AUSTRALIAN ENERGY REGULATOR

GPO Box 3131
Canberra ACT 2601

Telephone: (02) 6243 1233
Facsimile: (02) 6243 1205

www.aer.gov.au

CCP Consumer Challenge Panel

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AER Board
Mr Adam Pertersen, Co-ord Director – TG/ElectraNet/Murraylink Reset
Australian Energy Regulator
By email: adam.petersen@aer.gov.au Cc: ccp@aer.gov.au

Dear Paula,

Re: TG Transmission Determination 2018 to 2023

Please find attached our submission on the AER's Draft Decision and TG's Revised Proposal in relation to the above network determination/access arrangement.

Kind Regards,

Eric Groom

Consumer
Challenge
Panel

Submission to the Australian Energy Regulator (AER)

Consumer Challenge Panel Sub-Panel 9

Response to Draft Decision and Revised Proposal for Revenue Reset for TransGrid for 2018-2023

Sub-Panel 9

Eric Groom

Bev Hughson

Andrew Nance

Click here to enter Sub-panel member name.

January 2018

1. Executive Summary

CCP9 has considered the AER Draft Decision and the Revised Proposal of TransGrid (TG) in light of the objective of the CCP which is to:

- advise the AER on whether the network businesses' proposals are in the long term interests of consumers; and,
- advise the AER on the effectiveness of network businesses' engagement activities with their customers and how this is reflected in the development of their proposals.

In this section of our advice to the AER we summarise the issues of interest to CCP9 and our recommendations as follows:

1.1 Consumer Engagement

CCP9 has been closely monitoring the developments in the industry framework for effective consumer engagement that is being led by the ENA, AER and the Energy Consumers Association. The engagement process is being built around the principles of consumer collaboration with the networks in the development of their revenue proposals and tariff structures. CCP9's review of TG's consumer engagement since the publication of the draft determination reflects these trends towards respectful, transparent and collaborative decision making with all stakeholders including the regulatory bodies.

CCP9 notes that in its revised revenue proposal, TG's has also expressed interest in moving towards a more collaborative decision-making process. In this review of the customer engagement processes CCP9 has sought to contribute to TG's objective and further the overall industry reform by highlighting areas where TG could have benefited from a more collaborative approach and we note the comments from a number of stakeholders that they too are looking for these opportunities using approaches such as deliberative forums.

CCP9 also notes that TG's stakeholder groups have considerable expertise in renewable energy, demand management, energy efficiency as well as business and energy industry knowledge. This is an excellent base for TG to build on in the future. For example, in this review we have identified opportunities for collaboration on additional ways TG might tap into energy efficiency and demand opportunities outside the RIT-T process to improve reliability and reduce the pressure on expensive infrastructure programs.

Since the AER's draft decision, CCP9 attended, as observers, two meetings organised by TG during the development of its revised revenue proposal. Our observations in these meetings have been supplemented by a review of the submissions to the AER and further discussions with a number of these stakeholders.

Overall, TG's consumer engagement following the publication of the draft decision has been positively received by the stakeholders, particularly in the context of TG's decision to propose a modified Powering Sydney Future (PSF) project. Support for the modified PSF project was widespread amongst these stakeholders as they see the modifications as a practical response to the uncertainties around the forecasts of demand and cable reliability while still enhancing security of supply to meet Inner Sydney's growing population and new large infrastructure projects that are underway or in planning.

However, CCP9 also observed that some stakeholders remained uncertain about a number of the assumptions that TG has adopted in its modelling, particularly for replacement capex and the PSF proposal and for the AER to accept the outcomes of the engagement process. If TG wish to continuing moving to working collaboratively with consumers and have AER place substantial weight on the outcomes, the information needs to be presented in a balanced manner, in an accessible form, with sufficient detail and with sufficient time for stakeholders to analyse the information and consider their position. One option would be deliberative workshops with stakeholders that allow for deeper dives on specific issues.

