period. Whilst overall this solution will have greater social impact for local residents for a similar long run cost, it meets the immediate reliability requirements and ensures Sydney has the power necessary to maintain Australia's largest economic hub. Feedback from customers reflected their concern that reliability is a priority and they encouraged us to find a solution with the AER. We do not agree that the proposed network support control ancillary services should be provided for the next 35 years at no cost. See chapter 4 for a detailed response and supporting analysis.		
Operating Expenditure	$908m	$857m	$878m
Rationale	TransGrid accepts the AER's preference for its own approach to estimating trend (escalating base year costs into future years) and has adopted the AER's method. We have also accepted the AER's decision to reject the step-change for off-easement risk management. The AER invited TransGrid to provide further information to support the step change driven by new NSW licence conditions on IT security which we have responded to. We have made revisions to this cost estimate which has lowered the total amount we need to fund these compliance obligations. See chapter 5 for a detailed response and supporting analysis.		

($June 2018)	Revenue Proposal	Draft Decision	Revised Proposal
CESS	$24m	$26m	$34m
Rationale	TransGrid accepts the modifications the AER has made to the CESS calculation but we have also identified inconsistencies in the calculation of CESS payments with the intended operation of the scheme. The calculation both TransGrid and the AER applied incorrectly assumed benefits for financing costs arise in the first year of the regulatory period. In addition, a nominal WACC has been incorrectly applied rather than a real WACC. The revised proposal addresses this. See chapter 6 for a detailed response and supporting analysis.		
EBSS	$62m	$15m	$34m
Rationale	TransGrid has accepted various material modifications and adjustments to the EBSS calculation that the AER has made. However, we do not agree with either of the final year adjustments (for 2013/14 and 2017/18) the AER has imposed. Neither of these adjustments is consistent with a proper application of the AER's guideline. The adjustments unreasonably apply material and disproportionate penalties that are inconsistent with the guidelines, the incentive based regulatory framework and good regulatory practice. TransGrid expects its performance in the current period, and its year on year efficiency savings achieved over the last two financial years and forecast for the current financial year, to be recognised for what they are. Retrospective adjustments to economic incentive schemes are inconsistent with good regulatory practice. See chapter 6 for a detailed response and supporting analysis.		
STPIS	Parameters only for service and market components. 20 network capability (NCIPAP) projects	Accepted all but 1 of the proposed parameters 12 NCIPAP projects accepted	Accept
Rationale	TransGrid accepts the AER's preferred method to calculate the STPIS parameter. We have included only the AER approved NCIPAP projects in our revised NCIPAP project list.		

($June 2018)	Revenue Proposal	Draft Decision	Revised Proposal
WACC	6.6%	6.49%	6.49%
Rationale	TransGrid has accepted the AER's draft decision for rate of return, noting the risk-free rate will be updated in accordance with the agreed averaging period. Nevertheless we maintain our position that the AER's Guideline approach should be applied to the current market evidence. This currently generates an MRP of 7.0%. See chapter 7 for a more detailed response.		
Gamma	0.25	0.4	0.4
Rationale	We have accepted the AER's draft decision. TransGrid notes that a reliable and robust estimate for the utilisation approach of 0.34 can be calculated using the ATO Tax statistics method without reliance on assumptions or adjustments. See section 9.1.7.		
Forecast Inflation	AER Method	AER Method	Accept
Rationale	AER intends to apply the outcome of the current inflation review to the forecast inflation in their final decision. TransGrid has accepted this position.		
Debt Raising Costs	$40m	$17m	Accept AER's Approach
Rationale	TransGrid has accepted the AER's approach.		
Pricing Methodology	Method only	Accepted	Accept
Rationale	TransGrid proposal accepted		
Negotiating Framework	Method only	Accepted	Accept
Rationale	TransGrid proposal accepted		
Pass Through Events	Defined Events	Accepted	Accept
Rationale	TransGrid proposal accepted. We have also noted that two recent Rule changes should apply to TransGrid in the next regulatory period.		

($June 2018)	Revenue Proposal	Draft Decision	Revised Proposal
Shared Assets	Below threshold	Accepted	Accept
	TransGrid proposal accepted		
Contingent Projects	5 Projects	Accepted with modifications to triggers	Accept
Rationale	AER modifications to contingent project triggers materially accepted and clarified. TransGrid also submitted three new contingent projects in August to support policy development arising from the Finkel Review and the Federal Government's announcement of the Snowy 2.0 scheme. These additional projects, plus one further project, are included in our revised proposal.		

2.3 Changes in the sector since January 2017

Since TransGrid lodged its revenue proposal in January 2017 the policy and regulatory landscape that we operate in has changed significantly and remains volatile. The operating environment has also altered with peak demand reverting to, or exceeding, historic highs with the potential that the system overall is unable to meet demand.

Significant uncertainty remains in a range of areas, so we have tailored our modifications in the revised proposal to ensure costs will only be borne by consumers when the costs (if any) are certain and are proven to be the most cost-effective solution. No additional revenue has been directly included in this revised proposal to address these concerns.

The following sections detail the changes and the implications for this revised proposal and the next regulatory period.

2.3.1 Investment environment

The past year has seen a substantial decline in investment certainty across Australia's electricity industry. Our security holders and financiers have committed more than $10 billion to the business and stand ready to invest further substantial sums. This level of investment has been repeated all over the country by a range of Australian and international investors in electricity and other infrastructure sectors that underpin the provision of essential services to the Australian economy and support the prosperity families and businesses expect of a modern society.

Our investors must of course earn a reasonable return on their investment, as their investors in turn - superannuation funds and private investors - expect a commercial, risk-adjusted return on their investment. We are concerned that the decisions being made in recent months undermine the risk-adjusted agreement investors entered into. Examples of these challenges are the:

- AER's decision to move away from its own guideline to determine an appropriate cost of equity
- Federal Government's decision to overturn a fundamental component of the regulatory framework by removing the check and balance to the AER's decision making powers through the removal of limited merits review
- AER's decision that gamma should be measured on a utilisation basis that results in a larger reduction in revenue to businesses and accordingly investors earning less than the rate of return the AER determines is appropriate

- AER's draft decision to retrospectively adjust how the EBSS penalties should be applied
- Increasing regulatory obligations on businesses that are expected to be undertaken without funding; for example the:
  - AER's draft decision to not fund the new RIT-T requirements for replacement capital expenditure. TransGrid expects to run more than 50 individual RIT-Ts over the next regulatory period, with each RIT-T taking up to a year to complete – such processes come at a material cost that the AER has determined investors will fund without compensation
  - AER's draft decision that NSCAS services, a new regulatory obligation since TransGrid's last revenue decision, should be provided to customers without charge; the assets to provide this service are valued at $26 million but investors are not to be compensated for this necessary investment
- AEMC's decision to place new regulatory obligations on transmission networks to provide services such as system strength and inertia at cost, that is, the business carries all risk on delivery and makes no return on this service
- The exponential increase in cyber-attacks. Federal Government agencies including the Critical Infrastructure Centre (CIC) and the Computer Emergency Response Team (CERT) have expressed concerns particularly in relation to protecting critical infrastructure. In this regard, TransGrid has worked with the Federal Government agencies to agree a program of system improvements to provide for a more secure environment. These programs of work are set out in the Transition Plan which will form part of the Licence Conditions (see section 5.7.2).

2.3.2 Operating environment changes

Maximum Demand

On 10 February 2017 NSW experienced a very high peak demand day. Mandatory load shedding was implemented and calls were made across the State to reduce load. It is understood there was significant, but unmeasurable, voluntary curtailment as well.

This event triggered a substantial level of analysis to understand what had occurred and why. Whilst the problem was predominantly related to generation supply, the event placed strain on the network as generation was sourced from all locations to meet demand.

The likelihood of this event reoccurring remains real and perhaps inevitable by 2022 when Liddell Power Station retires, without substantial new investment in generation or inter-connectors into the State to relieve the supply shortfall. All levels of government are now mobilised and considering the most effective response both here in NSW and in other states.

TransGrid has reviewed what it can do to efficiently and effectively support this effort. The most immediate priority is to ensure arrangements are in place to support new pathways from new generation centres to load as future generation investments occur. We have proposed four new contingent projects, which will only proceed if generation investment occurs and the network connection supports benefits to consumers.

TransGrid has also made a modification to the triggers for existing contingent projects to allow them to be assessed and proceed on the basis of reliability requirements, should they in fact be required.

AEMO has issued two updates to its maximum demand forecasts since TransGrid lodged its revenue proposal. Each of these revised the outlook for maximum demand upwards over the coming years.

Friday 10 February 2017

On the morning of 10 February 2017 AEMO predicted a possible generation shortfall due to a high demand forecast, potentially close to the record of 14,744MW[1].

Steel tower affected by storms in southern NSW on 11 February 2017.

At 8.30am, AEMO declared a Level 4 emergency under the Power System Emergency Management Plan. TransGrid initiated and ran an emergency management response from our control centre in Western Sydney.

Other preparations included:

- NSW Energy Minister Harwin calling on residents to reduce electricity use
- Discussions with Tomago Aluminium Company about reducing 290MW of load if required
- TransGrid deploying field staff to critical substation sites in preparation for any required response, and recalling outage works to ensure reliability of the network.

At 11am, AEMO's updated NSW peak forecast was around 14,700MW, however generation capacity reductions continued, reducing the forecast reserve margin even further.

Tomago smelter turned off in stages in the afternoon, resulting in a maximum reduction of 290MW.

Recorded demand for NSW peaked at 4.30pm at 14,181MW. Several factors coincided at approximately 5pm to overload the NSW interconnectors with Qld and Vic. Another 1,300MW of supply was unavailable.

Tomago demand was restored at 7.05pm. No other customer load was shed but AEMO estimate voluntary load reductions of around 200MW. Due to generation shortfall, possible demand of 14,671MW could not be met without demand reductions.

Fire risk

The Level 4 emergency continued into Saturday 11 February, due to fires in NSW. An explosive failure of a current voltage transformer removed the Muswellbrook to Liddell 330kV transmission line from service. This reduced the capability of the Qld to NSW interconnector (QNI). Throughout the day, our staff managed the fire at the site and removed damaged plant. The feeder was returned to service at 6.35pm.

Meanwhile, a fire on a property adjacent to our Orange 132kV substation damaged a circuit which caused it to trip at 2.22pm. The fire was brought under control after several hours, and an emergency asset replacement job was initiated.

Later in the afternoon, storm activity moved in from the west, towards Wagga Wagga and the Snowy region. A busbar trip caused a major interruption at Wagga 330kV substation. Multiple trips of the 330kV line between Lower Tumut and Upper Tumut and the 132kV line between Wagga North and Murrumburrah caused the protection to lock out on both lines. The storm also caused serious damage to two steel towers and collapsed a timber structure.

The incidents of 10 and 11 February demonstrate the importance of a robust transmission network to ensure a safe and reliable supply of electricity, when demand is at its highest and the weather is at its most extreme.

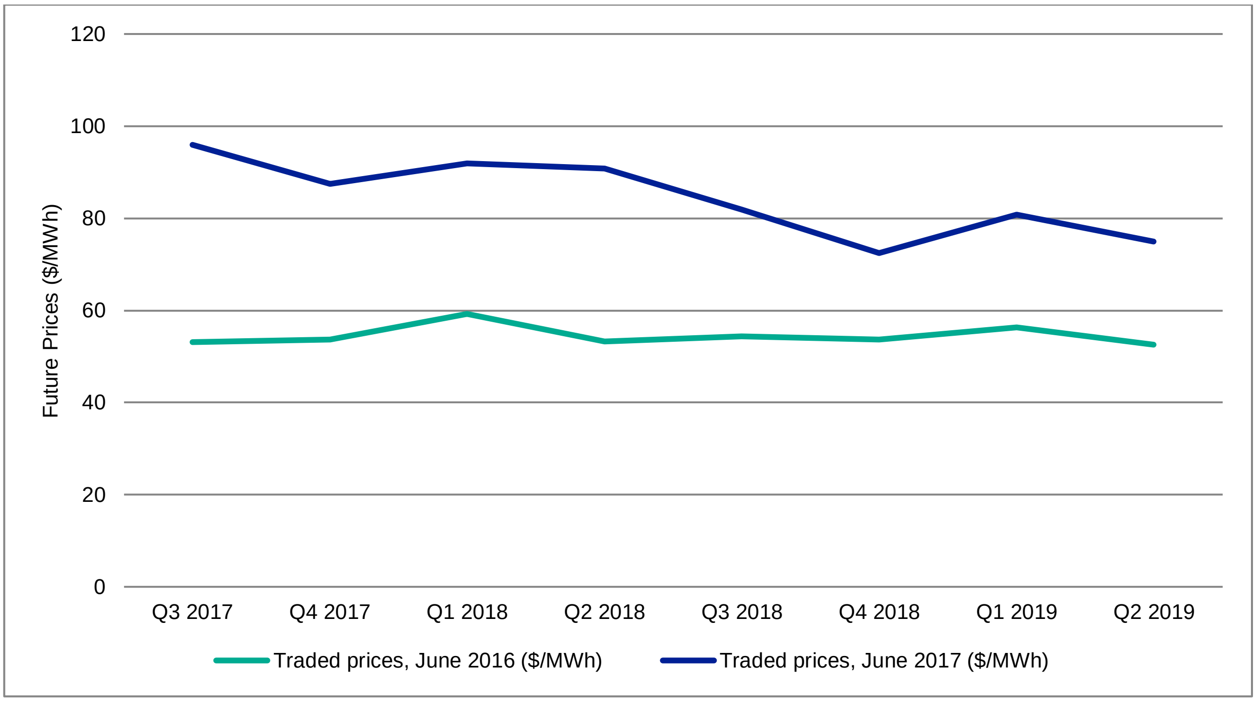
[1] This was the operational demand reported in AEMO's System Event Report. AEMO System Event Report, Available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2017/ Incident-report-NSW-10-February-2017.pdf. Viewed on 30 May 2017.

Wholesale Energy Prices

Electricity prices moved back into the media from the middle of this year when significant increases in wholesale energy market prices were included in retailers' annual price update for consumers. There have been a number of underlying drivers for these price trends including wholesale gas price increases as competition from overseas markets continues its upward pressure on competitive prices. Recovery of global coal prices and the restriction on on-shore gas development has also contributed to the increased price trend.

In June 2017, NSW base load futures prices for energy delivered in the first six months of 2018 were trading around 80% higher than they were a year earlier. These higher wholesale prices continue into 2019.

Figure 2.1: NSW comparative baseload futures prices ($/MWh)



Source: AER Wholesale statistics.
https://www.aer.gov.au/wholesale-markets/wholesale-statistics/new-south-wales-comparative-base-futures-prices

Whilst transmission prices, and indeed network prices more generally, have been falling across the state for some time now, the upward pressure from wholesale energy prices and retail margins has more than offset this effect. Consumers have faced significant hikes in energy prices as a result and their sensitivity to prices is justifiably high.

TransGrid's commitment is that transmission prices will be no higher than necessary and we are pleased we have been able to deliver a further five years of real annual average price cuts in this revised revenue proposal.

2.3.3 Regulatory and policy changes

Snowy Hydro 2.0

A feasibility study for extension of the Snowy Hydro scheme has been initiated by the Federal Government. This extension, known as Snowy 2.0, would fundamentally increase the generating capacity of the Snowy Hydro scheme. For customers to benefit from this investment the transmission network will need to be upgraded to allow the additional Snowy Hydro generation to reach customers.

Whilst the final outcome of this feasibility study is not yet known TransGrid has proposed a contingent project, which would only be triggered if the Snowy scheme goes ahead. This ensures that TransGrid is able to respond if the Federal Government proposal proceeds whilst ensuring customers face no costs for this investment unless it is required.

System Strength and Inertia

The AEMC's *System Security Market Frameworks Review Final Report* led to Rule changes which place significant new responsibilities on transmission networks to procure solutions for the network to manage system security. New needs are emerging in the network as the generation mix shifts from traditional fossil fuel generators to renewable generators with different properties and impacts on the stability of electricity networks.

The Rules have been established to allow material costs to be passed through to customers should they occur and TransGrid's pass through events component of the revised proposal has been modified to reflect these new Rules. TransGrid is also allowed to include forecast costs in the revised proposal for system strength, however at this time TransGrid does not expect to incur material costs related to these obligations over the next five years and has not made any adjustments to revenue requirements as a result of these Rule changes.

Finkel Review

COAG has adopted the majority of recommendations of the *Independent Review into the Future of the National Electricity Market*, led by Professor Finkel, including an integrated grid plan. Whilst the precise outcomes of this grid plan and many of the other recommendations such as the creation of renewable energy zones are uncertain in terms of timing, location and precise form, it can be assumed that change is coming to the sector.

To prepare for these uncertain changes in the most responsible manner, we have proposed three new contingent projects in the most likely vicinity of future renewable energy zones. This approach again positions TransGrid to respond to emerging needs in the industry without cost to consumers until costs and needs are certain and fully justified.

2.4 Consumer consultation

TransGrid has met with both our Revenue Proposal Working Group and our TransGrid Advisory Council to discuss the AER's draft decision and hear their thoughts on how we should respond. We were very pleased to see a high level of alignment between different customer representatives and our own views on the draft decision.

The AER's decision to reject Powering Sydney's Future was the foremost concern for customers with reliable supply into the CBD a priority for many customer representatives. Some business customers questioned the reasonableness of expecting major business customers to habitually provide the buffer for the system at times of peak load through targeted load shedding. Whilst they accepted it as an emergency measure, they expressed that it should not be considered a business as usual option.

Customer representatives thought it essential that we conveyed to the AER the risk being placed on NSW of this decision and that we should find a way to reach agreement on this project.

Overall, TransGrid saw good alignment. Further detail on the views of consumers, how we have worked with them and taken their views into account is set out in chapter 3 of this revised proposal.

2.5 Maximum Allowed Revenue building blocks

The following Table 2.1, sets out the revenue building blocks for TransGrid for the next regulatory period.

Table 2.1: Revised Unsmoothed Revenue Requirement ($m nominal)

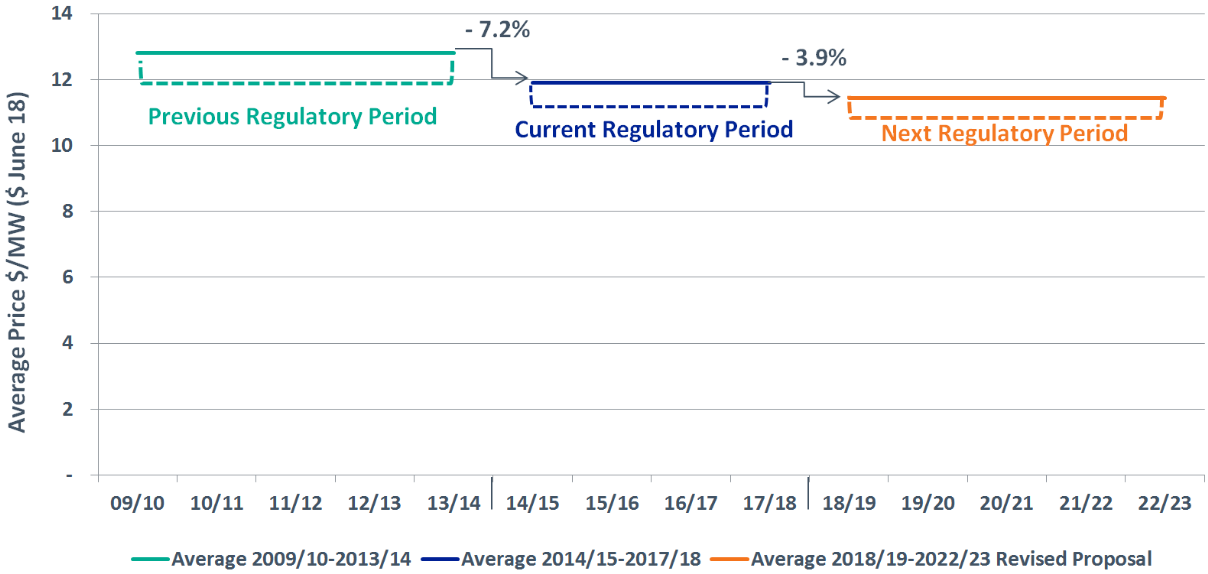
	2018/19	2019/20	2020/21	2021/22	2022/23	Total
Return on Capital	413.6	426.4	441.6	456.5	472.9	2,211.1
Return of Capital	99.9	118.4	132.4	136.4	148.0	635.1
Operating Expenditure	180.3	188.2	198.4	210.3	206.7	983.9
Revenue Adjustments	20.4	20.9	7.7	15.1	7.6	71.7
Net Tax Allowance	30.3	32.4	34.0	36.2	38.1	171.1
Annual Building Block Revenue Requirement (Unsmoothed)	744.4	786.3	814.2	854.6	873.4	4,072.9

2.6 Price path

The average price path over the 2018/19 to 2022/23 period is shown in Figure 2.2. This figure shows that TransGrid is still expecting to deliver real annual average price reductions in the next regulatory period compared to both the current period and the prior regulatory period.

We note the reduction in the next period has increased from a 2.5% price reduction to a 3.9% price reduction. Whilst the maximum allowed revenue in this proposal is 5% lower than our January revenue proposal, the price impact is moderated by the drop off in AEMO's most recent energy forecast which is on average 3% lower than the prior year's forecast. This drop in the energy forecast results in a smaller price reduction than would previously be expected.

Figure 2.2: Average Price Path ($ June 18)

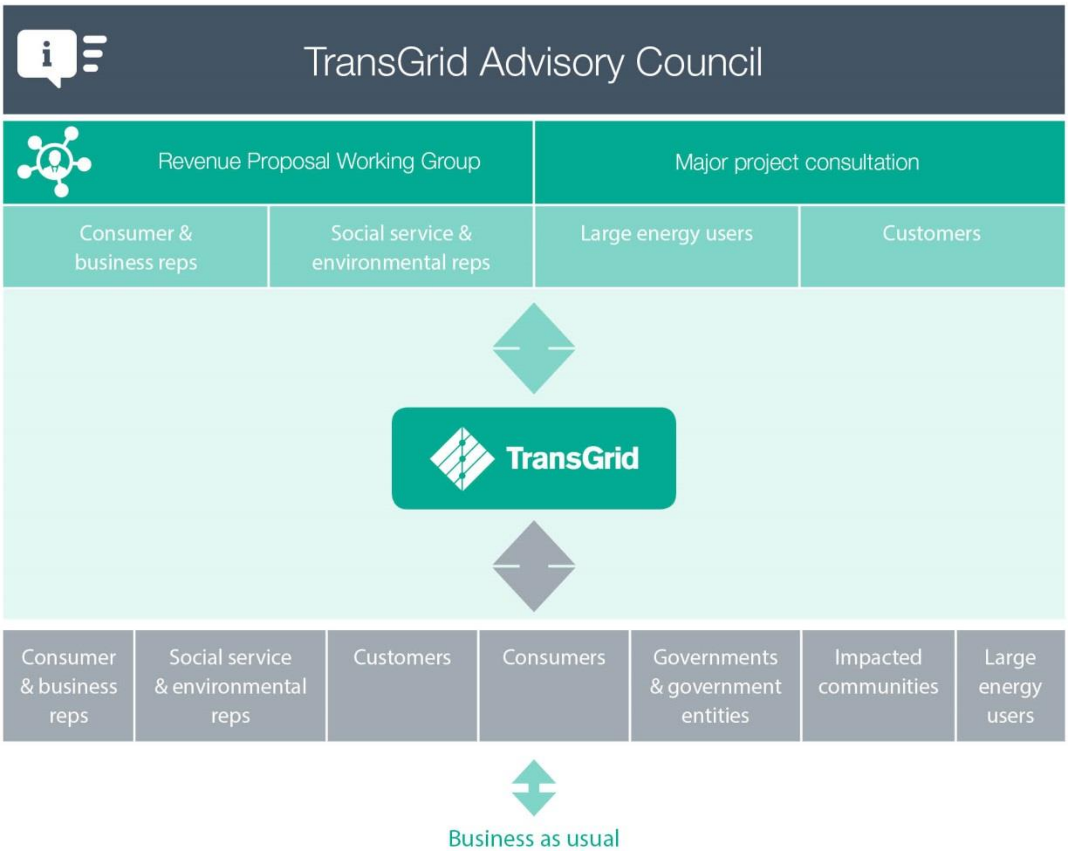


3. Consumer Engagement

3.1 Introduction

TransGrid regards proactive engagement with customers, stakeholders and energy consumers as an essential component of our business. We work alongside a wide range of stakeholders including directly connected customers, consumer representatives, government bodies, small businesses and regulators, in the development of our business plans and priorities. In this way, we aim to ensure that the views and positions of those at every stage of the energy supply chain are represented in and contribute to the decisions we make. As a result of the ongoing engagement that has occurred since our draft revenue proposal was submitted to the AER, TransGrid is pleased to provide further information regarding our consumer engagement program as part of this revised proposal for the 2018/19 – 2022/23 regulatory period.

Figure 3.1: TransGrid's engagement framework



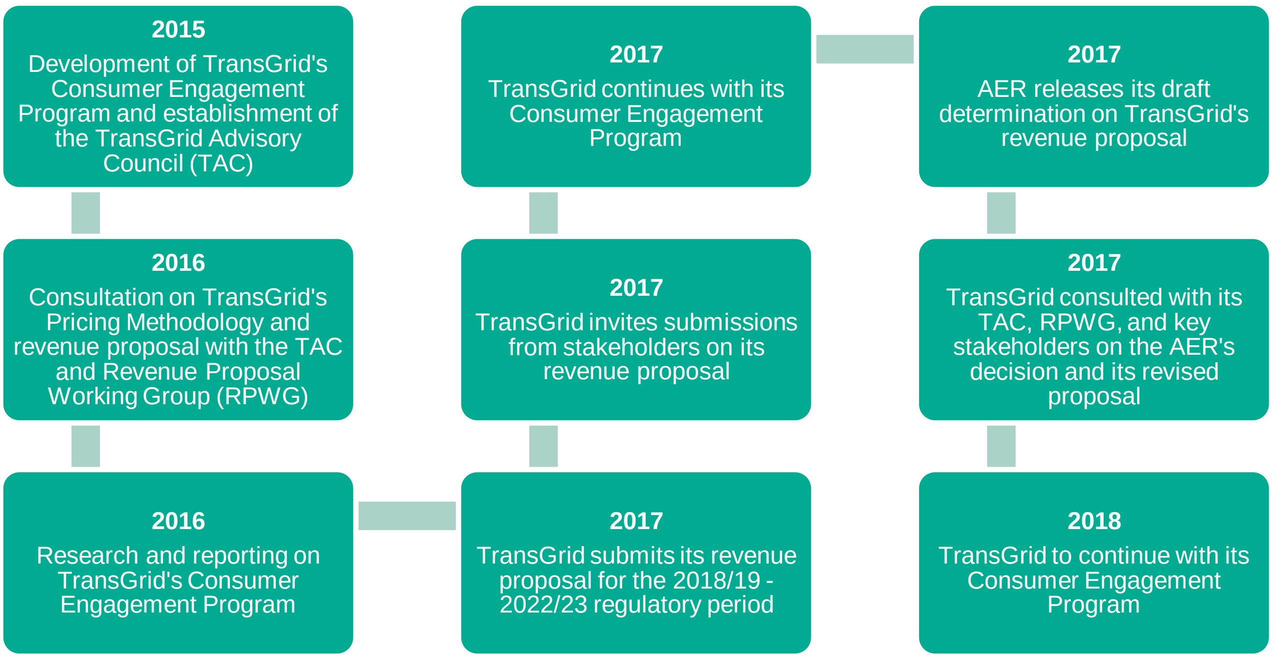
TransGrid's framework for engagement is centred on the recognition that different stakeholder groups have differing levels of knowledge and interest in our business. In recognition of this, TransGrid tailors our engagement program to include a variety of topics and channels. Central to our engagement framework is the TransGrid Advisory Council (TAC). The TAC is the key stakeholder advisory body to TransGrid, offering customer and consumer insights and engagement to improve the value of TransGrid's transmission services to NSW. The TAC forms a rich and consistent mode of engagement and comprises executive level representatives from a cross-section of external stakeholders. Beyond the TAC, TransGrid's engagement is focused on working with stakeholders regarding areas of the business that directly impact them, or in which they have an interest. Examples of this includes working with customers and business representatives on transmission pricing methodologies, working with impacted communities on easements and transmission plans, and engaging stakeholders in consultation for our major projects.

Engagement on our revenue proposal took place through the TAC and the Revenue Proposal Working Group (RPWG). The RPWG is a dedicated working group that was established by TransGrid to ensure customers, large energy users, consumer representatives and interested parties have an opportunity to understand and influence the approach to our revenue proposal. We engaged with the TAC and RPWG members both through formal group meetings and on an individual basis.

Given the rapid changes that have occurred within the energy industry since January 2017, when TransGrid submitted its revenue proposal, genuine open and collaborative engagement between networks and consumers continues to be of critical importance. Working collaboratively with stakeholders at all positions along the energy supply chain has been embedded within the organisation, and is evidence of the current cultural shift within TransGrid. Our engagement focus reflects an organisation that sees consumer engagement not as a means to an end, but as core operational value that underlies all that we do. With the level of uncertainty that we are currently seeing in the energy sector across Australia, TransGrid considers that genuine open and transparent consumer engagement is critical to ensuring we are well placed as a network to serve NSW and to meet the challenges of the future.

We are committed to working in collaboration with our stakeholders to deliver a revenue proposal that reflects the views and feedback we have received from our stakeholders in our consultations, as well as the valued feedback that we have received from the AER and the Consumer Challenge Panel (CCP). In our revised revenue proposal, TransGrid has again submitted a proposal that would deliver lower costs to consumers, and positions the business to continue to efficiently deliver safe and reliable energy to NSW at the lowest cost in this constantly changing landscape.

Figure 3.2: TransGrid's Consumer Engagement Journey



3.2 Engagement since submission

In the time since TransGrid submitted its revenue proposal in January, we have continued to consult with our TAC, the RPWG, consumer representative groups, industry representatives, government bodies, impacted residents, and the general community on issues related to TransGrid's operations and our place in the changing National Electricity Market (NEM). TransGrid has worked closely with our peak advisory body, the TAC, and our other advisory groups to ensure open access to information and the opportunity to guide and influence our response to the many changes that the industry has faced since the submission of our revenue proposal.

In 2017 TransGrid has consistently engaged with our TAC regarding positioning on the Finkel Report and how TransGrid should respond, as well as on our strategy to support the development of large-scale renewable zones in NSW, in line with the Finkel recommendations. We have also continued to engage on the Powering Sydney's Future project, see section 3.6 in this chapter.

- TransGrid's response to the Finkel Report
  - TransGrid consulted with the TAC to develop our position on the Finkel Report, and submitted a consultation piece for consideration by the TAC on our proposed position and response to Finkel
  - TransGrid found support from the TAC on our positioning and proposed response as a network company, and has committed to further develop and consult on this position
- TransGrid's proposal to support the development of large-scale renewable zones in NSW
  - TransGrid presented its plans for the development of large-scale renewable zones in NSW to the TAC for consultation in June, accepting feedback on the proposal and committing to further research to answer questions put by the TAC
  - TransGrid heard that while there was support from the TAC regarding the plans and the opportunity they presented to allow greater generation competition and renewables into the grid, there were questions around the investment risk in the current regulatory space, particularly the risk of stranding assets if the generation did not materialise or if technology changed. The TAC was also interested in exploring new ways for these investments to be costed beyond being placed in the RAB
  - TransGrid committed to working with the TAC to develop potential solutions that may make the development of large-scale renewable zones in NSW cost effective, and on the cost and risk structure that would underlie such investments.

3.2.1 TransGrid's Revenue Proposal Working Group

In response to the AER's draft decision and to support TransGrid in the development of its revised revenue proposal, TransGrid met with the RPWG to consult with its consumer representatives and key stakeholders. We held a full day meeting with members of the RPWG, observed by a member of the CCP. RPWG members' interests guided the consultation focusing on areas that the group felt were of key importance. Key feedback from the RPWG is presented below.

Table 3.1: Key feedback from the RPWG

Feedback received	Actions taken by TransGrid
RPWG wanted TransGrid to ensure that it included a response to the Finkel Review in its revised proposal	TransGrid has included a number of contingent projects in its revised proposal designed to support implementation of the Finkel Report recommendations
RPWG expressed the need for solutions other than load shedding as a means of demand response to meeting growing demand in Sydney, and supported a targeted approach to network augmentation	TransGrid is proposing a site-specific network augmentation program to ensure efficient investment in the areas of the network most at risk, including procurement of demand response followed by a network solution as the most cost effective approach that is in the long terms interests of consumers
RPWG was supportive of the emphasis TransGrid placed on asset management to ensure the longest life possible from its assets	TransGrid will maintain the asset management system as defined in the revenue proposal and continue to look for further efficiencies in its assets as part of its rigorous asset planning and maintenance regime. TransGrid recently became the first Australian organisation to receive the Jacobs Asset Management Recognition Medal, aligning the quality of our asset management strategies with organisations like NASA and the US Military
RPWG wanted to see TransGrid build more analysis and impact of the social costs of projects into its projections to ensure that proposals took account of the broader impacts of various proposed project options and timeframes	TransGrid will continue to include assessment of social costs, benefits and opportunity costs into the planning and design of its projects, which includes consultation with affected residents and communities on “least impact” options. For example, the extensive engagement associated with the Powering Sydney’s Future project assessed 31 potential cable routes before a preferred option was identified
RPWG wanted to understand why the AER had not used AEMO’s latest 2017 forecasts in its draft determination on the Powering Sydney’s Future project	TransGrid is working with Ausgrid, AEMO and the AER regarding the appropriate load forecasts for assessing the timing and justification for the Powering Sydney’s Future project. A forecasting workshop, facilitated by the NSW Government, was held in November 2017 to specifically address load forecasts

Feedback received	Actions taken by TransGrid
RPWG questioned on what basis the AER rejected the need for Powering Sydney's Future, and put to TransGrid that the AER must come up with alternative triggers and project timings if it does not accept the project as proposed by TransGrid	TransGrid is committed to working with the AER to better understand the AER's position on the project and the reasons it does not support the project as proposed in the current regulatory period. In late September TransGrid held a roundtable with the AER and CCP, and a workshop in November 2017 with the AER, AEMO, NSW Government and Energy Consumers Australia, to discuss load forecasts. In addition, TransGrid and the AER have had issue-specific meetings on Powering Sydney's Future since the draft decision was published
RPWG commented that the AER's decision on Powering Sydney's Future showed a different appetite for risk than TransGrid. RPWG stated that AER should declare the level of risk it feels is reasonable for a project such as Powering Sydney's Future, to provide clarity over the decision making process	TransGrid raised this concern of the RPWG with the AER at the November workshop, and again in our revised proposal
RPWG requested that the CCP challenge the AER on its decision to not support Powering Sydney's Future in its draft decision, including the need for greater justification by the AER of why the project proposal was not supported	The CCP has attended RPWG meetings, as well as TAC meetings and other engagement activities related to Powering Sydney's Future, and will offer its views on the project in its next public submission
RPWG stated that if forecasts such as those by AEMO are not deemed suitable by the AER for base projections for projects such as Powering Sydney's Future, then AEMO should be able to work with networks on site specific projections that accurately reflect demand within the project area	TransGrid, Ausgrid and AEMO have been working collaboratively in understanding differences in the base forecasts and relevant factors for a forecast suitable to assess the justification and timing of Powering Sydney's Future
RPWG questioned what the AER meant by a "Top Down Challenge" regarding TransGrid's proposed capital expenditure costs, and requested clarification as to what this would look like	TransGrid notes that previously it had been understood to be the AER's Repex model, a version of which was relied on for assessing much of Powerlink's capital expenditure requirements. TransGrid used a version of this model as a top down check but this has been disregarded by the AER. TransGrid also notes the higher discount rate TransGrid has used in its risk model provides a strong constraint bias to the forecasts, in effect a top down constraint on the size of the capital program

Feedback received	Actions taken by TransGrid
RPWG felt that the AER's draft decision on TransGrid's NSCAS proposal was not in the long-term best interest of consumers, and would lead to higher costs for consumers. RPWG commented that it was unreasonable to expect the service to be provided for free	TransGrid agrees with the RPWG that expecting TNSPs to provide prescribed services for free is unsustainable and unreasonable
RPWG wanted to understand the differences between TransGrid's and the AER's approach to WACC. There was uncertainty as to whether the AER had been consistent with its own guidelines	TransGrid discussed the differences in approach and explained the rationale for our position In this revised proposal we have accepted the AER's decision, if not the rationale, recognising that for consumers a lower WACC is a good outcome for prices.

3.3 Key issues raised by the AER in its draft determination

TransGrid thanks the AER and the CCP for their affirmation and feedback on our consumer engagement program. We are encouraged by the positive comments on our program as one that is sustainable, supported from an executive level, and allows for clear and open provision of information, including how stakeholders have influenced our decisions and positions. We are committed to furthering our engagement program and continually looking to improve our processes.

We thank the AER, CCP, and stakeholders for their feedback on where we can continue to improve our consumer engagement program. To ensure that we appropriately respond to the points raised by both the AER and the CCP, we will deal with both as separate entities and have separated the feedback into two distinct sections. Areas of feedback that were raised by both the AER and the CCP have been discussed under the response to the AER's feedback.

3.3.1 Industry models of engagement

TransGrid is committed to ensuring that its consumer engagement program is best practice, and notes the regulated businesses the AER has identified in its draft decision may be examples that TransGrid can learn from. In examining the processes that these businesses have undertaken to engage with their stakeholders, notwithstanding the difference between their business models and ours, we have identified some key areas within their engagement programs that we will investigate regarding their applicability to be incorporated into our consumer engagement practices.

> TransGrid notes the use by one organisation of a draft regulatory submission presented for consultation to stakeholders prior to the submission of its proposal in 2017. This provided a strong foundation for its early engagement on the submission itself and allowing its stakeholders to provide feedback on the proposed submission prior to lodgement with the AER. Within this regulatory period, TransGrid held workshops with the AER and our TAC to on our approach to developing our regulatory proposal.

  One of the outcomes of the process was the creation of the Regulatory Proposal Working Group as a dedicated forum for stakeholders and consumers to input into TransGrid's Regulatory Proposal. Through the RPWG TransGrid raised:

  – Its new approach to capital expenditure forecasting

- Our proposed approach to operating expenditure forecasting (which was further modified and updated based on comments and feedback received)
- Our proposed approach to WACC, gamma and pricing

TransGrid also published a consultation document on our Pricing Methodology for stakeholder submissions and input. However, we appreciate that these steps can always be further improved.

> We note the robust engagement framework demonstrated in another organisation's approach to its consumer engagement program, including a research phase from which key insights and results were implemented in the form of workshops and demonstrably adjusted engagement and business practises.

TransGrid sees the value in this form of consumer engagement evaluation and the implementation of research findings and has undertaken a similar process in the development of its consumer engagement program. We will continue to develop our research practices on our consumer engagement program to ensure that it is best practice and is informed by implementing the feedback of our stakeholders.

3.3.2 TransGrid's engagement model

The AER has made a number of comments regarding TransGrid's model of engagement and the depth to which the process impacts TransGrid's operations, providing some constructive ways in which TransGrid could improve on its current engagement model to ensure a greater penetration of consumer feedback. We are continuously looking to improve the way that we can engage with consumers and appreciate the suggestions that the AER has made.

The AER has proposed that TransGrid should consider ways that it can more consistently move from informing its stakeholders and sharing information with them, to directly consulting with them and ensuring that they are involved in the decision making process. We have accepted this advice and taken steps to better evaluate where on the spectrum our engagement sits based on feedback from participants. This will help us make targeted and appropriate improvements.

TransGrid included in its revenue proposal key items that were directly influenced by the feedback from our consumer engagements. For example, based on feedback received, we have modified our capital expenditure forecasting method with a more rigorous risk model based assessment of network risks and the costs to mitigate risks. TransGrid made changes to two of the three operating expenditure escalation factors as a direct result of input and feedback from consumer forums. Further to this, based on feedback from the RPWG, we revised our pricing methodology to ensure that the information was accessible to consumers and easily understood. TransGrid also made various changes to the presentation and depth of information provided throughout the proposal and supporting information.

Taking on the AER's feedback, TransGrid engaged with the TAC at its final meeting of 2017 to seek feedback on where our current level of engagement sits on the IAP2 engagement spectrum. TAC members praised the effort TransGrid had demonstrated to improve its consumer engagement program compared to other network businesses the members had exposure to, and identified that TransGrid's level of engagement tended to occur at the "consult" and "involve" levels of the IAP2 spectrum. Several TAC members highlighted that in their view some specific areas of engagement, particularly within the Powering Sydney's Future program, fell into the "collaborate" category.

The TAC provided feedback to TransGrid that we should look to identify areas where our engagement can move towards the "empower" category with stakeholders, rather than stop at "collaborate" as the AER suggests. Establishing consumer views on the setting of the Value of Customer Reliability (VCR) was provided as one example where TransGrid could do this. TransGrid is able to announce that this feedback has already been put into action with our revised Powering Sydney's Future project, submitted within this revised revenue proposal.

3.3.3 Inviting challenge to assumptions of modelling

The AER suggested that TransGrid could go to greater lengths to ensure that the assumptions that underlie the forecasts it provides to consumers are more open to critique. The value and necessity of critiquing assumptions of forecasts is something that we understand to be of great importance. TransGrid has worked to ensure that forecasts it puts forward are not only open to critique from stakeholders and the public, but are also supported by independent analysis from third parties.

In the development of our revenue proposal, we held full day workshops with both our RPWG and TAC on the development of our operating expenditure and capital expenditure submission. The focus of these was to ensure that the assumptions that underlie the submissions were open to both challenge and explanation. As mentioned earlier, this process led to modifications being implemented for our operating expenditure forecast, based on consumer feedback, and a lower amount of revenue asked for in the proposal.

Particularly highlighted by both the AER and the CCP as needing a greater level of critique, were the assumptions that underlie the Powering Sydney's Future project. TransGrid has completed two stages of the Regulatory Investment Test for Transmission (RIT-T) as required by the AER. The purpose of the RIT-T is to identify the transmission investment option which maximises net economic benefits and, where applicable, meets the relevant jurisdictional or Electricity Rule based reliability standards. As part of the RIT-T process, TransGrid released the Stage 1 – Project Specification Consultation Report (PSCR) and Stage 2 – Project Assessment Draft Report (PADR). The final stage is the Project Assessment Conclusions Report (PACR), which has been released in December 2017. TransGrid sought input from a wide range of stakeholders as part of the project planning process and to feed into each of the reports.

TransGrid undertook a separate comprehensive engagement program around the project, which included a public forum on the drivers of the project and the assumptions underlying the forecasts. The assumptions that underlie the forecasts and the project were also made public and consumers and stakeholders were invited to provide submissions regarding the project. As well as the separate project-specific engagement program, both the RPWG and TAC were briefed and consulted on the project, including opportunities to provide input and feedback on the assumptions used and TransGrid's proposed approach to the project.

The outcome of these engagements was that TransGrid pursued the involvement of non-network alternatives to try and defer expenditure on the project, based on consumer feedback. TransGrid, however, also understands that there is always work to be done to ensure that the assumptions that underpin the forecasts it uses for its projects are regularly reviewed and updated, and are open for critique. As outlined in section 3.2.1 above, TransGrid has engaged with its RPWG on the forecasts used for the Powering Sydney's Future project, submitted as a key capital expenditure project within this proposal, and highlighted by both the AER and the CCP as a project for which the underlying assumptions were not critiqued appropriately.

3.4 Key issues raised by the CCP

In approaching the feedback provided to TransGrid by the CCP, we would like to recognise and thank the CCP for its characterisation of our engagement as "transparent and open", and for the communication from that positive feedback received by them from TransGrid's stakeholders regarding its engagement. We would also like to thank the CCP for its constructive feedback to TransGrid regarding how to continue to improve our engagement approach. We have summarised key elements of feedback provided by the CCP and our responses below.

3.4.1 Level of information provided to stakeholders

The CCP provided feedback that there was an inconsistency of reception from stakeholders as to the level of information provided in consultation sessions, with some stakeholders finding the level of information clear and sufficient, while others found it too in-depth and hard to follow. This feedback highlights the difficulties in effective engagement with a range of stakeholders who have varying levels of background knowledge and differing perspectives. TransGrid agrees with the CCP on the need to ensure that the information being presented is accessible and finds the right balance on the level of detail.

To ensure that the information being presented to the TAC and RPWG is appropriate, TransGrid uses evaluation forms to collect feedback on each meeting and the level of information provided. For the engagement meetings for 2017, the level of information provided by TransGrid to the TAC and RPWG has been rated at an average of 8.15/10. We recognise that this is always an area that needs to be refined based on feedback and will continue to work with stakeholders to ensure that they receive the information they require and the level of depth that they would like.

Through our current evaluation processes, TransGrid has not received the same feedback provided by the CCP that the level of information provided by TransGrid may not be appropriate. As such, we appreciate the separate feedback provided by the CCP. Due to this disconnect in feedback received, we will look to further improve and enhance the evaluation processes and systems we utilise for each engagement meeting, in consultation with our stakeholders and consumers.

The CCP encouraged us to move from “inform” to “involve” and “collaborate”, as set out in the IAP2 spectrum. Encouraged by this, we sought guidance from our advisory council as to where they assessed we currently sit and what we should be targeting. Our TAC members confirmed that not only are we improving in our consultation but they already felt we were mostly at “involve” and some areas should be considered at the “collaboration” level using the IAP2 spectrum as their guide. Customers have also set our target high; they would like to see us aiming for our engagement at “empower” level wherever possible. TransGrid has accepted this challenge and will work to move further along this path.

3.4.2 Framework for the measurement and ongoing improvement of consumer engagement

Measurement of the effectiveness of a consumer engagement program is paramount to its success in genuinely including consumers in the decision making process. We are constantly engaging our consumers and stakeholders both formally and informally, and as part of that engagement we are looking for ways to improve our process. Feedback is taken after engagement sessions and used to inform subsequent engagements. Further to this, we complete an annual reputation survey which includes its consumers and stakeholders to collect feedback on our performance as an organisation and to identify areas for improvement.

TransGrid recognises that continuing to develop the evaluation framework for its engagement program is an area where further development is required, and accepts the CCP recommendation. Developing a more formal and transparent framework to measure levels and effectiveness of engagement, including set engagement markers/times for framework evaluation and feedback, will provide us with greater insights into how to further embed the consumer voice within the decisions that it makes. We look forward to following up the CCP’s recommendation and investigating ways to further formalise and improve our consumer engagement framework.

We are currently undertaking our 2017 annual reputation survey. This independent survey is structured to ask consistent questions to identify and track changes over time. TransGrid finds this a valuable and robust method to source honest and direct feedback on our performance across the business' operations and activities.

3.4.3 More proactive response to the changing energy market

The CCP has suggested TransGrid could take a more active role in responding to the changing energy market. Since the submission of our revenue proposal in January 2017, the energy industry has undergone a series of distinct changes that have called for leadership and progressive thinking from the industry. We see our role as a transmission network as positioning the organisation to be a leader within the industry, and have proactively worked with our stakeholders to respond to the risks and opportunities present in the future network. We have particularly taken a proactive role working with the TAC on how to respond to the Finkel Report, and particularly the role it can play in the development of large scale renewable energy zones as advocated by Finkel.

We have engaged with the TAC consistently since the Finkel recommendations were released, as well as consulting with industry and consumer stakeholders within varying contexts to collect feedback on our proposals. In answer to questions from the TAC, we have undertaken research into the potential locations for the proposed renewable zones and are currently engaged in discussions on the most appropriate way that such developments could be undertaken to ensure that the benefit and risk is equitably shared and to ensure that any decisions are in the best interests of consumers.

TAC members have challenged TransGrid on the role that non-network options could play in alleviating constraints on the network and responding to the changing energy landscape. In response to this, we are continuing to investigate how non-network options such as demand response and batteries can be used alongside network options to manage emerging network constraints.

3.4.4 Greater efficiency in the capital and operational expenditure

The CCP has expressed that it would like to see greater operating and capital expenditure efficiency demonstrated within TransGrid's revenue proposal, based on feedback that it has received from stakeholders. TransGrid has worked extensively with stakeholders on the capital and operating expenditure that it is proposing, including holding full day meetings with the TAC and RPWG to go through the proposed capital and operating expenditure forecasts, which led to a revised approach to the operating expenditure forecast. Ensuring that stakeholders are involved in the discussions to a level of their satisfaction is always something that must continually be evaluated and we appreciate the CCP feedback. With this feedback in mind, we have met with both the RPWG and TAC to consult with them on how we should respond to the AER and what should be included in its revised revenue proposal.

TransGrid recognises consumers need to have confidence in the efficiency of the business' operating and capital expenditures. In the lead up to the revenue proposal, TransGrid participated in various independent benchmarking studies that assessed the relative efficiencies of the business. These studies were submitted as part of the revenue proposal. TransGrid also notes the AER undertakes its own benchmarking studies and publishes these results.

3.4.5 Enhanced engagement around RIT-T

The CCP has noted that TransGrid has met and in some places exceed the AER guidelines for engagement on RIT-T projects, and we are thankful for the recognition of our efforts to engage the public around these projects. We do of course recognise that there are improvements that can be made regarding including consumer feedback at a greater depth in decisions and ensuring that consumers are engaged in the decision making process. TransGrid will continue to examine its engagement framework surrounding RIT-T investment to ensure that best practice engagement is embedded into the process frameworks.

3.4.6 Limitations of the underlying assumptions of Powering Sydney's Future

Further detailed discussion of the Powering Sydney's Future project can be found in chapter 4.

3.5 Powering Sydney's Future

TransGrid appreciates the feedback received from both the AER and CCP that TransGrid has gone further than most to engage consumers and the industry in RIT-T consultation. We strive to ensure that consumers are engaged in consultation at all levels and stages of the development of our capital works. Both the AER and the CCP have expressed concerns, however, that the critical assumptions that underlie the project, including Ausgrid's peak demand forecasts, have not been appropriately tested and challenged by consumers. Further to this, concerns were raised regarding TransGrid's assessment of non-network and demand management options that could defer investment in the project. We welcome the opportunity to provide more information to the AER and the CCP on the consumer engagement that occurred specifically regarding the Powering Sydney's Future project, and to address the specific concerns that have been highlighted.

3.5.1 Consumer engagement on Powering Sydney's Future assumptions

The assumptions that underlie the need for the Powering Sydney's Future project have been presented publicly on numerous occasions in the development of TransGrid's revenue proposal. This has included holding public forums and inviting submissions on the project as part of the RIT-T process. Further engagement with consumers and stakeholders, including discussion on the assumption on the demand forecasts, has occurred as part of our consultation with the RPWG, TAC, and in one to one stakeholder consultations in the lead up to TransGrid's revenue submission, and continuing beyond it. TransGrid is confident in the assumptions that underlie the need for this project and has engaged with its stakeholders extensively on these. We have engaged with both the RPWG and the TAC in the wake of the AER's draft decision to examine the project needs and assumptions that underlie it, to ensure that consumers are comfortable with the approach that we had undertaken.

Meeting with the RPWG in October 2017, we again went through the assumptions and forecasts that underlie the need for the Powering Sydney's Future project, including AEMO's 2017 NSW and Sydney forecasts, encouraging questions and critiques. The RPWG commented that although there are issues with the specificity of AEMO's 2017 forecast, and Ausgrid's peak demand forecasts, neither of these are grounds to assume that the demand is not there, noting that the area of Inner Sydney cannot be adequately reflected in broader geospatial forecasts based off an average demand. The RPWG questioned the AER's use of 2016 forecasts in its decision, despite the availability of more updated forecasts released by AEMO, and noted that the lack of granularity in the larger geospatial forecasts is reflective of a need for more detailed forecasts for areas such as the Inner Sydney region, that should be created in consultation with the local operators to ensure out of trend developments are reflected.

The RPWG was broadly supportive with the approach that TransGrid had taken regarding the forecasts and assumptions for Powering Sydney's Future. Further to this, the RPWG members specifically requested the CCP challenge the AER on the lack of detail and feedback in its decision to not approve Powering Sydney's Future in its draft determination, and to provide a better explanation of the exact basis on which it was decided the project would not be needed in this next regulatory period. RPWG members expressed that if the AER felt there were necessary grounds to reject the project as proposed, then the AER should be able to provide a set of triggers for the project as well as an expected timeframe wherein the project would be needed. TransGrid has committed to the RPWG to continue working with the AER to ensure that there is an understanding and agreement for the assumptions that underlie the project.

Further to meeting with the RPWG to discuss the Powering Sydney's future project, TransGrid met with the TAC in November to discuss the AER's draft determination and to seek feedback on how we should position our revised proposal. We communicated the sentiments of the RPWG to the TAC, and again consulted on key assumptions underlying the need for the project. TAC supported the underlying assumptions on which the project need is based, recognising that although there is uncertainty involved in predicting future demand, there was a need for a solution to ensure the security of supply to the city. Further to this, the TAC members provided feedback to the CCP that they were concerned about the lack of guidance provided by the AER with its rejection of the project, advocating that clarity around the methodology behind the AER's decision was essential for TransGrid to be able to deliver a solution that was acceptable to the AER.

3.5.2 Consideration of the risks involved in Powering Sydney's Future

The AER and the CCP have highlighted that greater consideration is needed of the risk involved with using demand forecasts for Powering Sydney's Future, and more broadly the impact of a premature triggering of capital investment for the project. TransGrid indeed recognises that there is a risk inherent in projects such as Powering Sydney's Future and that it is important that projects are triggered at the optimal time to ensure consumers are paying no more than necessary, no sooner than necessary. Regarding Powering Sydney's Future, there is also the parallel risk in the delaying of investment and the increased risk to security of supply. Both of these risks are of importance and should be balanced. TransGrid's risk model is specifically developed to make such an assessment with a robust and reliable framework.

TransGrid, in discussions with its RPWG and TAC, detailed the drivers behind the need for the project to be included in this regulatory period, such as the increasing demand forecasts (including spot loads not identified by AEMO) and increasing risk of cable failure over time. Feedback from customers to TransGrid highlighted that there was a different appetite for risk regarding the security of supply to the Sydney CBD between TransGrid and the AER's approach to the Powering Sydney's Future project, with consumers viewing the AER's appetite for allowing risk for the CBD being significantly higher than TransGrid's. Consumers provided feedback that due to the obvious differing appetites for risk; the onus should be on the AER to define clearly the level of risk it feels is appropriate to take regarding the security of supply to the Sydney CBD. In particular, the level of risk should be taken into account in its decision to reject the project in the upcoming regulatory period, having regard to the licence conditions and reliability standards TransGrid is required to comply with. Consumers did not think it was appropriate for the project to be denied without clear definitions from the AER as to what circumstances would be required before the project would be considered, and without a clear articulation of the risk that was acceptable to take with the security of supply to Sydney's CBD.

3.5.3 Pursuit of non-network options

TransGrid has undertaken a comprehensive approach to procuring non-network solutions to defer investment on the Powering Sydney's Future project. TransGrid held public information forums for non-network providers and has gone to market for expressions of interest from non-network providers. Engaging with the TAC at its meeting in August 2017, we presented our progress to date for the procurement of non-network options for Powering Sydney's Future. The TAC was satisfied with the approach that we had taken in sourcing non-network options with one TAC member stating that "you [TransGrid] have gone through a very rigorous process, and should be commended for that".

In the examination of the role that demand response could play in meeting the needs of the Sydney CBD and deferring the project, we engaged with the RPWG on how this would best be achieved, and included this as a consistent area of engagement with the TAC. There was support among the RPWG and the TAC for the role of demand response in future solutions to ensuring the security of supply to the Sydney CBD, however some customers expressed that demand response was only a last resort for their operations and that this should not be thought of as a regular or even permanent part of the solution for meeting growing demands within Sydney. Customers agreed that non-network options were important; however there was consensus that these could not replace a permanent solution to securing the supply to Sydney in the long term.

3.5.4 TransGrid's revised solution

Having engaged with consumers on the Powering Sydney's Future project, including its assumptions and concerns raised by consumers, stakeholders, RPWG, TAC and the AER and CCP, TransGrid has proposed an amended project to reflect the feedback we have heard. TransGrid's engagement with its consumers and stakeholders, and particularly with the RPWG and TAC, has supported the need for the implementation of the Powering Sydney's Future project as a solution to meeting the forecast demand for the Sydney CBD and ensuring the security of supply as the current Ausgrid cables are retired.

In response to this feedback regarding the uncertainty that forecast demand will eventuate, we have amended the project to include only a single cable, with the option of laying a second cable in the future if demand forecasts are realised. This solution has been informed directly through engagement with consumers and key stakeholders, and was endorsed by our TAC at its last meeting as a reasonable and responsible proposal to ensure both the security of supply and greater optionality for the future. A single cable option allows for the possibility of greater use of demand response and non-network solutions in the future, providing optionality for the growing needs of the city to be met in the most efficient way available at the time, while still ensuring that the security of supply to the Sydney CBD is ensured in the short-medium term.

3.6 Response to public submissions

TransGrid appreciates the submissions put forward by its stakeholders and consumers, and would like to thank them for the time taken to do so. Below are outlines of each of the submissions, and TransGrid's response.

3.6.1 City of Sydney

The City of Sydney is a key stakeholder for TransGrid, representing the local government body that governs the Sydney CBD and Inner Sydney area, and sits on both the TAC and RPWG. We are pleased to see that the City of Sydney supports TransGrid's strategic vision for the future, for the widespread deployment of renewable and low emission generation, and the City's recognition of the need for TransGrid to be appropriately resourced to ensure the continued supply of safe, secure and reliable electricity to the City.

The City of Sydney has made a number of comments within its submission on TransGrid's revenue proposal, with a particular focus on TransGrid's proposed capital and operating expenditure. The City of Sydney has emphasised the increased role that demand response should play in the management of critical network assets, including those in central Sydney that are part of the Powering Sydney's Future project. The City of Sydney has also noted that the Sydney CBD must continue to have a high level of electricity security given its important economic position within NSW and Australia. TransGrid has engaged extensively with the City of Sydney regarding the Powering Sydney's Future project on a continual basis through the TAC and the RPWG, including discussing the growing demand within the city and the non-network options that are available to defer the project to the point it is currently at. The

City of Sydney is a key stakeholder for the CBD area and TransGrid is committed to ensuring that the security of the electricity supply is not compromised.

Asset management was also highlighted by the City of Sydney as being in consumers' best interests, with the submission encouraging TransGrid to extend the life of assets where possible and to be properly compensated where this has been done. As discussed previously, this approach to asset management is consistent with TransGrid's current risk management framework, where assets to ensure they are maintained in a fashion that ensures the longest life and the least cost to consumers.

The City of Sydney also notes that the future of the electricity markets are uncertain, and that there was concern that growing levels of local generation may not be properly recognised in forward forecasts. Regarding current transmission charges, the City of Sydney has recommended that the transmission charges that are applied to local generation be reduced as this would be both economically efficient and suitable.

TransGrid is obliged to price in accordance with the National Electricity Rules, however we do note that the existing pricing framework places a very small proportion of the costs on generation.

3.6.2 Origin Energy Limited

Origin Energy's submission focused on our capital expenditure program and grid planning. Origin has provided commentary on how greater efficiencies in the delivery of capital projects can be found in the alignment of the timing and delivery of compatible projects, and has highlighted the importance of accurate risk and condition based analysis to underpin replacement expenditure. TransGrid agrees with these comments and is pleased to confirm that our forecasting method and asset management practices deliver on these objectives. We have aligned our replacement expenditure forecasts with a risk based approach to asset maintenance and replacement, ensuring that assets are maintained and replaced based on their condition and function to ensure maximum efficiencies in our expenditure.

Regarding TransGrid's proposed capital expenditure, Origin has proposed that the Powering Sydney's Future project should not be approved, but rather should be included as a contingent project until the RIT-T is concluded. We take Origin's feedback on board on this matter; however we maintain the need for Powering Sydney's Future to be a key capital expenditure project, and since Origin's submission, we have published the final RIT-T document. A further discussion of TransGrid's inclusion of the Powering Sydney's Future project can be found in chapter 4.

Origin also highlighted that there is great uncertainty in the future of the NEM, particularly around forecasts for the update of small scale renewable energy, and so questions how TransGrid will assess the impact this might have on the grid and its assets. We are continually monitoring the development and implementation of new technology and how that affects future use of the network. Origin also questioned the stability of TransGrid's grid planning model, recommending that the AER conduct a back-casting exercise to help determine the accuracy and stability of the model and its outputs. TransGrid has developed and maintains a robust up-to-date grid model of the NSW transmission network and beyond. This includes detailed models of the NEM and downstream distribution networks.

TransGrid has implemented annual external reviews for quality assurance that have improved accuracy and have set up our models for greater stability in future years.

3.6.3 Snowy Hydro Limited

Snowy Hydro Limited submitted specific comment on the proposed contingent project within TransGrid's revenue proposal pertaining to the reinforcement of the Southern network, stating that this project was an important strategic investment that would be critical for the decarbonisation of the NEM. Snowy Hydro proposed that TransGrid both expand the scope of the project to ensure that the Snowy

2.0 project is not constrained, and amend the triggers events that the project is based on, removing the RIT-T as a trigger and including approval for final investment from the Snowy Hydro Board, completion of the economic evaluation, and commitment from the TransGrid Board to proceed with the augmentation.

Snowy 2.0 was announced by the Federal Government after TransGrid's revenue proposal was submitted. We made a further submission to the AER in August 2017 on contingent projects reflecting outcomes of the Finkel Review, the Federal Government's announcement of Snowy 2.0 and having assessed the reliability consequences of 10 February 2017 generation shortfall in NSW.

TransGrid has proposed a specific contingent project related to Snowy 2.0, which would mean that if the generation project proceeds we would be able to provide the necessary network connections.

4. Capital Expenditure

4.1 Introduction

Capital expenditure includes expenditure on new assets to increase network capacity and reliability, on replacement of existing assets at the end of their service lives and on assets which support the business.

4.2 Overview

TransGrid proposed a capital expenditure program of $1,612 million in the revenue proposal, comprising $160 million for augmentation of the network, $962 million for replacement of existing assets and $331 million for the Powering Sydney's Future project which is needed to secure the Inner Sydney network on the basis of condition of existing assets and future growth in demand.

The draft decision for the 2018/19 to 2022/23 period has reduced TransGrid's capital expenditure allowance by $620 million (or 38%) to $992 million.[1] These cuts comprise broadly a rejection of the Powering Sydney's Future project and a 23% cut to the remainder of the capital program. Our proposed contingent projects were accepted with suggested amendments to the project triggers.

TransGrid disagrees with the proposed capital expenditure reduction, much of which appears to be based on erroneous analysis and a misinterpretation of our forecasting approach. The reduction is not in the long term interests of consumers; it will increase the risk of loss of supply events, lead to higher asset lifecycle costs and has potential safety and environmental impacts.

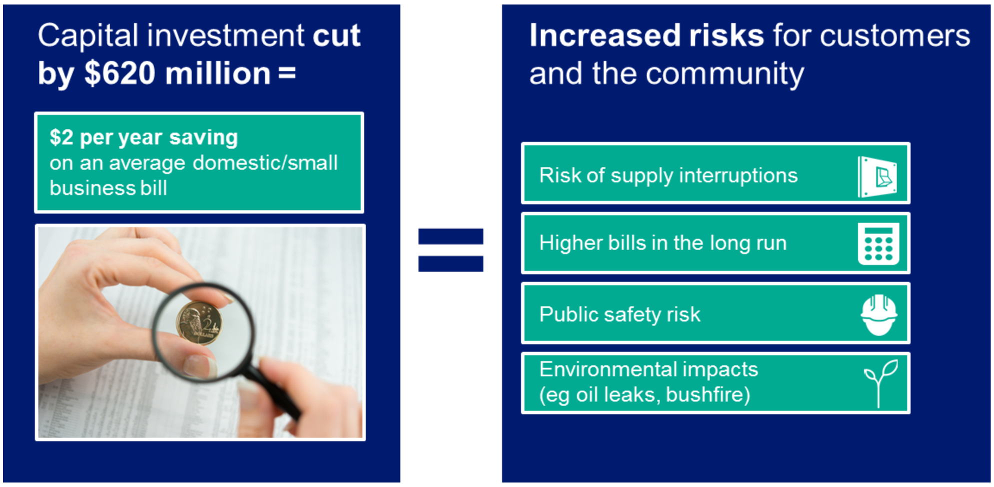
The AER has a different view:

> In making our draft decision, we specifically considered the impact our decision will have on the safety and reliability of TransGrid's network. We consider this capex forecast should be sufficient for a prudent and efficient service provider in TransGrid's circumstances to be able to maintain the safety, service quality, security and reliability of its network consistent with its current obligations. (Draft Decision 6-15)

Consequences of the proposed reduction

We recognise customer concerns about electricity prices; however such a large reduction in capital expenditure will have consequences which may also impact customers and others in our community.

[1] These values (and others in this chapter) exclude the NSCAS assets unless specifically stated.



At a time of significant and rapid change, where policy uncertainty has been the primary driver of higher electricity prices, the draft decision serves to further deter efficient long-term investment and does not further the provision of affordable, reliable and secure electricity.

We appreciate that the AER has remained open to reviewing further information.

AER draft decision

Details of the AER draft decision's $620 million capital expenditure reduction are shown in Table 4.1.

Table 4.1: Capital expenditure draft decision and reasons ($m June 18)

Component	Draft decision ($m)	AER assessment and rationale
Powering Sydney's Future (PSF)	0	***Reduction in our forecast: -100%*** AER rejected this project due to presumed uncertainty in key drivers including demand, cable availability and value of customer reliability.
Replacement (inc. Security & Compliance)	757.9	***Reduction in our forecast: -21%*** AER considers that the risks being managed by the program are overstated, so considers that the forecast is overstated.
Augmentation (ex-PSF)	96.6	***Reduction in our forecast: -40% in total across the category*** **Economic benefits driven** – AER found the identified needs were valid but investment benefits may be materially overstated *(-51%)* **Connection driven** – AER consider that historical connection capex would be more accurate than TransGrid's forward looking view *(-79%)* **Localised demand driven** – AER accepted most of this category but found insufficient information was provided for one project *(-15%)* **Reliability** – AER accepted the proposal, with a small update for inflation *(-0.5%)*
Non-Network (IT and business support)	137.7	***Reduction in our forecast: -13%*** AER did not agree with elements of the project benefit analysis for the IT projects (eg, failure rates, risk costs, options analysis). Business support costs were accepted.
Total	**992.2**	

The AER accepted the five proposed contingent projects subject to slight changes to the trigger events.

Concerns with the AER's conclusions and their basis

Our forecasting method is based on established asset management practices and a recognised approach to risk analysis. We are concerned with the AER's draft decision for capital expenditure as it:

- *Draws upon erroneous or inapplicable analysis*, which we identified and brought to the AER's attention in August 2017
- Is based on *an incorrect interpretation or misunderstanding of aspects of our risk analys*is and forecasting approach
- *Does not properly reflect the most recent and relevant information*.

We are also concerned that the AER's process has allowed incorrect information about our forecasting approach into the public domain.

We appreciated the opportunity to fact-check Energy Market Consulting Associates' (EMCa) draft report.[2] Despite notifying the AER of more than thirty factual and interpretative errors[3], the unchanged report was published without any indication that corrections could be required. Many of the most significant errors form the basis of the draft decision - especially the examples where risk consequence costs have been misinterpreted.

For example, the AER concluded that our use of "***worst case"*** risk assumptions in risk analysis[4] is "***overly risk averse***" and so "***capital expenditure is likely to be overstated***" (Draft Decision 6-3). This appears to be based on a poor understanding of our actual approach.

---

2 Review of aspects of TransGrid's forecast capital expenditure 2018-23, June 2017

3 Letter to AER, 23 August 2017.

4 This is a valid approach in risk management, ensuring high consequence risks are properly considered, even if they are unlikely.

Input values used out of context to support program-wide cuts

The AER highlights the use of a *'consequence cost of $400 million based on the Black Saturday bushfire'* which is *'likely to inflate the estimate of the risk cost' (Draft Decision 6-70).*

This conclusion and its basis are not reasonable. The $400 million value is merely a starting point based on a published source (i.e. it is 10% of the Victorian Bushfire Royal Commission's $4bn Black Saturday cost*).

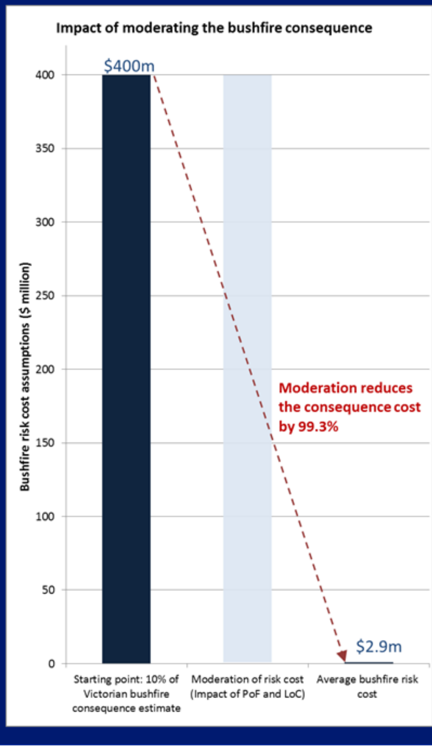
It is significantly moderated in our risk cost calculations, by:

- a **probability of asset failure** (~1 in 150 years for towers) **and**
- the **likelihood of the consequence** if the 1 in 150 year failure occurs in a location (given vegetation, terrain, land use and weather).

As illustrated in the figure, moderation reduces the bushfire consequence cost by 99.3%.

The average bushfire consequence cost per transmission line used in the capital expenditure forecast is $2.9 million.

This is **only 0.7% of the $400 million** which the AER and EMCa presented as evidence of a conservative approach.



**** 2009 Victorian Bushfire Royal Commission, Final Report, Summary, p1***

Correcting (at least) the most material errors prior to publishing would have allowed stakeholders and customers to respond based on factual information. Many analytical errors and misinterpretations are addressed in section 4.3.2 and the capital expenditure reductions these errors were used to support are identified throughout this chapter.

TransGrid's response to the draft decision

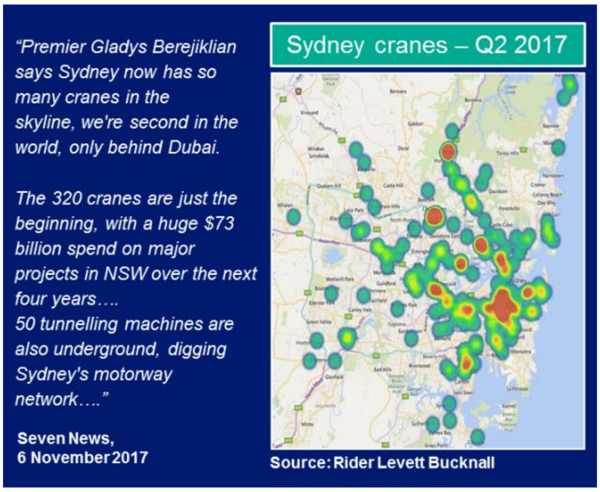
We agree with the AER:

- That contingent projects triggers can be amended largely as suggested
- To correct minor analytical errors, decreasing some parts of the forecast
- To update the IT investment analysis and provide further information as suggested.

We disagree with the AER that Powering Sydney's Future is not required when proposed, nor do we consider it should be treated as a contingent project.

There is very strong support from customers and stakeholders for securing the Inner Sydney network, especially in light of committed infrastructure projects, economic growth and historically high level of building approvals.[5]

The AER's comparison of the PSF demand forecast to out-dated AEMO forecasts covering different geographical areas is not appropriate. Its subsequent conclusions about demand uncertainty do not reflect available information, such as AEMO's 2017 forecast or evidence that large new loads are already connecting.



As a compromise, we are proposing a two-stage project to address the immediate supply risk and stop the oil leaks by retiring the old cables. This may also provide an opportunity to delay the second cable with demand management. However, we will need to manage additional community disruption from the second construction phase, potentially as soon as four or five years after the first construction period.

We disagree with the AER that forecast replacement expenditure is based on overstated risks. The AER's reliance on past trends appears to penalise a forecast created to address emerging and future risks. We have reviewed the areas of concern and analysed the latest asset condition information and have provided a similar forecast with minor updates.

We disagree with the AER that other parts of the augmentation forecast should be reduced. Economic benefits are not overstated and the forecast of expenditure related to new large but uncertain demand connections should be based on future conditions, not the past.

We propose a compromise in relation to the labour escalation forecast. For capital expenditure, the AER accepted the proposed labour cost escalation based on a Wage Price Index (WPI) for the Electricity, Gas, Water and Waste Services (EGWWS), prepared by BIS Shrapnel. However, the AER did not accept the same labour cost escalation forecast for operating expenditure, replacing it with a WPI EGWWS forecast prepared by Deloitte Access Economics.

As we clearly face the same labour cost escalation for both areas, we propose a compromise approach which is consistent with the AER's preferred approach in our current revenue determination. We have applied the average of an updated BIS Shrapnel[6] forecast and the AER's Deloitte Access Economics forecast to both capital and operating expenditure in this revised proposal. This ensures the integrity of

5 Source: Australian Bureau of Statistics, Building Approvals, Australia, catalogue number 8731.0

6 Since the submission of our proposal in January, BIS Shrapnel has been renamed BIS Oxford Economics

the respective forecasts. This update of the labour escalation has reduced our capital expenditure forecast by $13.5 million compared to the January 2017 proposal.

Updated forecast

TransGrid's revised capital expenditure forecast in comparison with our proposal and the draft decision is shown in Table 4.2.

Table 4.2: Revised capital expenditure forecast and rationale ($m June 18)

Program component	Proposal	Draft decision	Revised forecast	Comments	Section
Powering Sydney's Future	331.7[7]	0	252.3	We propose a two-stage project in response to AER and following customer consultations	4.4
Replacement (inc Security & Compliance)	961.8	757.9	937.1	Minor amendments made in response to AER comments	4.5
Augmentation (ex-PSF)	160.0[8]	96.6	186.6	Ten "ex-NCIPAP" projects added to the ex-ante capital program Updated supporting information is provided	4.5.7
Non-Network (IT and business support)	158.8	137.7	157.9	New IT option analysis has been completed in response to AER comments	4.7
Total	**1,612.3**	**992.2**	**1,534.0**		

This revised forecast has been influenced by new asset and demand information, updated analysis, consultation with stakeholders and aspects of the draft decision.

Overview of changes

The most significant change in this revised proposal is that we are proposing PSF as a two-stage solution – one cable first, with a second cable to be installed later. As the economic analysis for the RIT-T identified several options with similar benefits, the original single-stage option was "preferred" as it minimised the construction impact on the community.

However, we acknowledge the concerns of the AER and Consumer Challenge Panel (CCP) relating to flexibility. We therefore reviewed the options to consider the appropriate balance between retaining optionality, decreasing the initial capital cost and minimising community disruption.

Following this, we sought the views of customers and stakeholders represented by our TransGrid Advisory Council. They supported a two-stage option. A wider group of consumers, transmission customers, the AER and CCP also supported a two-stage option particularly as it provides flexibility. The installation of the second cable could be delayed if demand growth is lower than forecast and/or a higher quantity of lower cost non-network options emerges. The opposite could also occur and this

7 Our original forecast was $330.9 million. The AER moved $0.8 million from the connection forecast into the PSF forecast. We updated the PSF forecast in June 2017 to incorporate new information. We notified the AER of an increase to $373 million on 23rd June 2017

8 As noted for PSF, the AER moved $0.8 million from the connection forecast into PSF. Our original forecast for augmentation (which includes connection) expenditure was $160.8 million.

option would allow us to respond with a second cable earlier than planned should that become necessary.

The downside of a two-stage option is the second period of construction-related traffic congestion and related community impacts later in the next decade. This may not be trivial – for example, one of the impacted roads is currently used by almost 27,000 vehicles daily[9]. While these wider economic impacts cannot be included in a RIT-T, they still need to be properly considered. Nevertheless, we undertake to minimise these impacts. For example, this could be achieved by laying both sets of cable ducts in a single trench during the first phase and by carefully selecting joint bay locations to minimise later disruption where feasible.

Changes to the replacement expenditure forecast are the result of:

- Revising the scope of projects and programs in the forecast to account for the latest asset information and AER and EMCa comments
- Modelling corrections to reflect AER and EMCa comments.

The augmentation expenditure forecast (excluding PSF) now includes ten additional small projects which were not accepted into the Network Capability Incentive Parameter Action Plan scheme. Each of these projects results in positive market benefits at relatively low cost.

The IT expenditure forecast is slightly lower as a result of revised investment analysis.

Contingent projects

The five contingent projects have been updated with amended triggers in line with the AER's suggestions. There are also four new contingent projects: three related to the establishment of renewable energy zones and one for the proposed Snowy Hydro expansion. Three of these were foreshadowed to the AER in a letter on 22 August 2017.

Capital expenditure chapter content

The remainder of this chapter presents:

- An overarching response to the draft decision
- Detailed responses to specific cuts including new information where relevant, comments on the AER's analysis and how it has been applied
- Our updated forecast
- Updates to the contingent projects.

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9 Georges River Road traffic station reports around 27,000 vehicles pass *that section of the proposed route* on average each day in 2017. The source of vehicle count data is under Station ID 7275 at:

http://www.rms.nsw.gov.au/about/corporate-publications/statistics/traffic-volumes/aadt-map/index.html#/?z=13&lat=-33.90921191659774&lon=151.0794010162358&id=7275&tb=1&hv=1

4.3 TransGrid's overarching response

4.3.1 Areas of agreement and the inclusion of new information

TransGrid agrees with EMCa and the AER's assessments in some areas including that:

- Minor modelling errors should be corrected
- Some scope items could be removed from compliance projects.

As a result of these adjustments, and updating to account for new information, the revised proposal capital expenditure forecast is slightly lower than the January 2017 forecast. Table 4.3 shows a summary of changes from the revenue proposal forecast. [10]

Table 4.3: Summary of changes from the revenue proposal forecast ($m June 18)

Change made	Impact ($m)	Reason	More information
Actuals: Updated with 2016/17 actuals and 2017/18 forecast	11.5	Update to 2017/18 forecast	-
PSF: Update to Powering Sydney's Future Project	-78.0	Cost decreased as single cable option proposed	4.4
Augmentation: Timing change to 1443-Canberra Sub - Installation 132kV Switch bay - Line Single CB	0.1	Response to AER's draft decision	-
Augmentation: Removal of Travelling Wave Fault Location Project	-2.5	Removed from forecast following review of the need	4.6.1
Augmentation: Inclusion of projects not accepted in NCIPAP	21.6	Projects with clear benefits added to ex-ante forecast	4.6.1
Replacement: Project 1254 SCADA replacement timing change	-3.1	Project brought forward so some expenditure now in 2017/18	4.5.3
Replacement: Reduction and removal of projects	-9.1	Response to AER's draft decision	4.5.2
Replacement: Scope increase in replacement project (1556-Trans. Line Low Span St. 2)	3.8	Scope of measures required to remediate were different, leading to an increased estimate	4.5.3
IT: Revised IT Forecast	0.1	Response to AER's draft decision	4.7
Inflation: Updates to actual and forecast inflation	-9.1	Actuals for 2015/16 (corrected) and 2016/17 (added) Inflation forecast is 2.25% for 2017/18 and 2.47% thereafter[11]	-
Escalation: Labour escalation updates	-13.5	Average of DAE and updated BIS Shrapnel forecast	5.6.2
Total[12]	**-78.3**		

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10 Note: this table summarises changes made between CAM model submitted for the Revenue Proposal filename, 'TransGrid-Capital Accumulation Model-0117-PUBLIC.xlsb', dated 31/01/2017 and the CAM model submitted with this Revised Proposal filename, 'TransGrid-Capital Accumulation Model-1217-PUBLIC.xlsb', dated 01/12/2017.

11 Inflation based on geometric average of Reserve Bank of Australia Statement on Monetary Policy for two years and the midpoint of its target range for eight years

12 Note that table values do not add to this due to rounding. This is the correct total based on the unrounded individual entries.

4.3.2 Areas of disagreement

There are also aspects of the draft decision which we do not agree with.

A $620 million reduction in capital expenditure is not in the interests of consumers as it increases the risks of:

- Loss of supply events across the network, including sustained supply interruptions in the Sydney CBD (the source of around 7% of Australia's Gross Domestic Product)
- Higher asset lifecycle costs, which will ultimately flow through to customer bills
- Safety and environmental impacts within our community.

Given our concerns about the potential impacts on consumers and the community, we have carefully reviewed the rationale these aspects of the revised proposal are based on.

We consider that our risk analysis is robust but does not appear to have been well understood by EMCa and the AER. The draft decision and EMCa's report contain factual errors and misconceptions about the process and its inputs - the quantification of risk is the subject of many of these, including:

- Risk values being misread from a spreadsheet and presented as "evidence" of a systemic bias
- A lack of understanding of our risk analysis which has led to conclusions that we assume events to be a *factor of a thousand more likely* than actually modelled.

It is especially concerning that the draft decision relies so heavily on these:

> …we found some aspects of TransGrid's proposal were not consistent with the NER. Our findings on TransGrid's quantification of reliability, safety and environment (bushfire) risks used to derive project cost estimates largely explain why we are not satisfied that TransGrid's proposed total forecast capex meets the capex criteria. (Draft Decision 6-10)

TransGrid notified the AER in writing in August 2017 that there were a range of errors in the EMCa report. Other issues are the result of incorrect or inapplicable analysis and examples of both are provided throughout this chapter.

> ***The $620 million reduction in capital expenditure is largely based on the AER's findings in relation to the quantification of risks. Given the extent and nature of the errors and misunderstanding in relation to this, the AER's conclusions do not seem reasonable.***

Issues with the AER and EMCa's analysis

We understand that revenue reset processes are time constrained and involve the review of large amounts of information. Mistakes are possible and we appreciate that the AER and EMCa have given TransGrid an opportunity to correct errors in its material.

However, some of the AER's (and EMCa's) significant conclusions rely upon incorrect or inapplicable analysis and misinterpretation of our information. We are concerned about the adequacy of a process which has led to a $620 million capital expenditure reduction.

The EMCa Report

> ***The EMCa report contained more than 30 factual errors but the AER published it uncorrected and relied on the report to support many of its own conclusions.***

The EMCa report, 'Review of aspects of TransGrid's forecast capital expenditure', draws conclusions on TransGrid's capital expenditure forecast and is heavily quoted by the AER. We appreciated the opportunity to undertake a fact-check and identified more than thirty errors of fact and many interpretative errors in a response to the AER on 23 August 2017. We are disappointed that the AER issued the EMCa report without making any corrections and without indicating that some corrections could be required.

We are also concerned about direct contradictions between the draft decision and the EMCa report:

> EMCa found … bias in … risk assessment methodology: inadequate justification and **overstated project risk cost parameter assumptions (includes probability of failure**, likelihood that a hazardous event will lead to a consequence and the cost consequence of asset failures) (Draft Decision 6-70)**.** [Added emphasis]
>
> On balance, we consider that **TransGrid has applied a reasonable process, and that application of its process is likely to produce a reasonable estimate of the PoF** (EMCa Report p26) [Added emphasis]

Examples of errors, misinterpretations and misinformed conclusions

Various EMCa and AER analytical errors and misinterpretations are used to help justify many expenditure cuts. Significant examples are presented below with others provided in the sections detailing the relevant parts of the forecast.

> ***Example 1:*** *EMCa and AER incorrectly interpreted risk cost information and reported that the total network risk is **$1.6 trillion**.*
>
> ***Usage****: to conclude that we either overstate risk or are underspending imprudently in this period.*

The AER relied heavily upon EMCa's report, even re-quoting some of the more obvious errors to support its conclusions, for example:

> EMCa's concerns regarding a lack of portfolio optimisation is supported by its observation that TransGrid's risk cost modelling assumes that it is **exposed to $1.6 trillion** of risk per annum …if this was considered to be a reasonable estimate of risk exposure, ...TransGrid would be investing to manage this risk in the current (2015-18) regulatory control period…TransGrid is presently spending less than was forecast for the 2014-18 regulatory period. This suggests that TransGrid's estimated risk costs for the 2018-23 regulatory control period used in support of its proposed capex may not be credible. Further, this also suggests that TransGrid's proposed expenditure to manage risks is inconsistent with its actual practices. (Draft Decision 6-65)

The data used actually values pre-investment risk at **$1.6 billion** and we notified the AER of this in writing.[13] Regardless, $1.6 trillion is a large risk value - close to the value of Australia's 2016/17 GDP. It is reasonable to expect that a rigorous process would have identified such a large number if it was going to be used to demonstrate a flaw in TransGrid's approach.

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13 It appears that EMCa has summed a column in a spreadsheet but has incorrectly concluded that $1,620,425,704 is $1.6 trillion.

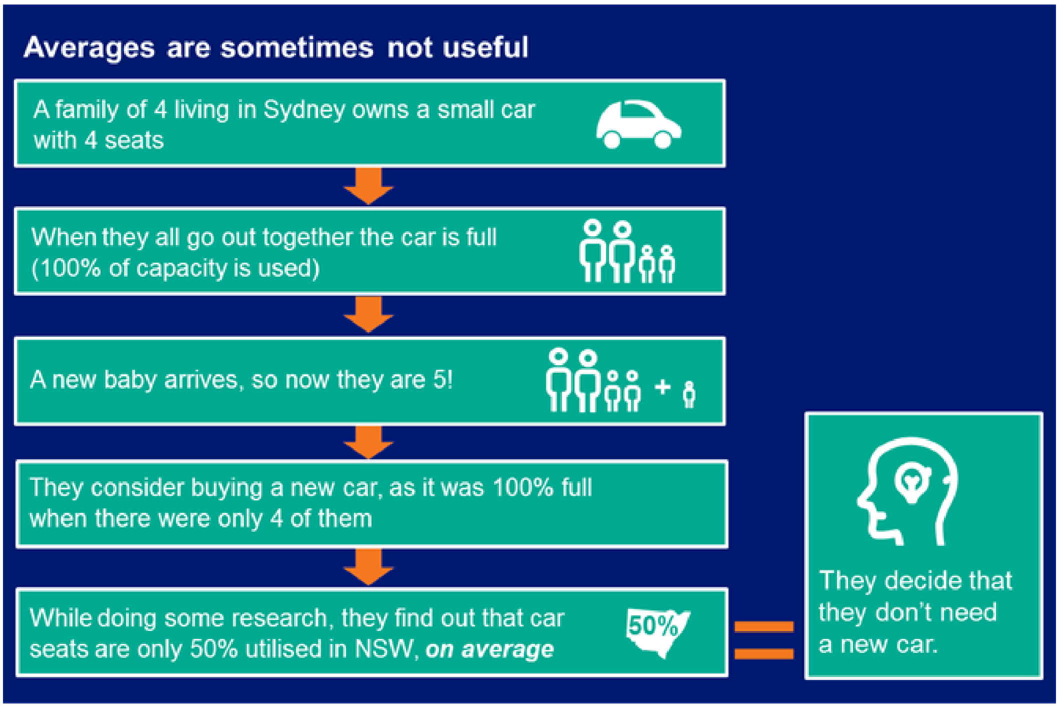
Example 2: *An average connection point utilisation calculation is not fit-for-purpose in credible network planning. The draft decision also appears to misrepresent the results of the calculation.*

Usage*: The calculation and results are used to conclude that demand driven augmentation should remain at historical levels.*

This basic analysis of connection point utilisation does not provide useful network planning information and the AER's conclusion cannot reasonably be reached from it.

A TNSP would be negligent to apply such an approach in considering how best to meet its obligations. Material flaws in this analysis include that:

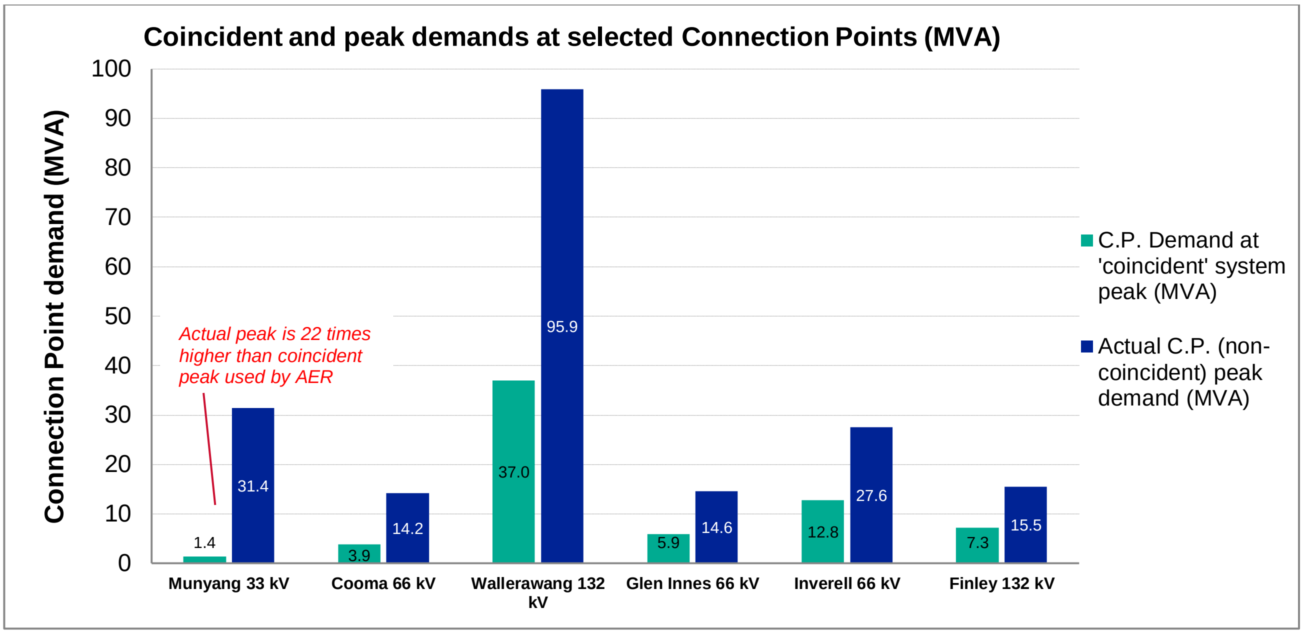
- Past average connection point utilisation provides no indication of whether customer needs or obligations can be met in the future ***at a particular connection point***[14]
- It provides no insight into where a problem might exist, nor does it identify other constraints (such as voltage or thermal limits on the network supplying the connection point)
- While non-coincident peak demand would be more representative, an "average utilisation" calculation is still not useful



[14] Average utilisation across two connection points at peak time might be 50% but the implications of this cannot be understood without looking at the individual connection points. For example, one could be 10% utilised and the other could be 90% utilised or they could both be 50% utilised.