CCP9's perhaps more fundamental concern is the impact that this approach has on consumers' perception of the regulatory process and their confidence in both TG and the AER. The consistent feedback received by the CCP9 is that stakeholders are looking for the AER and TG to come to an agreement on key assumptions early in the process so that stakeholders can focus on the application of these assumptions: "the revenue proposal should be about the application of the agreed parameters".

In line with a number of submissions from stakeholders CCP9 suggests that going forward, these issues can be better addressed through the use of mechanisms such as deliberative forums on key issues where consumers can more actively lead the process. Exploring ways to enhance energy efficiency and demand management provides an excellent first step on the next stage of TG's consumer engagement journey. The model used by Electranet and AGN – and proposed to be adopted by some of the NSW DNSPs in the current revenue reset – is the publication of a preliminary revenue proposal for review by stakeholders/public. CCP9 appreciates that TG has indicated it will consider this for its next reset.

Recommendations:

a) AER attends these important meetings, at TG's invitation, if only to clarify misunderstandings.
b) TG consider adopting joint deliberative forums (or similar) which provide more opportunity for stakeholders to participate and contribute depth to the revenue proposal based on their experience.

1.2 Revenues and Tariffs

The AER draft decision proposed an 8.5% reduction from the maximum allowed revenue (MAR) proposed by TG. The largest and most contentious change was the 40% reduction in the capex program, which resulted in an end-period RAB that was 9% below that proposed by TG. TG's Revised Proposal reduced the MAR by 4.6% compared to the original proposal. This was around half the reduction proposed in the draft decision. Capex remains the most contentious area and the proposed capex in the Revised Proposal was only 5% lower than in the original revenue proposal.

Regulatory revenues and prices fell during the current regulatory and revenues and prices for 2017-18 are below the average for the regulatory period (2014-18). Thus, while maximum allowed revenues will increase in real terms during the regulatory period, the average revenue for 2018-23 will below that for 2014-18 in real terms. The average MAR for 2018-23 under the draft decision is

5.9% below the average MAR for 2014-18 in real terms, but the MAR in 2022-23 is 3.5% higher in real terms than it is in 2017-18. Reflecting this, average prices increase by 6% in real terms from 2017-18 to 2022-23 under the draft decision.

1.2.1 Capital Expenditure and RAB

Overall it has been challenging for consumers to engage on the Capex program. The reviews of major programs such as Repex and Powering Sydney's Future by the AER have involved large volumes of material provided by TransGrid under information requests that were not made generally available. The timing of the requests and the responses have not been conducive to a process with which consumers can engage. Neither TransGrid nor the AER can escape criticism in this regard.

The level of disagreement between TransGrid and AER/EMCa is of concern and the parties should seek to work together in a collaborative manner to seek to reduce the extent of disagreement so that consumers to be confident that the level of expenditure is sufficient, but no more than that, to efficiently maintain reliability of supply. CCP9 would be happy to assist in the process to resolve the differences of view on the capex forecasts if all parties consider that would be helpful.

In relation to PSF, CCP9 is not of the view that no expenditure is a prudent response to the inevitability of replacing these oil-filled cables. However, the revised proposal for $252m is also a significant investment and has not yet been sufficiently justified.

Recommendations:

a) TransGrid and AER/EMCa should work together in a collaborative manner to seek to reduce the extent of disagreement so that consumers can be confident that the level of replacement capital expenditure is sufficient, but no more than that, to efficiently maintain reliability of supply. CCP9 would be happy to assist in the process to resolve the differences of view on the capex forecasts if all parties consider this helpful
b) AER review augmentation capital expenditure in light of the absence of discussion of whether the reliability improvements are ones that consumers are willing to pay for, or to meet compliance obligations
c) Seek IPART's opinion on the discretion afforded by the reliability framework in relation to Reliability capital expenditure forecasts (rather than this be interpreted by TransGrid or the AER)
d) AER review TransGrid's approach to connection driven capital expenditure, in particular the statement that the approach balances the costs to consumers but includes some risk for TransGrid
e) AER seek to provide briefings to key stakeholders on the assessment of PSF
f) Consider an alternative investment program that includes a comprehensive Demand Management Program in order to manage demand risk and a reasonable allowance for pre-construction costs that would allow for rapid implementation of a single-cable construction program in the subsequent regulatory period if the need is demonstrated five-years hence.
g) The IT capital expenditure be linked to productivity or capability improvements and AER to consider benchmarking of this significant expenditure category between NSPs.
h) Consider the contingent project triggers in light of AEMO's Integrated System Plan and seek consistency with the approach for other TNSPs. Consider presenting a range of plausible impacts on TransGrid's RAB of a proportion of the contingent projects in order for consumers to understand the potential scale of the investments proposed.