> The AER used “coincident demands” measured at each connection point at the system-wide peak. Many connection points have much higher demands at other times (so will appear to be less utilised at the system peak). Six examples are shown in Figure 4.1.

Figure 4.1: Connection point demands at coincident ‘system’ peak and actual peaks (2013/14)

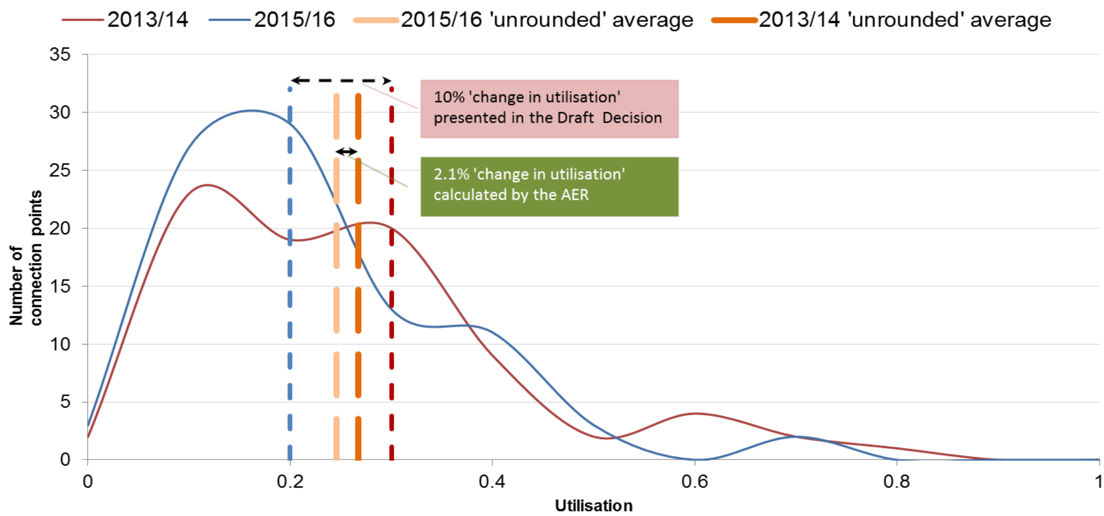


Source: TransGrid (transmission) 2013-14 - Category Analysis RIN - Templates (updated August 2015).

> Transformer “nameplate” capacities used give no information on the secure capacity at the connection point (ie, taking account of credible contingency events). Secure capacity is much more relevant as it relates to meeting reliability standards.

In addition to the inappropriate use of the above method, we are concerned that Figure 6.6 in the draft decision appears to misrepresent the results of the calculation. The spreadsheet provided to us shows that the chart presented did not use the calculated values. It used significantly rounded manually entered values. The corrected chart in Figure 4.2 compares calculated actual values with the “rounded up” values shown by the AER (Draft Decision, Figure 6.6).

Figure 4.2: 2013/14 and 2015/16 connection point utilisations (Coincident demand)



The chart shows how the AER's rounding presents a much more significant 10% "reduction in utilisation" between 2013/14 and 2015/16, rather than the calculated 2.1%[15]. This is an indicator of a lack of rigour and quality control within a process which has concluded with a reduction of $620 million in capital expenditure.

Table 4.4 summarises why calculating and applying an "average connection point utilisation" does not support the AER's conclusion.

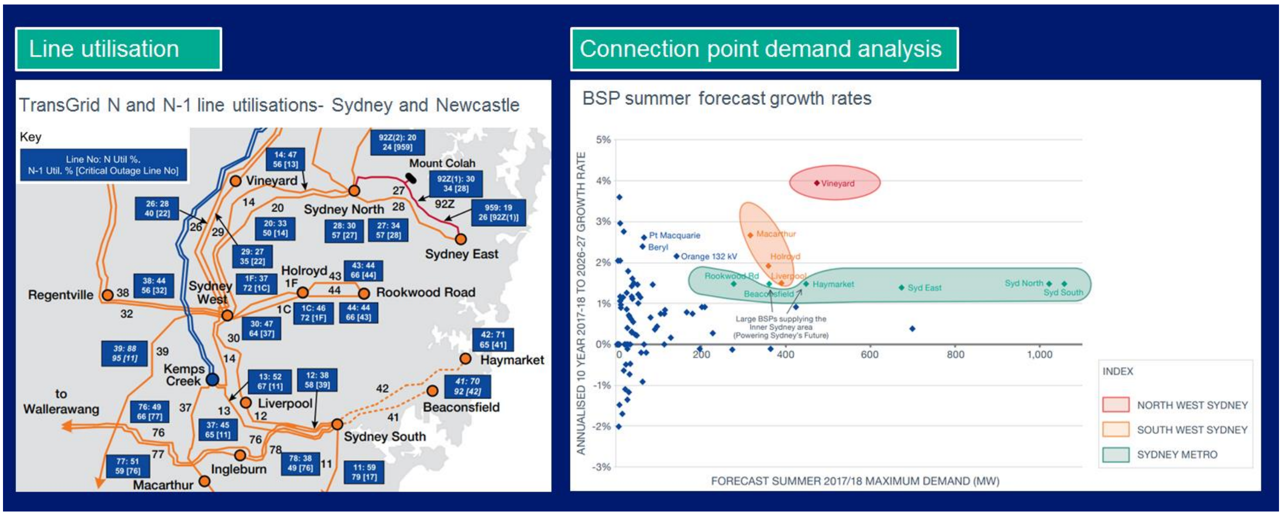
Table 4.4: Assessment of conclusions from average Connection Point utilisation

AER conclusion (Draft Decision 6-42)	**Is this reasonable?**	**Comments**
On average there has been a decrease in connection point utilisation on TransGrid's network	X	Conclusion is not possible as analysis did not use: > Actual non-coincident peak demands for each connection point (ie, the 'real' demand peaks) > Secure capacity at each connection point.
Taken together with the declining and flat demand growth, this suggests there is sufficient capacity in the network.	X	Even with correct demand, this analysis *cannot conclude* the network has "sufficient capacity", as: > It only covers one element of "TransGrid's network" – transformers at connection points > Average demand growth has no bearing on needs in areas with fast demand growth > Past history provides no insight into future demand and constraints.
Relevantly, this suggests that demand driven augmentation expenditure is unlikely to be above recent historical levels.	X	Even correcting all the above flaws, this analysis *cannot support any relevant conclusion* about future investment needs. Recent historical levels of augmentation are not a reasonable reference point for possible future needs.

[15] Connection point utilisations of 26.7% and 24.6% respectively were rounded to 20% and 30%.

We note that our Transmission Annual Planning Report (TAPR) publishes a range of useful information on connection point demand, network capacity and potential areas of constraint. Examples from TAPR 2017 are shown in Figure 4.3.[16]

Figure 4.3: Examples of published network utilisation and demand information



Note: the only demand-driven augmentation expenditure in the next period is at Macarthur (orange) and Vineyard (red) connection points.

> ***Example 3:*** *EMCa created a chart of risk reduction versus capital investment which was incorrect; it also included projects which were not relevant to the analysis.*
>
> ***Usage****: the chart was used incorrectly to conclude that $200 million of investment has limited benefits.*

The chart created was incorrect but the conclusion about "limited benefits" cannot be drawn from this data in any event – it is not a comparison of total benefits against capital expenditure.

The chart of cumulative risk versus capital expenditure was incorrect as it showed that forecast replacement expenditure (in red) and total capital expenditure (in blue) have exactly the same cumulative annual risk cost savings (left hand chart, y-axis). It appears that the "repex only" trace used the wrong column of cumulative risk savings.

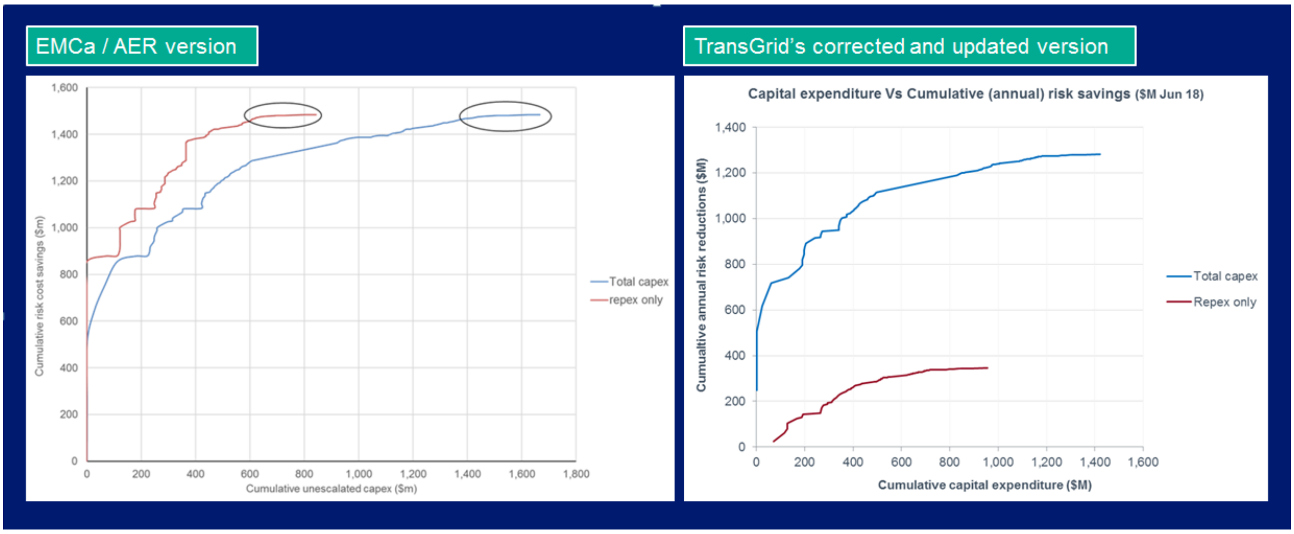
The chart also included projects which were not applicable for this analysis (including some which are not part of the ex-ante capital forecast).[17] These projects were forecast on a different basis and had no equivalent relevant values to include in the AER's analysis.

[16] These examples are Figure A3.2 - TransGrid N and N-1 line utilisations - Sydney and Newcastle (p.93) and Figure 4.7 - BSP summer forecast growth rates (p.60) in the 2017 Transmission Annual Planning Report available at: https://www.transgrid.com.au/news-views/publications/Pages/default.aspx

[17] Projects which were not relevant to this analysis included: Those required to manage ALARP safety risks and which by their nature, do not include a calculated 'risk cost saving' (eg, the Fleet Replacement forecast uses a base-step-trend method); Network Capacity Incentive Parameter Action Plan (NCIPAP) projects; and projects which continue from the current regulatory period.

A corrected version of the chart is shown alongside the EMCa / AER version[18] in Figure 4.4.

Figure 4.4: Corrected version of cost Vs annual risk saving chart



The EMCa / AER version:

> Included inapplicable projects
> Showed that "Repex only" benefits were equal to the benefits of the "Total capex" forecast (but this is not credible)
> Highlighted areas do not show investment with "marginal benefits". This is because y-axis shows annual cumulative benefits at a point in time (not the total benefits of an investment).

In TransGrid's corrected version:

> Fleet, NCIPAP and current period carryover projects were excluded and the impacts of minor modelling updates were incorporated[19]
> Annual "total capex" benefits (y-axis, green) are higher than the "replacement only" benefits forecast (y-axis, blue).

If the EMCa/AER chart was correct, it would indicate that TransGrid's entire augmentation expenditure forecast is associated with no benefit at all. However, this is clearly not the case (nor was it the AER's conclusion). The AER focused on the highlighted areas, concluding that these showed expenditure with limited marginal benefit. This is not correct as the y-axis is showing "annual risk reduction benefits" at a point in time (which in this case is assumed to be the mid-point of the regulatory period).

It does not show "total risk savings" of investments so highlighting these apparent areas of "marginal benefit" expenditure is misleading. These risk savings change over time so this is not an informative way to review the portfolio in any event.

This example indicates that application of our risk model and our investment analysis has not been fully understood. In fact, any project which is assessed as having a positive NPV has done so in spite of a conservative treatment of future benefits. We used a 10% nominal discount rate which conservatively reduced the present value of investment benefits. This inherent bias *against* capital expenditure in our

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[18] Sources: Draft Decision*: Figure 6-12 TransGrid - Areas of low incremental benefit (risk reduction)* and EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23, June* 2017, p. 40

[19] For example, refinement of the ALARP methodology, as discussed in the Replacement Expenditure section

analysis makes the investment hurdle higher and adds further support to the need for the proposed expenditure. The approach is described further in section 4.5.

While modelling errors can occur, this and the other examples above suggest that:

- EMCa and the AER may not have adequate quality control processes in place
- There has not been sufficient understanding of our approach or the information we provided, for the AER to draw conclusions about our expenditure.

Analysis errors and process failings undermine the draft decision

TransGrid is concerned by the nature and extent of the errors and misunderstandings in EMCa's report and the draft decision. As outlined above, significant capital expenditure cuts appear to be loosely based on analysis which is not credible or fit for purpose.

Apparent quality control failings also undermine the draft decision's capital expenditure conclusions. TransGrid is particularly concerned that the process has not accounted for the many issues we identified in August 2017.

Many more instances of errors and misunderstandings which have been used to support the draft decision occur throughout this revised proposal.

4.4 Powering Sydney's Future

4.4.1 Background

The Inner Sydney and CBD network is not only important to the local community it serves - it is essential to the NSW and national economies. It generates around 7% of Australia's Gross Domestic Product and is the site of more than 620,000 jobs.[20] It is home to a growing population with 22% population growth recorded in the City of Sydney LGA over the last five years. [21]

However, the electricity supply is increasingly at risk because:

- Many important transmission cables are deteriorating in condition – they are an increasing environmental risk through oil leakage and Ausgrid has plans to progressively retire them
- As the condition on remaining in-service cables deteriorates further, failure rates will increase and outages of up to 8 weeks will become more common.[22] Higher failure rates and long repair times increase the chance of coincident outages and loss of supply
- Peak demand is increasing, driven by the economic activity and new major infrastructure identified above.

A solution is needed by 2022 to secure the reliability of supply to Australia's largest city. A RIT-T process has been undertaken over the past year and a technically and economically feasible solution has been identified.

[20] As at June 2016, there were 623,760 jobs – 6.9% higher than the previous year. Source: National Institute of Economic and Industry Research (NIEIR), data published by City of Sydney

[21] Source: Australian Bureau of Statistics, Regional Population Growth, Australia (3218.0).

[22] The nature of these cables is that repair times are long as they need to be drained of oil before work commences then refilled after. Repairs are also more specialised than they would be with modern cable technology.

The RIT-T process is almost complete

The RIT-T process has consulted on a range of options but the most efficient option has been identified as a combination of:

Up to four years of demand management

- Non network options to help manage the increasing risk until new cable capacity is installed
- One of the the largest deferrals of a network project in Australia to-date

Two new 330kV underground cables from Rookwood Road to Beaconsfield West

- Option analysis considered installing both cables at once and installing one at a time
- The community has been consulted on a possible route – a preferred route follows major roads
- A two-stage cable installation increases the construction impact on the community

Consultation throughout the RIT-T and separately for our revenue proposal indicates that PSF is strongly supported by customers and stakeholders.

4.4.2 AER assessment

The AER has rejected all forecast expenditure for the Powering Sydney’s Future (PSF) project. It notes there is uncertainty around the key drivers, especially the demand forecast, the ratings and availabilities of existing cables and the Value of Customer Reliability used in modelling.

> As a result, the optimal timing for the Powering Sydney's Future project is likely to be beyond the 2018-23 regulatory control period. (Draft Decision 6-36)

However, the AER has remained open to further discussion:

> the key issue is whether the timing and scope of the upgrade is reasonable rather than whether an upgrade to the network is necessary. (Draft Decision 6-96)

City of Sydney submission in the Draft Decision

The AER referenced the City of Sydney’s Revenue Proposal submission to support its PSF conclusion:

‘…non-network solutions may become more prevalent over time such that the scope of any network investment may be reduced to meet demand. The City of Sydney has the view that the scale and shape of future energy markets are very uncertain.’ ***Draft Decision 6-105***

However, the City of Sydney made other important points:

“In relation to TransGrid’s proposed future capital expenditure, the City notes:

- *The scale and shape of future energy markets are very uncertain.*
- *Demand management deserves a bigger role in future management of critical network assets, and should be appropriately rewarded.*
- *This includes assets in central Sydney that are part of the ‘Powering Sydney’s Future’ project. It is critical that Sydney CBD and inner suburbs continue to have a high level of electricity security given that this area accounts for 7% of the total Australian economic activity.*
- *TransGrid should be encouraged to extend the life of existing assets where feasible and economic.”*

City of Sydney, TransGrid Regulatory Determination 2018-2023, Submission to Revenue Proposal

While we agree there is some uncertainty, it is not to the extent portrayed by the AER. As demonstrated in the Project Assessment Conclusions Report (PACR) for the RIT-T, the project is robust under a number of reasonable scenarios.

Specific concerns

The AER's concerns and our responses are summarised below:

Demand forecast: the AER is not convinced about the growth in the demand forecast and has asked for more information about new spot loads. ***The AER's conclusion relied on AEMO's forecast which covers a much larger geographical region and was already revised significantly upwards before the draft decision was published.***

Cable ratings: the AER concludes that TransGrid's cable capacity assumptions are inconsistent with industry practice, suggesting emergency ratings should be used instead of cyclic ratings. ***The highest technically feasible ratings have been modelled and the AER has misinterpreted the information provided.***

Cable availabilities: The AER rejected the inclusion of corrective outages in cable unavailability rates because they include events within the control of Ausgrid. The AER's own consultants, EMCa, found the approach reasonable and it is unclear why the AER has disagreed with them**.** ***TransGrid and Ausgrid maintain that the cable availability modelling conducted by Ausgrid is a robust and reasonable basis for the forecast.***

Value of Customer Reliability: The AER notes that TransGrid has value of customer reliability (VCR) assumptions higher than estimates used in determining planning standards for the Inner Sydney and the CBD network. ***TransGrid has re-run the analysis using the VCR value used in IPART's planning standards; there is no change in the scope or timing of the project.***

Sensitivity analysis: The RIT-T process included a range of sensitivity modelling but the AER was interested in specific scenarios relating to the demand, VCR, load growth and cable failure rates. ***These scenarios have been completed and provided to the AER.***

4.4.3 Impact of failing to secure Sydney's electricity supply

If Powering Sydney's Future does not go ahead, the impacts for the community and economy are potentially serious:

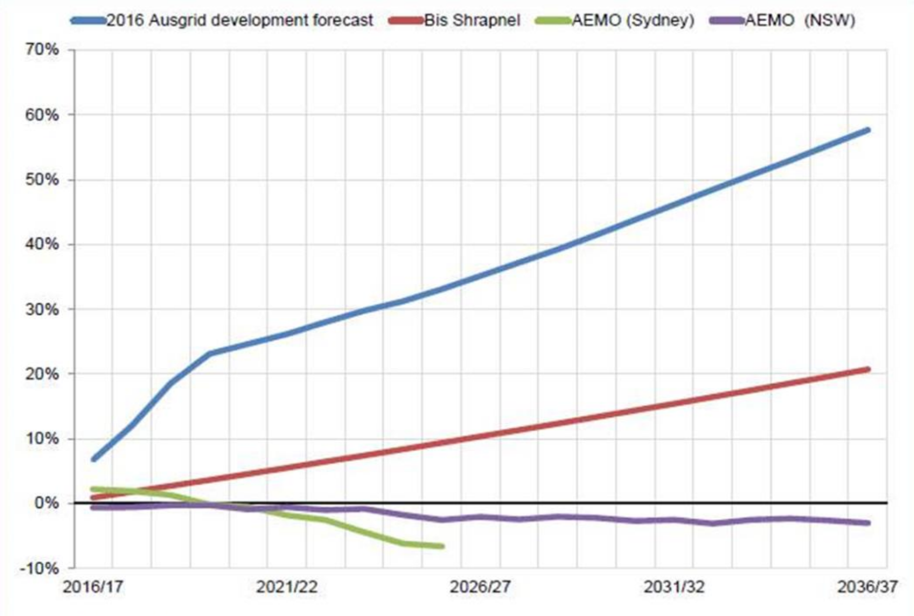
- Sustained power supply interruptions, lasting weeks or even months
- Environmental damage, via increasing cable oil leaks
- Higher costs to customers over the long term.

4.4.4 Response to AER's concerns

Demand forecasts - AER comparisons were inappropriate

The AER did not base its draft decision on the most recently released demand forecasts from AEMO. The forecasts it used were more than a year out of date and covered different geographic areas. The AER published the chart in Figure 4.5 to question the growth in the PSF demand forecast (in blue).

Figure 4.5: AER comparison of demand growth



Source: AER analysis

The figure is misleading as these "comparison" forecasts all have a different basis:

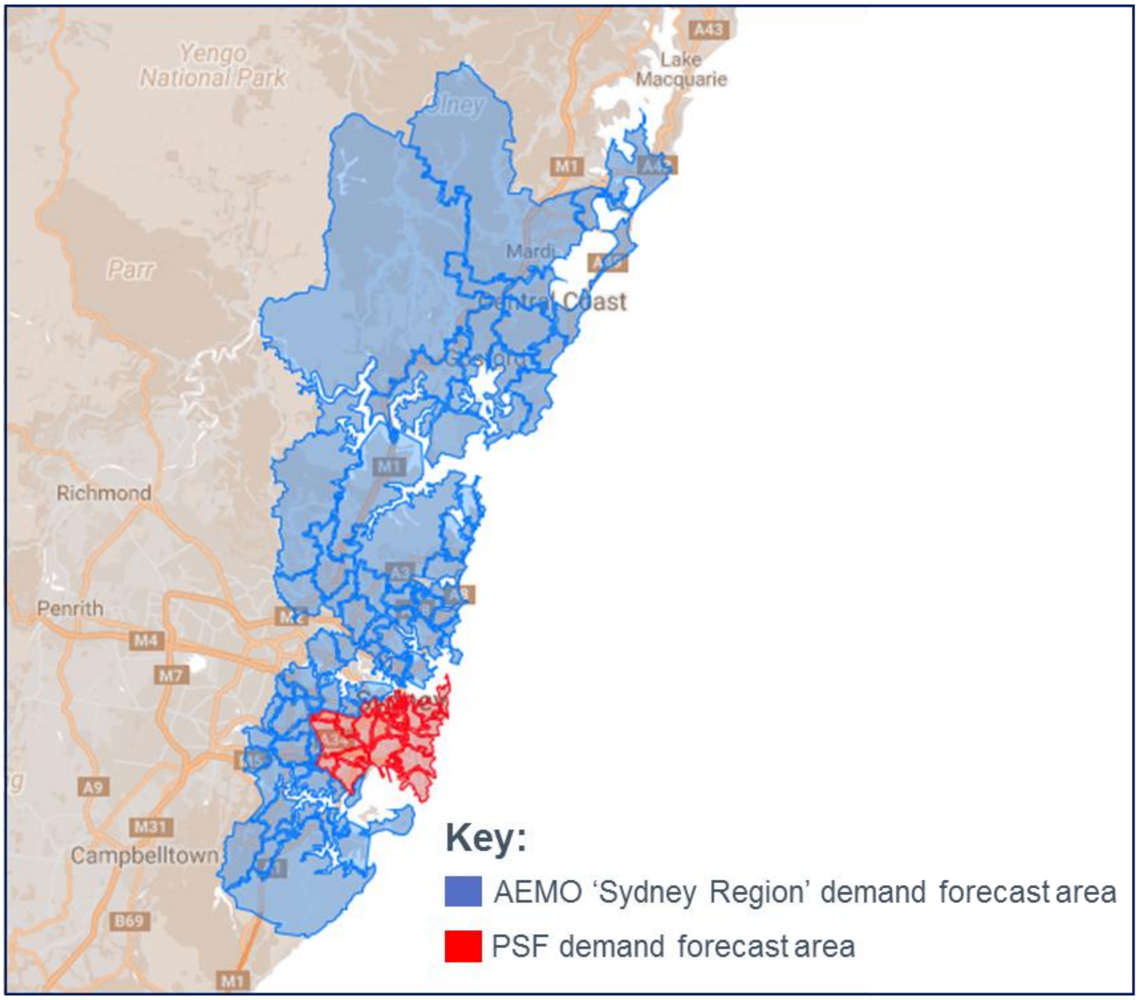
- AEMO's "Sydney" connection point forecast (green):
  - is for a much wider area, including outer suburbs and the Central Coast
  - has been 'reconciled' to the NSW Region forecast.[23]
- BIS Shrapnel (red) specifically does not include spot loads
- AEMO's whole of NSW forecast (purple) is prepared to support an assessment of total generation capacity – it is not directly relevant for local network planning.

This is not a criticism of these forecasts – they are simply inappropriate for comparison purposes.

[23] This is where AEMO's regional forecasts are reconciled to the NSW Region forecast. In this process, some unreconciled regional forecasts increase and some will decrease. While this step ensures that AEMO's forecasts are internally consistent and reflect State level trends, they may not reflect trends which exist at the granular level..

Figure 4.6 shows the significant differences in geographical areas covered by the PSF and AEMO Sydney Region forecasts.

Figure 4.6: Differences in demand forecast areas



AEMO's "Sydney Region" connection point forecast (blue area) extends north across the Hawksbury River into the Central Coast area and goes past Cronulla in the south. It is a much wider area which includes significantly different customer and demand profiles, including a higher proportion of residential and medium density load. It includes eight TransGrid Connection Points.[24]

It does not provide a good comparison for the PSF forecast (red area) which has two TransGrid Connection Points and where non-residential customers account for 85% of summer peak. Differences in residential and non-residential customer demand include their respective load profiles (eg. they peak at different times of day) and their different responses to price. The PSF demand forecast was developed to account for the specific characteristics of the underlying load, including the connection of large new spot loads (which the AEMO forecast does not include[25]).

The expectation that there will be load growth is supported by the most recently recorded PSF area summer peak and AEMO's latest "Sydney Region" forecast.

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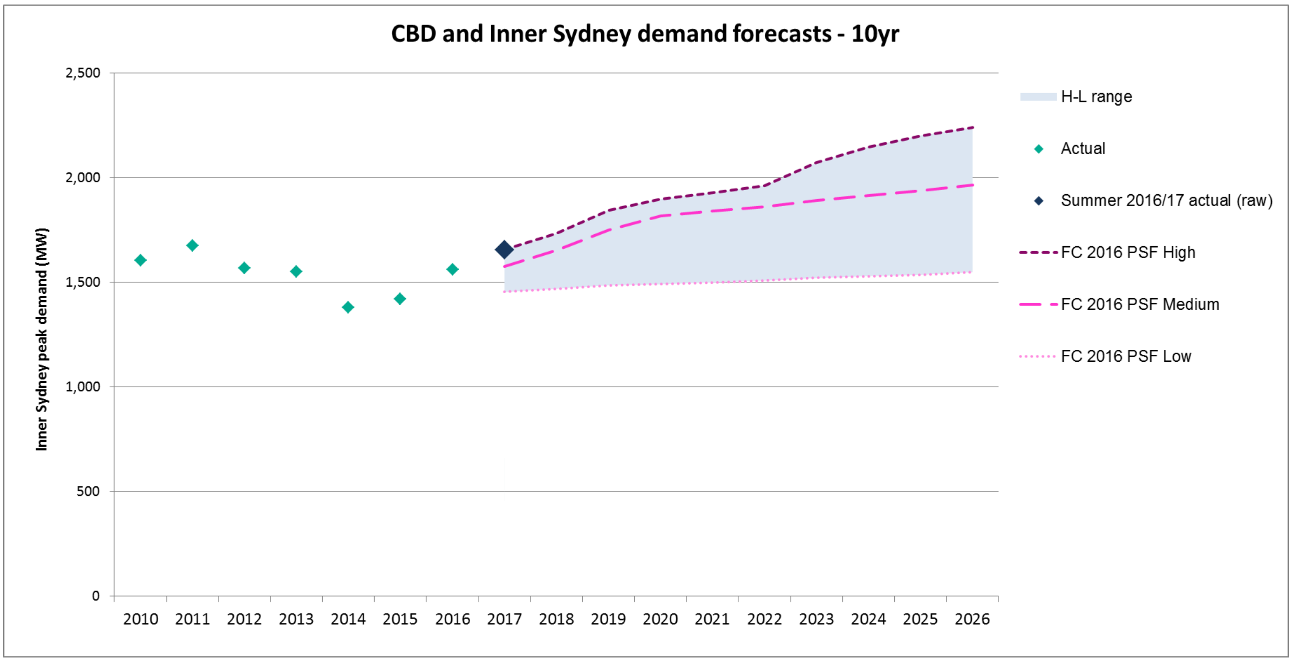
[24] AEMO forecasts over this wider area as significant sub-transmission meshing in the Sydney area which limits its visibility of changes in demand at individual connection points.

[25] AEMO's method assumes that loads less than 5% of the maximum demand are captured in the underlying growth trend.

Figure 4.7 shows that the summer 2016/17 raw demand for Inner Sydney coincides with the "high" forecast published as part of the RIT-T consultation.

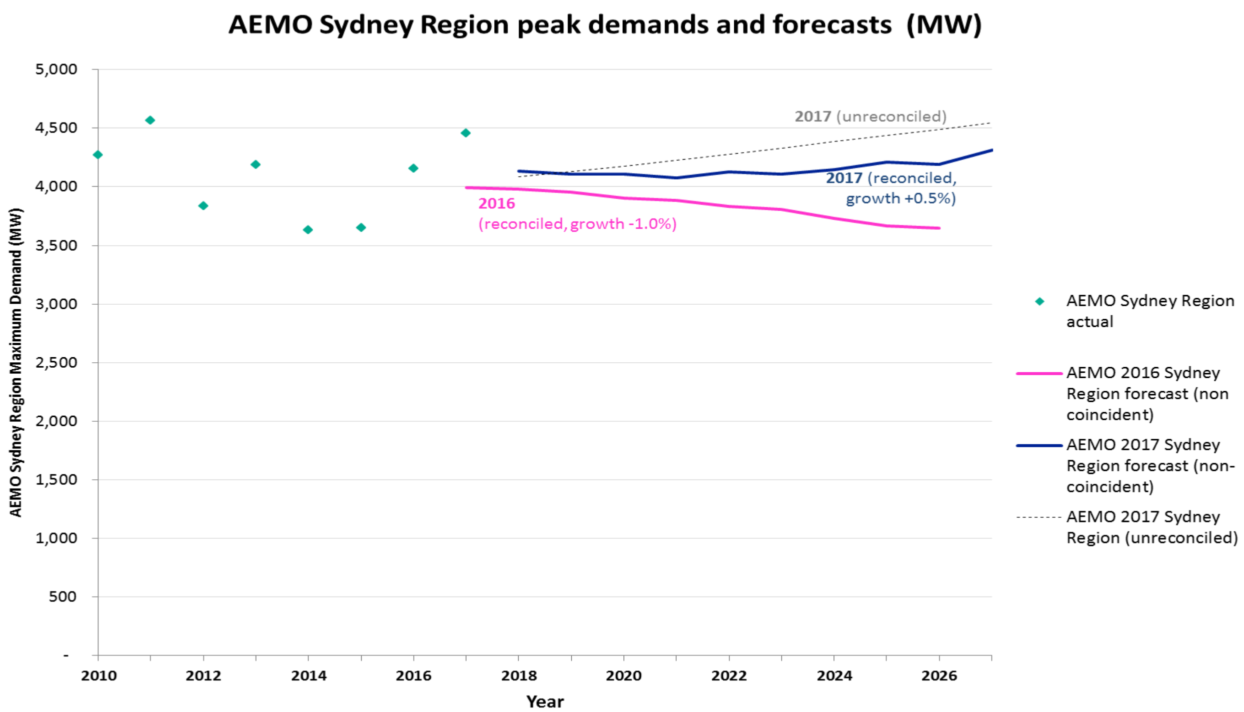
Figure 4.7: Inner Sydney (PSF) peak demand forecast and actuals



Note: "Raw" actual demand is the metered flow into the area on 10 February 2017 (via "cut-set 1" feeders).

More recent versions of AEMO's NSW and Sydney Region forecasts were available from July and early September 2017, respectively. Both were revised upwards compared to the 2016 forecasts. Figure 4.8 shows the difference between the latest (2017) AEMO "Sydney Region" forecast and the 2016 version.

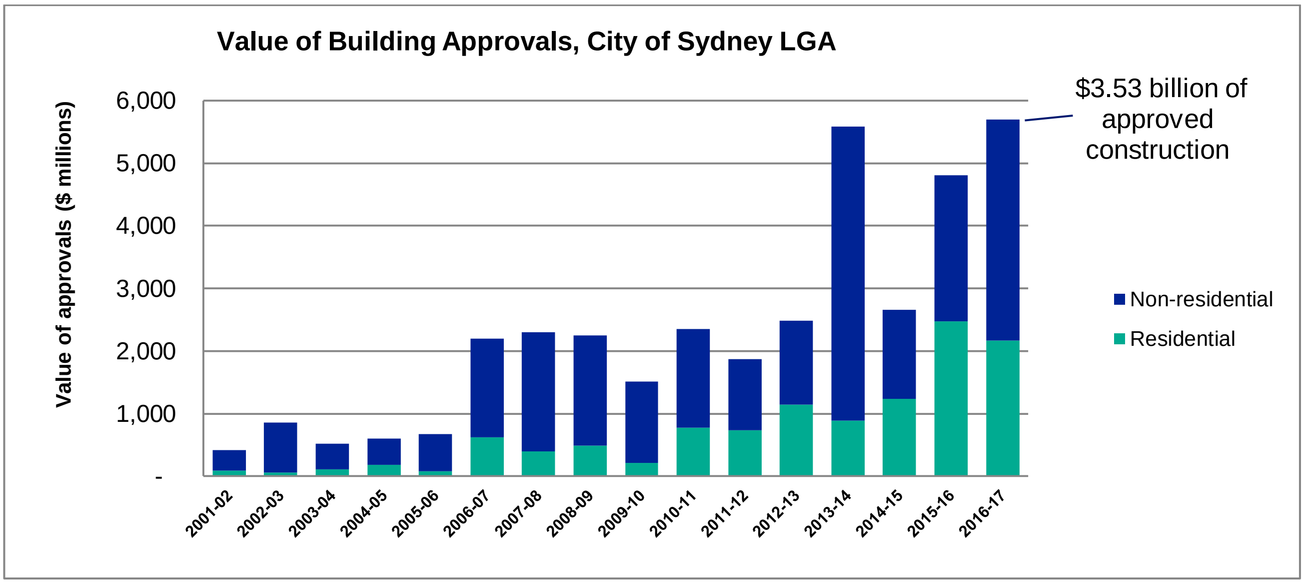
Figure 4.8: AEMO Sydney Region peak demand forecasts



The most recent AEMO forecast indicates load growth for the Sydney Region. While it is still different to the PSF forecast there is much less divergence than suggested in the 2016 forecast comparison published by the AER.

While there is uncertainty in any forecast, this projected demand growth is supported by other lead indicators. For example, Figure 4.9 shows that residential and commercial construction approvals are at historic highs.

Figure 4.9: Value of building approvals in City of Sydney LGA 2001/02 to 2016/17



Source: Australian Bureau of Statistics, Building Approvals, Australia, catalogue number 8731.0.

Significant one-off infrastructure projects are underway and many residential and commercial developments are in progress. As a result, Ausgrid's latest PSF load forecast includes around 340MW of spot loads in 2022/23, including:

- Large new infrastructure and commercial loads, including:
  - WestConnex motorway tunnels – 38MVA by 2021
  - Light Rail & Sydney Metro – up 7MW until 2021, then increasing to 69MW
  - Data centre loads – 35MW by 2022
- Large residential and commercial developments, totalling around 18 MVA by around 2020
- Many smaller spot loads of up to 150MVA by 2022, mainly connecting at 11kV. These will be driven by increases in medium and high-density dwellings (replacing lower density residences).

All these forecast spot load values have been reduced by a probability weighting, based on how close they are to being committed and historical conversion rates for proposed spot loads.[26] The weightings for the large new infrastructure loads also account for an average load diversity factor for the specific industry class.[27]

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[26] Weightings are based on analysis of recent history. More developed 11kV loads are weighted by 0.78 and other less likely connections are weighted by 0.34. For example, a development seeking a 5MW connection at 11kV but which is not yet well developed will go into the forecast as 1.7MW.

[27] This load diversity factor reduces loads to account for the fact their highest levels may not coincide with the local system peak. There are different factors for rail, data centres, road tunnels and airports for example.

Both WestConnex and Light Rail & Sydney Metro are currently under construction, so their omission from demand forecasts is not credible. Demand in the CBD and Inner Sydney is growing and the forecast for PSF remains valid.

Cable availabilities

Cable availability assumptions are based upon outage histories (to determine outage frequencies) and a study of the failure types (to determine mean time to repair). The resulting annual "cable unavailability" assumptions are important factors in the calculations of "unserved energy".

The AER did not consider the modelled cable availabilities for PSF to be valid. This is contrary to their expert adviser, EMCa's advice which concluded:

> Ausgrid's models are likely to provide a reasonable estimate of cable unavailability for the cables we reviewed, namely the eight Ausgrid 132kV cables identified for replacement in the PSF project. (EMCa Report, page iv.)

TransGrid has applied the results of the above modelling without further modification. The use of the unavailability data is discussed further below.

The AER disagrees with the cable availability modelling inputs as they were calculated from historical outage data which includes "planned corrective" cable outages as well as "breakdown" ones. The issue is partly related to the categorisation of outages. Some "planned corrective" outages are only planned in the sense that they are not automatic outages due to faults– they are arranged at very short notice to avoid imminent faults, further damage and/or manage oil leaks. Based on a further review of outage data, Ausgrid has estimated that about 40% of these planned outages needed a quick response for these reasons. It is therefore incorrect to exclude all planned corrective outages from the availability calculation.

There is also a limit on how many outages can be planned for shoulder periods. Currently, it is the longer planned outages, such as those with longer recall times, which are scheduled for outside peak periods. Review of data from September to mid-October 2017 shows that there were at least two, and up to four planned outages at any one time across the group of cables in the PSF area. This outage congestion makes it impractical to move all nominally discretionary outages to the shoulder period.

The AER also presented an alternative view regarding the use of a weighted average to calculate the average mean time to repair (MTTR) of cable faults. We did not apply this approach during the initial analysis due to data availability. Further review and data consolidation has now allowed us to apply it.

Even if 60% of planned corrective outages were moved to a shoulder period and the alternatively derived MTTR values were applied, sensitivity analysis shows that the optimal timing of PSF does not change.

Cable ratings

The AER concluded that PSF analysis should have assumed that cables could use emergency ratings during faults (increasing supply capacity when most needed).

The modelling did assume "emergency cyclic ratings" whenever this was technically feasible. That is, emergency cyclic ratings were applied if:

> A cable was in a trench by itself, or
> A cable was adjacent to another which was assumed to be out of service.

This resulted in the use of emergency cyclic ratings on 22 of 27 cables covered by the analysis, with an average capacity increase of 16%.

Cable capacity ratings

A cable can operate safely at different capacity ratings depending on:

- Its maximum allowed **operating temperature**
- The **thermal conductivity** and **thermal capacity** of the cable and the surrounding materials
- The **loading pattern**
- The presence of **other heat sources** (eg parallel cables).

A ***'continuous cyclic rating'*** is a daily loading/unloading pattern which allows for enough cooling time so that the maximum operating temperature is not exceeded.

An ***'emergency cyclic rating'*** is a daily loading/unloading pattern which allows for temporary changes in the operating environment. For example, a cable rating can increase when another heat source (like an adjacent cable) is out of service.

The suggested alternative −applying emergency ratings to all situations − would be neither prudent (as it increases the likelihood of a fault) nor efficient (as higher temperatures accelerate cable degradation). The AER's conclusion that the use of emergency ratings would move the need for PSF beyond 2023 is neither technically feasible, nor based on an accurate understanding of our modelling. It would not be prudent, as it would require cables to be operated outside the parameters advised by the manufacturers.

Value of Customer Reliability

The RIT-T analysis conducted for the Powering Sydney's Future (PSF) project used VCRs of $90/kWh for customers in the Inner Sydney and $170/kWh for CBD customers. These were based on analysis by HoustonKemp of earlier VCR studies. The AER considers these to be too high.

The values were used to take into account the nature of the disruptions to supply that may occur, and accurately reflect the costs imposed on the particular customers affected. In the case of PSF and the Inner Sydney and CBD network:

> Outages of fluid-filled cables could be prolonged
> High value commercial loads are located in the Inner Sydney and CBD area and major transport networks run through it.

Based on this, TransGrid and Ausgrid concluded for the PSF RIT-T:

> AEMO's standard VCR estimates were not appropriate
> A higher VCR was appropriate for the CBD compared to the rest of Inner Sydney although the value chosen was higher than that defined by IPART for the NSW transmission reliability standards.

We acknowledge that consistency with the IPART VCR values is desirable so we have changed the PSF analysis to reflect this. A central VCR estimate of $90/kWh is used for customers in both the CBD and Inner Sydney. As shown in the sensitivity analysis in the following section, this does not impact on the timing of the project need.

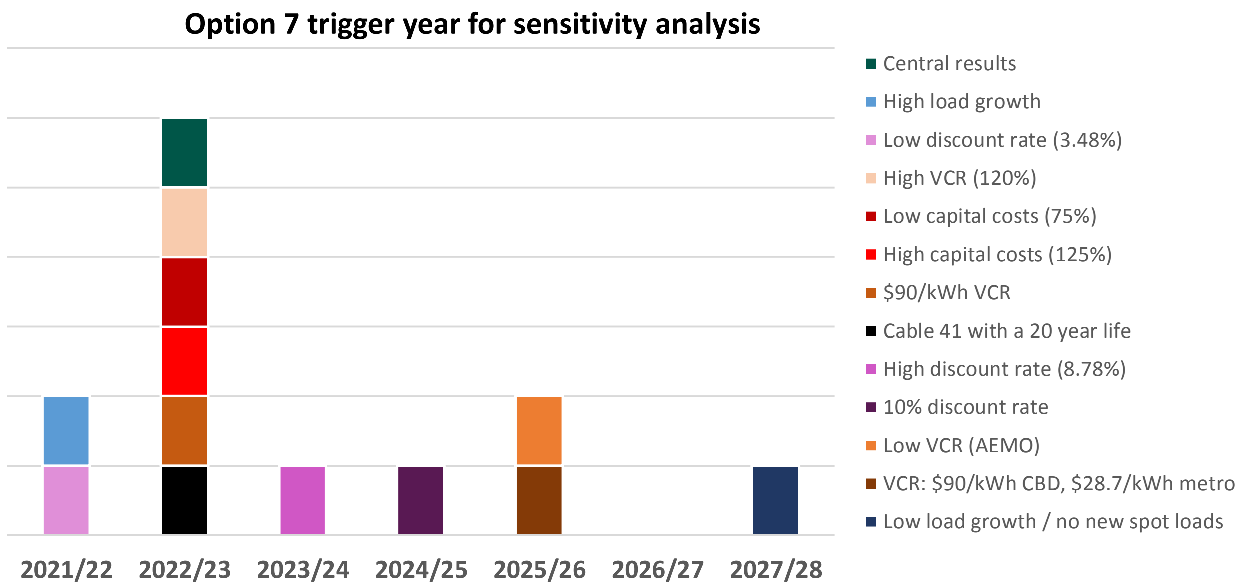
Sensitivity analysis

The Project Assessment Draft Report (PADR) for the RIT-T identified Option 7 as the "preferred" option – an efficient solution across different scenarios which also accounted for external community impacts.

The option envisaged the use of non-network solutions from 2018/19 to 2021/22 with two new 330kV cables installed by 2022/23.

A range of further sensitivities were undertaken, testing if the “trigger year” moved in response to changes in: discount rates (pink/purple), load growth (blue), capital costs (red) and VCR (orange/brown) and an extended life for Cable 41 (black). Results are shown in Figure 4.10.

Figure 4.10: Option 7 trigger year for various sensitivities



The conclusion was that the trigger year for this option was 2022/23 in a majority of scenarios.

Using significantly lower VCRs or a discount rate of 10% would extend the commissioning year to the next period, although construction would still need to begin in the 2018/19 to 2022/23 period. These are relatively adverse assumptions that depart from those normally applied. Only under the low load growth scenario would the trigger year be late enough for construction to begin after 2022/23.[28] This is considered very unlikely in light of the latest forecast information and spot loads identified above.

4.4.5 Updated proposal for PSF

Given the information presented above, it is our view that:

- The need for PSF is demonstrated and the assumptions used in the economic analysis are reasonable (including that the most recent AEMO demand forecasts provided further support)
- The project is strongly supported by customers and stakeholders and this has been clear from consultation throughout the RIT-T process.

Analysis for the RIT-T process showed that several options have similar NPVs. In the PADR, Option 7 was identified as “preferred” after taking into account feedback on minimising community disruption with a single stage project.

However, we also acknowledge the valid concerns of the AER and Consumer Challenge Panel (CCP) relating to future uncertainty. As a result, we reviewed the PSF options to consider the appropriate balance between minimising community disruption, having a lower initial capital cost and retaining

[28] The “low load growth” demand forecast is very unlikely. It would require, for example, that the under-construction WestConnex and Sydney Metro are stopped.

optionality in the face of uncertainty. Following this, we consulted further with consumers, transmission customers, the AER and CCP and found there was broad support for a two-stage option with a lower initial capital cost and optionality.

We are therefore proposing a two-stage cable option, with the first cable being commissioned in the 2018/19 to 2022/23 regulatory period, following a period of demand management.

Proposed two-stage option

The proposed two-stage option is based upon Option 2A in the RIT-T analysis but with an additional year of deferral using demand management. The option includes:

- A combination of various non-network solutions for four years, managing the risk of unserved energy before the first cable is commissioned in 2022/23
- Operating TransGrid's Cable 41 at 132 kV, installing two 330 kV cables in separate stages
- Decommissioning Ausgrid cables in two stages.

Analysis indicates that the economic timing of Option 2A would be 2021/22, following only three years of demand management[29]. However, we propose to maintain the original timing of PSF, with four years of demand management before the first stage of the network option commissions ahead of summer 2022/23.

The expectation is that this will contribute to the development and maturing of the demand management market and lead to lower cost contract prices. These are important factors in realising the value of the optionality in this two-stage cable option. Delaying the second cable due to (say) a lower demand forecast is clearly more viable if DM costs are lower and the providers have a demonstrated track record of delivering.

The two-stage option will have a higher community impact with a second period of construction-related road congestion and noise later in the next decade. We undertake to minimise this impact by laying both sets of ducts in the same trench during the initial phase, carefully selecting the location of joint bays and considering similar design options during the first stage.

Network support costs

As noted above, demand management is a critical component of the Powering Sydney's Future project. The resulting network support cost forecast has been developed as a result of market sounding throughout the RIT-T process and engagement with the proponents. The estimated costs which have been included in the Maximum Allowed Revenue calculation are shown in Table 4.5.

Table 4.5: PSF Network support costs forecast ($m June 18)

PSF Network Support costs ($m)	2018–19	2019-20	2020–21	2021–22	2022–23	Total
Forecast used in MAR calculation	0.7	2.55	5.83	10.04	-	**19.1**

TransGrid will treat this as a network support pass through under Clause 6A.7.2 of the Rules.

29 This is because the lower capital cost has a lower deferral value which suggests demand management is less economic in the fourth year (2021/22).

Interaction with Ausgrid's forecast

Ausgrid has confirmed that its upcoming revenue proposal will not include replacement capital expenditure, or material operating expenditure to manage the condition of cables scheduled for retirement beyond the anticipated commissioning date of Powering Sydney's Future. This is on the understanding that the most cost-effective solution to address the asset condition problems is via the Powering Sydney's Future project. Ausgrid has reserved the position to change this in its revised proposal, if Powering Sydney's Future is deferred or not accepted by the AER.

Revised forecast for the two-stage option

An updated forecast for this option is shown in Table 4.6. It does not include the expenditure for installing the second cable which will be considered in the subsequent regulatory period.

Table 4.6: Revised capital expenditure forecast for Powering Sydney's Future ($m June 18)

Powering Sydney's Future	2018–19	2019-20	2020–21	2021–22	2022–23	Total
Original proposal	1.1	15.9	32.6	133.7	147.6	**330.9**
Revised proposal	27.0	25.6	57.5	116.7	25.4	**252.3**
Difference	26.0	9.8	24.8	-17.0	-122.2	**-78.6**

4.5 Replacement expenditure (including Security & Compliance)

The draft decision recommends a $203.9 million cut to the forecast replacement expenditure. An overview of the reduction, the AER's reasons and our response is shown in Table 4.7.

Table 4.7: Summary of response to draft decision on replacement expenditure

AER expenditure reduction and reasons	TransGrid's response
Asset replacement program *Reduction of $191 million (-20%)* The Risk Model is a work in progress TransGrid's assumptions are conservative Risks are overstated, therefore the forecast is overstated. Optimal timing is not demonstrated	**The $191 million reduction relies upon a range of analytical errors and misunderstandings** The AER was notified of many of the errors its draft decision was based upon in August. The Risk Model is robust and reflects accepted asset management practice. The model is similar to the approach accepted by Ofgem in the UK and ElectraNet in South Australia. The assumptions are indeed conservative and bias the model outputs against investment.

AER expenditure reduction and reasons	TransGrid's response
Regulatory Investment Tests for Transmission (RIT-T) costs *Reduction of $2.8 million (-100%)* Expenditure is not required as it covers what a prudent business would already be doing.	**The AER is not correct to disallow expenditure to meet a new regulatory requirement** Undertaking RIT-Ts for replacement expenditure is a new regulatory requirement as of September 2017. Significant costs arise from this Rule change and TransGrid expects to do in excess of 50 RIT-Ts in the period. In absence of a regulatory requirement, a prudent business would not choose to undertake a process which adds substantial cost and almost a year to the investment pathway.
"Tools, plant and compliance costs" *Reduction of $10.1 million (-100%)* This is duplicated within the "Non-network" capital expenditure allowance (within a "heavy plant" category).	**The AER has confused this category with another part of the forecast.** This is not a duplicate of the "heavy plant" forecast – it is for tools and test equipment related to network asset work.

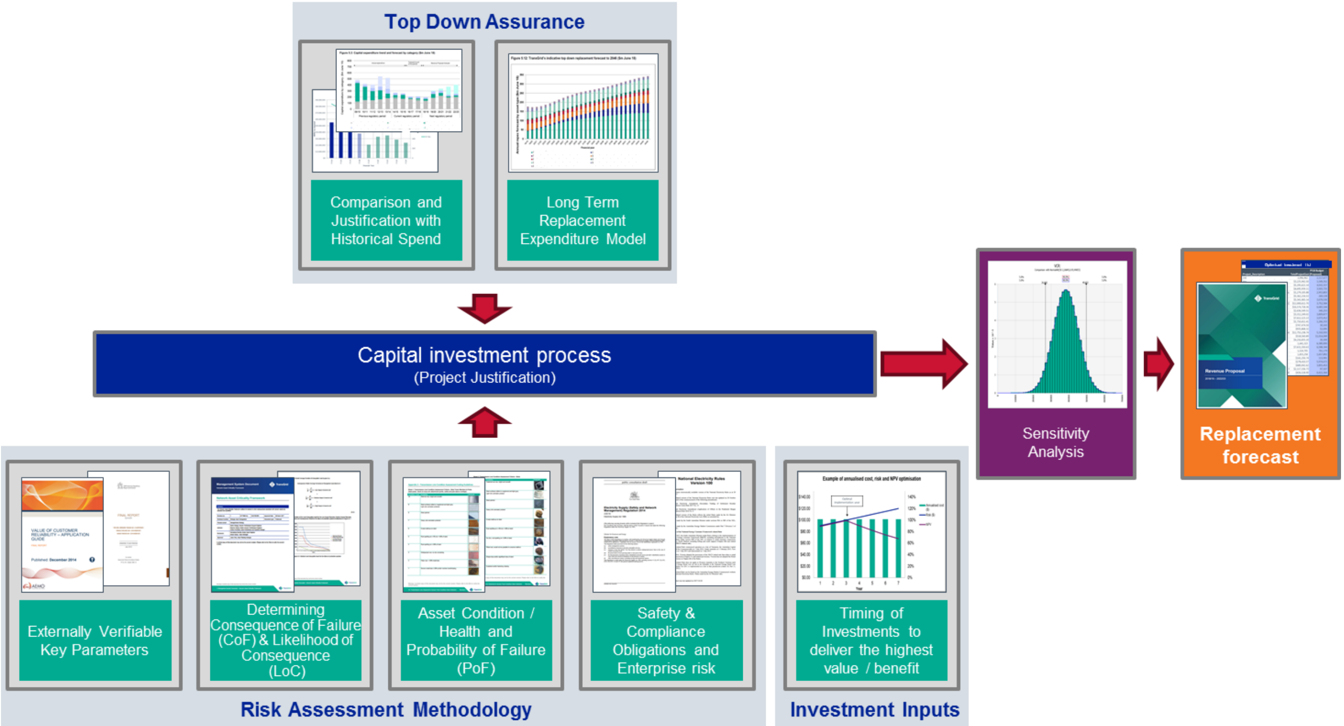
These are discussed in turn following a short summary of our risk assessment and investment analysis approaches.

4.5.1 Recap of TransGrid's robust approach

Overview

TransGrid's robust approach to replacement forecasting is summarised in Figure 4.11. It is evolving, as any good asset management framework should be but it is not a 'work in progress'.

Figure 4.11: Replacement Expenditure Planning Process



The key aspects of this process are:

- **Risk assessment methodology**
  - Uses externally verifiable parameters to calculate asset health and failure consequences[30]
  - Assesses and analyses asset condition to determine remaining life and probability of failure
  - Applies a worst case asset failure consequence and significantly moderates this down to reflect the likely consequence in the particular circumstances
  - Identifies safety and compliance obligations with a linkage to key enterprise risks
- **Investment analysis inputs** are biased *against* investment to ensure efficient timing (eg, a 10% discount rate). Only NPV positive (or compliance) projects proceed
- **"Top down" portfolio checks**
  - Review of changes in expenditure levels including comparisons with the content and quantum of previous investment
  - Alignment with long term Repex modelling
- **Investment modelling** selects the most efficient option.

Sensitivity analysis **around key inputs.**

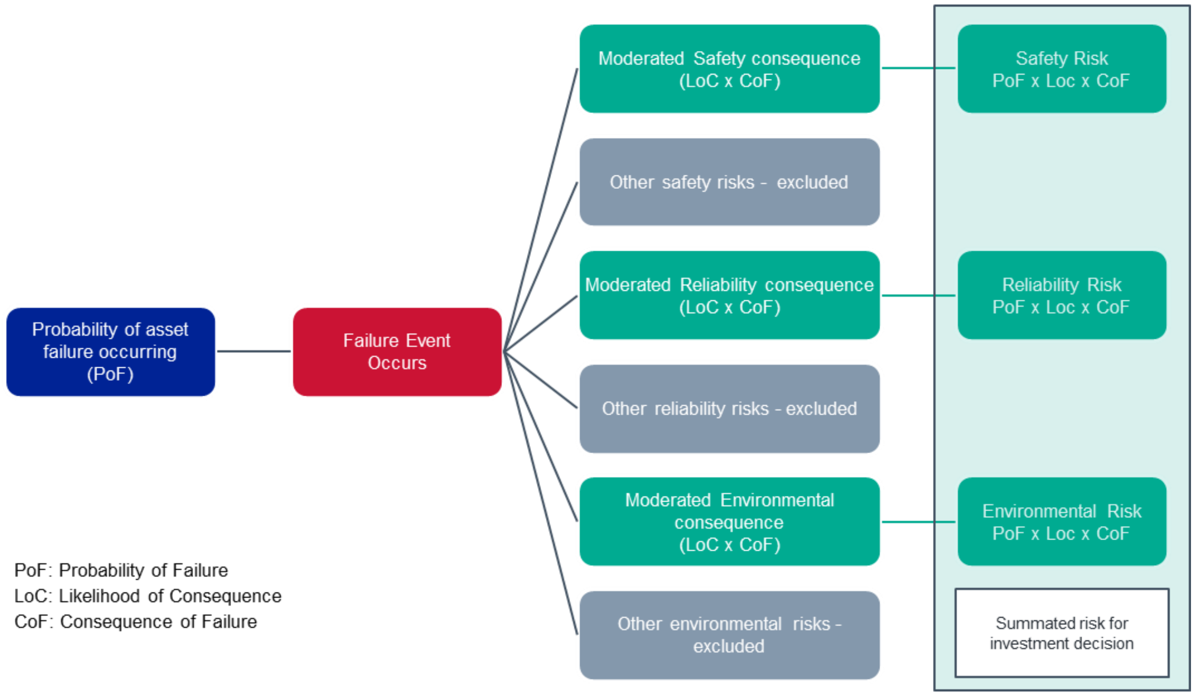
Calculation of risk costs

A fundamental part of the approach is calculating the "risk costs". These are the monetised impacts of the reliability, safety, environmental and other risks.

[30] For example, AEMO's VCR, Federal Government Guidelines and Royal Commission Findings - Refer to Network Asset Health Framework and Network Asset Criticality Framework.

The method is structured and follows an accepted approach for calculating risk impacts. Figure 4.12 shows the generic calculation model for every risk cost assessment.[31]

Figure 4.12: Quantification of risk



Risk costs are calculated based on the Probability of a Failure (PoF), the Consequence of Failure (CoF) and the corresponding Likelihood of consequence (LoC) in the particular situation.

It is important to note that consequence costs in TransGrid's risk assessment are reduced depending on the chance they will occur in those circumstances. The high consequence costs which have been highlighted by the EMCa and the AER are heavily moderated when they are applied in the modelling.

Probability of Failure

Each failure mode that could result in a consequential impact is considered. For replacement planning, only 'life ending' failures are ultimately used to calculate the risk cost[32]. PoF is calculated for each failure mode considering "conditional age" (chronological age adjusted by asset health); failure and defect history and benchmarking studies. For "wear out" failures a Weibull curve may be fitted and for random failures a static failure rate may be used.

Consequence of Failure (CoF) and Likelihood of Consequence (LoC)

TransGrid uses a moderated "worst case" consequence to value risk. This is an accepted approach in risk management with the benefit of ensuring that low probability but high consequence events are not dismissed or overlooked. It also excludes the risk costs of lower consequence but potentially more likely events (as shown in the greyed out 'risk cost' boxes in Figure 4.12). This calculated risk is lower than it would be if these were included.

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[31] Note that the figure does not show other consequence categories which contribute much less to risk costs. These include estimates of legal costs, for example.

[32] Other, lower impact failures are not considered in the risk consequences, regardless of the expected frequency of these. This means that calculated risk costs are lower than they would otherwise be.

Use of a “worst case” LoC does not mean that we are overly conservative nor does it mean that risk is overstated. When “worst case” CoF is multiplied by an appropriately small LoC it is realistic and credible.

The LoC is the likelihood of this ‘worst case’ consequence occurring in the particular situation, *if* the relevant failure occurs. LoC generally reduces the CoF significantly, as the worst case consequence is unlikely to occur each time an asset failure occurs.

As noted in the example in section 4.2**Error! Reference source not found.**, the average bushfire LoC applied to transmission lines is 0.7% to account for local factors such as vegetation, terrain, land use and weather. When applied, this LoC reduces the bushfire consequence cost of $400m by 99.3% to $2.9 million, on average.

Risk analysis can also exclude projects

GE FACs protection relays are found on busbars throughout our system. This asset population meet some criteria for replacement consideration – they are at or past economic life and are unsupported by the manufacturer.

However, risk analysis considers both the likelihood of failure and the likelihood of the identified consequence occurring.

In this case, the calculated PoF for the relays is low (1.1%) and genuine busbar faults are very rare (LoC 0.03%). The coincidence of these two events is extremely unlikely - once every 300,000 years.

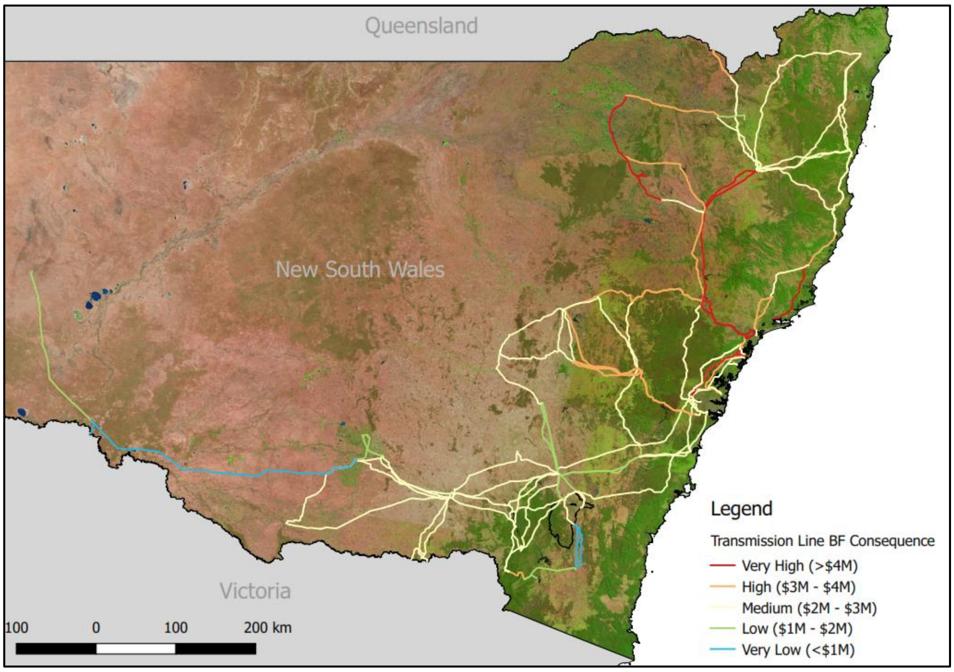
For relays protecting 330kV busbars, an uncleared main system busbar fault has a potential system instability consequence valued at $397.5 million.

However, when the PoF and LoC are applied, the risk cost is reduced to just $1,300 per relay.

The GE FACs relays are not being replaced, avoiding $13.6 million of potential capital expenditure.

Figure 4.13 shows a map of moderated bushfire consequences for our transmission lines. It is developed based on an assessment of bushfire risk factors in specific places.

Figure 4.13: Bushfire Consequence Map



Examples of risk cost moderation

The following examples show how high consequence risk costs are significantly moderated by Likelihood of Consequence factors.

Safety example: TransGrid uses a Value of Statistical Life of $10 million for certain high consequence safety risks, based on various relevant Work Health and Safety valuation studies. When this is used to calculate a risk cost, it is moderated based on the likelihood that the consequence will occur in the event of the relevant asset failure. Table 4.8 shows how this risk cost is moderated by LoC.

Table 4.8: Moderation of the safety risk consequence

Moderation factor (LoC)	Source of LoC
Substations: likelihood that staff are adjacent to equipment in the event of a failure **= 4% on average** (1% to 10%, depending on site) ***After moderation, the $10 million consequence reduces to $400,000 on average***	Maintenance records (excluding unplanned and project work) ***NB: This underestimates actual time***
Lines: likelihood that staff are working on a transmission line in the event of a failure **= 2.9% on average** (for the line) ***After moderation, the $10 million consequence reduces to $290,000 per line on average***	Routine maintenance records with small addition for general public (high risk spans only)[33]

To calculate the risk cost, the moderated consequence cost still has to be multiplied by the relevant Probability of Failure (of the event which would lead to the particular consequence).

Reliability example: For reliability risks, TransGrid calculates the consequence cost using a Value of Consumer Reliability (VCR). [34] The consequence cost is a function of VCR, the load subject to the fault (MW) and the repair time (hours). It also takes account of load restoration.

An example of moderation of the reliability consequence of a transformer failure is shown in Table 4.9.

Table 4.9: Moderation of the reliability risk consequence

Moderation factor (LoC)	Source of LoC
Transformers – A 'redundancy factor' is applied, based on how many parallel failures are required (and the likelihood of this) before load is lost. For the more common N-1 scenario (ie, one transformer failure can be tolerated) the redundancy factor is 0.4% (based on historical unplanned unavailability rates for transformers). ***The relevant reliability consequence cost is only incurred once for every 250 transformer failures.*** For an N-2 scenario the redundancy factor is 0.0016% {$(0.4\%)^2$} - the consequence is incurred once for every 62,500 transformer failures.	TG network analysis

As for the transmission lines example, to calculate the full risk cost, the moderated consequence cost still has to be multiplied by the relevant Probability of Failure (of the event which would lead to the particular consequence).

Special case – testing if network safety obligations are met

TransGrid is required to comply with the Electricity Supply (Safety and Network Management) Regulation 2014. This requires us to take all reasonable steps to ensure the following risks are eliminated, or if that is not reasonably practicable, reduced 'as low as reasonably practicable' (ALARP):

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33 These are identified in TransGrid's Public Electricity Safety Awareness Plan (PESA)

34 AEMO's VCR value published in 'Value of Customer Reliability (VCR) Review', September 2014 is escalated to the relevant year ($38.35/kWh)

- The safety of the public and persons working on the network
- The protection of property and the environment
- Safety aspects arising from the protection of the environment (including bushfire)
- Safety aspects arising from the loss of electricity supply.

In the context of investment decisions "ALARP" is tested through the use of disproportionality factors which increase the risk cost consequence in risk analysis. These increase risk consequence costs to just below the level which the community, government and law would consider risk reduction expenditure to be 'grossly disproportionate'.[35] The values we use (in Table 4.10) were determined through a review of practises and legal interpretations across multiple industries, with particular reference to the work of the UK Health and Safety Executive.

Table 4.10: TransGrid's ALARP multipliers

Risk	Consequence Severity	Disproportionality multiplier
Safety	Potential for single fatality contained within TransGrid site (eg, explosive failure of substation equipment)	3
Safety	Potential for multiple fatalities outside of a TransGrid controlled area (eg, conductor drop on transmission line easement)	6
Bushfire	Potential for multiple fatalities and extensive property damage	6

Investment analysis

The risk costs are used alongside other inputs in the investment analysis steps.

We note that the AER and EMCa consider that our approach is conservative and is likely to overstate the capital expenditure forecast. However, there are a number of controls built into the investment analysis approach which significantly limit this possibility:

- The list of possible investments is limited
  - Investment analysis is only undertaken where condition reports or other analysis suggests that action might be required
- The analysis approach and overall assumptions are biased against finding projects to be economically viable
  - Investment analysis uses a 10% (nominal) discount rate. As a result, the present value of "avoided risk benefits" in future years is reduced more than the capital expenditure is (as it occurs earlier)
  - The risk values used in the NPV analysis are not escalated. As the discount rate is expressed in nominal terms, this compounds the over-discounting of any benefits
  - Program investment analysis assumes that the benefits of avoided risk only begin to accrue when the full program is complete.

[35] For example, these levels are expressed in Regulation and Court recommendations

These significant constraints on the size of the "bottom-up" investment forecast have not been recognised by EMCa or the AER.

4.5.2 Asset replacement program reductions

Concerns about AER's methods and understanding of our approach

The AER summarises its conclusion on our replacement expenditure as follows:

> We have found that TransGrid's:
>
> - Proposed unit costs are reasonable; however,
> - Proposed scope of works, and therefore the proposed capex, are overstated.
>
> **We have formed this view on the basis of the systemic issues that EMCa identified** in TransGrid's proposal. It appears that **TransGrid has systemically overstated**:
>
> - **The risks** associated with its assets; and therefore
> - **Prudent and efficient capex**.
>
> **We have placed significant weight on the outcomes of EMCa's technical review** of TransGrid's governance, asset risk framework, and forecasting methodologies and in its review of TransGrid's major repex programs. As such, we consider TransGrid's proposed repex is materially biased upwards. (Draft Decision 6-55) [Added emphasis]

Our interpretation of this decision process is that:

- EMCa concluded that we systemically overstate asset risks therefore capital expenditure forecast is overstated
- The AER relied heavily on EMCa's findings to reduce replacement expenditure by $200 million.

As noted throughout this revised proposal we are concerned that the conclusions in the draft decision are not supported. The AER 'placed significant weight' on EMCa's report yet was aware it contained:

- **Factual errors** - including examples where risk values have been misread from a spreadsheet and presented as "evidence" of a systemic bias
- **Fundamental misunderstandings** of our actual asset management framework and forecasting approaches – including examples concluding that our model assumes events are *a factor of a thousand more likely than* we have modelled.

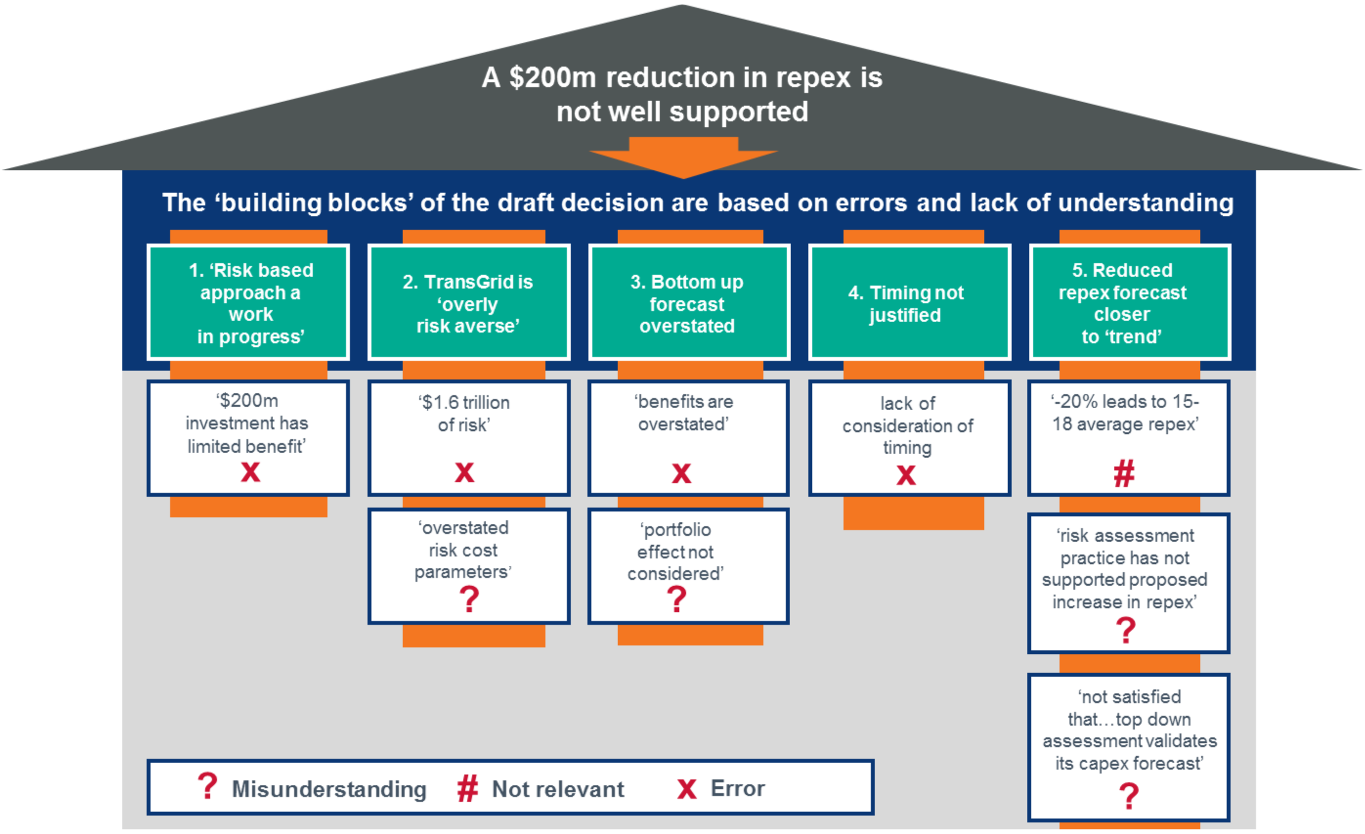
Despite TransGrid identifying these errors and misunderstandings in writing, the AER relied upon the EMCa report and incorporated some of the same errors in its draft decision.

Other conclusions in the draft decision are supported by analysis and assertions which do not reflect a strong understanding of transmission network planning, TNSP obligations or the context in which we operate. In one example, the AER has suggested that the actual failure rate for a specific transmission line should be replaced by the system-wide average transformer failure rate.

Replacement expenditure cut relies on errors and misunderstandings

Figure 4.14 illustrates our view that the main “building blocks” of the AER’s $200m reduction in replacement expenditure are poorly supported.

Figure 4.14: Basis of AER conclusions on replacement expenditure



The sections below provide details on the errors and misunderstandings which support each of the five “building blocks” of the replacement conclusions.

1. **Approach is a work in progress**

Our approach, summarised in section 4.5.1, is not a work in progress (Draft Decision 6-66) and the AER and EMCa’s rationale for concluding this is not valid. This conclusion appears to disregard the detailed information provided throughout this process.

An example of EMCa’s misunderstanding of our process and the risk cost analysis was its creation of an incorrect chart showing that “$200m investment has limited benefit”. As detailed in Section 4.2.3, this was incorrectly constructed, using inapplicable project data and was not interpreted correctly.

From the extent and nature of the errors and misunderstandings in EMCa’s report and the draft decision, it is our view that our approach has not been well understood. As a result the conclusion cannot credibly be reached.

TransGrid’s view: *this conclusion cannot reasonably be drawn.*

2. **TransGrid is ‘overly risk averse’**

On the basis of errors and misunderstandings, the draft decision has concluded that TransGrid is:

> overly risk averse, such that prudent and efficient capital expenditure is likely to be overstated. (Draft Decision 6-3)

It has been based on identifying high value risk cost examples in our models and highlighting these outside of the context of the full risk analysis to conclude that we over-state risks. Many examples indicate that our approach and modelling has been misunderstood.

> TransGrid's risk cost modelling assumes that **it is exposed to $1.6 trillion of risk** per annum. (Draft Decision 6-65)

The highlighted risk value was taken incorrectly from a spreadsheet and increased by a factor of 1000. It is reasonable to assume that such a high risk value should have prompted further investigation - $1.6 trillion is close to Australia's annual GDP. We notified the AER of EMCa's error but it was used to conclude that our process results in assessed risks which are too high (more details in example in section 4.3.2).

> EMCa found…inadequate justification and overstated project risk cost parameter assumptions… (includes probability of failure, likelihood that a hazardous event will lead to a consequence and the cost consequence of asset failures). (Draft Decision 6-70)

It is our view that there are too many examples of EMCa misunderstanding our process for it to reasonably make this conclusion. For example, in relation to its review of substation civil structures projects, EMCa interpreted a 2% Likelihood of Consequence incorrectly:

> TransGrid allocate a 2% LoC, based on its assessment that the whole substation will lose this level of load for this period of time, which is comparable to a 1 in 50 years event. (EMCa p70)

This conclusion misrepresents LoC – it is not the combined probability of the event occurring and the consequence being realised. It is the probability that the consequence will occur, following a catastrophic failure.

In this case, the PoF was 1% - one failure is expected every 100 years. The 2% LoC means that, if this event happened, there is a one in fifty chance of the consequence occurring. The likelihood of failure and complete load loss is therefore: 1% (PoF) x 2% (LoC) = 0.02% or 1 in 5,000 years (not 1 in 50 years).

TransGrid's view: *there are too many examples of EMCa misunderstanding our process for this conclusion to be reasonably reached.*

Aurecon Report used selectively

To support its conclusion that we materially over-state risk, the AER quoted an Aurecon assurance report*.

> Aurecon commented that:
>
> … TransGrid has gone to great lengths to provide credible referenced sources to validate potential CoF values, albeit **erring towards worst-case scenarios** as supported by one of the key elements of the NACF, **namely a likelihood based element to assess the likelihood of the worst-case consequence occurring**. Whilst the consequence magnitude should not be underestimated (or overestimated) a realistic estimate is deemed advisable. When the stakes are high, as is the case with several key hazardous events, a range of techniques as well as industry expertise is suggested to arrive at a cost of risk estimate that is **credible and realistic** [AER emphasis].
>
> … indicates that TransGrid's risk analysis is biased towards worst-case hazardous events and worst-case consequences such that it is likely to materially overstate network risks and therefore proposed capex.' Draft Decision (p 6-69)

Aurecon actually concluded:

> …Aurecon believes that TransGrid's framework for the preparation of its capital expenditure plan for the 18/19 to 22/23 regulatory period **will result in a CAPEX forecast that is in accordance with good electricity utility practice** and **will meet the capital expenditure criteria**... [Added emphasis]

***Aurecon, *Independent Review of TransGrid's CAPEX Plan, Final Report*, 25 January 2017**

3. Bottom up forecast overstated

The draft decision has concluded that the bottom up forecast is overstated because:

- Individual project benefits are overstated
- There is no portfolio optimisation process.

These are addressed in turn.

Firstly, the AER is incorrect to state that project cost estimates are derived from the risk costs:

> Our findings on TransGrid's **quantification of reliability, safety and environment (bushfire) risks used to derive project cost estimates** largely explain why we are not satisfied that TransGrid's proposed total forecast capex meets the capex criteria. (Draft Decision 6-10) [Added emphasis]

Risk costs are used to identify if there will be a net benefit via a reduction in risk, if a project is implemented. Project costs are derived separately based on recent project costs.

Even if project costs were derived from the risk costs, many examples of 'overstated benefits' in the draft decision are based on incorrect analysis. Two examples are provided below.

> ..the outage rate for the line (94M) at 49 per cent is higher than the average line outage rate of 17 per cent across its network… potential to overstate the level of reliability risk. This may have the effect of overstating the benefits… (Draft Decision 6-141)

This conclusion is based on incorrect analysis. The 17 per cent average outage rate is the system-wide value for transformers (not lines). Our analysis has correctly used the actual outage rate for a 132kV transmission line.

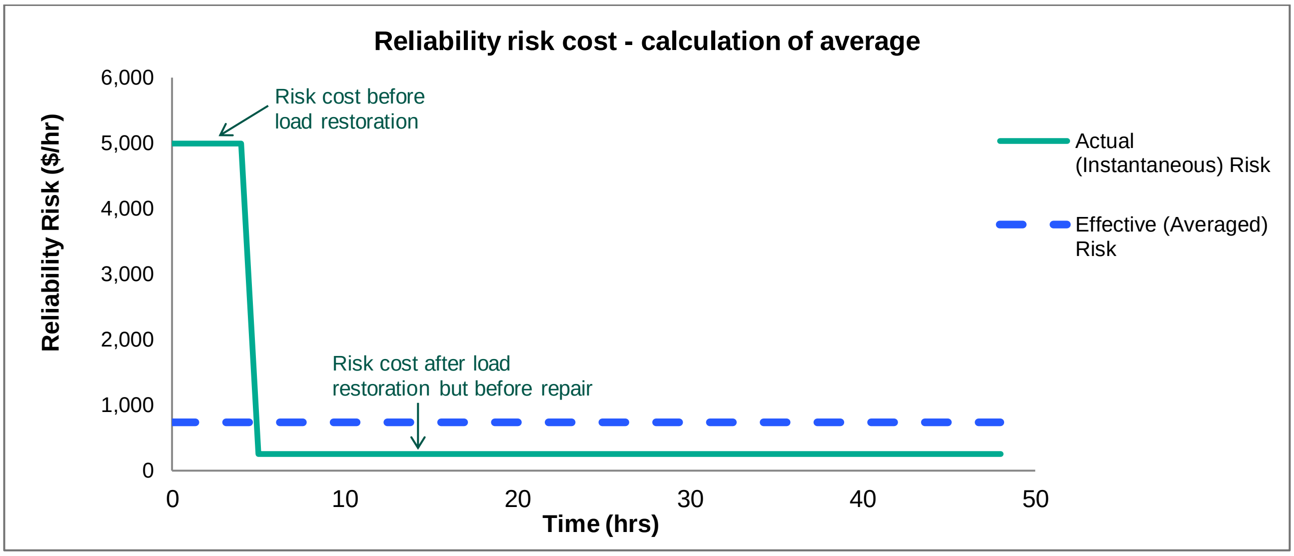
In another example, TransGrid's calculation of a reliability consequence has not been understood.

> TransGrid apply a $/hour assumption to calculate the reliability consequence of load at risk for loss of a major substation element (ie, line, transformer etc.). EMCa noted that it is not clear how the analysis considers the moderation of the "effective" outage duration by load restoration activities and is likely to overstate the reliability impact, and therefore results in a forecast that does not reflect a prudent and efficient level of capex. (Draft Decision 6-73)

The effect of load restoration activities has been accounted for. This is done by determining two separate values of load at risk. An initial (higher) value from the time of the incident until load restoration occurs and, a lower value for the period after load restoration until the repair of the failed equipment.

The overall reliability consequence cost is an average of the two "load at risk" values, as shown in Figure 4.15.

Figure 4.15: Risk cost based on load before and after restoration begins



The conclusion that the reliability is overstated is based on EMCa's lack of understanding of the approach, rather than finding an actual problem with it.

The AER considered that our:

> capital investment framework does not appear to include an effective portfolio optimisation process (Draft Decision 6-13).

Our forecast does take account of the portfolio optimisation process. Firstly, project cost inputs are based on past actual investments, which include the impact of portfolio optimisation. Also, portfolio impacts are considered during the needs identification and options evaluation process. Issues which interact are considered together and optimised where appropriate. An example of this was considering the renewal of 22kV primary plant at Broken Hill when secondary systems replacement options were being assessed.

***TransGrid's view:** the conclusion that the bottom up forecast is overstated is not supported by the analysis.*

4. Project timing is not justified

The AER considers that TransGrid does not target its efforts managing risk.

> an absence of evidence that TransGrid has taken a targeted approach to managing any identified risks (Draft Decision 6-72)

This is not supported by evidence. Our risk management process aims to identify risks and determines how to address *only* those which are critical for compliance or which have the greatest net benefit.

Investment analysis is only undertaken where a potential need has been identified in asset condition information or a similar indicator. This results in a forecast which is targeted at the highest net benefit in terms of risk reduction. This is evident in:

- Transmission line programs which target only those structures and line components which have an identified risk (rather than complete line rebuilds)
- Undertaking substation asset programs rather than complete substation replacement projects

> Development of secondary system relay replacement programs where feasible (as opposed to wider secondary system replacements).

As already noted, the investment analysis is biased against capital expenditure. A 10% discount rate is used and the model assumes that benefits only accrue when a program ends.

Despite this, each replacement project in the forecast (excluding compliance projects) has a positive net benefit. This indicates that project timing is optimised.

However, EMCa and the AER consider that timing of the replacement program has not been optimised:

> The economically optimum project implementation time is when the annual risk cost exceeds the annualised cost of avoiding/mitigating the risk (Draft Decision 6-75)

Wood pole replacement program is targeted

The AER stated:

> *EMCa observed that TransGrid appears to be replacing all wooden poles…It is not clear how to us, how entire pole replacement and the proposed strategy of targeted pole replacement based on condition is evidence of uniform application of its asset management approach (Draft Decision 6-76)*

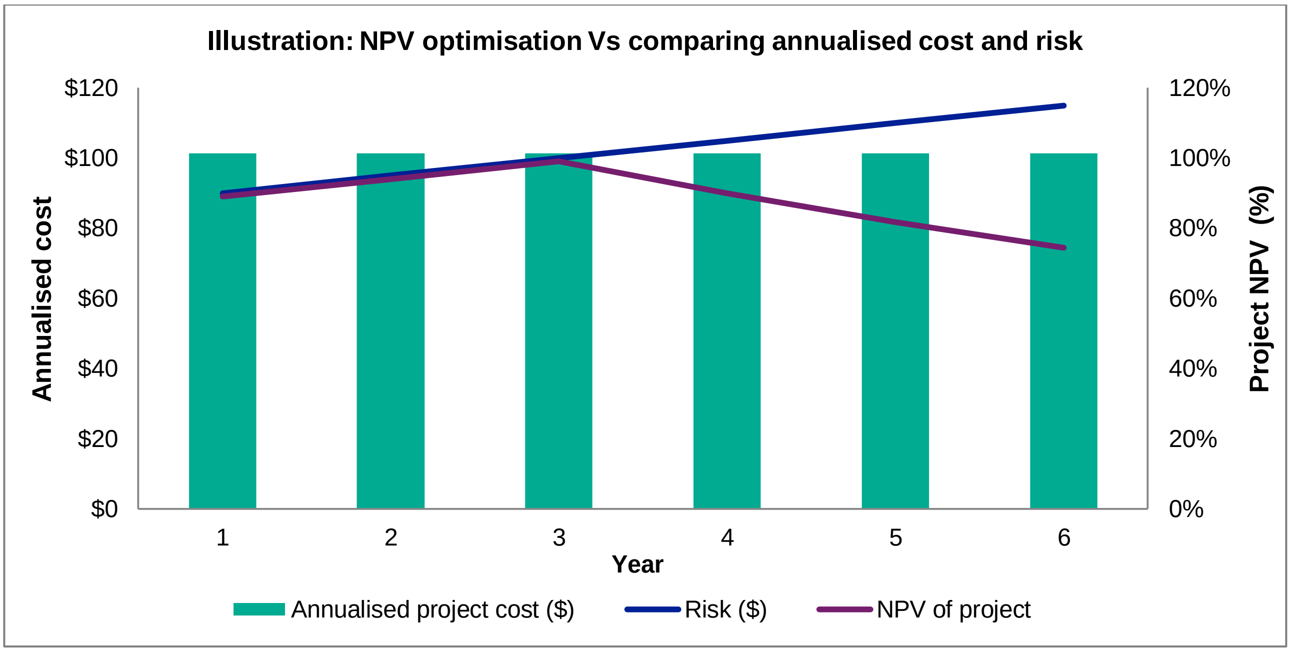
EMCa had access to detailed needs statements and options evaluation reports (OERs) so it is unclear how this conclusion could be reached.

OER 1558 "132kV TL Wood Pole Replacement" identifies the number of planned pole replacements per line. Four lines have less than ten pole replacements planned and Line 97A has *only two.*

EMCa's conclusion that we are "replacing all wooden poles" is therefore not credible.

We agree with this statement. It is not inconsistent with our approach of only including replacement projects with a positive net benefit. This similarity of the two approaches is illustrated in the Figure 4.16. The point at which the "annual risk cost exceeds the annualised cost of avoiding/mitigating the risk" is the point which maximises the net benefit of the investment.

Figure 4.16: Illustration – NPV optimisation



To validate the timing of projects in the forecast, we calculated the change in benefits with a deferral of one year. In every case, the present value of the investment benefit reduces with a one year delay. We also compared the annual risk cost against the annualised cost of mitigating the risk – in all cases (except for compliance and "ALARP" driven investments), AER / EMCa's test of the 'economically optimum project implementation time' was passed.

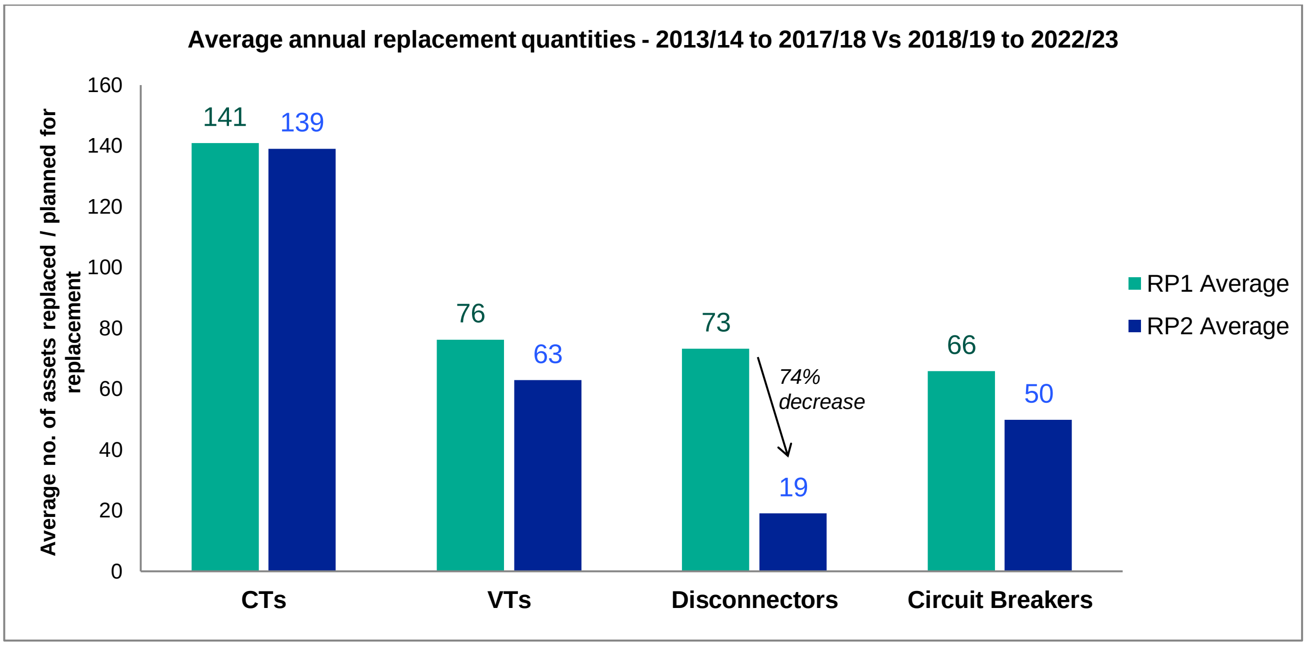
TransGrid's view: *timing is a key consideration in TransGrid's process and analysis and we have demonstrated that the net benefits reduce if replacements programs are deferred.*

5. **Reduced repex forecast closer to "trend"**

The AER does not consider that the proposed increase in replacement expenditure (compared to the current period level) has been supported by the risk assessment practice. Given the number of errors and extent of misunderstanding of our approach, this is not a reasonable conclusion.

It also suggests that the other supporting information has not been considered appropriately. A range of information we provided shows that asset replacement needs are changing. Figure 4.17 shows that, replacement needs for some asset types are lower over the next period.