i) Reject the addition of NSCAS assets to the RAB at a value above $0

1.2.2 Operating Expenditure

The AER's assessment of TG's opex is based on its well-documented base-step-trend approach. In its draft decision the AER reduced TG's proposed opex by $75m, predominantly due to the exclusion of step changes proposed by TG and different assumptions on trend changes. The AER found that TG was not materially inefficient and accepted the forecast base opex with minor changes. It rejected the TG's step change for off-easement vegetation management and proposed debt raising costs. In estimating cost trends the AER assumed a trend productivity improvement of 0.2% rather than TG's assumption of 0%, and did not accept TG's assumed rate of increase in wages and salaries and the weighting to be given to wages and salaries.

In its Revised Proposal TG accepted most of the changes proposed by the AER. Overall, CCP9 is pleased to see the greater degree of accordance between the AER's DRAFT DECISION and TG's revised proposal. CCP9 understood that in its initial proposal, TG was seeking to introduce what it saw as innovation in the AER's approach.

The variations between the opex in AER's Draft Decision and the opex in TG's Revised Proposal reflect:

- Updated data
- Minor changes that TG consider correct or improve on AER's estimates
- Further information on the step change for compliance with the security provisions of its operating licence.

TG reverts to the productivity assumption of 0% on the basis that that this reflects AER's approach in the Draft Decision up-dated for AER's most recent benchmarking data.

We support AER's proposed opex in its draft decision with the amendments proposed by TG subject to the following:

- The need for AER to carefully review the minor adjustments to the base year opex proposed by TG, particularly in light of their ongoing impacts
- CCP9's concern, which is shared by other customer groups, at the ongoing low opex productivity growth in the sector
- The need for the AER to review the cash flow timing assumptions in the PTRM given the upward bias identified in the draft report

We agree that the assumption of the 0% productivity improvement is consistent with the latest benchmark data but consider that a higher productivity assumption would be achievable and more consistent with the objectives of incentive-based regulation and the long-term interest of consumers. We remain very concerned that the industry measures continue to show a decline in opex partial factor (and multi factor) productivity. In normal competitive market circumstances, it would be reasonable to expect that replacement of assets and investment in IT would at the very least, result in improvements in opex productivity measures. The fact that it does not, and has not done so over an extended period of time, suggests that the opex productivity measure and/or the EBSS are not delivering the outcomes consumers should expect.

Recommendations:

a) CCP9 supports AER's proposed opex in its draft decision with the amendments proposed by TG in its revised proposal subject to the recommendations below.
b) Given the cash flow bias identified in the draft decision, the AER should separately review the cash flow assumptions in the PTRM.
c) Given that this figure is the starting estimate for the forecasts and the impact of errors in the initial starting point is cumulative over the forecast period, small differences in the starting estimate can have a more substantial impact across the five years, the AER should carefully examine the base year opex figures to ensure that they do not include one-off events that should not be carried forward.
d) The base year estimate for opex use in forecasting opex should also be used for the EBSS.
e) CCP9 agrees with TG, that the AER should adopt EI's revised transmission output measures and update the customer number forecast but forecasts of customer numbers over the next regulatory period should rely on multiple established forecasting sources
f) AER should update its analysis of benchmark debt transactional costs
g) CCP9 remains very concerned that the industry measures continue to show little, if any, productivity growth and considers that the regulated transmission industry as a whole has not responded effectively to the regulatory incentive regime. The AER should separately undertake a review of the effectiveness of the incentive schemes and the overall expenditure forecasting approach