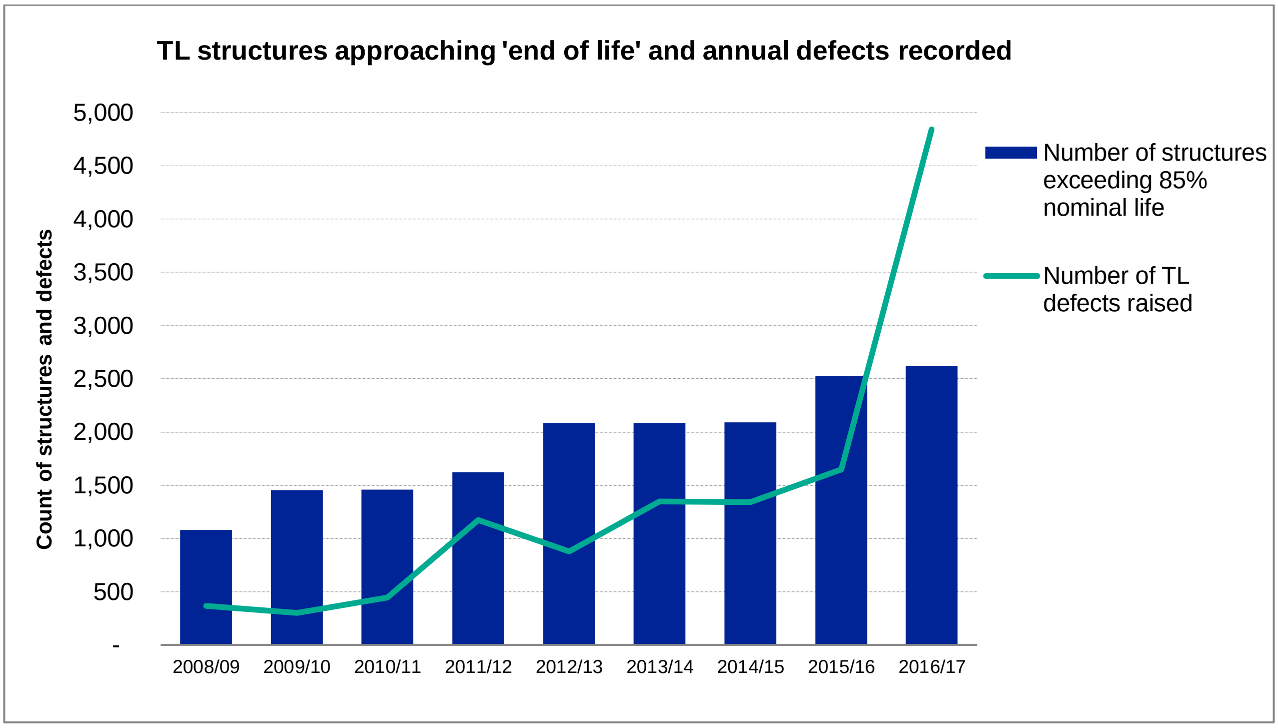
Figure 4.17: Changes in replacement volumes



In the case of disconnectors, it is the application of our risk analysis which has shown that this decrease is prudent. While proposed replacement rates are significantly lower than the expected long term average the analysis gives confidence that this forecast is appropriate. A simple "trend" method would not identify this change.

For some assets, an increase in replacement expenditure is forecast over the 2018/19 to 2022/23 period and this is supported by the underlying age, performance and condition information which has been provided. The example in Figure 4.18 shows age and condition trends for transmission line structures.

Figure 4.18: Transmission line structures; lifetime and condition issue trends



In this example, the increase in identified issues is partly due to the implementation of a new inspection regime which is aimed at collecting more detailed asset condition information to support better decision-making.[36] However, this more granular data collection is uncovering a higher number of issues which need to be dealt with relatively soon. For example, between 2015/16 and 2016/17 there was more than a threefold increase in transmission lines issues to be dealt with within a year.[37] The data demonstrates an increase in condition related issues in a manner which aligns with what could be expected from the age profile.

It seems reasonable to conclude that the types of information highlighted in Figure 4.17 and Figure 4.18 above would have provided some indication of whether an increase in asset replacement was justified.

However, the AER concluded that an increase in replacement expenditure was not supported. This was based on an incorrect understanding of the risk analysis and without referencing the underlying asset information. It reduced the replacement forecast back towards a historical average,

> our reduction of 20 per cent to TransGrid's major repex programs forecast will provide a level of repex that is consistent…[with]…the 2015-18 regulatory control period. (Draft Decision 6-56)

A TNSP would be negligent to forecast efficient expenditure solely based on historical spend and without considering a range of indicators on the condition of the assets. A reliance on trend for transmission asset replacement is inadequate, as the AER itself notes:

> Transmission, however, is characterised by fewer assets that are high value in nature, and are replaced in groups, leading to lumpy expenditure over time. (Draft Decision 6-34)

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[36] For example climbing inspections on all structures (poles and towers) are undertaken rather than ground based inspections.

[37] The highest increases were in category P4 (respond within 12 months) up to 1896 from 540 in 2015/16; and in category P5 (respond at next outage/maintenance) up from 567 to 2779 in 2015/16.

We disagree that our approach does not include a "top down" portfolio review. The AER disregarded the version of the 'repex model' which was provided. Modifications we made to make this more relevant for looking forward are not considered valid. Output showed that our proposed increase in replacement expenditure did not halt the increase in average asset class ages.

TransGrid's view: *a 20% reduction in replacement expenditure does not have a basis. It is based on a backward looking trend analysis and does not adequately consider future asset condition and risks. It relies on a risk methodology review which included many errors*

4.5.3 Addressing specific AER comments

Incentive costs removed

As identified by EMCa, benefits associated with increased incentive scheme revenue were erroneously included in the analysis for two projects. We accept these findings and have adjusted the analysis to exclude these benefits. This updated analysis led to a reduction in replacement expenditure of $0.9 million for the VT Renewal Program.

Note, more recent condition information has identified the need to replace additional Haefely type units which has moderately increased the program costs. The net impact of these changes is a reduction $0.23 million.

Safety consequences – legal and legislative costs input

The AER noted that the modelling for transmission line portfolio applied a total safety consequence cost of $20 million. This analysis correctly used the value of statistical life (VoSL) of $10 million. However, the addition of legal and legislative costs incorrectly brought the total to $20 million; this total should have been $11 million. The correction has been made, however it results in no change to the required investments in the transmission line portfolio.

Review of ALARP methodology

While EMCa did not dispute the use of the ALARP methodology, it considered that the cost of capital should be applied when annualising the cost of the investment. TransGrid has revised the ALARP methodology to include the cost of capital (using 6.75%). This correction has led to the reduction in scope of two projects and a reduction in the replacement expenditure of $0.95 million.

Reduced scope - substation security (CCTV) and noise compliance

Following review of the EMCa report and AER draft determination, revised analysis was carried out on the following needs:

- CCTV System Renewal (1398)
- Substation Noise Non Compliance Program (1454).

TransGrid has accepted some of the AER's findings and modified the CCTV program (relating to thermal vision). This has reduced the replacement expenditure by $3.4 million.

For the Substation Noise Non Compliance Program, we re-evaluated the potential risk and risk mitigation strategies. As a result we reduced the total number of targeted sites from six down to two. This led to a reduction of $4.9 million.

Of the two remaining sites one has already had noise complaints and the other has an increasing noise source (ie, 55 years old transformer) that will likely increase in noise level in the next regulatory period.

4.5.4 Changes in the replacement forecast

Changes made to the replacement forecast but not described elsewhere in this chapter are summarised here.

SCADA replacement project

The SCADA replacement project has been brought forward to facilitate its completion by 2020. This deadline is driven by TransGrid's Licence Conditions relating to cyber security and is the result of discussions with IPART and other government agencies. Further detail was provided to the AER on 6th July 2017.

The result is that the replacement forecast for 2018/19 to 2022/23 is reduced by $3.1 million as this amount will now be spent in 2017/18 to accommodate the earlier commissioning date.

Project scope increases

Since January 2017 updated asset health, asset condition and cost information has become available. As a result, the forecast for one project has increased slightly.

The cost estimate for the Transmission Line Low Spans Stage 2 project (1556) has increased after a further assessment of the expected cost of remediation measures. This has resulted in an increase to the forecast of $3.8 million.

Summary of replacement forecast changes

All changes made to the replacement expenditure forecast are shown in Table 4.11. Note that these are the changes after the inflation and labour escalation updates shown in section 4.3.

Table 4.11: Changes to the replacement expenditure forecast ($m June 18)

Project need description	Updated forecast	Change from Proposal	Reason
Yanco Sub Low 33kV Busbar Clearance	**0**	**-0.57**	Amended ALARP methodology
Various Locations Bushing Renewal	**5.47**	**-0.38**	Amended ALARP methodology
Substation Noise Non Compliance - Muswellbrook & Molong	**5.64**	**-4.93**	Reviewed program and removed lower risk sites
CCTV System Renewal	**7.92**	**-3.39**	Review showed less project need
Various Locations VT Renewal Program	**17.67**	**-0.69**	Net impact of removing incentive benefits and adding Haefely VTs
Transmission Line Low Spans Stage 2	**6.85**	**3.84**	New information identified increased need
SCADA replacement	**12.6**	**-3.1**	Brought forward to ensure NSW licence compliance – some expenditure in 2017/18
Net change		***-9.22***	

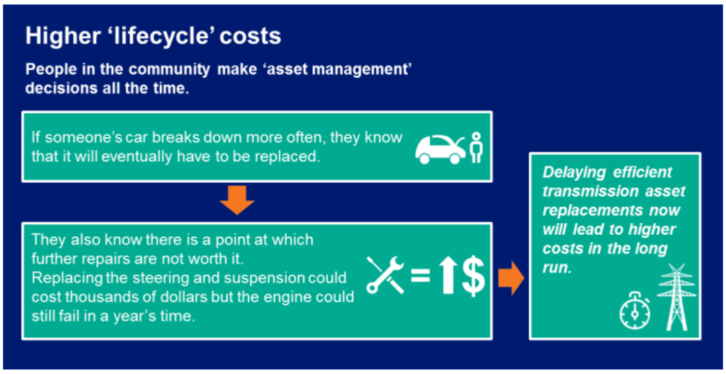
Consequences of the replacement expenditure cut

The replacement portfolio has been reviewed to consider the impact of the AER's reduction. As we are aware of risks to the community, safety and environmental (especially bushfire-related) expenditure will be prioritised.

It is more likely therefore that the largest impacts of this expenditure reduction will be increases in:

- Reliability risk (that is, supply interruptions will be more likely)
- Asset lifecycle costs – there will be higher operating costs as asset failure rates increase and asset replacement is pushed back in time.

Analysis of the replacement portfolio demonstrates that we will not undertake expenditure where the project costs are lower than costs and risks avoided.



The present value of the net benefits from the projects which might not be undertaken is estimated at around $130 million. This is an additional economic cost on customers via reliability risk, higher asset lifecycle costs and safety risks.

Table 4.12 provides some details about Secondary Systems and Substation projects which would be unlikely to proceed if the draft decision became final.

Table 4.12: Projects unlikely to proceed under the draft decision

Investment category and details	Projects not undertaken	Impacts
Secondary Systems 22 projects, total cost $63 million	Renewals of: > 8 full secondary systems > Instrument transformers > 415V distribution systems > Protection relays and busbar protection.	**Unrealised benefits** (NPV) of $114 million across 22 projects **Outstanding annual reliability risk** valued at $18 million
Substations 4 projects, total cost $24 million	Renewals of: reactors, bushings at various locations, transformers.	**Unrealised benefits** (NPV) of $24 million across 4 projects **Outstanding annual reliability risk** valued at $0.5 million **Higher lifecycle costs** $0.75 million per year

4.5.5 Rejection of increased RIT-T costs

Overview

The forecast included $2.8 million to cover the cost of what was (in January 2017) expected to be a new regulatory requirement to undertake Regulatory Investment Tests for Transmission (RIT-T) for replacement expenditure.

AER assessment

The AER did not allow this expenditure and reduced the allowance by the full amount. It reasoned that the expenditure covered what a prudent business would already be doing.

Response

TransGrid supports increased transparency in transmission investment decision making. However, in absence of a regulatory requirement, a prudent business would not choose to undertake a process which adds substantial cost and almost a year to the investment pathway. Undertaking RIT-Ts for replacement expenditure is a completely new requirement which will cause TransGrid to incur new costs.

Under Part 1 of the National Electricity Law, '7a Revenue and pricing principles':

> A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in — …(b) complying with a regulatory obligation or requirement **National Electricity (South Australia) Act 1996, Part 1, 7A**

As a result, TransGrid considers that the draft decision is not in line with the "Revenue and pricing principles".

The new requirement is due to the "replacement expenditure planning arrangements" Rule which was implemented in 2017. In implementing the Rule, the AEMC's final rule determination recognised the likely cost increase:

> There will be some increase in regulatory burden from extending the regulatory investment tests to replacement expenditure.[38]

While replacement expenditure has always been subject to economic analysis, the RIT-T process is more onerous, requiring public consultation. For this to be meaningful, some effort is required to ensure documentation is accessible to those consulted and to undertake consultation.

Each RIT-T will take a minimum of about nine months and there is a requirement to publish at least two rounds of consultation documentation. As TransGrid expects to do in excess of 50 RIT-Ts in the period this Rule change drives significant costs.

In line with the revenue proposal, we have included $2.8 million in the revised capital forecast.

4.5.6 Rejection of "tools, plant and compliance costs"

Overview

The forecast included $10.1 million for tools and test equipment related to network asset activities.

38 National Electricity Amendment (Replacement expenditure planning arrangements) Rule 2017, Determination, p70

AER assessment

The AER did not allow this expenditure and reduced the allowance by the full amount. It reasoned that tools and equipment capital expenditure was already allowed for within the "Non-network" capital expenditure allowance.

Response

The "Tools and Equipment" forecast is not duplicated in the non-network capital expenditure forecast (which is for ICT and Motor Vehicle).

This forecast includes a range of specialised tools and test equipment such as protection testing equipment, SF6 gas analysers, thermovision cameras, hydraulic crimping/cutting equipment and oil degasification plant.[39]

It appears that the AER's conclusion is because the "Tools and Equipment" forecast is allocated to the same regulatory asset class category as "Motor Vehicle and Mobile Plant", namely "Minor plant, motor vehicles and mobile plant (2018-23)".

TransGrid has included $10 million for Tools and Equipment capital expenditure in line with the revenue proposal amount (adjusted for inflation).

4.5.7 Revised replacement expenditure forecast

An updated forecast for replacement expenditure is shown in Table 4.13.

Table 4.13: Revised replacement capital expenditure forecast ($m June 18)

Replacement expenditure	2018–19	2019-20	2020–21	2021–22	2022–23	Total
Original proposal	142.2	189.5	225.3	197.5	207.4	**961.8**
Revised proposal	158.6	194.4	213.9	184.8	185.4	**937.1**
Difference	16.4	4.9	-11.4	-12.7	-22.0	**-24.7**

In total, it is $24.7 million lower than our original proposal. This is driven by the program-specific decreases detailed in section 4.5.3 and the adjustments to labour escalation and inflation.

39 As part of the information gathering process a breakdown of this part of the forecast was provided to the AER on 5th June 2017

4.6 Augmentation (excluding PSF)

The draft decision recommends an allowance of $96.7 million for augmentation expenditure (excluding PSF). Our forecast of $160.8 million has been reduced by $64.1 million. An overview of the reduction, its reasons and our response is shown in Table 4.14.

Table 4.14: Summary of AER draft decision and reasons

Expenditure reduction and reasons	TransGrid response
Economic benefits driven *Reduction of $31.5 million (-51%)*[40] 5 project forecasts were reduced by 20%. AER agreed the needs were valid but considered the benefits to be materially overstated. The remaining Dynamic Voltage Support project was rejected due to uncertainty but the AER suggested it could be a contingent project.	**Conclusion partly relies upon a misunderstanding** of the risk cost modelling and investment analysis. All risk cost (ie, benefit) assumptions were moderated for the specific circumstances. The dynamic voltage support projects are too small to be eligible as contingent projects but new generation is now committed in the relevant areas and further new generation connections are now more likely.
Reliability and security driven *Reduction of $0.2 million* Program accepted in full with adjustment for a small correction in historical CPI.	**We accept this adjustment.**
Connection driven *Reduction of $28.5 million (-79%)* Historical connection capex more reasonably reflects expected demand. New connections are less likely than TransGrid has assumed.	**Historical connection capex is not relevant.** The forecast is forward-looking, driven by known, possible new large mining and resources loads. Updated information is presented to support the likelihood of the new connections. This forecast was created on a probabilistic basis to reflect the uncertainty of any one project proceeding. It reflects the fact that across the identified projects, some will connect and expenditure will be required.
Localised demand driven *Reduction of $3.2 million (-15%)* Insufficient evidence to justify timing of new switch bays at Macarthur.	**Macarthur switch bays are required** Further information clarifies that these are part of the most efficient solution developed in joint planning (with Endeavour Energy).

Further detail on each of these areas follows.

4.6.1 Economic benefits driven capital expenditure

Overview

This program consists of augmentation projects which result in net economic benefits by improving power quality, load restoration times, network resilience and operational efficiency.

[40] This includes $0.8 million of two connections project that the AER moved to Powering Sydney's Future

Ten projects with clear net economic benefits have been added to this part of the capital expenditure forecast. These projects were originally included in the January 2017 proposal as part of the Network Capacity Incentive Parameter Action Plan (NCIPAP). The AER determined they did not meet the specific objective of the NCIPAP scheme – to increase network capacity in response to an identified network limitation. TransGrid accepts this decision and has transferred them into the main capital program.

AER assessment

The AER removed one project (suggesting it should be a Contingent Project) and reduced the forecast for the five others by 20%. This reduced expenditure from $62.7 million to $30.4 million, a reduction of 51%. For the 20% reduction, the AER's view was that:

- Identified needs seem valid but the benefits calculated were "likely to be materially overstated"
- Proposed timing was not evidenced.

For the Dynamic Voltage Support project, the AER concluded that the uncertainty about the need was sufficient that the project could be a Contingent Project. We appreciate the AER has remained open to receiving more information about this project.

Response – five projects reduced by 20%

The rationale largely relies on EMCa and the AER's conclusions that there was "systemic overestimation" of risk cost savings (ie, investment benefits) in the replacement forecast:

> For the same reasons outlined in our assessment of repex, we are not satisfied that the proposed augex that is driven by economic benefits is reasonably likely to reflect prudent and efficient costs. Furthermore, as there is evidence of the same systemic overestimation of risk for augex and augex we have applied a 20 per cent reduction. (Draft Decision 6-48)

The AER's reliance on EMCa's report and its findings on replacement expenditure are problematic as these findings have been shown to be weakly supported.

In relation to EMCa's review of these projects[41], we respond to specific concerns as follows:

- For the smart grid control projects, the reliability risk calculation does include moderation of peak load in case it is not peak time when a fault occurs. A factor of 0.5 is applied
- For the Yass Circuit Breaker capacity increase project, EMCa queried the different circuit breaker "outage" and "failure" rates. These differ because the modelled failures are different events, with an outage being more likely than a failure. The risk cost calculation use both, as both events need to occur in sequence for this risk impact to eventuate.

As observed for the replacement program, an arbitrary reduction of 20% appears to have been applied on the basis of a flawed review of our risk analysis method.

Following a review of the need and AER feedback on the project, the Travelling Wave Fault Location project, which was originally part of this group of projects, has been removed.

Response – dynamic voltage support

The dynamic voltage support project is a response to the impact of increasing renewable generation connections in weaker parts of the network. The original forecast was probability weighted. The total

[41] EMCa Report, page 47

forecast capital cost for responding to these generation connections was discounted by 40% to account for the uncertainty around actual connections.

The AER noted:

> We are satisfied that TransGrid has demonstrated that its dynamic voltage support program would be required to achieve the capex objectives in the event the forecast demand materialises. However, we consider that the need for the project and the associated costs are not sufficiently certain. (Draft Decision 6-48)

We appreciate that the AER recognises that the potential need is valid but uncertain. As this project is a grouping of two potential needs, individually, neither of these is large enough to meet the contingent project threshold.[42]

Since January 2017, renewable generation has been committed in the areas in question and increasing levels of proposed renewable generation are progressing through the connection process. Table 4.15 shows new generation activity in relation to the connection levels which trigger the need for reactive support.

Table 4.15: Dynamic voltage support triggers and latest generation connection interest

Area / likely location [43]	Generation level triggers	Generation activity since January 2017
South west Darlington Pt 330kV	617 MVA	**230 MW** of generation is committed (Connection Agreements signed) **880 MW** of generation at an advanced stage (two are close to committing)
Central west Wellington 330kV	1234 MVA	**180 MW** of generation is committed (Connection Agreements signed) **250 MW** of generation at an advanced stage
North Tamworth 330kV	1649 MVA	**250 MW** of generation at an advanced stage **1,000 MW** of connection enquiries in the region

From this information, TransGrid's view is that the south west need is very likely to be triggered and potentially quite soon.

Ten additional projects with economic benefits

Ten projects were originally proposed as part of the Network Capacity Incentive Parameter Action Plan (NCIPAP) incentive scheme. They were not accepted into that scheme as they did not meet its relatively narrow objective to increase network capacity.

However, they will all result in net benefits, addressing reliability risk and improving wholesale market efficiency. TransGrid therefore proposes to include the projects detailed in Table 4.16 in the capital expenditure forecast.

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[42] Clause 6A.8.1(b)(iii) of the National Electricity Rules (NER) states that 'the proposed contingent capital expenditure exceeds either $30 million or 5% of the value of the maximum allowed revenue for the relevant Transmission Network Service Provider for the first year of the relevant regulatory control period whichever is the larger amount.'

[43] Other locations considered have already been shared with the AER in NOS 1650

Table 4.16: New economic benefits projects (ex-NCIPAP) ($m June 18)

Projects	Forecast ($M)	Benefit and reasons
Deniliquin full SCADA augmentation	0.4	**Reliability** Reduces fault restoration time of Deniliquin 66 kV network
Overvoltage control after automatic under-frequency load shedding	4.1	**Reliability** Reduces overvoltage risk in the event of under-frequency load shedding (UFLS).
Remote or self-reset of bus protection	4.1	**Reliability** CCTV system allows remote busbar switching to significantly reduce supply restoration times following a busbar fault
Two-way disconnector to replace line tee connection to Morven substation	3.0	**Reliability** Reduces the duration of supply interruptions following any fault on line 996
Finley full SCADA augmentation	0.3	**Reliability** Significantly reduces the fault restoration time of the Finley 66kV supplies.
Two-way disconnector replaces line 976 tee connection to Murrumbateman substation	2.8	**Reliability** Reduces duration of supply interruption to customers following any fault on line 976
Albury area under voltage load shedding scheme	0.2	**Reliability** UVLS allows 132kV system to remain supplied during outages at Jindera[44]
Taree 132 kV bus capacity augmentation	1.0	**Reliability** Establishing two bus bar protection zones halves the impact of a busbar section trip
Remote relay interrogation	2.0	**Market efficiency** Faster diagnostics and better accuracy of voltage and transient stability constraints. Can improve inter-regional transfer limits.
Two-way Disconnector On Line 94M for Ilford Tee	2.9	**Reliability** Reduces the duration of supply interruptions following any fault on line 94M
Total	**20.9**	

[44] Outages of a Jindera 330/132 kV transformer or Jindera-ANM 132 kV line or Jindera-Albury 132 kV line

Updated forecast

An updated forecast for economic benefits driven expenditure is shown in Table 4.17.

Table 4.17: Economic benefits driven capital expenditure ($m June 18)

Economic benefits driven expenditure	2018–19	2019-20	2020–21	2021–22	2022–23	Total
Original proposal	3.0	15.2	26.7	7.3	10.5	**62.7**[45]
Revised proposal	8.2	22.1	29.4	9.8	11.4	**80.9**[46]
Difference	*5.1*	*7.0*	*2.7*	*2.4*	*0.9*	***18.1***

This revised forecast is $18.1 million higher than the amount we proposed in January. This is the net effect of removing the Travelling Wave Fault Location project and adding the ten ex-NCIPAP projects.

4.6.2 Reliability driven expenditure

Overview

This program is driven by investment to meet new reliability standards.

AER assessment

The program was accepted in full and we acknowledge the AER's decision and maintain the project in the revised proposal. However, for both Molong and Mudgee supply points, the AER requested further information on:

- The basis for not considering network support services
- Whether we considered the flexibility in the reliability standard in complying with the obligation.

Response

There is limited flexibility in the reliability standards[47]. TransGrid can deviate from the specified unserved energy limit *if* there is a **demonstrable firm plan** to satisfy local reliability needs, which provides a greater net benefit. Approval for this is at the discretion of IPART.

TransGrid fully supports the use of non-network solutions. However, contracting with non-network service providers for compliance purposes will be complex. There is not enough time to find proponents[48], clearly communicate our requirements, agree legal and commercial terms, execute contracts and have these reviewed and approved by IPART in time to comply.

Updated forecast

An updated forecast for reliability driven expenditure is shown in Table 4.18.

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[45] Note that the Draft Decision presented our forecast for Economic Benefits Driven Expenditure as $61.9 million (p 6-38). This was because the AER moved $0.8 million from this forecast into the Powering Sydney's Future project.

[46] This forecast also includes the expenditure for the two projects which were treated as PSF by the AER. These are separate projects required at Beaconsfield and Haymarket irrespective of PSF. Further information is provided in TransGrid-OER 1440 Beaconsfield 132kV Cable Replace-0117-PUBLIC and TransGrid-OER 1448 Haymarket 132 kV Ausgrid Cables Replace-0117-PUBLIC

[47] Section 4 of the NSW Electricity Transmission Reliability and Performance Standard 2017

[48] For compliance purposes, we might need more than one provider.

Table 4.18: Reliability driven capital expenditure

Reliability driven expenditure	2018–19	2019-20	2020–21	2021–22	2022–23	Total
Original proposal	15.5	25.6	0.0	0.0	0.0	**41.2**
Revised proposal	21.9	26.6	0.0	0.0	0.0	**48.6**
Difference	*6.4*	*1.0*	*0.0*	*0.0*	*0.0*	***7.4***

In total, it is $7.4 million more than the amount we proposed in January. This is caused by a delay to the Mudgee project.

4.6.3 Connection driven capital expenditure

Overview

This part of the augmentation capital expenditure forecast is to manage constraints created by large new customer connections.

The forecasting process involved identifying the possible impacts of a number of known potential industrial and resource extraction loads which were not included in other forecasts. We have forecast the costs of managing the four identified constraints and reduced it by 40 per cent to reflect the uncertainty around the connections. This means that TransGrid has shared the risk – it will still need to manage the constraints if a majority of these loads connect.

AER assessment

The AER reduced connection driven expenditure from $36.0 million to $7.5 million, a reduction of 79%. It considers that the forecast expenditure does not reflect a realistic demand forecast as:

- Past connection-related investment provides a more realistic basis for the forecast
- It has different views on the likelihood of the specific new connections the forecast is based on.

Response

The AER is correct that there is uncertainty. However, it is TransGrid's view that it is unreasonable to use past connection-related investment as an indicator of future needs. A prudent TNSP would consider the possible impacts in light of available forward looking information and these large, diversely located spot loads are not covered in historic trends.

That is why we have applied a reduced probability-weighted forecast - balancing the costs of managing the potential constraints with the need to connect the new loads, if they eventuate. Consultation with our stakeholders about this revised proposal, suggests there is a high level of support for this type of approach when there is uncertainty. It is our view that many of the 19 possible connections will connect and some expenditure will be required. New information suggests that some of these have become more likely since January 2017.

Each constraint area is discussed in turn below.

Beryl area constraint

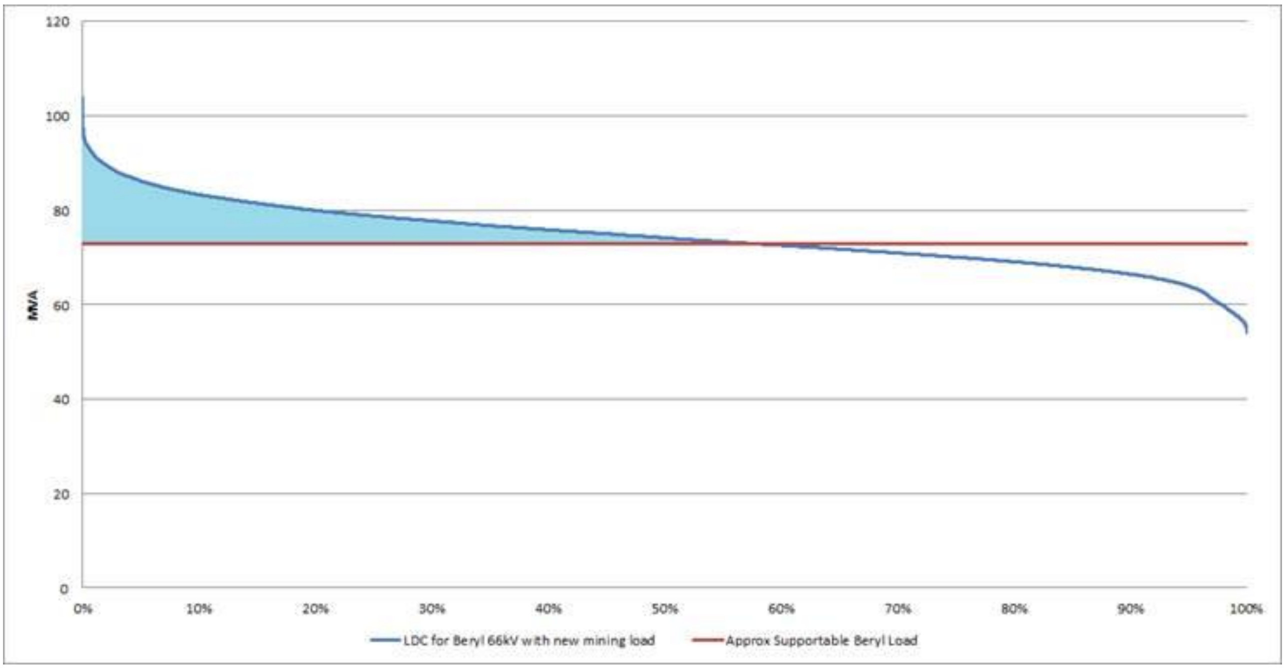
The constraint is the potential for voltage collapse following a trip of Line 94B, once Bowden's silver mine and another identified coal mine are added to the existing load.

In August 2017, Bowden's silver mine submitted a connection enquiry to TransGrid. Its development approval has also progressed further – the specification for its Environmental Impact Statement (EIS) is finalised and the EIS is expected to be exhibited in early 2018. [49]

In response to the AER comments about the analysis method:

- The calculated cost of unserved energy does not assume a trip has to occur at the peak time. This is not the assumption – as indicated in Figure 4.19, the load will be above the supportable level for 60% of the year with both mines connected. Even with Bowden's silver mine only, there is potential for a constraint.

Figure 4.19: Beryl load duration curve showing the 'supportable' demand level



- The 10MVAr expected reactive shortage noted by the AER is a calculated reactive margin for the Beryl busbar as recommended under the Rules support shortfall. It is not the shortfall
- Static reactive support is not a viable solution – reactive compensation already in place means the network is very sensitive to voltage instability. More static reactive support would worsen this
- A network support service is not viable. Load curtailment is not one hour per year. As indicated above, it would be around 4,500 hours per year
- The options considered focused on dynamic reactive support – 35MVAr is insufficient and the option for 50MVAr of support cost is only marginally higher than for 40MVAr. This is currently preferred, as it allows for future growth.

In summary, TransGrid considers that its analysis of the Beryl area constraint is valid and the option used for the forecast is efficient. One of the mining loads has progressed to the point where a connection enquiry has been submitted. This constraint is more likely than it was in January 2018.

[49] https://bowdenssilver.com.au/environmental-impact-statement/

Thermal limitation on 969 line

This constraint will exist if the Shenhua mine connects. Calculations for the January 2017 proposal showed that there was enough capacity for 20 to 25MW of mine load. However, the latest demand forecasts for Gunnedah and Narrabri have increased significantly. Updated analysis shows that only around 10 – 18MW of new mining load could be supported.

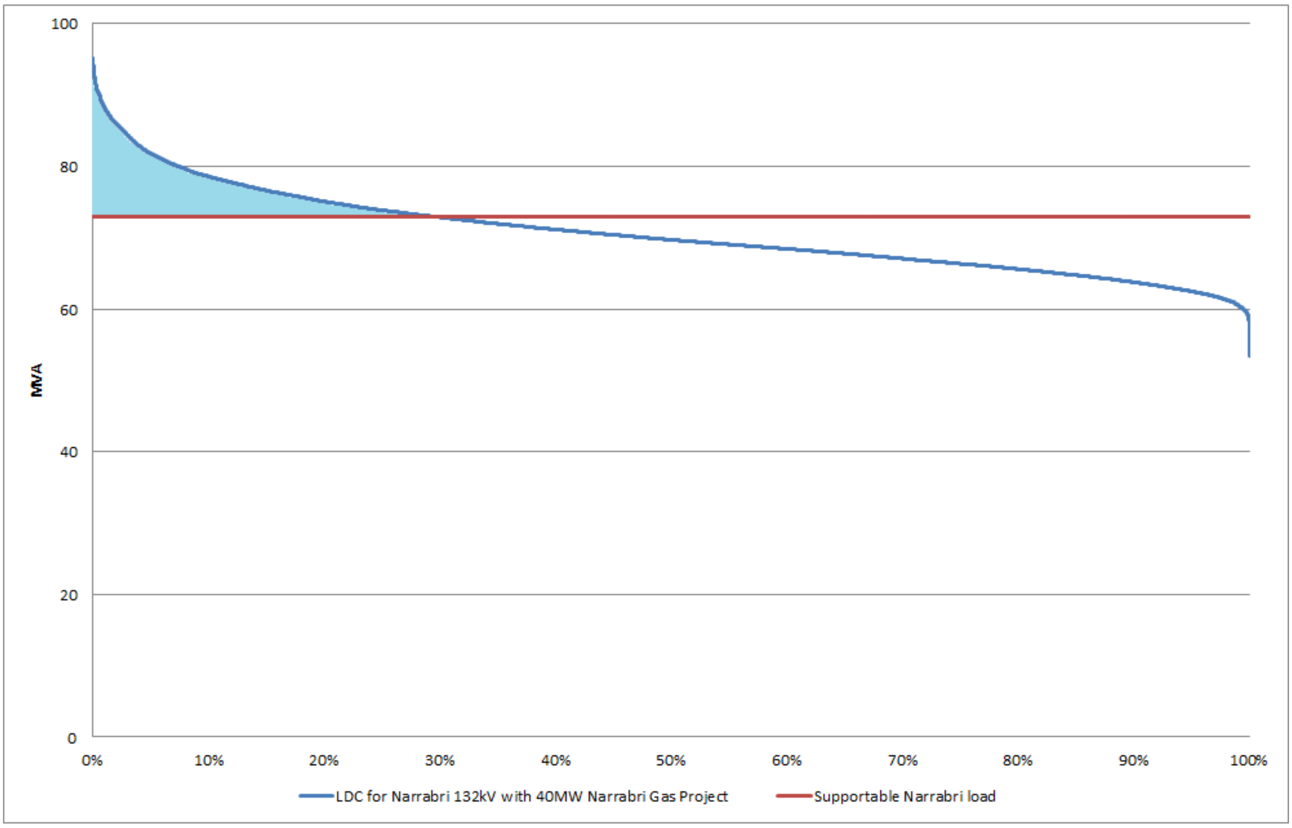
The Shenhua mine is understood to be progressing - in September 2017 it had further discussions with Essential Energy in relation to its connection.

Connection of the Narrabri gas project

The Narrabri gas project will create the potential for voltage collapse at both Narrabri and Gunnedah if either the 968 or the 969 line trips.

The draft decision is not correct in stating that four events need to occur for the constraint to exist. Neither the local load nor the gas plant demand need to be at their peak – the load duration curve in Figure 4.20 shows that the constraint would exist for around 30 per cent of the year (2,500 hours) by 2023. This includes the latest forecast of Narrabri peak load in 2023, which has increased to 55MW from 44MW in the previous forecast.

Figure 4.20: Narrabri load duration curve showing the "supportable" demand level



The only event of consequence is the trip of either the 968 or the 969 lines. Northerly power flows are a worst case scenario but not the only scenario that causes the issue. Both of these lines have had extended outages of 96 hours in the recent past, so the use of the average 132kV feeder restoration time of 24 hours was considered valid. Also, the nature of voltage collapse caused by the trip of these lines means that an outage of the entire Narrabri load is a valid assumption.

We concur with the AER's view that coal seam gas approvals are complex. However, since January 2017, the project's Environment Impact Statement (EIS) was exhibited and submissions are under review. The project is considered more likely than it was in January 2017.

Strengthening Far West NSW network

This constraint will exist when the Hawsons Iron Project connects near Broken Hill. The connection creates the potential for a non-compliant transient voltage if the mine trips when local loads are low. The AER's view is that six events need to coincide for the problem to occur.

The first is the trip described above and the remaining five are inter-related. It is reasonable to expect that these could coincide, as some are related to the same mining load and the others occur for a majority of the time. In relation to these, we note that:

- A high flow on the X2 line would coincide with the trip of the mine, as this high flow will be caused by supplying this mining load
- A trip of the entire mine load is viable as there is likely to be one point of failure at the mining substation transformer, and two circuit breakers that connect it to a TransGrid site which can cause the whole load to trip
- Mining loads are typically flat, so assuming it is at (or close to) maximum is a reasonable assumption
- The gas turbines at Broken Hill are normally not operating
- The Broken Hill Solar Farm is semi-scheduled intermittent generation so cannot be relied upon at all times.

The planning undertaken assumed typical mining site load patterns and more detailed analysis would be completed as part of responding to the constraint in reality. However, analysis shows that the maximum supportable load on the X2 line is around 60MW to remain within the Rule requirements. This is around 50MW less demand than the mine site originally nominated for the feasibility study. Further, TransGrid has an obligation to ensure it has sufficient network capability to meet the new mines' demand while complying with Rule clause S5.1a.4 pertaining to Power Frequency Voltage levels, under light load and transient conditions.

It is TransGrid's view that its analysis in relation to this possible constraint remains valid and this problem is a real possibility if the mine connects.

TransGrid is open to demand management and non-network solutions but these can have limited application in managing dynamic voltage swings in these circumstances. In the event that the issue at Broken Hill eventuates, we will consider both network and non-network solutions. Should a non-network solution be the most economic option, TransGrid will treat this as a network support pass-through under Clause 6A.7.2 of the Rules.

TransGrid proposes a network support payment for Broken Hill in each year of the regulatory control period of $0 million. As we noted in the Revenue Proposal, this appears superfluous with no dollar value. However, this provides access a network support pass-through payment if network support is required. Should no requirement for network support eventuate during the regulatory control period, there will be no cost to consumers.

Updated forecast

An updated forecast for connection driven expenditure is shown in Table 4.19.

Table 4.19: Connection driven capital expenditure

Connection driven expenditure	2018–19	2019-20	2020–21	2021–22	2022–23	Total
Original proposal	5.4	16.5	10.9	0.9	2.3	**36.0**
Revised proposal	3.8	18.8	10.8	0.8	2.3	**36.5**
Difference	*-1.6*	*2.3*	*-0.1*	*0.0*	*0.0*	**0.5**

This is $0.5 million higher than in our original proposal due to a minor change in the timing for Strengthening Far West NSW network project and Connection of the Narrabri gas project.

It is important to note that this forecast for connection driven expenditure balances the costs to consumers but includes some risk for TransGrid. The forecast capital expenditure is 60 per cent of the amount we estimate is required to manage all the above constraints.

4.6.4 Localised demand driven capital expenditure

Overview

This area of the forecast is driven by known demand growth which is requiring the development of new distribution connection points for brand new suburbs (mainly in Sydney's North West and South West Growth centres). These circumstances are well suited for joint planning – in this case, TransGrid and Endeavour Energy have worked together to find the most efficient combination of transmission and distribution infrastructure to meet the need. For example, creation of a new transmission connection point can remove the need for new or uprated distribution feeders.

AER assessment

AER rejected a component of one project which was the result of joint planning with Endeavour Energy.

It appears that the information provided by Endeavour relating to the need for a new switch bay at Macarthur was misinterpreted from a complex options analysis.

> We note that the proposed new switch-bay at Macarthur facilitates Endeavour Energy's plan to duplicate the Macarthur-Ambarvale 66 kV line (line 853) to accommodate the future load growth. Notably, Endeavour Energy's annual planning report shows that line 853 will have 11MVA spare capacity by 2021. (Draft Decision 6-128)

Response

The need for the switch bay has been confirmed. It is required to provide supply to Menangle Park Zone Substation which will service new residential connections. It is not intended to facilitate duplication of the Macarthur – Ambarvale 66kV line 853.

This is the most efficient option, as alternative supply for Menangle Park Zone Substation would be multiple 11kV augmentations. The Macarthur Supply Point is only 2km from the Menangle Park site and the new switch bay will facilitate the connection via a 66kV feeder.

Updated forecast

An updated forecast for localised demand driven expenditure is shown in Table 4.20.

Table 4.20: Localised demand driven capital expenditure forecast ($m June18)

Localised demand driven expenditure	2018–19	2019-20	2020–21	2021–22	2022–23	Total
Original proposal	2.6	2.4	2.9	6.3	6.7	**21.0**
Revised proposal	1.2	2.2	2.9	7.7	6.8	**20.7**
Difference	-1.5	-0.2	0.0	1.4	0.1	**-0.3**

In total, it is $0.3 million less than the amount we proposed in January. The difference is the result of a minor cost adjustment.

4.6.5 Revised total augmentation (ex-PSF) capital expenditure forecast

The updated forecast for all of the augmentation (ex-PSF) expenditure is shown in Table 4.21.

Table 4.21: Augmentation (ex-PSF) capital expenditure ($m June18)

Augmentation (ex-PSF) expenditure	2018–19	2019-20	2020–21	2021–22	2022–23	Total
Original proposal	26.5	59.7	40.5	14.5	19.5	**160.8**
Revised proposal	35.0	69.8	43.1	18.3	20.4	**186.6**
Difference	8.5	10.1	2.6	3.8	0.9	**25.8**

In total, it is $25.8 million higher than our original proposal. This is largely due to the addition of the projects which were not eligible for the NCIPAP allowance.

4.7 IT expenditure

Overview

Information Technology (IT) expenditure is included in the “Non-network” category by the AER, alongside other business support expenditure. The draft decision recommended a $21.1 million reduction to the forecast IT expenditure only, with a new total of $81.8 million (-20%). Other expenditure in the “Non-network” category was unchanged.

AER assessment

The AER concluded that the forecast was not well justified and raised concerns with the IT project risk assessments and lack of justification for increases in capability and IT/OT strategy.

In terms of investment analysis, the AER considered that:

- The options analysis was inadequate
- There was “double counting” in parts of the risk analysis and risk costs were not appropriate
- Efficiency benefits had inappropriately been included
- “Bundling” of risk assessments made it harder to review components of programs.

The AER also considered that

- A prudent TNSP would extend the asset life of software assets beyond the “standard life”
- The proposed costs for meeting the NSW Licence Conditions were not justified.

Response – investment analysis approach

In light of the AER's comments, TransGrid reviewed and amended its approach to investment analysis for the IT portfolio. The revised approach:

> Uses a new risk model which is more appropriately aligned to IT requirements and is more transparent for a reviewer
> Includes options analysis for all programs. This now includes consideration of a base case (replacing asset as planned), a two year delay (ie, a life extension) and a five year delay
> Includes updated risk assumptions, including the removal of efficiency benefits and revised risk impacts which the AER was concerned might be double counted.

The investment analysis now considers the options of delaying each program by two and five years. TransGrid generally assumes that software assets have a five year lifetime, in line with accounting treatment. We agree that it is not prudent to automatically replace a system or software after five years - the trigger for replacement or upgrade depends on a risk analysis.

The option analysis takes account of the increased risk of running software past this lifetime. It takes into account:

> Increased risk of failures and poor performance
> Cyber security risks, which increase once software is no longer supported. The impacts of these could include high costs, data breaches, non-compliance and in worse cases, network asset impacts
> Higher ongoing support costs. Based on our experience with the current ERP, we have assumed an increase of 20 per cent per year for the first two years of "out-of-support" delay. After two years, we have assumed that this increase is 40 per cent. At this point, it is less likely that vendor support is available so some reliance on specialist third parties is expected
> Higher costs when upgrades are completed later – due to more complex data migration, the need to manage compatibility with interacting systems and to implement more significant changes in the organisation.

Each program investment analysis now includes three options:

> Option A – Replace current systems at end of asset life
> Option B – Extend the asset life of current systems by 2 years then replace
> Option C – Extend the asset life of current systems by 5 years then replace.

Updated investment analysis is now detailed in the Options Evaluation Reports for each of the IT programs.

Response – cyber security increase

The significant increase in the volume and sophistication of cyber-attacks against the electricity industry drives the need to enhance the capability in detecting and countering these. Our revenue proposal in January 2017 included a program to address this.

Since January 2017 it has become clear that compliance with our Licence Conditions requires additional capability with a consequent increase of $2.5 million in the "Pervasive Security" program.

The Licence requires TransGrid to ensure that:

> The transmission system can only be operated and controlled from within Australia (condition 6.1(b))

> Data on the quantum of electricity delivered and personal information is accessible only from within Australia (conditions 7.1(a) and (b)).

Compliance also requires an enhanced monitoring and event logging capability to identify changes in vulnerabilities and abnormal data network traffic.

Other changes to the forecast

There have been other changes to programs within the forecast. Items of scope which were previously justified on the basis of efficiency savings have been removed. These have been offset by increases in the Pervasive Security program (discussed above) and an increase in the Digital Enterprise program. Table 4.22 shows the changes in each of the eight programs.

Table 4.22: changes in the IT capital expenditure forecast ($m June18)

Program	Updated estimate ($m)	Change ($m)	Reason
Digital Enterprise	38.5	1.3	Forecast ERP implementation cost reduced slightly following recent market analysis. The integration platform scope was transferred in to better align the work program. Scope items transferred to Information Infrastructure Refresh for greater program alignment[50]
Digital Field Force	6.3	-2.6	Efficiency-driven scope items have been removed
Intelligent Operations Centre	7.3	-3.1	Integration platform scope transferred to Digital Enterprise "Asset monitoring and predictive analytics" items (previously based on efficiency savings) were removed
Intelligent Asset Design	2.6	-0.5	Efficiency-driven scope item has been removed
Pervasive Security	10.1	2.5	Increase to support data protection license requirements
Enterprise Analytics Platform	7.6	-0.8	Efficiency-driven "KPI dashboards" scope was removed Following updated market analysis implementation costs for enterprise content management increased slightly
Information Infrastructure Refresh	18.1	2.5	Scope items on power system analysis, workflow management and integrated service delivery added for greater program alignment
Corporate Data Network Refresh	11.6	0.0	No change
Total	**102.2**[51]	**-0.5**	

[50] Items relate to power system analysis, workflow management and integrated service delivery

[51] Table entries sum to $102.1 million. The difference of $0.1 million is expenditure on a program continuing from 2017/18

Updated Information Technology forecast

The updated IT capital forecast showing in Table 4.23 is $102.2 million, $0.5 million lower than our original proposal.

Table 4.23: Information Technology capital expenditure forecast ($m June18)

IT expenditure	2018/19	2019/20	2020/21	2021/22	2022/23	Total
Original proposal	13.8	28.4	28.0	14.9	17.6	**102.7**
Revised proposal	28.6	28.5	7.7	20.0	17.5	**102.2**
Difference	*14.8*	*0.0*	*-20.4*	*5.1*	*-0.1*	***-0.5***

4.8 Contingent projects

4.8.1 Overview

TransGrid proposed five contingent projects in January 2017. The AER was satisfied that these might reasonably be required if certain events occurred but it suggested changes to the trigger events. We have reviewed these and have updated our triggers in response.

We have also made additional updates to the triggers in response to changes in the sector. We notified the AER of these in August 2017.

Also in response to the rapidly changing circumstances, this revised proposal includes a further four contingent projects. We notified the AER about three of these in August 2017, while the potential need for the fourth only became apparent after that.

These four new projects and the revisions to the triggers of the original five reflect:

> The possibility that a new pathway for transmission investment may be developed
> The possibility that some projects have potential reliability triggers as well as market benefits triggers.

These are described in turn below.

Possible new method of initiating transmission investment

The ongoing policy and regulatory reform which followed the endorsement of the Finkel Review recommendations could create a new method (or methods) for the initiation of transmission investment.

The possible changes are mainly reflected in two Finkel Review recommendations (5.1 and 5.2)[52] which can be summarised as:

> AEMO is to develop an integrated grid plan to identify efficient locations for renewable energy zones and subsequently to identify potential priority transmission projects to facilitate the connection of these
> Specifying a potential role for governments in supporting specific transmission investments, if the market does not deliver. This would be supported by a rigorous framework of project evaluation, to be developed by the AEMC. The intention was that this process minimises the risk to consumers of

[52] Independent Review into the Future Security of the National Electricity Market, Blueprint for the Future, June 2017. Covered on pages 124 to 127

bearing unnecessary cost. It is possible that this could be separate from, or an alternate to the RIT-T process.

AEMO's first Integrated Plan is in development and is expected to be released in mid-2018. TransGrid and other TNSPs are providing AEMO with detailed information to assist development of the plan.

Reliability corrective action

A 'reliability corrective action' is an investment to meet the service standards related to technical requirements in schedule 5.1 of the National Electricity Rules (NER) or in another 'applicable regulatory instrument', such as a jurisdictional transmission licence.

A reliability corrective action investment can still be justified with a negative net economic benefit (ie, a net cost) and this is reflected in the requirements of the RIT-T. An example of an investment to comply with schedule 5.1 of the Rules could be one which manages a voltage constraint. The inclusion of "reliability corrective action" triggers for these contingent projects reflects the need to comply with the NSW Electricity Transmission Reliability and Performance Standard 2017. This trigger is most likely to occur for the Broken Hill project.

Commitment to work with the AER

The updated triggers and four new contingent projects have been written to reflect the possible new transmission investment initiation mechanism and the possibility of projects having reliability as well as market led triggers.

TransGrid understands that the uncertainty around the investment mechanism complicates the AER's assessment but we are committed to a continued dialogue with the AER should further information or refinement be required.

4.8.2 AER assessment and our response on the original five contingent projects

TransGrid proposed the following five contingent projects in January 2017:

- New South Wales to South Australia Interconnector
- Reinforcement of Southern Network
- Reinforcement of Northern Network (QNI upgrade)
- Support of South Western NSW for Renewables
- Supply to Broken Hill.

Background information and supporting documentation for these five contingent projects was provided in the Revenue Proposal. To avoid repetition, general project information is not covered again.

This section presents only amended triggers and cost ranges for the five contingent projects proposed in January 2017. The new triggers are largely in line with the AER's suggestions.

New South Wales to South Australia Interconnector – revised trigger

Having reviewed the AER's suggested wording, TransGrid proposes the following updated trigger:

(a) Two or more of the following:
   (i) Inclusion of interconnection between NSW and South Australia in AEMO's Integrated Grid Plan or similar plan as recommended by the Independent Review in to the Future Security of the National Electricity Market by Professor Alan Finkel and accepted by the COAG Energy Council

(ii) Notification to TransGrid by the Federal Government, COAG Energy Council, NSW Government, South Australia Government or the Energy Security Board that it considers that interconnection between NSW and South Australia is required in order to meet or manage the expected demand for prescribed transmission services or comply with an applicable regulatory obligation or requirement associated with the provision of prescribed transmission services

(iii) Successful completion of a RIT-T or alternate framework introduced in response to the recommendation of the Independent Review in to the Future Security of the National Electricity Market by Professor Alan Finkel and accepted by the COAG Energy Council (including comprehensive assessment of alternative options) demonstrating that:

  (A) new interconnection between NSW and South Australia is the option or part of the option that maximises the positive net economic benefits; or

  (B) new interconnection is the option that most cost effectively addresses system security issues

(iv) Determination by the AER that the proposed investment satisfies the RIT-T or abovementioned alternate framework

(b) TransGrid Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.

The AER's suggested trigger is slightly modified by the addition of the system security objective.

The NSW component of the project has a cost estimate ranging between $276 million (low capacity) to $1,074 million (high capacity) depending on the option. The cost estimate exceeds the applicable contingent project threshold of $30 million or 5% of MAR.

Reinforcement of Southern Network – revised trigger

Taking into account the AER's draft decision, TransGrid proposes the following updated trigger:

(a) New generation of more than 350 MW is committed in southern NSW at any current or future connection point(s) south of Bannaby and Marulan or NSW import capacity from Southern Interconnectors is determined to be increased by more than 350 MW due to committed expansion of southern interconnections.

(b) Two or more of the following:

  (i) Inclusion of renewable energy zones in Southern NSW and/or Northern Victoria in AEMO's Integrated Grid Plan or similar plan as recommended by the Independent Review in to the Future Security of the National Electricity Market by Professor Alan Finkel and accepted by the COAG Energy Council

  (ii) Notification to TransGrid by the Federal Government, COAG Energy Council, NSW Government, Victorian Government or the Energy Security Board that it considers that augmentation of the transmission network to deliver increased capacity from Southern NSW and/or Northern Victoria is required in order to meet or manage the expected demand for prescribed transmission services or comply with an applicable regulatory obligation or requirement associated with the provision of prescribed transmission services

  (iii) Successful completion of a RIT-T or alternate framework introduced in response to the recommendation of the Independent Review in to the Future Security of the National Electricity Market by Professor Alan Finkel and accepted by the COAG Energy Council (including comprehensive assessment of alternative options) demonstrating that increasing the capacity of the network in Southern NSW at 330/132kV or other voltages used in future is the option that maximises the positive net economic benefits

(c) Determination by the AER that the proposed investment satisfies the RIT-T or abovementioned alternate framework

(d) TransGrid Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.

The project has a cost estimate ranging between $60 million to $393 million, which exceeds the applicable contingent project threshold of $30 million or 5% of MAR.

Reinforcement of Northern Network (QNI upgrade)

Having reviewed the AER's suggested wording, TransGrid proposes the following updated trigger:

(a) One or more of the following:
    (i) Committed retirement of more than 1,100 MW of generation in the Hunter or Central Coast area
    (ii) New generation of more than 1,100 MW is committed in northern NSW at any current or future connection point(s) north of Armidale
    (iii) New generation of more than 350 MW is committed at any current or future connection point(s) south of Liddell and Bayswater

(b) Two or more of the following:
    (i) Inclusion of an augmentation to increase the capacity of the interconnection between NSW and Queensland in AEMO's Integrated Grid Plan or similar plan as recommended by the Independent Review in to the Future Security of the National Electricity Market by Professor Alan Finkel and accepted by the COAG Energy Council
    (ii) Notification to TransGrid by the Federal Government, COAG Energy Council, NSW Government, Queensland Government or the Energy Security Board that it considers that augmentation of the transmission network to increase the capacity of the interconnection between NSW and Queensland is required in order to meet or manage the expected demand for prescribed transmission services or comply with an applicable regulatory obligation or requirement associated with the provision of prescribed transmission services
    (iii) Successful completion of a RIT-T or alternate framework introduced in response to the recommendation of the Independent Review in to the Future Security of the National Electricity Market by Professor Alan Finkel and accepted by the COAG Energy Council (including comprehensive assessment of credible options) demonstrating that increasing capacity of the network between Bulli Creek and Liddell zones at 330/132kV or other voltages used in future is the option or part of the option that maximises the positive net economic benefits
    (iv) Determination by the AER that the proposed investment satisfies the RIT-T or abovementioned alternate framework

(c) TransGrid Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.

The project has a cost estimate ranging between $63 million to $141 million, which exceeds the applicable contingent project threshold of $30 million or 5% of MAR.

Support of South Western NSW for Renewables

Taking into account the AER's draft decision, TransGrid proposes the following updated trigger:

(a) One or more of the following:
    (i) New generation more than 400 MW is committed in South Western NSW (west of Wagga)
    (ii) New generation is committed in North West Victoria:

(A) exceeding 800 MW for connection to the Ballarat - Waubra - Ararat - Horsham 220 kV Lines or connection point(s); and/or

(B) exceeding 200 MW for connection to the Redcliffs – Weman – Kerang 220 kV Lines or connection point(s); and/or

(C) exceeding 500 MW for connection to the Ballarat – Terang – Moorabool 220 kV Lines or connection point(s); and/or

(D) exceeding 1,500 MW in the North West Victoria zone

(b) Two or more of the following:

(i) Inclusion of renewable energy zones in South Western NSW and/or North Western Victoria in AEMO's Integrated Grid Plan or similar plan as recommended by the Independent Review in to the Future Security of the National Electricity Market by Professor Alan Finkel and accepted by the COAG Energy Council

(ii) Notification to TransGrid by the Federal Government, COAG Energy Council, NSW Government, Victorian Government or the Energy Security Board that it considers that augmentation of the transmission network to deliver increased capacity from South Western NSW and/or North Western Victoria is required in order to meet or manage the expected demand for prescribed transmission services or comply with an applicable regulatory obligation or requirement associated with the provision of prescribed transmission services

(iii) Successful completion of a RIT-T or alternate framework introduced in response to the recommendation of the Independent Review in to the Future Security of the National Electricity Market by Professor Alan Finkel and accepted by the COAG Energy Council (including comprehensive assessment of credible options) demonstrating that increasing capacity of the network in South Western NSW at 330/220/132kV or other voltages used in future is the option that maximises the positive net economic benefits

(iv) Determination by the AER that the proposed investment satisfies the RIT-T or abovementioned alternate framework

(c) Where the optimal solution involves works in NSW and Victoria, successful completion of joint planning obligations under the NER demonstrating that strengthening the high voltage interconnection between New South Wales and Victoria is the option that maximises the positive net economic benefits

(d) TransGrid Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.

The project has a cost estimate ranging between $89 million to $470 million, which exceeds the applicable contingent project threshold of $30 million or 5% of MAR.

Supply to Broken Hill

Taking into account the AER's draft decision, TransGrid proposes the following updated trigger:

(a) Notification from Essential Energy of available capacity of backup generation at Broken Hill that would result in expected unserved energy exceeding 10 minutes at average demand

(b) Either:

(i) Where the investment is driven by market benefits:

(A) Successful completion of the RIT-T (including a comprehensive assessment of the credible options) that demonstrates a network investment by TransGrid maximises the market benefits while meeting reliability of supply obligations to the Broken Hill area

(B) Determination by the AER that the proposed investment satisfies the RIT-T; or

(ii) Where the investment is driven by a need for reliability corrective action that emerges during TransGrid's 2018-2023 regulatory control period, successful completion of economic evaluation demonstrating that a network investment is the most efficient option to meet the applicable electricity transmission reliability standard

(c) TransGrid Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.

The project has a cost estimate ranging between $52 million to $177 million, which exceeds the applicable contingent project threshold of $30 million or 5% of MAR.

4.8.3 New contingent projects

In total there are four new contingent projects, three are related to renewable energy generation zones and one is for the proposed Snowy Hydro upgrade. Three of these were foreshadowed to the AER in a letter on 22 August 2017.

The new contingent projects are:

> Reinforcement of Southern Network in response to Snowy 2.0
> Support Central Western NSW for Renewables
> Support North Western NSW for Renewables
> Renewables development in the Mt Piper to Wellington area.

These projects and their associated triggers are described below.

4.8.4 Reinforcement of Southern Network in response to Snowy 2.0

Background

The Federal Government's announcement of the Snowy 2.0 expansion occurred after the submission of TransGrid's revenue proposal. TransGrid's revenue proposal included "Reinforcement of Southern Network" as a contingent project but the scale of this is not sufficient to accommodate the transmission augmentation required to connect Snowy 2.0.

As the timing and exact requirements of the augmentation are not yet known it is appropriate to treat this as a contingent project, rather than incorporating it into the ex-ante capital expenditure forecast.

As noted in section 4.8.1, there is some uncertainty about the exact process for investment in the transmission network to support Snowy 2.0. We have therefore included a description of potential trigger mechanisms which may eventuate from ongoing policy and regulatory reform.

TransGrid anticipates that transmission investment to enable the output from Snowy 2.0 will form part of AEMO's inaugural integrated grid plan which is due by mid-2018.

Driver of investment

It is likely that there will be market benefits from transmission to connect the new Snowy 2.0, including:

> Lower costs associated with meeting the supply reliability standard in NSW, through facilitating access to the output from expanded Snowy 2.0 generation
> A reduction in the risk of blackouts (and therefore unserved energy) at times where demand is high and the output from renewable generators is low, such as occurred in the summer of 2016/17
> Lower market dispatch costs (and hence lower prices for consumers) resulting from the additional output from Snowy 2.0 and the facilitation of additional output from new renewable generators.

Project trigger

TransGrid proposes the following trigger to augment the Southern Network if a commitment is made to build Snowy 2.0:

(a) Notification from Snowy Hydro that its Board has made a final investment decision to proceed with Snowy 2.0

(b) Two or more of the following:

  (i) Inclusion of the Snowy 2.0 transmission augmentation in AEMO's Integrated Grid Plan or similar plan as recommended by the Independent Review in to the Future Security of the National Electricity Market by Professor Alan Finkel and accepted by the COAG Energy Council

  (ii) Notification to TransGrid by the Federal Government, COAG Energy Council, NSW Government, Victorian Government or the Energy Security Board that it considers that augmentation of the transmission network to deliver increased output from Snowy 2.0 is required in order to meet or manage the expected demand for prescribed transmission services or comply with an applicable regulatory obligation or requirement associated with the provision of prescribed transmission services

  (iii) Successful completion of a RIT-T or alternate framework introduced in response to the recommendation of the Independent Review in to the Future Security of the National Electricity Market by Professor Alan Finkel and accepted by the COAG Energy Council (including comprehensive assessment of credible options) demonstrating that a Snowy 2.0 transmission augmentation is the option that maximises the positive net economic benefits

  (iv) Determination by the AER that the proposed investment satisfies the RIT-T or abovementioned alternate framework

(c) TransGrid Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.

The trigger is specific and capable of objective verification, relates to a specific location or locations, and is probable but too uncertain to include the proposed contingent project in the forecast capital expenditure in this proposal.

The project has a cost estimate ranging between $831 million to $1,228 million, which exceeds the applicable contingent project threshold of $30 million or 5% of MAR.

4.8.5 Support Central Western NSW for Renewables

Background

TransGrid has interest from renewable energy proponents seeking to connect to its network in South Western New South Wales. It is possible that South Western New South Wales will be identified as a renewable energy zone in AEMO's integrated grid plan.

This network impacted is around the Wellington area. It is a parallel network of 132 kV and 330 kV lines connecting to the 500 kV substations at Mt Piper and Wollar.

There is around 150 MW of generation currently connected in the area. A further 230 MW of new generation is committed and more than 400 MW of capacity is well advanced. As the timing and exact requirements of the augmentation are not yet known it is appropriate to treat this as a contingent project, rather than incorporating it into the ex-ante capital expenditure forecast.

Driver of investment

If transmission constraints are addressed, it is anticipated that new generator connections in Central Western NSW would deliver market benefits. Sources of benefits include:

> Lower costs for meeting the supply reliability standard in New South Wales, through facilitating access to the output from these generation connections
> Lower market dispatch costs (and hence lower prices for consumers) assuming these are low cost generators.

As noted in section 4.8.1, there is some uncertainty about the exact process for investments which facilitate renewable energy zones. We have therefore included a description of potential trigger mechanisms which may eventuate from ongoing policy and regulatory reform.

Transmission investment to enable a Central Western NSW renewable energy zone may be identified in AEMO's 2018 integrated grid plan.

Project trigger

TransGrid proposes the following trigger:

(a) New generation more than 900 MW is committed in Central Western NSW (west of Wollar and Mt Piper)
(b) Two or more of the following:
   (i) Inclusion of renewable energy zones in Central Western NSW in AEMO's Integrated Grid Plan or similar plan as recommended by the Independent Review in to the Future Security of the National Electricity Market by Professor Alan Finkel and accepted by the COAG Energy Council
   (ii) Notification to TransGrid by the Federal Government, COAG Energy Council, NSW Government or the Energy Security Board that it considers that augmentation of the transmission network to deliver increased capacity from Central Western NSW is required in order to meet or manage the expected demand for prescribed transmission services or comply with an applicable regulatory obligation or requirement associated with the provision of prescribed transmission services
   (iii) Successful completion of a RIT-T or alternate framework introduced in response to the recommendation of the Independent Review in to the Future Security of the National Electricity Market by Professor Alan Finkel and accepted by the COAG Energy Council (including comprehensive assessment of credible options) demonstrating that increasing capacity of the network in Central Western NSW at 330/132kV or other voltages used in future is the option that maximises the positive net economic benefits
   (iv) Determination by the AER that the proposed investment satisfies the RIT-T or abovementioned alternate framework
(c) TransGrid Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.

The trigger is specific and capable of objective verification, relates to a specific location or locations, and is probable but too uncertain to include the proposed contingent project in the forecast capital expenditure in this proposal.

The project has a cost estimate ranging between $120 million to $455 million, which exceeds the applicable contingent project threshold of $30 million or 5% of MAR.

4.8.6 Support North Western NSW for Renewables

Background

TransGrid has received applications for a number of generator connections to the North Western NSW transmission system.

Some of these projects are proposed to connect to the 132 kV and 66 kV network, increasing the power flow from the local 132 kV network to 330 kV network. One generator of 170 MW is partially commissioned and other well advanced projects have a total capacity of 280 MW.

Connections directly to the 330 kV network are also expected. There is 270 MW of committed generation capacity and 200 MW at an advanced stage of development. There is little spare capacity on this part of the 330 kV network.

Across this whole network area, a further 1,000MW of generation capacity has expressed interest in connecting.

Driver of investment

If transmission constraints are addressed, it is anticipated that new generator connections in North Western NSW would deliver market benefits. Sources of benefits include:

- Lower costs for meeting the supply reliability standard in New South Wales, through facilitating access to the output from these generation connections
- Lower market dispatch costs (and hence lower prices for consumers) assuming these are low cost generators.

Project trigger

The proposed trigger is:

(a) New generation more than 800 MW is committed in North Western NSW (north of Bayswater and Liddell)

(b) Two or more of the following:

  (i) Inclusion of renewable energy zones in North Western NSW in AEMO's Integrated Grid Plan or similar plan as recommended by the Independent Review in to the Future Security of the National Electricity Market by Professor Alan Finkel and accepted by the COAG Energy Council

  (ii) Notification to TransGrid by the Federal Government, COAG Energy Council, NSW Government or the Energy Security Board that it considers that augmentation of the transmission network to deliver increased capacity from North Western NSW is required in order to meet or manage the expected demand for prescribed transmission services or comply with an applicable regulatory obligation or requirement associated with the provision of prescribed transmission services

  (iii) Successful completion of a RIT-T or alternate framework introduced in response to the recommendation of the Independent Review in to the Future Security of the National Electricity Market by Professor Alan Finkel and accepted by the COAG Energy Council (including comprehensive assessment of credible options) demonstrating that increasing capacity of the network in North Western NSW at 330/132kV or other voltages used in future is the option that maximises the positive net economic benefits

  (iv) Determination by the AER that the proposed investment satisfies the RIT-T or abovementioned alternate framework

(c) TransGrid Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.

The trigger is specific and capable of objective verification, relates to a specific location or locations, and is probable but too uncertain to include the proposed contingent project in the forecast capital expenditure in this proposal.

The project has a cost estimate ranging between $500 million to $945 million, which exceeds the applicable contingent project threshold of $30 million or 5% of MAR.

4.8.7 Renewables development in the Mt Piper to Wellington area

Background

There is strong interest from at least three renewable energy proponents seeking to connect to the 132 kV network between Mt Piper and Wellington in New South Wales.

The three generation connections have a total combined capacity of around 360MW. The project proponents and their details are confidential (although they can be made available to the AER). Of the three, one is committed (it has signed a Connection Agreement) and the others are at advanced development stages but are not yet committed.

Driver of investment

If all three of these renewable generators connect, their outputs will be constrained under system normal conditions to maintain the transmission network within acceptable limits. The constraint is due to the thermal rating of the network and it will limit the ability to transfer power out of the area. Initial market modelling indicates there would be net market benefits from augmenting the transmission network to provide additional capacity.

Project trigger

TransGrid proposes a new contingent project to support these and future renewables. The proposed trigger is:

(a) New generation more than 150 MW is committed in Mt Piper to Wellington area

(b) Successful completion of a RIT-T or alternate framework introduced in response to the recommendation of the Independent Review in to the Future Security of the National Electricity Market by Professor Alan Finkel and accepted by the COAG Energy Council (including comprehensive assessment of credible options) demonstrating that increasing capacity of the network between Mt Piper and Wellington at 132kV or other voltages used in future is the option that maximises the positive net economic benefits

(c) Determination by the AER that the proposed investment satisfies the RIT-T or abovementioned alternate framework

(d) TransGrid Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.

The trigger is specific and capable of objective verification, relates to a specific location or locations, and is probable but too uncertain to include the proposed contingent project in the forecast capital expenditure in this proposal.

The estimated project cost is $36.8 million, which is expected to exceed the applicable contingent project threshold of 5% of MAR[53].

4.9 Network support events

The AEMC's *System Security Market Frameworks Review Final Report* led to Rule changes which place significant new responsibilities on transmission networks to procure solutions which manage system security.

The two Rule changes were:

> Managing power system fault levels (system strength) – to address potential shortfalls in fault levels as large synchronous generators retire

> Managing the rate of change of power system frequency - to address potential shortfalls in inertia within potential network islands, especially as large synchronous generators are replaced by generation with low physical inertia.

These Rules have been established to allow material costs to be passed through to customers, either via the general pass-through provisions of clause 6A.7.3 or via the network support pass through provisions of clause 6A.7.2 of the Rules.

At this point, TransGrid does not expect there to be an increase in cost related to these new services but it will seek to recover costs if this changes within the 2018/19 to 2022/23 period.

4.10 Network Support and Control Ancillary Service

Background

TransGrid currently provides Network Support and Control Ancillary Service (NSCAS) for voltage control based on a contract executed with AEMO in 2013. Currently, this is a non-prescribed service and the related reactor assets are not part of the regulatory asset base (RAB).

The contract was put in place after new Rules relating to NSCAS commenced in April 2012.[54]

These require TNSPs to respond to an 'NSCAS gap' identified by AEMO. TNSPs can put in place an operational or asset based solution or can procure the service directly. NSCAS is then treated as a prescribed service, with revenue recovered depending on the solution in place.

Network Support and Control Ancillary Services (NSCAS)

NSCAS are non-market ancillary services which:

- maintain system security and reliability
- maintain or increase the transfer capability of the transmission network, where this is beneficial.

For example, NSCAS can increase the power flow on an interconnector. If lower cost electricity can flow into a region with higher market prices, consumers will benefit.

There are various types of NSCAS. TransGrid provides a Voltage Control Ancillary Service (VCAS) which can be provided by generators or network plant.

However, after the implementation of these Rules in 2012 there was insufficient time for TransGrid to undertake a RIT-T for an NSCAS gap identified from July 2013.[55] In line with the Rules, AEMO then ran an open tender process to procure the service from the lowest cost source.

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[53] When $36.8 million is converted to a nominal amount ($39.9 million), it is higher than 5% of the first year MAR in this revised proposal (around 38.5 million)

[54] The Network Support and Control Ancillary Services rule (ERC0108) became live on 5 April 2012. However, the process for procuring this particular service was already in progress so the existing process applied.

[55] 'Network Support and Control Ancillary Service (NSCAS) Assessment 2012', AEMO, p8

TransGrid made the lowest offer to the competitive tender and the non-prescribed contract was put in place with AEMO. It is due to expire at the end of June 2019 after which the service is expected to still be required.

This NSCAS contract is costing consumers much less than it did before 2013/14. AEMO's "Non-Market Ancillary Services Cost and Quantity Report" shows that the service cost $30 million less in 2013/14 than it did in 2012/13 with a different provider.[56]

4.10.1 TransGrid's proposal

The NSCAS contract will expire at the end of June 2019. As the service is still expected to be required at that point, TransGrid propose to provide it as a prescribed service.

We proposed that this could be achieved by incorporating the relevant reactor assets into the RAB from 1 July 2019, at a depreciated value of $26 million. The service would then be funded like any other prescribed service provided by assets in the RAB.

4.10.2 AER draft decision

The AER accepted the need for the service and accepted that the assets should be included in the RAB. However, it proposed that their asset value should be set at $0.

In effect, the AER is proposing that TransGrid provides this service for free for the next 35 to 40 years.

The rationale was that TransGrid should earn no further revenue from the assets as by July 2019, their costs will have been recovered via the NSCAS contract revenue.

4.10.3 Our response

TransGrid is confident that the existing assets can provide the required service for the lowest cost. However, it is unreasonable to require a business to provide a free service for 35 to 40 years. Like any business, TransGrid is entitled to make a fair return on its investments.

The fact that some costs may have been recovered prior to their use as a prescribed asset does not lessen the need for the business to make a return on the investment.

Higher risk for TransGrid, savings for customers

TransGrid is providing a service which reduces electricity costs to consumers but is exposed to higher risk while doing so.

This NSCAS service has resulted in considerable customer savings – in the region of $30 million per year based on the contract in place previously. In fact, TransGrid responded to AEMO and installed the assets earlier than planned so that the customer savings could be realised earlier.[57] However, the NSCAS contract exposes us to a higher level of risk than a prescribed service as it includes onerous penalties for asset unavailability.

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[56] AEMO publishes annual NSCAS costs for each state in its 'Non-Market Ancillary Services Cost and Quantity Report'. Table 5 of the 2016/17 report shows: In 2012/13 and 2013/14, the costs for the previous provider of this service were $23,772,200 and $44,497,327 respectively. In 2014/15, consumers paid $9,896,698 for TransGrid's service.

[57] This was reflected in the contract terms, which allowed for partial service delivery prior to the full service commencement date in the event that we fully commissioned some of the reactor assets early.

Adding the assets to the RAB at a depreciated value and earning a fair return is a reasonable proposition. It is consistent with both the regulatory framework and reasonable business expectations. The AER's draft decision is not reasonable in that:

- It will require us to provide a free service for many years
- It does not offer a fair return on assets which have saved customers possibly up to $100 million since 2013 (assuming the previous contract had continued on).

TransGrid discussed this decision with its Revenue Proposal Working Group, which comprises consumer representative groups and transmission customers. All members seemed perplexed by the AER's decision and some expressed that it was unreasonable.

Regulatory precedent

This draft decision may be unprecedented in requiring a business to earn no revenue on assets put in place for the benefit of consumers over so many years.

In fact, there is also some evidence of a contradictory precedent. The Directlink Market Network Service Provider (MNSP) converted to regulated status in 2006. When the regulatory test (a precursor of the RIT-T) was applied, it was found that neither Directlink nor an alternative was a justified investment.

In its draft decision, the AER described the situation as follows:

> On the one hand it could be argued that Directlink should be provided with an asset value of zero since its construction could not be justified today. However, on the other hand as **Directlink already exists and provides benefits to market participants over and above its operating costs, an asset value that is greater than zero would be appropriate**. [58] [added emphasis]

Then in reviewing an alternative asset valuation method, it was also noted that:

> In applying this approach the AER was conscious of **the need to avoid adversely affecting incentives for future investment**. [added emphasis]

This approach was considered reasonable, as it provided a fair and reasonable risk adjusted return on efficient investment.

It is acknowledged that much time has passed, the circumstances were different and we now operate under different Rules. However, the example highlights the contrast with our situation. At that time it was considered fair and reasonable that an existing asset whose construction "could not be justified" was still able to earn a return.

In contrast, our assets provide a necessary and valued service and yet are to be provided for free.

4.10.4 Revised proposal

TransGrid has reviewed the rationale of the draft decision. We feel that it is unreasonable and have found that consumer representatives and customers support this conclusion.

We therefore propose that, from 1 July 2019, the assets providing the NSCAS service should be incorporated into the RAB with a depreciated value of $26 million.

The assets will earn a fair return while continuing to provide a valuable service to consumers, who have already benefited greatly from the cost savings they have created.

58 'DJV application for conversion and revenue cap—draft decision' (Page ix), AER, 5 December 2005

5. Operating Expenditure

5.1 Introduction

In its revenue proposal, TransGrid submitted a forecast operating expenditure that is an efficient, prudent and realistic level of expenditure, developed using up to date forecasts and closely aligned with the AER's guidelines. TransGrid proposed a total forecast operating expenditure of $908 million ($June 2018) for 2018/19 to 2022/23[59]. An additional $14 million ($June 2018) step change relating to compliance with TransGrid's licence conditions was subsequently included and considered by the AER in addition to our January 2017 revenue proposal.

In the draft decision, the AER proposed an alternative total forecast operating expenditure of $857 million ($June 2018), excluding debt-raising costs, representing a 5.6% reduction. Debt-raising costs are covered separately in Section 5.8.

The comparison between the revenue proposals and draft decision is shown in Table 5.1 below.

Table 5.1: TransGrid's proposed operating expenditure and the AER draft decision[60] ($m June 18)

	2018/19	2019/20	2020/21	2021/22	2022/23	Total
TransGrid proposed operating expenditure	177.2	178.8	181.3	184.0	186.4	907.7
AER draft decision operating expenditure	169.6	170.7	171.4	172.2	173.2	857.1
TransGrid revised proposal operating expenditure	**172.0**	**173.4**	**175.3**	**177.4**	**179.6**	**877.6**

Source: TransGrid. Totals may not add due to rounding.

The Rules[61] require the AER to accept the transmission network service provider's forecast operating expenditure included in the revenue proposal if it is satisfied that the operating expenditure for the regulatory control period reasonably reflects:

- The efficient costs of achieving the operating expenditure objectives
- The costs that a prudent operator would require to achieve the operating expenditure objectives
- A realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives[62].

TransGrid has spent considerable time in reviewing alternatives and improving its operating expenditure estimates to ensure the obligations of the Rules are met and that there is a sufficient and efficient level of operating expenditure to deliver transmission services.

59 Excludes debt raising costs.
60 All numbers exclude debt raising costs.
61 *National Electricity Rules.*
62 *National Electricity Rules*, Clause 6A.6.6(c).

These considerations were set out in our revenue proposal and included:

- How TransGrid's operating expenditure aligns with our commitment to:
  - Testing new ideas and practices to drive improvements
  - Listening and responding to consumers
  - Demonstrating a strong level of efficiency and performance
- Considering alternative and more balanced approaches for determining forecasted growth
- Committing to achieve ongoing cost savings through transformational change
- Seeking independent experts assessments and benchmarking reports to confirm its estimates presented and when considering differing approaches
- Establishing a base year.

In this revised proposal, TransGrid has carefully considered whether to accept the AER's draft decision operating expenditure estimate and the methodology used to prepare its operating expenditure forecasts. Overall, the AER has not accepted most of the improvements proposed by TransGrid and has applied the same approach and benchmarks used in its recent Network Service Provider (NSP) determinations and TransGrid's last determination.

The AER has accepted TransGrid's more accurate starting forecast and acknowledges this. TransGrid accepts the AER's preference for its own approach to estimating trend and has adopted the AER's method. TransGrid has also accepted the AER's decision on the step-change for off-easement management.

Within these parameters, TransGrid has set out a forecast operating expenditure it considers is required to achieve the operating expenditure objectives for the 2018/19 to 2022/23 regulatory period of $877.6 million, which is marginally higher than the AER's alternative estimate by 2.4%.

The primary drivers for the increase over the AER's draft determination are:

- Utilising the latest available information and data since submitting the proposal
- Utilising the same rate of change methodology as the AER, and updating the factors using the AER's latest benchmarking results
- Reconfirming the step change requirement to meet NSW licence requirements
- Correcting the AER's operating expenditure model errors.

In this revised proposal, TransGrid has updated its expenditure forecast considering the matters raised by the AER in its draft decision as well as noting that the AER will consider updating its final determination with the latest data available including the economic benchmarking results from the AER's 2017 Transmission Benchmarking Report.[63]

The total forecast operating expenditure as a result of these amendments set out above has reduced TransGrid's proposed operating expenditure by approximately $44 million over the 2018/19 to 2022/23 period compared to the revenue proposal.

[63] AER: Draft Decision TransGrid transmission determination 2018 to 2023, September 2017, p.7-32.

The table below sets out our proposed operating expenditure.

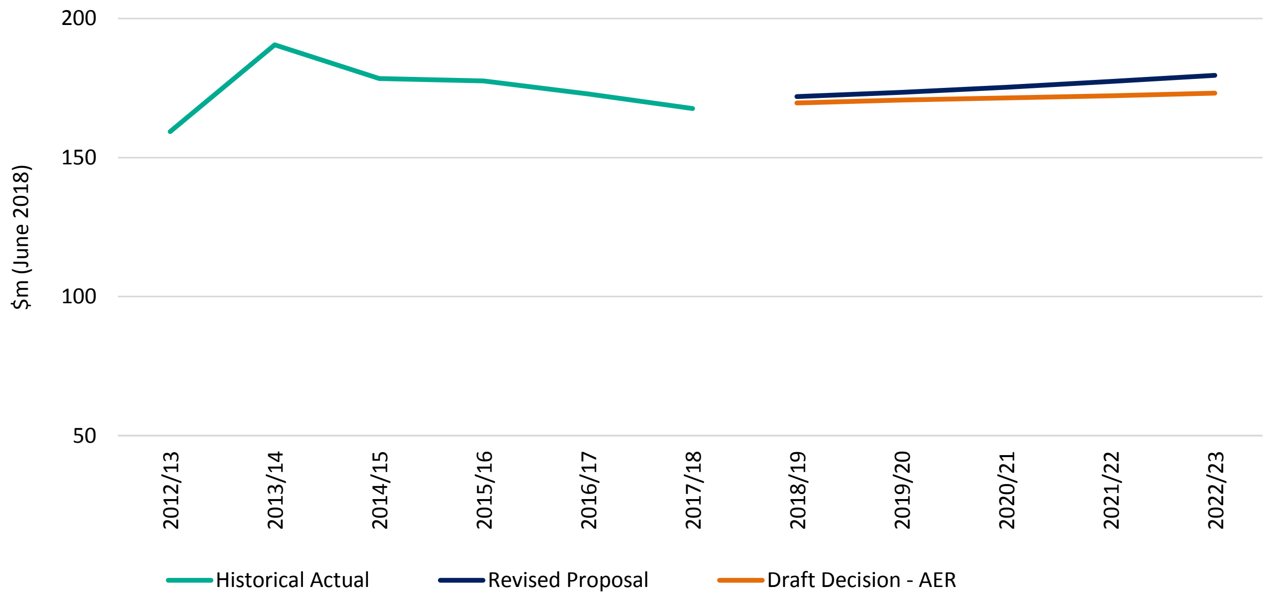
Table 5.2: TransGrid's Proposed operating expenditure and the AER draft decision ($m June 18)

$m June 2018	2018/19	2019/20	2020/21	2021/22	2022/23	Total
Revised proposal operating expenditure[64]	172.0	173.4	175.3	177.4	179.6	877.6

Source: TransGrid. Totals may not add due to rounding.

This revised proposal operating expenditure compared to the AER's draft determination is set out in Figure 5.1.

Figure 5.1: Comparison of operating expenditure forecasts, $m June18



5.2 Summary of TransGrid Proposal

Chapter 6 of TransGrid's revenue proposal sets out the methodology, key inputs and assumptions used to determine the operating expenditure forecast for the next regulatory control period.

TransGrid closely aligned its forecast methodology with the AER's expenditure forecast assessment guideline with a small number of variations supported by independent expert advice. Specifically TransGrid undertook enhanced approaches for the following areas:

- Forecast starting point
- Weighting of the wage forecast
- Industry productivity
- Output growth.

[64] Excludes debt raising costs.

5.2.1 Forecast Starting Point

The forecast starting point for TransGrid's operating expenditure estimate of the control period did not use the AER approach. The AER's methodology for forecast starting point, takes the current regulatory period (2014/15 – 2017/18) base year under, or over spend, away from the final year allowance as the basis for setting the future allowance for the next regulatory period (2018/19 – 2022/23). TransGrid proposed a more accurate measure of establishing the starting point allowance for the proposal by taking its latest revealed base year operating expenditure (2016/17) and escalating it using the most recently available estimates of cost escalators resulting in a 3% real planned cost savings in 2017/18.

Whilst TransGrid has proposed to deliver cost savings during 2017/18, we recognised that further material savings may not be achievable in the near term based on an environment of increasing regulatory pressures[65] and benchmarking trends indicating negative industry productivity[66].

5.2.2 Escalation Trend

Weighted wage forecasts were based on BIS Shrapnel's independent forecast of wage changes with weightings based on TransGrid's actual internal labour composition. We applied an internal labour proportion of 70% of operating expenditure in the 2016/17 base year reflecting:

- The long term trend of TransGrid's actual labour ratios
- An efficient actual operating expenditure according to various sources, including the AER's final revenue decision in 2015, the AER's 2016 Benchmarking Report and the 2015 ITOMS report.

Forecast industry productivity was set to zero instead of the AER's benchmarked 0.2%. We considered a wide range of independent productivity measures that all indicated negative productivity for Australian utilities.

The output growth methodology used by the AER for the majority of its recent decisions for transmission network service providers was replaced with network growth factors in our proposal. Our approach was to calculate output growth by considering commissioned augmentation relative to the replacement cost of the network, modified by economies of scale. TransGrid considers that it reflects a more accurate method and the AER had accepted a similar network growth approach proposed by AusNet. At the time of submitting our revenue proposal, we addressed the AER's concerns around the AusNet methodology and were reluctant to adopt the AER's methodology given concerns with the accuracy of the AER's benchmarking approach.

5.2.3 Step Changes

TransGrid identified two step changes in operating expenditure that were scheduled to commence in 2018/19 and continue through the regulatory period, specifically:

- Off easement risk management
- Compliance with NSW Licence conditions.

We included the step change of $37.5 million in our forecast for 'off-easement risk management' to mitigate fire risks from trees which are outside TransGrid easements but could contact conductors if they fell. This requirement is related to the new compliance framework put in place when our safety regulator changed.

[65] TransGrid: Revenue proposal, January 2017, p.123.

[66] TransGrid: Revenue proposal, January 2017, p.145.

TransGrid's second step change is the need to comply with the Transmission Operators Licence under the Electricity Supply Act 1995 (NSW), introduced on 7 December 2015 and various conditions from the Foreign Investment Review Board arising from the change in ownership. At the time of the revenue proposal, TransGrid did not have sufficient information to complete any cost adjustments. A business case, further details and responses to information requests were subsequently provided to the AER prior to its determination. TransGrid recommended an additional $14.4 million of operating expenditure and submitted this to the AER on 5 July 2017.

5.2.4 Debt Raising Costs

TransGrid proposed debt raising costs of $40 million comprising benchmark unavoidable costs which include arrangement fees, legal fees, company credit rating fees and other transaction costs that are incurred in the course of debt raising activity.

We used modern debt management practices to ensure businesses can maintain appropriate credit ratings to estimate the benchmark efficient costs of raising debt. The debt raising costs proposed by TransGrid comprise three main drivers, which are:

- The transaction related costs of issuing the bonds
- Refinancing maturing debt at least three months ahead of the debt maturing
- Meeting formal requirements with respect to liquidity (which refers to the buffer the business has to meet for short term cash requirements).

Whilst the AER has previously accepted transaction related costs, TransGrid engaged economic consultants, Incenta, to consider the other two drivers and based upon their advice we considered that:

- refinancing three months ahead and liquidity costs are costs that a prudent and efficient operator will incur when participating in debt markets over the next regulatory control period
- Incenta has demonstrated that a prudent and efficient operator incurs costs to meet the requirement in relation to liquidity and the timing of refinancing of debt in order to maintain an investment grade credit rating as well as maintaining an investment grade credit rating[67].

5.3 Summary of AER's Draft Decision

In the draft decision, the AER used a base-step-trend approach to forecast the operating expenditure. The AER draft decision did not accept TransGrid's proposed forecast of $908 million[68] ($June 2018) and estimated an amount of $857 million ($June 2018)[69].

The AER estimate was lower due to:

- Applying a lower rate of change for forecast growth in prices, output and productivity
- Excluding the step change for off-easement risk management and allowing only part of the costs for NSW licence compliance
- Setting a lower forecast of debt raising costs.

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67 Incenta (December, 2016), Debt Raising Cost – TransGrid's 2018/19 to 2022/23 Revenue Determination, Report for TransGrid. [TransGrid-Incenta-Appendix L Debt Raising Cost TransGrid 2018_19 to 2022_23 Revenue Determination-0117-PUBLIC], p.1.

68 Excluding debt raising costs.

69 Excluding debt raising costs.

5.3.1 Forecast Starting Point

The AER was satisfied with TransGrid's starting point operating expenditure estimate as the basis of establishing the 2018/19-2022/23 allowance. The AER has accepted that our 2016/17 expenditure drivers which establish the starting point are likely to reflect those in the forecast period. Having also considered the benchmarking results the AER is satisfied that the estimate is not materially inefficient[70].

The AER accepted TransGrid's forecast for 2017/18 efficiency improvements for transformational changes and carried these forward into the 2018/19-2022/23 operating expenditure forecast as proposed by TransGrid[71].

5.3.2 Escalation Trend

The AER forecast trend for output was based on the results of its 2016 partial factor productivity benchmarking for transmission businesses[72] and did not accept TransGrid's alternative of considering commissioned augmentation relative to the replacement cost of the network, modified by economies of scale.

The AER did not accept the BIS Shrapnel labour escalation forecasts used by TransGrid but rather used forecasts prepared by Deloitte Access Economics.

Further the AER forecast productivity growth of 0.2 percent per year based on its expert consultant's, Economic Insights, recommendations as well as evidence of historical measured productivity growth[73].

The AER did not accept TransGrid's input price weights based on actuals of 70% labour and 30% non-labour and used a 62% and 38% weighting respectively.

5.3.3 Step Changes

The AER did not accept TransGrid's step change for off easement risk management totalling $37.5 million and partially accepted the step change for TransGrid's compliance with NSW Licence conditions for $7.8m of the requested $14.4 million.

5.3.4 Debt Raising Costs

The AER did not accept TransGrid's approach to measuring debt raising costs (comprising transaction, debt raising and liquidity costs) and based the forecast debt raising costs transaction costs only.

5.4 TransGrid's Revised Proposal

TransGrid is pleased that the AER has accepted the 2016/17 year as an efficient base year for forecasting future costs. 2016/17 represents the first full year of operations under the new ownership. Further, the AER accepted that our 2016/17 expenditure drivers which establish the starting point are likely to reflect those in the forecast period. Having also considered its benchmarking results the AER is satisfied that the estimate is not materially inefficient. TransGrid's actual operating expenditure result for 2016/17 is lower than forecast, having achieved additional efficiency savings since submitting its proposal.

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70 AER: Draft Decision TransGrid transmission determination 2018 to 2023, September 2017, p.7-21.

71 AER: Draft Decision TransGrid transmission determination 2018 to 2023, September 2017, p.7-38.

72 AER: Draft Decision TransGrid transmission determination 2018 to 2023, September 2017, p7-33.

73 Economic Insights, Memorandum: TNSP MTFP Results, 29 April 2016, p.5.

The AER has accepted TransGrid's more accurate method of determining the starting point forecast and acknowledges this. The AER has also accepted our 3% efficiency saving forecast for 2017/18 comprising wages and output growth and transformation program expenditure savings.

TransGrid accepts the AER's preference for its own approach to estimating trend and has adopted the AER's method.

TransGrid has also accepted the AER's decision on the step-change for off easement management.

We note the AER has only partially accepted the increased costs arising from the NSW licence conditions for IT security and has requested further information. TransGrid proposes a reduced amount of $13.9 million is required to support these new obligations and has provided further detail in confidential Appendix B with a summary in section 5.7.1.

TransGrid considers that the AER's operating expenditure forecast needs to be increased; otherwise it understates the efficient costs of achieving the necessary operating expenditure objectives for a transmission business. The key drivers for TransGrid's revised operating expenditure forecast are:

- Utilising the latest available information and data since the proposal
- Utilising the AER's rate of change methodology
- Updating the rates of change with the AER's latest benchmarking results
- Reconfirming the step change requirement to meet NSW licence requirements
- Removing the step change for off-easement risk management
- Correcting a CPI calculation error in the AER's operating expenditure model used in the draft determination.

In preparing our alternative forecast, we have used the latest available information and data since our original submission in January 2017. Specifically, the revised operating expenditure forecast has been updated to incorporate:

- 2016/17 actual operating expenditure set out in the annual economic benchmarking RIN and TransGrid's Annual Regulated Accounts, both submitted to the AER on 25 October 2017
- The most recent forecast of inflation and Reserve Bank inflation forecasts[74], consistent with the AER's practice of using the most recent information at the time of a decision
- The most recent forecast labour escalation, adopting the AER's previous determination practice of applying an average of the forecast from BIS Shrapnel for EGWWS WPI for NSW (October 2017) and Deloitte Access Economics (supplied by the AER in October 2017 draft determination Opex Model)
- The AER's method of using TransGrid's forecasts outputs measures and the AER's benchmarked weights, and updated both of these to be consistent with the AER's latest benchmarking report[75].

TransGrid has accepted the AER's preferred approach to output growth, trends and industry productivity. We have applied the AER's output growth trend and productivity trend updated for the latest 2017 AER benchmarking report.

TransGrid has accepted the AER's draft determination for the removal of the step change for off easement risk management. The implications of this exclusion from the forecast operating expenditure over the next regulatory period is discussed at section 5.7.2.

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[74] RBA statement of monetary policy inflation forecast, August 2017, Table 6.1

[75] AER, Annual Benchmarking Report, Electricity transmission network service providers Draft Only, November 2017.

As a result of these amendments set out above, the forecast operating expenditure has reduced by approximately $44 million over the 2018/19 to 2022/23 period compared to our revenue proposal.

The table below sets out a summarised breakdown of our revised proposal, taking into consideration the amendments outlined above, compared to the AER's draft determination[76].

Table 5.3: TransGrid's operating expenditure proposals and the AER draft decision ($m June 18)

	TransGrid Proposal (Incl. revised Step Change)(1)	AER Alternative Estimate	Difference to TransGrid	TransGrid Revised Proposal	Difference to AER Alternative Estimate
Based on reported operating expenditure in 2016/17	868.7	862.9	-5.8	864.3	1.4
2016/17 to 2017/18 Increment	**-26.6**	**-26.4**	**0.2**	**-25.9**	**0.5**
Output growth*	2.3	2.7	0.4	6.3	3.6
Price growth* - Wage Increases/Labour Ratio	**26.0**	**15.1**	**-10.9**	**19.1**	**4.0**
Productivity growth*	0.0	-5.1	-5.1	0.0	5.1
Step change - (Off Easement & Licencing Conditions)	**51.7**	**7.8**	**-43.9**	**13.9**	**6.1**
Total operating expenditure	**922.1**	**857.1**	**-65.0**	**877.7**	**20.6**

* Revised proposal based on AER draft TNSP benchmarking results November 2017

[1] TransGrid has removed the AER's economies of scale assumption when re-presenting Output Growth & Productivity Growth

Source: TransGrid. Totals may not add due to rounding.

5.5 Base operating expenditure

In the draft decision the AER accepted TransGrid's forecast operating expenditure in 2016/17 as an efficient base year expenditure. Further, the AER has accepted that our 2016/17 expenditure drivers which establish the starting point are likely to reflect those in the forecast period. Having also considered the benchmarking results, the AER is satisfied that the estimate is not materially inefficient. TransGrid cited a number of benchmarks to confirm its operating expenditure efficiency.

The AER accepted TransGrid's starting point for forecasting operating expenditure in 2018/19-2022/23. From the base year we use a differing approach to the AER to forecast the operating expenditure. We take the latest revealed base year operating expenditure (2016/17) and escalate it using the most recently available estimates of cost escalators, including planned cost savings in 2017/18. It is our view that a more accurate estimate is obtained by this approach. Our operating expenditure proposal includes an additional cost savings expected in 2017/18 to deliver a further 3% net reduction compared to 2016/17 expenditure.

TransGrid identified an error in the CPI table of the AER's operating expenditure model, which impacted the value of the starting point, and this has now been corrected in this revised proposal.

[76] Excluding debt raising costs.

5.6 Rates of change

5.6.1 Overall Approach

The AER's approach to forecasting a trend for operating expenditure comprises:

- Price change, which measures how the underlying prices are expected to change over time
- Output change, which measures how the total quantity of a business' output is expected to change over time
- Productivity change, which is a measure of how an industry's efficiency of production is assessed to change over time.

The AER has relied on its annual benchmarking report from 2016, prepared by its expert consultant, Economic Insights as the basis for preparing rate of change for revenue determination purposes. TransGrid has previously disagreed with aspects of the benchmarking of TNSPs and the AER's approach to forecasting the rate of change of operating expenditure when preparing its current regulatory period revenue proposal[77] Again, when preparing this proposal we looked at alternative methods and benchmarking data for particular components of the rates of change to assist in developing a forecast with the best information and data available.

Given that the AER has again applied its standard approach, we will accept the AER's preferred approach to the rate of change in the revised proposal.

5.6.2 Price Change

Given the changes in ownership, TransGrid sought to apply a wages growth index that reflected a broader industry Wages Price Index (WPI) measure that applied to private utilities.

In the draft decision the AER adopted forecast growth in the public and private WPI for the NSW utilities industry to forecast labour price growth provided by Deloitte Access Economics (supplied by the AER in October 2017 draft determination)

Accepting the AER's concerns about the use of a private utility index for all of Australia, TransGrid has sought an update from BIS Shrapnel using the NSW wage price index for the Electricity Gas Water Waste & Sewage sector.

Consistent with the AER's previously used methodology, TransGrid has updated the price change index to use an average of the NSW EGWWS WPI forecasts from BIS Shrapnel (updated October 2017) and Deloitte Access Economics (supplied by the AER in September 2017 draft determination). BIS Shrapnel's latest forecast is set out at Appendix A.

The AER has also adjusted the forecast for CPI based on more up to date information and TransGrid has corrected a CPI index table in the operating expenditure model and agreed with the AER those corrections

In our proposal, we sought independent advice to confirm the applicability of using our internal labour to expense ratio as a substitute for the AER's benchmark values, as we considered that:

- AER's benchmarking rates were out of date, where the 62% estimate for labour composition was initially developed in 2004 by Pacific Economics Group and later reviewed by Economic Insights[78].

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[77] TransGrid, Revised revenue proposal 2014/15 – 2017/18, 13 January 2015, p.89.

[78] Economic Insights: Memorandum to the AER – Operating expenditure input price index weights, 19th February 2016, pp.2-3.

- AER's estimate was based on five electricity and one gas distribution business with assets, service requirements and operations which are quite different from TransGrid's
- Third party advice from Herbert Smith Freehills supported the use of TransGrid's rate "… the operating expenditure objectives require an accurate forecast to be determined. We do not consider that the 62% weighting recently used by the AER would result in an accurate forecast that would reflect the realistic input costs of TransGrid.[79]

Whilst the AER did not accept TransGrid's estimate of 70% and applied 62% weighting to labour, the AER recognised that over time the efficient input mix could change and anticipated the 2017 benchmarking process would conclude prior to making a final determination[80] and that if further analysis is done the AER will consider this in its final decision.

With the 2017 benchmarking data now available, TransGrid has updated the labour weighting to 70.4% consistent with the AER's expert consultant, Economic Insights, benchmarking report[81] stating:

> Across all TNSP's, the proportion of labour (from in-house labour, field services contracts and non-field-services contracts) was 70.4 per cent. We used the updated proportion in this report for all years.

5.6.3 Output Change

A measure of output change is required to adjust the base year costs for the differing levels of activity in the future years, for example, as the network grows then a larger operating and maintenance expenditure may be required (all else being equal).

TransGrid's proposal considered a network growth moderated by economies of scale methodology. The AER had accepted a similar approach by AusNet in its November 2015 proposal. Noting the AER had a number of qualifications, we took care to address the AER's concerns on this approach. In developing our revised approach we sought advice from the TransGrid Advisory Council, and based on the advice from our customers and stakeholders, forecast network growth as follows:

$$Network\ growth_t = \frac{Forecast\ prescribed\ augmentation\ expenditure_t}{Forecast\ replacement\ cost\ of\ prescribed\ network_t}$$

To calculate the effect of network growth on operating expenditure TransGrid used similar economies of scale factors to AusNet, applied on a lagging one year basis:

$$Growth\ in\ opex\ requirement_{t+1} = Network\ growth_t\ x\ Economy\ of\ Scale\ Factor_t$$

We explored this alternative approach against the AER's standard approach[82] as we held concerns around the benchmarking method and were reluctant to adopt the AER's methodology until the AER and Economic Insights had an opportunity to consider our proposal and comment on Frontier Economics report[83]. This report set out a number of concerns with the AER's benchmarking methodology.

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79 Herbert Smith FreeHills: *TransGrid – Operating expenditure*, 23rd January 2017. [TransGrid-Herbert Smith Freehills-Appendix K Operating expenditure advice-0117-PUBLIC]

80 AER: Draft Decision TransGrid transmission determination 2018 to 2023, September 2017, p7-27.

81 Economic Insights: Economic Benchmarking Results for the AER's 2017 TNSP Benchmarking Report, p.6.

82 AER: Draft Decision TransGrid transmission determination 2018 to 2023, September 2017, p.7-30.

83 TransGrid; Revenue Proposal, 31 January 2017, Appendix G.

In its draft determination the AER did not accept TransGrid's approach for measuring output growth and adopted its standard approach of applying benchmarked output measures with TransGrid's asset information supplied in TransGrid's RIN submitted with the revenue proposal.

TransGrid has accepted the AER's approach to establish output growth from the AER's draft determination in this revised submission and has updated the operating expenditure model with:

- Output measures, using Economic Insights 2017 benchmarking report from the AER[84]
- Replacing connection points with the AER's NSW customer data used in the benchmarking report (2006-2016 customer data) and extrapolating customer numbers for the next regulatory period using the ordinary least squares regression method to establish a historical based customer growth rate.

We note that the Distributors RINs will be available in January 2018 to the AER, which will enable the AER to update TransGrid's estimate of the forecast customer numbers before it completes its final determination.

From the draft decision we note that the AER is currently reviewing its economic benchmarking report including the consideration of using end users rather than voltage-weighted connections as well as updating the weights.

Economic Insights in preparing its Benchmarking report for the AER stated that:

> There was general support for all aspects of the revisions other than the substitution of end-user numbers for the voltage-weighted number of connections. On balance, we view moving to incorporating end user numbers as beneficial in capturing important aspects of scale and complexity, removing some anomalous results, and utilising robust data that is already available[85].

The AER in its draft benchmarking report agreed with Economics Insights assessment in moving to customer numbers.[86]

5.6.4 Productivity Change

A measure in productivity change captures the ability to identify and implement efficiency improvements and benefits from broader economy wide productivity improvements such as technology changes.

TransGrid in establishing a suitable productivity measure for forecasting efficiency changes for its revenue submission wanted to make an informed decision rather than relying on the AER's historical measures. Our recent change in ownership structure and new licencing obligations pose additional constraints on how the business can operate and will potentially reduce opportunities that could drive productivity in the future.

TransGrid considered the following potential alternatives to establish an appropriate productivity factor:

- The Productivity Commission's *Productivity Update for 2016*, where the report indicates that EGWWS productivity has declined by 1.2% p.a. over the 1989/90 to 2014/15 period[87]

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84 Economic Insights: Economic Benchmarking Results for the Australian Energy Regulator's 2017 TNSP Benchmarking Report, 12 September 2017.

85 Economic Insights: Economic Benchmarking Results for the Australian Energy Regulator's 2017 TNSP Benchmarking Report, 12 September 2017, p.5.

86 AER: Annual Benchmarking Report – Electricity transmission service providers Draft Only, November 2017, p.10.

87 Productivity Commission Productivity update, April 2016, p.10.

- *Productivity in NSW* by David Buckland & Harley Smith, NSW Trade & Investment, published 18 September 2014, indicates a decline in NSW utility productivity of approximately 1.86% p.a. between 1995 and 2013 using a multi factor productivity measure[88]
- The AER's latest assessment of distribution networks productivity, from their 2016 benchmarking report, where the aggregate Australian distribution network service provider productivity in operating expenditure terms has declined at a rate of approximately 1.8% per annum since 2005/06[89].

Whilst the results from the productivity reports above all indicate a significant negative industry productivity trend. TransGrid assumed *no change* in industry productivity for the forecast period in its proposal.

This was a conservative assumption, which reduced TransGrid's forecast revenue requirement. The AER did not accept TransGrid's productivity growth measures, which they considered less suitable than the industry measure they had used[90]. The AER's productivity measure in the draft determination and other recent transmission determinations[91] implies 0.2% productivity growth factor for Australian TNSPs. This is based on the operating expenditure specific measure of productivity called *industry-level partial factor productivity-opex*. The AER forecast is based on analysis undertaken by its expert consultant, Economic Insights, from the 2016 benchmark data.[92]

Since the AER's draft determination, the AER's draft benchmarking data has become available. Based on this, TransGrid has calculated regression based growth rates using the same models as Economic insights, for:

- 2006-2016, partial productivity operating expenditure rate, (using Economic insights new specification) -0.37% indicating a productivity decrease
- 2006-2016, partial productivity operating expenditure rate, (using Economic insights old specification) +0.07, indicating a negligible productivity growth.

The figure below sets out a comparison of the partial productivity operating expenditure factors of the transmission businesses comparing the AER's 2016 benchmarking data to the 2017 benchmarking data, using the old and new benchmarking methods. Transmission businesses productivity levels have been clearly trending down since 2013. The trend growth rate of operating expenditure partial productivity from 2006 to 2015 was 0.2 percent per annum and under the new method the trend growth rate has subsequently fallen to -0.37 per cent.

88 David Buckland & Harley Smith, NSW Trade & Investment, Productivity in NSW, 18 September 2014.

89 AER, Economic Insights DNPS benchmarking data files, 7 November 2016, Series PP Operating expenditure.

90 AER: Draft Decision TransGrid transmission determination 2018 to 2023, September 2017, p.7-35.

91 AER: Draft decision Powerlink transmission determination operating expenditure model September 2016.

92 Economic Insights: Memorandum: TNSP MTFP, 29 April 2016, p.5.

Figure 5.2: Comparison of AER 2016 & 2017 operating expenditure productivity benchmarks

Source: TransGrid using AER economic benchmarking data (2016 and 2017).

TransGrid in its revised proposal has held its view, supported by the latest benchmarking results, that productivity in the transmission and associated industries is clearly in decline. However adopting a negative trend is inconsistent with TransGrid's expected performance and we have again assumed *no change* in the industry productivity for the forecast period. Again, this is a conservative assumption compared to the available information, including the AER's benchmarking report. The assumption reduces TransGrid's revenue.

In its revised proposal, TransGrid has a 3% real efficiency saving target for 2017/18 over 2016/17 results.

In one part of its draft decision the AER incorrectly applied TransGrid's proposed economies of scale which were part of the output growth measure to industry productivity. This is incorrect and inconsistent with TransGrid's revenue proposal[93].

5.7 Step Changes

5.7.1 Licence Conditions

This step change arises from the need for TransGrid to comply with the Transmission Operators Licence under the Electricity Supply Act 1995 (NSW), introduced on 7 December 2015 and the various conditions from the Foreign Investment Review Board arising from TransGrid's change in ownership.

TransGrid submitted the details of the step change request to the AER on 5 July 2017, requesting $14.4 million to meet the new compliance requirements and supplemented this request through subsequent information requests from the AER.

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93 AER: Draft Decision TransGrid transmission determination 2018 to 2023, September 2017, p.7-33.

The AER in its draft determination included an amount of $7.8 million as it was not satisfied that TransGrid required the full cost increase it proposed to comply with the licence conditions in the 2017/18 – 2022/23 regulatory control period[94].

Since the AER's draft determination the NSW government has drafted revised licence conditions which are expected to be completed prior to the AER's final revenue determination in April 2018. The business needs and the extent of the allowance for the step change differs between the existing conditions and the final version of the proposed conditions and the timing of any approval by the State and Commonwealth. Therefore, TransGrid has prepared this step change submission, with its revised revenue submission, based on two possible outcomes:

- The step change allowance requirement under the retention of the "existing" licence conditions, requiring incremental costs of $13.9 million ($June 2018), a reduction from the original submission
- The step change allowance under the "proposed" licence conditions, if and when they become approved, which would reduce the incremental costs to $8.0 million ($June 2018).

TransGrid has prepared a confidential paper with the further information requested at Appendix B. This paper sets out:

- Findings from the recently completed IPART audit of TransGrid's licence conditions
- An explanation of the expenditure required to comply with and maintain compliance.

Until the proposed licence conditions have been ratified, our revised revenue proposal includes an amount of $13.9 million for the next regulatory period.

5.7.2 Off Easement Risk Management

TransGrid's revenue proposal set out the detailed requirement to address the management of off easement trees that pose a safety and reliability risk to the network. Whilst the costs are new, material and real TransGrid accepts the AER's view that they do not fit within the definition of step changes and have not included these costs in the revised proposal.

5.8 Debt Raising Costs

TransGrid maintains that the debt raising costs included in the January 2017 revenue proposal are an accurate estimate of the benchmark costs for an efficient business. The AER's approach is out of date and does not recognise the increased costs businesses face in raising debt post the global financial crisis (GFC). TransGrid also believes the AER is incorrect to claim timing of the PTRM calculations can offset these costs. These costs, as the AER recognises, are not working capital.

Nevertheless TransGrid accepts the AER will not recognise these costs in the revenue decision and has not included them in the revised proposal. In practice, equity investors will be further undercompensated as a result of this decision.

Table 5.4: Proposed debt raising costs ($m June 18)

$m June 2018	2018/19	2019/20	2020/21	2021/22	2022/23	Total
Debt Raising Costs	3.2	3.3	3.3	3.3	3.4	16.5

Source: TransGrid. Totals may not add due to rounding.

[94] AER: Draft Decision TransGrid transmission determination 2018 to 2023, September 2017, p.7-47.

6. Incentive Schemes

6.1 Introduction

This chapter covers the three incentive schemes:

> Capital Expenditure Sharing Scheme (CESS)
> Service Target Performance Incentive Scheme (STPIS)
> Efficiency Benefit Sharing Scheme (EBSS).

6.2 Capital Expenditure Sharing Scheme

The capital expenditure sharing scheme (CESS) allows savings to be shared between consumers and a transmission business when capital expenditure in a period is lower than the capital expenditure allowance. Consumers benefit through lower future network charges and the transmission business receives a financial benefit for becoming more efficient. The business could also be subject to a financial penalty if actual capital expenditure is higher than the allowance.

TransGrid accepts the modifications and updates the AER has made to TransGrid's revenue proposal for the CESS allowance. However, following a review, we have identified inconsistencies in the approach TransGrid and the AER have used with the intended operation of the scheme. Following a review by HoustonKemp, expert economic advisors, we have made three further modifications to the calculation of the CESS allowance, to align it with the AER's intended operation.

6.2.1 TransGrid's Proposal

CESS was presented in chapter 14 of TransGrid's revenue proposal and calculated based on CESS Version 1. As the CESS has never been applied before, we acknowledge there may be some refinement required in how to accurately calculate the CESS allowance.

TransGrid's proposed CESS revenue of $24.3 million ($m June 18):

> Excluded capital expenditure incurred for the network capability component of the Service Target Performance Incentive Scheme (STPIS)
> Excluded capital expenditure deferred into the 2018/19 to 2022/23 control period
> Was based on net capital expenditure
> Adopted a June to June CPI adjustment
> Used the nominal vanilla WACC updated for cost of debt for the regulatory years 2015/16, 2016/17 and 2017/18
> Proposed that the CESS would apply to the 2018/19 to 2022/23 regulatory control period, excluding capital expenditure incurred for the network capability component of the Service Target Performance Incentive Scheme (STPIS) and based on net capital expenditure.

6.2.2 AER's Draft Decision

The AER's draft decision accepted TransGrid's proposal for CESS but:

> updated the calculation for CPI
> updated the WACC values for more recent information
> adjusted the approach used to smooth the CESS revenue across the regulation period.

6.2.3 Response to Draft Decision

TransGrid accepts the modifications as set out in the AER's draft decision; however, following a quality review by HoustonKemp, we suggest that further adjustments are necessary.

The AER's Framework and approach for TransGrid final decision states that the CESS version 1 (November 2013) will apply subject to the following clarifications:[95]

> The calculation of costs and benefits already incurred is to be consistent with the timing assumptions within the post-tax revenue model (PTRM), including:

> The PTRM assumes that capex is incurred in the middle of the year. The return on capital is not calculated until the start of the next year. To compensate the service provider for the time between when capex is assumed to have been incurred and when the return on capital is calculated, before it is rolled into the RAB, we inflate the nominal capex by a half yearly WACC.

> The use of an appropriate rate of return, ie:

> When applying the rate of return to calculate incentive payments under the CESS we do not intend to reward or penalise a service provider for inflationary effects.

> That the CESS will apply to capital expenditure net of both capital contributions and disposals.

Following advice from HoustonKemp included as Appendix D, our revised proposal contains the following changes from the model we submitted with our revenue proposal (January 2017), and that adopted by the AER in the draft decision:

> The removal of any financing benefit in the year that the underspend or overspend is incurred, because a return on capital is not provided on capital expenditure until the start of the following year

> The financing benefit for each subsequent year incorporates the capitalisation of a ½ year return on capital, consistent with the approach adopted in the PTRM and roll forward model (RFM)

> The financing benefit for each subsequent year is calculated by multiplying the underspend (or overspend) grossed up for the ½ year return on capital and the real Vanilla WACC, because the PTRM delivers a real rate of return.[96]

The results for actual capital expenditure for 2015/16 and 2016/17 and forecast capital expenditure in 2017/18 are shown in Table 6.1.

95 AER, *Framework and approach for TransGrid | For regulatory control period commencing 1 July 2018*, July 2016, pages 20-22.

96 An explanation of why the regulatory framework delivers a real return on capital is set out in the AER's, *Regulatory treatment of inflation | Preliminary position,* October 2017, pages 60-61.

Table 6.1: Current period CESS performance ($m nominal)

	2015/16	2016/17	2017/18
CESS capital expenditure target	309.7	242.4	230.2
Actual/forecast CESS capital expenditure	237.3	174.7	220.4
Difference (actual/forecast underspend against CESS target)	72.4	67.7	9.7

Source: TransGrid. Totals may not add due to rounding.

On the basis of the outlined modifications to the AER's model, a CESS total of $32.8 million ($m June 18) has been included in TransGrid's revised revenue proposal for 2018/19 to 2022/23.[97] The CESS payment for each year of the regulatory control period is set out in Table 6.2.

Table 6.2: CESS payment per year ($m June 18)

	2018/19	2019/20	2020/21	2021/22	2022/23	Total
Revenue Proposal CESS	4.9	4.9	4.9	4.9	4.9	24.3
AER Draft Decision CESS	5.3	5.3	5.3	5.3	5.3	26.5
Revised Proposal CESS	6.7	6.7	6.7	6.7	6.7	33.7

Source: TransGrid. Totals may not add due to rounding.

6.3 Service Target Performance Incentive Scheme

The service target performance incentive scheme (STPIS) provides incentives for transmission network service providers to improve and maintain the performance of the network for the benefit of consumers. The scheme incentivises the business to outperform relative to its own previous performance which becomes increasingly challenging over time. TransGrid has participated in the service target performance incentive scheme since 2004. We have responded to the incentives to maintain or improve reliability in accordance with the service component, reducing transmission congestion during equipment outages in accordance with the market impact component. The STPIS is composed of three components:

- Service Component (SC)
- Market Impact Component (MIC)
- Network Capability Component (NCC).

6.3.1 TransGrid's Proposal

STPIS was presented in chapter 16 of TransGrid's revenue proposal.

In accordance with the scheme, TransGrid proposed:

- Performance targets, caps and floors for parameters of the SC

[97] The modified model used to calculate the CESS payment is attached to this revised proposal.

> A performance target, unplanned outage event limit and dollar per dispatch interval for the MIC
> Delay of the introduction of the symmetrical financial incentive
> A Network Capability Incentive Parameter Action Plan (NCIPAP) for the NCC containing 22 priority projects.

6.3.2 AER's Draft Decision

In the draft decision, the AER has:

> Accepted the performance targets, caps and floors for parameters of the SC with the exception of the lines rate fault parameter based on the Anderson-Darling statistic
> Determined the SC lines rate fault parameter based on the Kolmogorov-Smirnov statistic
> Provided placeholder performance targets for the MIC, to be updated with 2017 data
> Not accepted the proposed delayed introduction of the symmetrical financial incentive for the MIC
> Accepted 12 of the 22 priority projects from TransGrid's NCIPAP.

6.3.3 Response to Draft Decision

TransGrid:

> Accepts the AER's performance targets, caps and floors for parameters of the SC
> Accepts the introduction of the symmetrical financial incentive for the MIC
> Accepts a NCIPAP with the 12 approved projects.

For clarity, the NCIPAP projects accepted by the AER in the draft decision and included in this revised proposal are:

> North Western transfer tripping scheme
> Replace limiting high voltage plant at Wagga 132 kV substation (Line 99X rating augmentation)
> SMART wires on Upper Tumut-Yass 330 kV line
> Dynamic line rating monitoring
> Implementation of transfer tripping scheme at Cooma
> Implementation of transfer tripping scheme at Gadara, Tumut and Burrinjuck
> Queensland-New South Wales (QNI) interconnector capacitor bank
> Implement dynamic rating system for Darlington Point 330/220 tie transformers
> Replace limiting high voltage plant on Mt Piper-Wallerawang 330 kV lines (TL 70 and 71)
> Armidale capacitor transfer tripping scheme
> Increase ratings of Wagga-Lower Tumut 330 kV line (TL 051)
> Capacitor bank to improve NSW-Vic transfer limit.

These projects amount to $27.13 million ($m June 18), representing 0.68% of the MAR in our revenue proposal and therefore below the scheme's threshold of 1%.

The AER asked us to provide the 2017 data with the revised proposal. It has been agreed with the AER this data will be provided at the end of January 2018 following end of year and the availability of a complete data set.

6.4 Efficiency Benefit Sharing Scheme

6.4.1 Introduction

The efficiency benefit sharing scheme (EBSS) provides incentives for transmission network service providers to make ongoing efficiency improvements in operating expenditure. The version of the EBSS used by the AER and TransGrid for this revenue determination is EBSS version two[98], with a default carryover period of five years.

The EBSS is intended to work in combination with a revealed cost approach to setting operating expenditure forecasts. This ensures there is a continuous incentive for network service providers (NSPs) to make operating expenditure efficiency savings and a fair sharing of any efficiency gains and losses between NSPs and their customers[99]. In simple terms, both objectives are achieved by setting future operating expenditure allowances on the basis of revealed efficient costs and carrying over the incremental differences (gains/losses) between operating expenditure allowances and actual expenditures from the current regulatory period into the next regulatory period. With a five year regulatory period and a five year EBSS carryover period, this results in a 'benefit-sharing ratio' between the NSP and its customers in respect of the present value (PV) of any efficiency gains and losses of approximately 30:70, respectively, assuming a 6% real discount rate.

It's important to note that any efficiency gains/losses represented in the EBSS carryover amounts are derived from the application of the Rules and EBSS framework to historically determined operating expenditure allowances and actual expenditure achievements/outcomes resulting from decisions made *several years* prior (often two prior regulatory periods) to the upcoming regulatory control period.

TransGrid has focused on achieving year-on-year efficiencies via a number of initiatives in its business operations and has achieved expenditure levels below allowances set for the current 2014/15 – 2017/18 regulatory period. We have delivered real year-on-year savings, notwithstanding the absorption of costs from ownership changes, increased compliance, licencing requirements and regulatory risk. In setting our operating expenditure we intend to deliver a 3% real cost reduction from 2016/17, effectively delivering $26 million ($June 2018) of savings to customers for the next regulatory period.

In its draft decision the AER accepted TransGrid's operating expenditure in the 2016/17 base year as relatively efficient expenditure (based on its benchmarking data) and found no evidence of material inefficiency[100].

The AER's draft EBSS decision reduced TransGrid's proposed EBSS carryover amounts due to:

- Differing assumptions and sources of information used by TransGrid and the AER
- A mix of one-off and permanent adjustments to address EBSS framework inconsistencies.

The AER's draft determination approved carryover amounts totalling $15.3 million from the application of the EBSS in the 2014/15 – 2017/18 regulatory control period compared to TransGrid's $62.4 million in its proposal. TransGrid's revised submission is for $33.7 million as set out in the table below.

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98 AER: Efficiency Benefit Sharing Scheme for Electricity Network Service Providers, November 2013

99 AER: Framework and Approach for TransGrid 2018-2023, July 2016, p.13.

100 AER: TransGrid transmission draft determination 2018-23, September 2017, p.7-21.

Table 6.3: Revised EBSS carryover from the current period ($m June 18)

Regulatory year	2018/19	2019/20	2020/21	2021/22	2022/23
EBSS Carryover	13.1	13.1	0.4	7.0	-

Source: TransGrid.

6.4.2 Summary of TransGrid Proposal

TransGrid in its submission to the AER raised two matters regarding the EBSS framework:

- The length of the EBSS carryover period, when there is a change in the regulatory control period
- The inter-relationship between TransGrid's operating expenditure forecast and the EBSS.

Having addressed these issues, TransGrid applied the AER's EBSS guidelines along with the AER's EBSS model and proposed the following EBSS carryover values.

Table 6.4: Proposed EBSS carryover from the current period ($m June 18)

Regulatory year	2018/19	2019/20	2020/21	2021/22	2022/23
EBSS Carryover	25.4	25.4	3.4	8.3	-

Source: TransGrid.

Length of carryover period

In the AER's May 2015 determination for TransGrid, the AER determined that a four-year carryover period would apply for the 2014/15 to 2017/18 regulatory control period. At the time of the determination, TransGrid's next regulatory control period commencing 2018/19 was anticipated to be four years in duration.

With the forthcoming regulatory control period set to five years, TransGrid raised concerns with the AER that the four year carryover period for the EBSS may not be in the long term interests of consumers. TransGrid provided a number of examples in its revenue submission where we showed that the four-year EBSS carryover does not function correctly.

TransGrid prior to its revenue proposal had submitted to the AER through the Framework and Approach process that the current four year carryover period should be replaced with a five year carryover period for the EBSS incentives to work correctly[101]. The AER responded in the Framework and Approach final decision:

> …we understand TransGrid's concern that applying a four year carryover period may create inappropriate incentives.
>
> We consider the NER provides the flexibility for us to implement an EBSS in a way which will address any inappropriate incentives arising from a change in the duration of regulatory control periods. Noting this, if TransGrid considers that a four year carryover period creates inappropriate incentives, TransGrid should continue to pursue efficiency gains in line with the objectives of the EBSS. If, at the time of submitting its regulatory proposal, TransGrid maintains that a five year

[101] TransGrid, *Proposal to change EBSS carryover resulting from the current regulatory control period from 4 to 5 years*, Letter to the AER, 11 April 2016 [TransGrid-Letter to AER Regarding TransGrid 4 Year Carryover-0416-PUBLIC]

> carryover period is preferable, then we will consider whether that better meets the requirements of the NER. [102]

On the basis of the AER's advice TransGrid continued to pursue efficiency gains for the remainder of the current regulatory period and when submitting its revenue proposal applied a five year carryover period for its EBSS proposal.

Relationship between the EBSS and TransGrid's operating expenditure forecasts

In our revenue proposal, TransGrid proposed an alternative approach to estimating final year operating expenditure for the purposes of deriving operating expenditure forecasts over the upcoming regulatory control period. Our alternative is based on utilising the most recently available information about efficient costs to formulate the forecast rather than costs forecast at the previous regulatory reset.

In establishing the starting point for its operating expenditure forecast, TransGrid also considered the inter-relationship between the setting of operating expenditure forecasts and the application of the EBSS. We contended that it was appropriate to use our alternative approach to estimating an efficient and appropriate level of final year operating expenditure while using the AER's original approach when determining EBSS payoffs.

TransGrid progressed with this approach supported by advice provided by Frontier Economics; this advice indicated that there are no perverse or unintended outcomes in TransGrid using an alternative forecast for 2017/18 for its operating expenditure forecast in conjunction with version two of the EBSS:

> … it would be appropriate to continue applying the EBSS by using the existing methodology for final year estimation of actual opex alongside the use of the alternative methodology for forecasting opex for the next RCP [regulatory control period]. This combination would expose the TNSP to approximately 30% of the one-off gain or loss arising from differences between RoCn and RoCn+1. [103]

RoCn and RoCn+1 means the rate of change of operating expenditure in the current period and the rate of change of operating expenditure in the next period.

Therefore, TransGrid retained the AER's standard approach for calculation of the EBSS payments whilst adopting a modified approach to estimation of actual operating expenditure in the final year of the current regulatory control period.

6.4.3 Summary of AER's Draft Decision

In the draft decision, the AER approved EBSS carryover amounts from the 2014-2018 regulatory control period totalling $15.3 million ($2017-18). This is $47.1 million less than TransGrid's proposal of $62.4 million.

The AER applied version 2 of the EBSS[104] to TransGrid in the 2018/19 – 2022/23 regulatory control period with debt raising, network support and network capability costs excluded from the scheme[105].

The AER's draft EBSS decision reduced TransGrid's proposed EBSS carryover amounts due to:

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[102] AER: Framework and approach for TransGrid for regulatory control period commencing *1 July 2018*, July 2016, pp. 16-17

[103] Frontier Economics: *Prescribed operating expenditure forecast starting point*, January 2017, p.16 [TransGrid-Frontier Economics-Appendix J Opex forecast starting point-0117-PUBLIC]

[104] AER: Efficiency Benefit Sharing Scheme for Electricity Network Service Providers, November 2013

[105] AER Draft Decision TransGrid transmission determination 2018-2023, September 2017, p.9-7.

- Differing assumptions and sources of information used by TransGrid and the AER
- Newly introduced EBSS adjustments by the AER to address perceived inconsistencies in TransGrid's EBSS carryover amounts.

The reduction in EBSS carryover amounts was a result of the AER making the following decisions:

1. Reducing the carryover amount by $13.1 million to reflect a new modification to the EBSS made in response to one of the consequences of changing from a four to five year carryover period. According to the AER, changing from a four to five year carryover period in respect of incremental efficiencies made in the *current* regulatory period would result in TransGrid unfairly benefitting from an incremental efficiency loss made in the final year of the *previous* regulatory period (2013/14). To address this, the AER proposed to carry over the 2013/14 loss for an extra year, into the first year of the *next* regulatory period (2018/19).
2. Adjusting for an error in the AER's EBSS template that was incorrectly lagging inflation used to calculate the carryover amounts, resulted in a reduction of $10.8 million (*the actual impact was calculated by TransGrid to be $13 million*)
3. Reducing the carryover amount by $9 million to reflect differing:
    a. forecast determination allowances for 2009/10-2013/14 and 2014/5-2017/18 regulatory control periods (*2014-18 adjustments were as a consequence of the incorrect lagging of inflation above*)
    b. provision movements in defined benefits contributions and other employee provisions based on additional information
4. Reducing the carryover amount by $8.4 million to reflect a modification to the AER's standard approach, as set out in its EBSS guideline, to estimating final year (2017/18) operating expenditure for the purposes of determining EBSS carryover amounts. The AER instead used the same estimate of final year operating expenditure it used for the purposes of setting operating expenditure allowances for the next regulatory period. This resulted in treating $1.7 million of the underspending achieved in 2016/17 that was not repeated in 2017/18 as a 'non-recurrent efficiency gain' in 2016/17 and deducting it from TransGrid's carryover rewards for the next regulatory period.
5. Alignment of operating expense categories, as a consequence of differing AER decisions from one regulatory period to the next has resulted in expense categories (for example, self-insurance and demand management) being included or excluded from the EBSS allowances; to calculate the EBSS rewards or penalties on the same basis across regulatory periods (2009/10-2013/14 and 2014/15-2017/18) the cost categories have been aligned, resulting in a reduction of $5.9 million.

6.4.4 TransGrid's Revised Proposal

TransGrid accepts the AER's draft decision for points 2, 3 and 5 above and we explore the AER's decisions further in this section. TransGrid does not accept all of the AER's adjustments to the EBSS carryover amounts proposed in the draft determination. We have been penalised by the AER in its draft determination of the EBSS for:

- Changes to the regulatory control periods from five to four years in 2014/15 – 2017/18 and back to five years in 2018/19 – 2022/23
- Setting a realistic forecast of efficient expenditure.

The table below summarises the AER's adjustment to the EBSS carryover amounts and TransGrid's response to these.

Table 6.5: Summary of AER adjustments in the revised proposal

	AER Draft Decision Adjustment	TransGrid Response
1	AER adjustment to impose an additional one year penalty for an incremental efficiency loss in 2013/14.	TransGrid does not accept the AER's draft decision. TransGrid considers this to be a retrospective adjustment that should not apply, and the reasons are explained further in Section 13.4.2.
2	AER adjustment for an error in the AER's template for inflation.	TransGrid accepts the AER's draft decision.
3	AER adjustments for: > Forecast determination allowances > Provision of movements in defined benefits contributions and other employee provisions.	TransGrid accepts the AER's draft decision. TransGrid sourced its data from the final applicable AER revenue decision.[106] The AER has chosen to use an alternative source. The difference between the information used by TransGrid and the AER is immaterial, so TransGrid will accept the AER's decision. For 2013/14-2017/18 allowance adjustments the AER used a differing calculation method to convert to June 2018 dollars.
4	AER adjustment for 2017/18 operating expenditure forecasts.	TransGrid does not accept the AER's draft decision. TransGrid considers that the original guideline-based estimate of 2017/18 operating expenditure should not be adjusted and should be used for the purposes of determining EBSS carryover amounts. Making such an adjustment is inconsistent with the operation of the EBSS and imposes an inappropriate penalty on the business. TransGrid's reasons are explained further in Section 13.4.3.
5	AER adjusted 2012/13 and 2013/14 for expenses excluded in 2014/15.	TransGrid accepts the AER's draft decision.

Context to TransGrid's revised proposal for EBSS carryover amounts

The process of establishing the EBSS carryover amounts should be a result of:

- A simple application of the EBSS framework calculating the movements between allowances set in the prior periods and actual expenditure, taking away excluded expenditure, adjusting for accounting provisions and using the AER's determinations and the NSP's audited regulatory accounts
- Confidence by the business, when making expenditure decisions, that outcomes from the scheme are predictable and without risk of retrospective adjustments.

[106] AER: AER – Statement on updates for TransGrid transmission determination 2009-10 to 20013-14, Table 5: AER conclusion on TransGrid's controllable operating expenditure, for EBSS purposes. 25th November 2009.

TransGrid sought guidance from the Rules when preparing its revised proposal and considering whether to accept or not accept the EBSS adjustments and modifications by the AER in its draft determination.

Under the Rules, Section 6A.6.5, the EBSS should provide for a fair sharing of:

> Efficiency gains derived from the operating expenditure for a *regulatory control period* being less than the AER allowance
> The efficiency losses derived from the operating expenditure for a *regulatory control period* being more than the AER allowance[107].

Further, under Section 6A.6.6 a revenue proposal should include the forecast operating expenditure a TNSP considers is required to achieve the operating expenditure objectives. The AER must accept the forecast expenditure if it is satisfied that it reasonably reflects:

> The efficient costs of achieving the *operating expenditure objectives*
> The costs that a prudent operator would require to achieve the *operating expenditure objectives*[108].

The Rules do not contemplate the EBSS mechanism being used to allow the AER to reach into the next regulatory control period and penalise NSPs for costs incurred by the NSP, in the present regulatory period, that the AER has already found to be prudent and efficient and incorporated in the next period's operating expenditure allowance. The EBSS is explicitly set up to ensure fair sharing of the efficiency gains and losses made within a regulatory period, compared to the allowance set by the AER.

TransGrid's revenue proposal achieves the objectives of the Rules for both operating expenditures and EBSS, in a manner consistent with the AER's Expenditure Forecast Assessment Guideline and EBSS Guideline without recourse to special, punitive adjustments that do not meet the intent of the rules.

The AER's adjustments are considered further below.

Length of the carryover period

The five year carryover period adopted by TransGrid results in a:

> Resolution of the issues raised by TransGrid in a manner consistent with the representations made to TransGrid during the Framework and Approach process
> Fair sharing of efficiency gains and losses made in the current regulatory period (the EBSS aims to achieve a 30:70 sharing ratio with customers of incremental gains/losses based on a notional WACC of 6%).

Frontier Economics confirms that adopting TransGrid's five year carryover period for incremental efficiencies made in the current regulatory period achieves the above outcomes and correctly solves the problem of a change in carryover period lengths[109].

TransGrid has prepared its revenue submission in good faith

With the forthcoming regulatory control period set to five years, we raised concerns with the AER during the Framework and Approach process[110] that the four year carryover period for the EBSS may no

107 NER, cl 6A.6.5 (a) (1), (2).

108 NER, cl 6A.6.6.

109 Frontier Economics: Starting point operating expenditure and the efficiency benefit sharing scheme, November 2017, p.6.

110 TransGrid, *Proposal to change EBSS carryover resulting from the current regulatory control period from 4 to 5 years,* Letter to the AER, 11 April 2016 [TransGrid-Letter to AER Regarding TransGrid 4 Year Carryover-0416-PUBLIC]

longer be in the long term interests of consumers. This is because a four year carryover period combined with a five year regulatory control period:

> Does not fairly share efficiency gains made in the current regulatory period between TransGrid and its network users
> Creates an incentive for TransGrid to increase operating expenditure in the expected base-year
> Can reward TransGrid for efficiency losses and penalise it for efficiency gains
> Does not provide a continuous incentive for TransGrid to pursue efficiency improvements in operating expenditure.

TransGrid provided examples in its revenue proposal showing where the four-year EBSS carryover does not function correctly.

On the basis of the AER's advice in the Framework and Approach paper we continued to pursue efficiency gains for the remainder of the current regulatory period and when submitting our revenue proposal we applied a five year carryover period for EBSS revenue proposal.

What is an efficiency loss?

The AER considers the business has made an incremental efficiency loss if the underspend (allowance less expenditure) is less in one year than the prior year. TransGrid has achieved and expects to achieve, 3% real efficiency savings on operating expenditure from 2015/16 to 2016/17 and again in 2017/18. That is to say, year-on-year real operating expenditure reductions will be achieved. The AER's EBSS however measures TransGrid's 2017/18 savings as an incremental efficiency loss as the allowance in 2017/18 was also lower and our underspend is not as large as it was in the prior year.

AER has applied a one-off adjustment to TransGrid's EBSS carryover values

The AER in its draft determination now knowing that the regulatory control period commencing in July 2018 will be for five years has found that due to the current period only being four years, TransGrid's proposal for a five year carryover period would reward us for higher operating expenditure incurred in 2013/2014.[111]

The AER set out examples of the effect of switching to a five year carryover period in its draft determination as well as providing us with a spreadsheet model showing the impacts on the sharing ratios between the NSP and its customers pertaining to incremental efficiencies arising in different years.

As a consequence of the modelling the AER agreed with TransGrid that applying a four year carryover period for 2013/14 – 2017/18 would:

> Not fairly share efficiency gains between TransGrid and its network users
> Create an incentive for TransGrid to increase operating expenditure in the expected base-year, 2016–17
> Reward TransGrid for efficiency losses and penalise it for efficiency gains
> Not provide a continuous incentive for TransGrid to pursue efficiency gains[112].

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[111] AER Draft Decision TransGrid transmission determination 2018-2023, September 2017 p.9-11.

[112] AER Draft Decision TransGrid transmission determination 2018-2023,September 2017, p.9-13

The AER also considered that TransGrid's proposal to use a five year carryover period did not solve these problems and that it only changes the timing of them[113].

The AER draft decision referenced the NER requirement that the EBSS provides continuous incentives[114] and the AER generally considers this occurs when the length of the carryover period is the same as the length of the regulatory control period. However, we note that the Rules allow for changes in base years and regulatory control period lengths[115], but do not contemplate any adjustments to the EBSS (including carryover period) for changes of regulatory period lengths.

Therefore the AER has applied its own alternative approach by making a one off adjustment in respect of the incremental efficiency loss in 2013/14 by carrying it over for an additional year, into 2018/19. This means that the AER will be modifying TransGrid's carryover payments and operating expenditure target in the *next* regulatory period as a result of outcomes in the *previous* regulatory period. The value of this adjustment was a $13.1 million reduction in TransGrid's EBSS carryover amounts in the 2017/18-2022/23 regulatory period.

TransGrid's EBSS carryover amounts should not include a one-off adjustment

TransGrid proposes that a five year carryover period should be applied in calculating the EBSS component of the next revenue decision. This is because the current four year carryover period produces inappropriate rewards and penalties that are at odds with the objectives of the EBSS and a five year carryover period would align with the length of the next regulatory control period. We have honoured the spirit of the scheme and acted in accordance with its intended incentive properties and the AER's assurances, rather than seeking to take advantage of the potential gaming opportunities available under the current four year carryover period (eg, by boosting 2016/17 operating expenditure).

TransGrid rejects the AER's adjustment of $13.1 million to the EBSS carryover amounts for the next regulatory period.

As a regulatory principle, changing how a business is rewarded or penalised under an incentive scheme four years after the fact is at best, poor regulatory practice, and at worst an appropriation of business value.

TransGrid considers that the AER's adjustment:

- Is not consistent with the specific NER provisions, and
- Retrospectively alters EBSS payments in respect of incremental (in)efficiencies arising in the *previous* regulatory period even though TransGrid's business and operating decisions in 2012/13 and 2013/14 would not have been made on the basis of receiving any future windfall rewards or penalties as a consequence of the changing regulatory control period lengths and carryover periods.

The AER has not previously indicated any issues nor potential adjustments to the EBSS when the NSPs request a change in their regulatory control period lengths, and TransGrid's change was known well before TransGrid submitted its revenue proposal.

TransGrid engaged Frontier Economics to review the AER's justifications for adjusting the EBSS carryover amounts for the next regulatory period. We have attached their report which is set out at Appendix C. We set out below their key observations in respect of the AER's adjustment below.

[113] AER Draft Decision TransGrid transmission determination 2018-2023, September 2017, p.9-13

[114] NER, cl 6A.6.5 (b) (1).

[115] NER, cl 6A4.2 (a)(7)

I also note that the AER's modifications are not justifiable by reference to the specific NER provisions the AER emphasised in its EBSS guideline and explanatory statement regarding the length of the carryover period: The AER's modifications are not relevant to ensuring TransGrid faced continuous and balanced incentives to make opex savings in 2013/14. This is because at that time, TransGrid had no reason to believe that it did not face a continuous incentive to make efficiency savings or that it had incentives to (inefficiently) capitalise expenditure. The decision to adopt a four year RCP (2014/15 to 2017/18) and a four year carryover period was made too late to realistically influence TransGrid's opex and capitalisation incentives for that year. Thus, there is no efficiency purpose served by now retrospectively altering the EBSS payoffs in respect of the last RCP[116].

Conversely, TransGrid's behaviour from 2016/17 onwards was explicitly and directly influenced by the AER's representation that TransGrid "should continue to pursue efficiency gains in line with the objectives of the EBSS". No such undertaking was made by the AER prior to that representation, even though the adoption of the current four year RCP naturally altered the sharing ratios applicable to incremental savings made in the previous (2009/10 to 2013/14) RCP[117].

Further:

Modifications made now to sharing ratios that apply retrospectively to 2013/14 could not and will not affect TransGrid's incentives to make opex efficiencies and/or capitalisation decisions at any point in time. As such, they are inconsistent with the intrinsically forward-looking nature of expenditure incentive schemes and incentive regulation more generally[118]

The AER's modifications represent a far more detailed and *ad hoc* change to the EBSS than simply altering the length of the carryover period. Unlike the question of carryover length, the AER's modifications have not previously been discussed or even flagged in either the NER, the EBSS guideline or the AER's explanatory statement to the guideline. In this context, I highlight again that the AER's modifications have not even been defined algebraically, as the existing EBSS has.

For all these reasons, adoption of the AER's additional modifications to the EBSS would represent a departure from good regulatory practice[119].

Conclusion

TransGrid does not necessarily disagree with the intentions of the AER to appropriately apply the Rules and the EBSS Guidelines to ensure that the incentives, rewards and integrity of the EBSS scheme are maintained. However the application of an ad hoc, retrospective adjustment to TransGrid's carryover amounts in the EBSS serves no efficiency purposes, is inconsistent with the EBSS guideline, has not been previously flagged and accordingly, undermines good regulatory practice.

116 Frontier Economics: Starting point operating expenditure and the efficiency benefit sharing scheme, November 2017, p6.
117 Frontier Economics: Starting point operating expenditure and the efficiency benefit sharing scheme, November 2017, p6.
118 Frontier Economics: Starting point operating expenditure and the efficiency benefit sharing scheme, November 2017, p8.
119 Frontier Economics: Starting point operating expenditure and the efficiency benefit sharing scheme, November 2017, p8-9.

6.4.5 Forecast Starting Point

TransGrid's expenditure is accepted as efficient

The AER has accepted TransGrid's 2016/17 base year operating expenditure incorporating up to date escalation to be the appropriate basis of establishing the 2018/19-2022/23 allowance. The AER's benchmarking has accepted that TransGrid operates relatively efficiently when compared to the other service providers in the NEM. Having considered its benchmarking results, the AER is satisfied that TransGrid's estimate of operating expenditure in 2016/17 in not materially inefficient.[120] In the latest AER benchmarking study (2017), TransGrid is ranked second for operating expenditure partial factor productivity measurement[121], reflecting operational cost effectiveness.

TransGrid has been focused on achieving ongoing sustainable efficiency savings across all aspects of its business in the current regulatory period, including a critical evaluation of the business, externally undertaken by various independent parties for the purposes of the TransGrid lease transaction. The new lease holders acting on this advice implemented various business improvements following the award of the lease on 15 December 2015.

The long term cost savings initiatives and change of ownership has resulted in:

> Achieving an aggregate operating expenditure level in the current four year 2014/15 – 2017/18 regulatory period below the aggregate allowance set for the period

> An overall reduction in operating expenditure in real terms, year on year, for the past four years

> The 2016/17 year reflects the first full year of operations under a new ownership structure with a further reduction in actual operating expenditure compared to the forecast submitted by TransGrid in its revenue proposal

> TransGrid maintaining a high level of operating expenditure productivity in the AER's annual benchmarking study results

> The AER accepting TransGrid's forecasted operating expenditure in the 2016/17 base year as relatively efficient expenditure.

The 2016/17 results have been achieved notwithstanding that the nature and structure of the organisation has changed with TransGrid incurring increased costs in order to comply with new regulatory and statutory obligations following privatisation. This has occurred at the same time as public attention on the sector has increased, demanding increased participation in – and the allocation of managerial and staff resources to – the public energy policy debate and energy reviews, while at the same time dealing with increasing levels of regulatory and security risk.

Further, TransGrid in setting its operating expenditure for the next regulatory period intends to deliver a 3% real cost reduction from 2016/17 from its transformation program, effectively delivering $26 million ($June 2018) of savings to customers through a lower operating expenditure allowance for the next regulatory period.

[120] AER: Draft Decision TransGrid transmission determination 2018-2023, September 2017, p.7-21

[121] AER: Annual benchmarking report, electricity TNSPs Draft, November 2017, p.33.

TransGrid's EBSS carryover amounts should not contain penalties for efficient expenditure

The AER, in its draft decision, stated that it will adopt TransGrid's estimate of 2017/18 operating expenditure for the purposes for setting TransGrid's forecast allowance for the 2018/19 – 2022/23 regulatory control period. In doing so, the AER inferred that TransGrid's estimate implied a "non-recurrent efficiency gain" of $1.7 million in 2016/17, as TransGrid's 2017/18 estimate was $1.7 million higher than the estimate obtained using the AER's standard methodology[122].

The AER's standard methodology to establish the forecast starting point under its Expenditure Forecast Guideline[123] subtracts the current regulatory period (2014/15 – 2017/18) base year under or over spend from the final year operating expenditure allowance. This final year (2017/18) allowance was set in April 2015, using a trend forecast developed in 2014 as the basis for setting the allowance for the next regulatory period (2018/19 – 2022/23). This approach effectively uses a fictional starting point to estimate future efficient operating expenditure.

Put simply, the AER has accepted TransGrid's more accurate operating expenditure forecast for the 2018/19 – 2022/23 period but this, accordingly, has resulted in a $1.7 million higher allowance than it would have achieved if the AER applied its standard methodology. The AER has offset the same amount in the EBSS for the next five years.

TransGrid's EBSS carryover amounts should not contain penalties for efficient expenditure

TransGrid does not accept that the presumed "non-recurrent efficiency gain" in 2016/17 should be subtracted from EBSS payments made in the next period, especially as our base year operating expenditure has been accepted as an appropriate and efficient level of expenditure moving forward. Therefore, the fact that our 2017/18 allowance is below our 2016/17 allowance (which contributes to the inference of a non-recurrent saving in 2016/17) should not be taken into account in either setting our operating expenditure allowance for the next regulatory period *or* our EBSS payments in respect of incremental efficiencies made in the current period.

TransGrid does not agree with the EBSS adjustment as:

- It appears to be contrary to section 7A(2) the National Electricity Law by not allowing TransGrid a reasonable opportunity to recover *at least* its efficient costs
- Using efficient actual levels of expenditure as the base for the next regulatory control period will ensure that the magnitude of EBSS gains and losses are more representative of the real expenditure performance against the allowance set
- It will effectively discourage network service providers (NSPs) from submitting a realistic and efficient level of expenditure required to meet their operating requirements, as there is no incentive to do so with equal offsetting increase/decrease adjustments to the EBSS carryover amounts
- The AER's adjustment, in effect, undermines the very intent of the Rules 6A.6.6 which requires the AER to approve an efficient operating expenditure allowance
- The AER's approach does not consider any rate of change (RoC) impact that occurs over time from one regulatory period to the next when applying this adjustment, to the extent that TransGrid's final year estimate reflects updated RoC, it would be more appropriate to estimate final year operating expenditure for EBSS purposes using the old RoC (determined at the previous reset); this is because changes to the RoC are outside the NSP's control and hence there is no efficiency purpose served in exposing NSPs to the unmanageable risk of RoCs changing over time.

[122] AER: Expenditure Forecast Assessment Guideline November 2013.

[123] AER: Expenditure Forecast Assessment Guideline for Electricity Transmission, November 2013, p.30-31.

Conclusion

The AER's approach to adjusting EBSS carryover payments as a corollary to adopting TransGrid's proposed starting point operating expenditure estimate is not in accordance with the setting of an appropriate net operating expenditure target for the coming regulatory period. This is inconsistent with the requirements of the National Electricity Law and Rules, which provide that network service providers have a reasonable opportunity to at least recover their efficient costs.

6.4.6 Proposed carryover amounts from the current period

TransGrid has calculated the following carryover amounts using the AER's EBSS determination and adjusting for the items that TransGrid did not accept in this revised proposal.

Table 6.6: Proposed EBSS carryover from the current period ($m June 18)

Regulatory year	2018/19	2019/20	2020/21	2021/22	2022/23
EBSS Carryover	13.1	13.1	0.4	7.0	-

Source: TransGrid.

6.4.7 Application of the EBSS 2018/19 – 2022/23

TransGrid proposes the following operating expenditure forecast for EBSS purposes which is consistent with its operating expenditure forecast and excludes debt raising costs.

Table 6.7: Forecast operating expenditure for EBSS 2018/19 to 2022/23 ($m June 18)

Regulatory year	2018/19	2019/20	2020/21	2021/22	2022/23
Forecast operating expenditure for EBSS	172.0	173.4	175.3	177.4	179.6

Source: TransGrid.

7. Rate of Return

7.1 Introduction

The allowed return on capital is the building block component that covers the costs to the business of both debt and equity capital funding.

In all respects, TransGrid's proposal and the AER's draft decision were consistent on the approach to calculating the return on capital with the exception of the estimation of the market risk premium (MRP).

In our January 2017 proposal we estimated the MRP at 7.5% by applying the estimation method set out in the 2013 Guideline to the data that was available at the time of our proposal. Our estimate of the MRP is currently 7.0%, reflecting more recent movements in market rates. By contrast, the AER has consistently allowed an MRP of 6.5% since the publication of its 2013 guidelines, even as the relevant evidence has changed materially.

We note that the AER's MRP is now lower than almost every other recent regulatory decision issued in the last year. In its draft decision for TransGrid, the AER considered 14 recent regulatory determinations. Of these, 12 adopted an MRP above 7%, one adopted an MRP of 6.5% and one was legislatively required to use an MRP of 6%.

Nevertheless, in this revised proposal we have elected to accept the AER's draft decision MRP of 6.5% in the interests of reaching a consensus with the AER and minimising prices for consumers.

All other WACC parameters of the AER's draft decision and TransGrid's revenue proposal are agreed and TransGrid maintains these positions in this revised proposal.

7.2 TransGrid's approach

TransGrid's approach is in accordance with the AER's draft decision as follows:

> The allowed return is estimated as the vanilla weighted-average cost of capital (WACC) – a weighted average of the estimates of the cost of equity and the cost of debt
> The allowed cost of equity is estimated using the Sharpe-Lintner Capital Asset Pricing Model (SL-CAPM) and the AER's preferred values for the equity beta of 0.7, the MRP of 6.5% and the risk free rate.
> The allowed cost of debt is estimated as the yield on Australian 10-year broad BBB-rated corporate bonds in accordance with the estimation methods and transition approach set out in the Guideline and the AER's subsequent decisions
> Gearing (the relative proportion of debt financing) is estimated in accordance with the Guideline.

TransGrid proposes an allowed return (vanilla WACC) of 6.49%. We note that the risk-free rate and cost of debt will be updated with observations from the agreed averaging period prior to the AER's final decision being made and that the allowed cost of debt will be updated at the beginning of each year of the next control period.

Our return on capital proposal differs from the rate proposed in January 2017. These differences reflect:

> Current measures for the risk-free rate, which the AER will update again with observations from the agreed averaging period when it occurs
> A MRP of 6.5%, which reflects the AER's draft decision.

Table 7.1: Summary of TransGrid's Approach to the Rate of Return

Parameter	AER Rate of Return Guideline	TransGrid's approach	Value
Risk-free rate	Estimated at the commencement of each regulatory period as the yield on 10-year CGS averaged over 20 days.	Follows Guideline estimation approach. To be updated prior to the final decision.	2.66%
Equity beta	0.7	Adopts Guideline fixed estimate.	0.7
Market risk premium	Estimated at the commencement of each regulatory period commensurate with the prevailing market conditions. > Greatest[124] consideration to the long-run mean of historical excess returns; > Significant[125] consideration to the AER's DGM estimates. Two-step approach: > Set a range based on the aggregated ranges of its historical excess returns and DGM estimates; and > Use other relevant evidence to select a point estimate from within that range.	Accept AER draft decision	6.5%
Cost of equity	Sharpe-Lintner CAPM formula.	Follows Guideline approach.	7.2%
Cost of debt	Spot cost of debt estimated at the commencement of each regulatory year as the mid-point of RBA and Bloomberg estimates of the yield on Australian 10-year broad BBB-rated bonds. AER 10-year transition method applied. Updated at the beginning of each year of the regulatory period.	Follows Guideline estimation and transition approach. Quoted rate is for first year of regulatory period and reflects TransGrid's current transition path. To be updated prior to the final decision.	6.01%
Gearing	60%	Adopts Guideline fixed estimate.	60%
WACC	Vanilla WACC formula.	Follows Guideline approach.	6.49%

124 AER Rate of Return Guideline, Explanatory Statement, p. 95.

125 AER Rate of Return Guideline, Explanatory Statement, p. 97.

7.3 Cost of debt

In relation to the cost of debt, TransGrid has adopted, in full, the approach set out in the AER's 2013 Rate of Return Guideline. We have taken the mid-point of estimates provided by the Reserve Bank of Australia and Bloomberg for 10-year Australian BBB-rated corporate bonds and have applied the AER's transition from a "rate on the day" approach to the "trailing average" approach.

The AER has agreed with TransGrid's estimation of the cost of debt and we acknowledge this. We maintain the same approach to estimating the cost of debt in this revised proposal noting that the cost of debt allowance will be updated following completion of the agreed averaging period, and that this updated value will be applied in the final decision.

The cost of debt allowance will continue to be updated annually in accordance with the AER's transition approach.

7.4 Cost of equity

In relation to the cost of equity, TransGrid has aligned its estimate with the AER's draft decision in using the Sharpe-Lintner Capital Asset Pricing Model (SL-CAPM) as a foundation model.

TransGrid has adopted a risk-free rate of 2.66%, estimated as the yield on 10-year Commonwealth Government Securities in accordance with the AER's Guideline approach.[126]

TransGrid has adopted an equity beta of 0.7, consistent with the fixed estimate adopted in the AER's Guideline. TransGrid considers this figure to be conservatively low in that:

- More recent evidence indicates an increase in statistical beta estimates
- The AER's estimate does not fully correct for the low-beta bias that has been documented for the SL-CAPM
- The AER's estimate does not consider unregulated infrastructure firms that operate in workably competitive markets.

TransGrid has accepted a MRP estimate of 6.5% reflecting the AER's draft decision. However, we note that since the 2013 Guideline was published, the excess returns estimate has remained largely the same whereas the AER's DGM estimates have increased materially. This leads to a MRP of 7.0% for the prevailing market conditions. This is higher than the 6.5% estimate that the AER adopted for the financial market conditions in 2013. This higher MRP is commensurate with the change in market evidence over the ensuing period, and the application of the AER's Guideline approach to the more recent evidence.

Nevertheless, TransGrid's proposed cost of equity is based on:

- A risk-free rate of 2.66%
- An equity beta of 0.7
- A MRP of 6.5%.

This produces a cost of equity estimate of 7.2%,[127] which is 16% less than the allowed cost of equity in the 2013 Guideline.[128]

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[126] This will be updated to reflect an averaging period close to the commencement of the next regulatory control period, in accordance with the Rate of Return Guideline.

[127] 2.66%+0.7×7.0%=7.6%. This estimate will be revised to reflect data over the specified averaging period prior to the commencement of the next regulatory control period

The AER and TransGrid have agreed on the model to be used to estimate the cost of equity, the averaging period for the risk-free rate observations, and the equity beta. TransGrid maintains all of these positions in the revised proposal. Furthermore, TransGrid accepts the AER's draft decision MRP of 6.5%.

7.5 Averaging Periods

The AER has accepted TransGrid's proposed averaging periods for both the cost of debt allowance and the cost of equity allowance. TransGrid appreciates this and accepts the AER's decision.

7.6 TransGrid's revised proposal

TransGrid's revised proposal for the rate of return is 6.49%, reflecting a cost of debt estimate of 6.01% and a cost of equity estimate of 7.2%.

[128] 4%+0.7×6.5%=8.6%.

8. Depreciation & Regulatory Asset Base

8.1 Depreciation

Regulatory depreciation is part of the annual revenue building block reflecting the depreciated value of the regulatory asset base (RAB) over the 2018/19 to 2022/23 regulatory period.

8.1.1 TransGrid's Proposal

Depreciation was presented in chapter 10 of TransGrid's revenue proposal and calculated based on the AER's approach set out in the Roll Forward Model (RFM) and the Post-Tax Revenue Model (PTRM) respectively.

8.1.2 AER's Draft Decision

In the draft decision, the AER has:

> Accepted the straight-line depreciation calculation methodology
> Accepted the weighted average method to calculate remaining asset lives
> Accepted the inflation forecast methodology
> Accepted TransGrid's proposal to most of the standard asset lives except for Transmission Line Life Extension asset class. The AER has extended the proposed asset life of 25 years to 35 years
> Rejected the proposed roll-in amount for NSCAS and replaced it by the amount of zero
> Rejected the proposed depreciation for 2018/19 to 2022/23 period resulting from the changes made to forecast capital expenditure and updated for inflation and actual WACC adjustments on opening RAB.

8.1.3 Response to Draft Decision

TransGrid acknowledges the AER's acceptance of:

> The straight-line depreciation methodology
> The weighted average method to calculate the remaining asset lives
> Inflation forecast methodology
> Standard asset lives for most asset classes except for Transmission Line Life Extension asset class.

TransGrid accepts the AER's draft decision to extend the standard asset life for Transmission Line Life Extension asset class to 35 years. We do not accept all of the AER's changes to the capital expenditure forecast, and have revised our capital expenditure forecast as set out in chapter 4. TransGrid disagrees with the AER's draft decision to roll-in NSCAS at zero value. This is further discussed in chapter 4.

8.1.4 Revised Depreciation Forecast

The revised regulatory depreciation forecast on the basis of the revised capital expenditure and the latest RBA inflation forecast is shown in Table 8.1.

Table 8.1: Depreciation forecast ($m nominal)

	2018/19	2019/20	2020/21	2021/22	2022/23
Straight-line depreciation	257.6	281.0	300.8	310.5	328.4
Less: Inflation adjustment on RAB	-157.8	-162.6	-168.4	-174.1	-180.4
Regulatory depreciation	99.9	118.4	132.4	136.4	148.0

Source: TransGrid. Totals may not add due to rounding.

8.2 Regulatory Asset Base

The value of the regulated asset base is calculated in the AER's roll forward model (RFM). It refers to assets used by TransGrid to provide regulated network services.

8.2.1 TransGrid's Proposal

Chapter 7 of TransGrid's revenue proposal provided details of the proposed values for RAB as at 1 July 2018 and 30 June 2023 using the AER's RFM and post-tax revenue model (PTRM).

8.2.2 AER's Draft Decision

In the draft decision, the AER:

> Updated the opening RAB value as at 1 July 2018 reflecting the latest actual inflation and WACC for 2016/17

> Revised the forecast closing RAB at 30 June 2023 to reflect its draft decision forecast capital expenditure and regulatory depreciation

> Accepted the inclusion of the Network Support and Control Ancillary Services (NSCAS) assets as part of RAB but with a roll-in value of zero.

8.2.3 Response to Draft Decision

8.2.3.1 Opening RAB at 1 July 2018

TransGrid accepts the AER's RFM updates for 2016/17 actual inflation and the actual WACC input for 2017/18 and its effect on the level of depreciation. We acknowledge that the AER accepted the actual capital expenditure in our proposal for the 2014/15 and 2015/16 regulatory years.

In this revised proposal, we have updated the RFM with the actual audited capital expenditure for 2016/17, consistent with the annual regulatory accounts submitted to the AER for 2016/17 financial year. We have also substituted the 2017/18 capital expenditure forecast and asset disposals with the latest update. In addition, we have updated the forecast inflation for 2017/18 based on the August RBA Monetary Policy.

All of these updates are consistent with the AER's preferred approach.

The revised opening RAB as at 1 July 2018 is shown in Table 8.2.

Table 8.2: Roll Forward Value of the RAB ($m nominal)

RAB	2014/15 Actual	2015/16 Actual	2016/17 Actual	2017/18 Expected
Opening RAB	6,075.8	6,190.6	6,284.9	6,286.0
Net capital expenditure as incurred	254.6	251.7	188.0	230.4
Straight-line depreciation	-244.2	-261.9	-279.7	-265.0
Inflation adjustment	104.4	104.5	92.8	125.7
Closing RAB	6,190.6	6,284.9	6,286.0	6,377.0
Opening RAB 1 July 2018				**6,377.0**

Source: TransGrid. Totals may not add due to rounding.

8.2.3.2 Forecast Closing RAB at 30 June 2023

TransGrid accepts the updates on the inflation, actual WACC in the RFM and the amendment to the standard asset life for the “Transmission line life extension” asset class that we proposed.

We do not accept the AER’s draft decision on forecast capital expenditure and the roll-in value of zero for NSCAS.

In our revised proposal, we have revised downward our forecast capital expenditure for 2018/19 to 2022/23 as set out in chapter 4. We also updated the inflation forecast based on the August RBA Monetary Policy. Consequently the regulatory depreciation has been revised in section 9.1 of this chapter in accordance with the AER approved methodology.

Using the opening RAB shown in Table 8.2, the revised forecast capital expenditure and regulatory depreciation, the forecast RAB for 2018/19 to 2022/23 is shown in Table 8.3.

Table 8.3: Forecast Regulatory Asset Base ($m nominal)

RAB	2018/19	2019/20	2020/21	2021/22	2022/23
Opening RAB	6,377.0	6,573.8	6,807.6	7,038.1	7,291.1
Net Capital Expenditure as Incurred	296.6	352.2	362.9	389.4	295.2
Straight-line Depreciation	-257.6	-281.0	-300.8	-310.5	-328.4
Inflation Adjustment	157.8	162.6	168.4	174.1	180.4
Closing RAB	6,573.8	6,807.6	7,038.1	7,291.1	7,438.3

Source: TransGrid. Totals may not add due to rounding.

9. Maximum Allowed Revenue

The maximum allowed revenue (MAR) defines the maximum amount of revenue TransGrid proposes to be allowed to recover in each year of the upcoming regulatory control period.

9.1 Building Block Approach

9.1.1 Regulatory Asset Base

The revised opening RAB based on the updated actual capital expenditure for 2016/17 and revised forecast capital expenditure for 2017/18 is $6,377.0 million.

Asset values have been rolled forward using revised forecast capital expenditure described in chapter 4 and forecast regulatory depreciation and forecast RAB for 2018/19 to 2022/23 regulatory period are detailed in chapter 9. The revised forecast regulatory asset base is set out in Table 9.1.

Table 9.1: Revised Forecast Regulatory Asset Base ($m nominal)

RAB	2018/19	2019/20	2020/21	2021/22	2022/23
Opening RAB	6,377.0	6,573.8	6,807.6	7,038.1	7,291.1
Net Capital Expenditure as Incurred	296.6	352.2	362.9	389.4	295.2
Straight Line Depreciation	-257.6	-281.0	-300.8	-310.5	-328.4
Inflation Adjustment	157.8	162.6	168.4	174.1	180.4
Closing RAB	6,573.8	6,807.6	7,038.1	7,291.1	7,438.3

Source: TransGrid. Totals may not add due to rounding.

9.1.2 Inflation

The AER has accepted TransGrid's proposal to apply the current AER inflation forecast methodology based on the Reserve Bank of Australia's Statement of Monetary Policy.

TransGrid has applied 2.47% inflation based on the August 2017 Reserve Bank of Australia's Statement of Monetary Policy. We have used the RBA forecast for June 2018 and June 2019 with the mid-point of its long term target for this revised proposal as a proxy. This will be updated with the RBA June 2019 and June 2020 forecasts as they will be available when the AER makes the final decision.

The AER is currently undertaking a review of the approach to calculate expected inflation. The final decision is expected to be made by the end of 2017. In its draft decision, the AER has stated that it will adopt changes made to the Post Tax Revenue Model (PTRM) and Roll Forward Model (RFM) from the inflation review in the final decision. TransGrid accepts this position.

Currently, TransGrid bears the risk of any difference between forecast and actual inflation under the rules. In the 2014/15 to 2017/18 regulatory period, there has been a mis-match between forecast and actual inflation that is resulting in TransGrid receiving significantly reduced revenue than what would have been allowed if there had not been a mis-match. The level of under-recovery in this period to date is unprecedented. The revenue shortfall for 2014/15 to 2017/18 period arising from the error in the inflation forecast is $150 million in nominal dollars.

We note that the AER's approach of using a 10-year estimate, but re-setting everything after 5 years will always result in a mis-match between actual and forecast inflation. The impact of using a 10 year estimate means the forecast would on average be correct if applied for 10 years (assuming no bias in the forecast) but when reset every 5 years with a future 10 years of data means it will always mis-match actual inflation. IPART's WACC Review Draft Decision moves to a 5-year inflation forecast for precisely this reason.

9.1.3 Return on Capital

The return on capital has been calculated by applying the post-tax nominal vanilla WACC to the opening RAB in the respective year using the PTRM.

The revised post-tax nominal vanilla WACC is 6.49% detailed in chapter 7. The revised return on capital is summarised in Table 9.2.

Table 9.2: Revised Return on Capital ($m nominal)

	2018/19	2019/20	2020/21	2021/22	2022/23	Total
Opening RAB	6,377.0	6,573.8	6,807.6	7,038.1	7,291.1	
Return on Capital	413.6	426.4	441.6	456.5	472.9	2,211.1

Source: TransGrid.

9.1.4 Regulatory Depreciation

The revised regulatory depreciation, ie, return of capital, is discussed in chapter 9 and calculated using the PTRM and shown in Table 9.3.

Table 9.3: Revised Return of Capital ($m nominal)

	2018/19	2019/20	2020/21	2021/22	2022/23	Total
Return of Capital	99.9	118.4	132.4	136.4	148.0	635.1

Source: TransGrid.

9.1.5 Operating Expenditure

The revised operating expenditure is discussed in chapter 5. The forecast operating expenditure for 2018/19 to 2022/23 is summarised in Table 9.4.

Table 9.4: Revised Operating Expenditure ($m nominal)

	2018/19	2019/20	2020/21	2021/22	2022/23	Total
Operating Expenditure	176.2	182.1	188.6	195.6	202.9	945.4
Network Support Cost	0.7	2.7	6.3	11.1	-	20.7
Debt Raising Cost	3.3	3.4	3.5	3.7	3.8	17.8
Total	180.3	188.2	198.4	210.3	206.7	983.9

Source: TransGrid. Totals may not add due to rounding.

9.1.6 Revenue Adjustments

9.1.6.1 Efficiency Benefit Sharing Scheme and Capital Expenditure Sharing Scheme

The revised efficiency benefit sharing scheme (EBSS) and capital expenditure sharing scheme (CESS) outcomes are discussed in chapter 6. A summary of the EBSS and CESS amounts are detailed in Table 9.5.

9.1.6.2 Shared Assets

TransGrid acknowledges that the AER considers the shared assets proposal is reasonable and the materiality threshold is not met in any year of the 2018/19 to 2022/23 regulatory period and that the AER has not applied a shared asset revenue adjustment.

Updates contained in this revised proposal do not change this position and TransGrid maintains the position set out in the revenue proposal. No material updates to shared asset revenue or the maximum allowed revenue necessitate a further submission.

Table 9.5: Revised Revenue Adjustments ($m nominal)

	2018/19	2019/20	2020/21	2021/22	2022/23	Total
EBSS	13.5	13.8	0.5	7.7	-	35.4
CESS	6.9	7.1	7.2	7.4	7.6	36.2
Total	20.4	20.9	7.7	15.1	7.6	71.7

Source: TransGrid. Totals may not add due to rounding.

9.1.7 Value of Imputation Credits

The AER's draft decision for the value of imputation credits is 0.4 based on a utilisation method. In this revised proposal we have accepted this decision recognising the positive benefits to customers. Nevertheless, we do not agree with the AER that 0.4 reflects the best estimate. Rather, if applying a utilisation rate then the most appropriate and reliable method for estimating gamma is the ATO statistics approach which generates an estimate of 0.34. Further, the AER's analysis indicates that the ATO tax statistics approach provides an upper bound for the estimate of gamma.

We believe the AER overstates the difficulties in implementing reliably the ATO tax statistics approach, and understates the problems with its alternative estimation technique, the equity ownership approach which requires assumptions and adjustments to the data to generate an estimate.

9.1.8 Corporate Tax

Clause 6A.5.4(a)(4) of the Rules requires that the estimated cost of the corporate income tax allowance must be made as part of the post-tax nominal approach to the revenue decision.

TransGrid's proposed corporate tax was presented in chapter 11 of the revenue proposal.

In the draft decision, the AER has accepted the opening tax asset base at 1 July 2018 of $4,025 million. This has been updated for actual audited 2016/17 capital expenditure, consistent with the annual regulatory accounts submitted to the AER for the 2016/17 financial year. TransGrid has also revised its forecast capital expenditure and updated forecast inflation for 2017/18 in the revised proposal. The revised tax asset base for the 2014/15 to 2017/18 regulatory period is shown in Table 9.6.

Table 9.6: Revised Tax Asset Base Roll Forward ($m nominal)

	2014/15	2015/16	2016/17	2017/18
Opening Tax Asset Base	3,702.9	3,797.2	3,847.1	3,826.8
Net Capital Expenditure	285.6	252.1	133.7	363.8
Tax Depreciation	-191.3	-202.2	-154.1	-135.5
Closing Tax Asset Base	3,797.2	3,847.1	3,826.8	4,055.1

Source: TransGrid. Totals may not add due to rounding.

In the draft decision, the AER amended TransGrid's inputs for forecasting the cost of corporate income tax allowance for the 2018/19 to 2022/23 period including the standard tax asset lives and the value of imputation credits – gamma.

We accept the AER's amendments.. The AER's PTRM has been used to calculate the corporate tax allowance for the revised proposal.

The revised proposal for corporate tax is calculated based on:

> revised opening RAB, to reflect the actual 2016/17 capital expenditure and revised forecast expenditure for 2017/18
> standard tax asset lives aligning with AER's draft decision
> revised forecast operating expenditure in chapter 5
> revised forecast capital expenditure in chapter 4
> revised WACC in chapter 7
> revised EBSS and CESS in chapter 6
> revised gamma of 0.4 aligning with AER's draft decision.

TransGrid's revised corporate tax allowance using the AER's PTRM in accordance with the methodology set out in Clause 6A.6.4 of the Rules for the 2018/19 to 2022/23 regulatory period is shown in Table 9.7.

Table 9.7: Revised Corporate Tax Allowance ($m nominal)

	2018/19	2019/20	2020/21	2021/22	2022/23	Total
Corporate Income Tax	50.5	54.0	56.7	60.4	63.5	285.2
Less: Value of Imputation Credits	-20.2	-21.6	-22.7	-24.2	-25.4	-114.1
Total Allowance	30.3	32.4	34.0	36.2	38.1	171.1

Source: TransGrid. Totals may not add due to rounding.

9.1.9 Maximum Allowed Revenue

TransGrid's proposed unsmoothed revenue requirement for each year of the regulatory control period is calculated as the sum of the building block components. Based on the building blocks outlined in the previous sections, the revised unsmoothed revenue requirement for 2018/19 to 2022/23 is shown in Table 9.8.

Table 9.8: Revised Unsmoothed Revenue Requirement ($m nominal)

	2018/19	2019/20	2020/21	2021/22	2022/23	Total
Return on Capital	413.6	426.4	441.6	456.5	472.9	2,211.1
Return of Capital	99.9	118.4	132.4	136.4	148.0	635.1
Operating Expenditure	180.3	188.2	198.4	210.3	206.7	983.9
Revenue Adjustments	20.4	20.9	7.7	15.1	7.6	71.7
Net Tax Allowance	30.3	32.4	34.0	36.2	38.1	171.1
Annual Building Block Revenue Requirement (Unsmoothed)	744.4	786.3	814.2	854.6	873.4	4,072.9

Source: TransGrid. Totals may not add due to rounding.

9.1.10 Smoothed Maximum Allowed Revenue

The unsmoothed revenue is required to be smoothed over the 2018/19 to 2022/23 regulatory period. The revised smoothed revenue and x-factors over 2018/19 to 2022/23 period are shown in Table 9.9.

Table 9.9: Revised Smoothed Revenue Requirement ($m nominal)

	2018/19	2019/20	2020/21	2021/22	2022/23	Total
Unsmoothed Revenue	744.4	786.3	814.2	854.6	873.4	4,072.9
Smoothed Revenue	744.4	778.2	813.4	850.2	888.7	4,074.9
X-factor	-1.88%	-2.00%	-2.00%	-2.00%	-2.00%	

Source: TransGrid. Totals may not add due to rounding.

9.1.11 Average Price Path

TransGrid calculates its transmission charges based on the AER's approved revenue and the pricing principles in Clause 6A.23 of the Rules. The indicative average price path is estimated using the AER's PTRM, by dividing the smoothed revenue requirement by the energy delivered in New South Wales forecast by AEMO. The AER has adopted the June 2017 neutral operational forecast in its draft decision. We have adopted the same category data. TransGrid has used the latest demand forecast that was published by AEMO in its NEM Electricity Statement of Opportunity on 5 September 2017[129].

AEMO's latest energy forecasts have reduced by an average of 3.2% since we submitted the revenue proposal, this reduction in energy increases the calculated average price for customers. TransGrid's revised proposal annual average price reduction has accordingly reduced compared to the January proposal, to an average 3.89% real price reduction.

The average price path over the 2018/19 to 2022/23 period is shown in figure 9.1.

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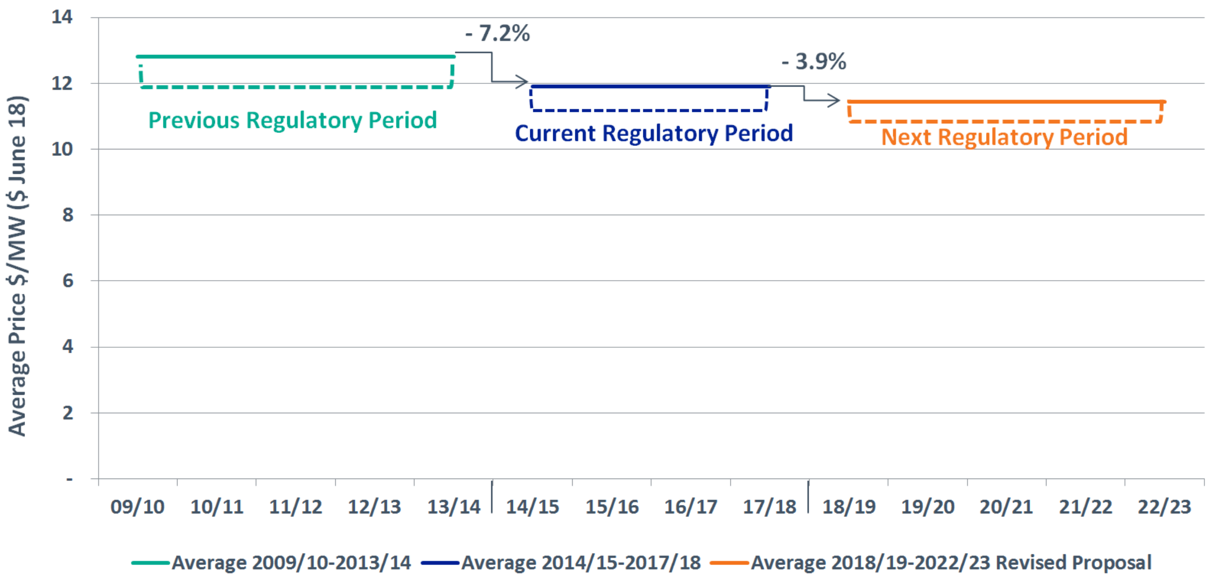
[129] AEMO, NEM Electricity Statement of Opportunity, September 2017. TransGrid notes that the AEMO confirmed that the years indicated in the forecast are referring to financial year end.

Figure 9.1: Average Price Path ($ June 18)



Source: TransGrid.

10. Pass through events, Negotiating Framework and Pricing Methodology

10.1 Introduction

This chapter covers:

- Pass through events
- Negotiating Framework
- Pricing Methodology.

10.2 Pass through events

Cost pass through arrangements provide for adjustments to the allowed revenue if a non-controllable predefined event occurs that leads to a material change in TransGrid's costs. It is intended for a TNSP to recover at least the efficient costs of uncontrollable, material events that either cannot be insured for or where the establishment of self-insurance is not economically viable.

The AER has accepted TransGrid's nominated pass through events.

TransGrid notes that since submission of its revenue proposal the Rules have changed and further prescribed pass through events have been included within Clause 6A.7.3., reflecting new obligations placed on transmission network businesses. We expect that these new pass through events will apply to TransGrid in the event they should occur during the 2018/19 to 2022/23 regulatory period.

10.2.1 TransGrid's proposal

Chapter 17 of our revenue proposal sets out the following nominated pass through events in addition to those prescribed by Clause 6A.7.3 of the Rules:

- Insurance cap event
- Terrorism event
- Insurer credit risk event
- Natural disaster event.

Under Clause 6A.7.3 the prescribed pass through events at the time of TransGrid's revenue submission, were:

- Regulatory change event
- Service standard change event
- Tax change event
- Insurance event.

10.2.2 AER's Draft Decision

The AER has accepted TransGrid's nominated pass through events in the draft decision.

10.2.3 Response to Draft Decision

We acknowledge the AER's acceptance of the proposed nominated pass through events.

On 17 September 2017, the Australian Energy Market Commission (AEMC) made a final rule to place an obligation on Transmission Network Service Providers (TNSPs) to procure minimum levels of inertia or procure other services such as frequency control services that reduce the minimum level of inertia required. The relevant TNSP must make continuously available minimum required levels of inertia, determined by AEMO, where an inertia shortfall exists in a sub-network either by itself or procure inertia services from third parties such as generators. The Rules permit the TNSPs to invest in or contract with third-party providers of alternative frequency control services ("inertia support activities"), including fast frequency response (FFR) services, as a means of reducing the minimum required levels of inertia, with approval from AEMO.

The final Rule determination states that a new category of pass through event – an "inertia shortfall event" will be added under chapter 6A.7.3 of the Rules[130].

On 19 September 2017, the AEMC published a final rule to place an obligation on TNSPs to maintain minimum levels of system strength[131]. The final rule enables the TNSPs to procure these services in a timely manner needed to maintain system security.

The final rule adds a new category of pass-through event under Clause 6A.7.3 – a "fault level shortfall event". A fault level shortfall event occurs where a TNSP is required to provide, or cease providing, system strength services and meeting this requirement materially increases or decreases the TNSP's costs of providing prescribed transmission services.

TransGrid expects the final decision should reflect the new Rules which will apply to TransGrid should any inertia shortfall event or fault level shortfall event occur during the 2018/19 to 2022/23 regulatory period.

10.3 Negotiating framework

In its draft decision the AER approved TransGrid's proposed negotiating framework for Negotiated Transmission Services for the 2018/19 to 2022/23 regulatory period.

TransGrid accepts the AER's draft decision and maintains this position in the revised proposal.

10.4 Pricing Methodology

In its draft decision the AER approved TransGrid's proposed Pricing Methodology for the 2018/19 to 2022/23 regulatory period.

TransGrid accepts the AER's draft decision and maintains this position in the revised proposal.

[130] Rule Determination National Electricity Amendment (Managing the rate of change of power system frequency) Rule 2017, Australian Energy Market Commission, Executive Summary, P10.

[131] Rule Determination National Electricity Amendment (Managing power system fault levels) Rule 2017, Australian Energy Market Commission, Executive Summary

11. Glossary

Acronym/Term	Definition
ABS	Australian Bureau of Statistics
ACT	Australian Capital Territory
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ALARP	As low as reasonably practicable
ASD	Australian Signals Directorate
ATO	Australian Taxation Office
BEE	Benchmark Efficient Entity
CAPM	Capital Asset Pricing Model
CBD	Central Business District
CCP	Consumer Challenge Panel
CDN	Corporate Data Networks
CERT	Computer Emergency Response Team
CESS	Capital Expenditure Sharing Scheme
CIC	Critical Infrastructure Centre
CPI	Consumer Price Index
COAG	Council of Australian Governments
CoF	Consequence of Failure
DGM	Dividend growth model
DM	Demand management
EBSS	Efficiency Benefit Sharing Scheme
EGWWS	Electricity, Gas, Water and Waste Services
EIS	Environment Impact Assessment
EMCa	Energy Market Consulting Associates
ES C2M2	Electricity Subsector Cybersecurity Capability Maturity Model
FFR	Fast frequency response
FTE	Full time equivalent
Gamma	The value of dividend imputation tax credits

Acronym/Term	Definition
GFC	Global financial crisis
IAP2	International Association for Public Participation
IPART	Independent Pricing and Regulatory Tribunal
ISMS	Information Security Management System
LoC	Likelihood of consequence
MAR	Maximum allowed revenue
MIC	Market Impact Component
MRP	Market risk premium
NASA	National Aeronautics and Space Administration
NCC	Network Capability Component
NCIPAP	Network capability incentive parameter action plan
NEM	National Electricity Market
NER	National Electricity Rules
NIEIR	National Institute of Economic and Industry Research
NPV	Net Present Value
NSCAS	Network Support Control Ancillary Services
NSP	Network Service Provider
NSW	New South Wales
NTNDP	National Transmission Network Development Plan
OER	Option Evaluation Report
PACR	Project Assessment Conclusion Report
PADR	Project Assessment Draft Report
PESA	Public Electricity Safety Awareness Plan
PoF	Probability of failure
PSCR	Project Specification Consultation Report
PSF	Powering Sydney’s Future
PTRM	Post Tax Revenue Model
PV	Present value
QNI	Queensland-New South Wales Interconnector
RAB	Regulatory asset base
RBA	Reserve Bank of Australia
RCP	Regulatory Control Period

Acronym/Term	Definition
Repex	Replacement capital expenditure
RFM	Roll Forward Model
RIT-T	Regulatory Investment Test for Transmission
RPWG	Revenue Proposal Working Group
Rules	National Electricity Rules
SC	Service Component
SCADA	Supervisory control and data acquisition
SL-CAPM	Sharpe-Lintner Capital Asset Pricing Model
SSZ	Substation Security Zone
STPIS	Service Target Performance Incentive Scheme
TAC	TransGrid Advisory Council
TAPR	Transmission Annual Planning Report
US	United States of America
VCR	Value of Customer Reliability
VoSL	Value of Statistical Life
WACC	Weighted-average cost of capital
WPI	Wage Price Index

12. Appendices

Appendix	Topic	Author
A	Expected Wage Changes	BIS Oxford Economics
B	IT Step Change compliance with NSW licence conditions	TransGrid
B1	Licence Conditions Audit	HIVINT
B2	Licence Draft Transition Plan	TransGrid
C	AER modifications to the EBSS	Frontier Economics
D	Review of the CESS model	HoustonKemp