1.2.3 Rate of Return, Inflation and Tax

The AER Draft Decision proposed a WACC of 6.5% (nominal vanilla), consistent with the AER's Rate of Return Guideline, and slightly lower than the 6.6% WACC proposed by TG) due to the retention of the market risk premium (MRP) of 6.5%. The AER used a gamma (value of imputation credits) of 0.4, consistent with the Rate of Return Guideline, in estimating the allowance for tax expense, compared to TG's proposed gamma of 0.25. In preparing its Revised Proposal TG accepted the AER draft decision in regard to the WACC, although with some reservations on the MRP and Gamma.

CCP9 supports the application of the AER's application of the Rate of Return Guideline and, as a consequence of this, the proposed WACC of 6.5%. CCP9 also welcomes TG's acceptance, with reservations, of the AER's draft decision. In doing so, CCP9 notes that it also has reservations – albeit different ones – in regard to the AER Draft Decision.

- It considers that AER's current approach and values for key parameters have resulted in WACCs that have systematically erred on the high side, but that this is best considered through the current review of the Rate of Return Guideline.
- It supports the CCP submission to the Rate of Return guideline.

Recommendations:

a) CCP9 accepts the proposed WACC of 6.5% (nominal, vanilla) and recommends that in its final decision the AER updates the proposed WACC for changes in interest rates but does not otherwise change it.

b) CCP9 supports the AER's Draft Decision to use a gamma of 0.4 and the AER's current methodology for estimating inflation expectations (2.5% based on current data)

1.2.4 Incentive Schemes

The AER's Draft Decision proposes to continue to apply the EBSS, CESS, and STPIS with an EBSS carryover of $15.3 million and CESS carryover of $24.3 million from the 2014-18 regulatory period. TG accepted the Draft Decision on the incentive mechanisms but proposed modifications to the calculation of the carryover amounts

CCP9 considers that the incentives to improve efficiency are in the long-term interest of consumers as long as the efficiency gains are not at the expense of service quality and supports the application of the EBSS, CESS, and STPIS as proposed in the AER's draft decision. We have carefully considered the proposed changes to the calculation of the carryover amounts . The key questions in regard to the EBSS are:

a) whether the same estimate of opex in 2017-18 should be used in forecasting Opex for the next regulatory period and calculating the EBSS carryover. Our view is that it should, which is consistent with the AER's draft decision.
b) Whether, in changing the carryover period to apply to 2014-18, the carryover from 2013-14 should also be changed to avoid creating a windfall gain/loss. Our view is that it should, which is consistent with the AER's draft decision.

The issues in regard to the calculation of the benefits under the CESS are complex. We consider that the current calculation accurately calculates the cash flow benefit to the TNSP from capex efficiency. But TG has raised questions as to whether this properly reflects the revenue allowed under the AER's revenue building block models. We consider that in principle the two values should be the same and the apparent differences raise concerns that need to be considered.

Recommendations:

a) CCP9 supports the calculation of the carryover amounts under the EBSS as proposed in the Draft Decision
b) The AER should examine further the reasons for the discrepancy between the HK approach and the current CESS model, which CCP9 considers correctly values the financing benefit from the increased cash flows.
c) Unless the two models can be reconciled or it be shown that the current approach does not correctly value the financing benefits of the improved cash flows, the current approach, as set out in the Draft Decision, should be maintained.
d) CCP9 supports the application of the EBSS, CESS, and STPIS as proposed by the AER.

2. Background

- This advice was prepared in accordance with the Schedule of Work agreed upon between sub-panel CCP9 working on the TG revenue reset and Adam Petersen and Andrew ley, Co-ordination Directors for 2018-2023 Revenue Resets for Electranet, Murraylink and TG.
- TG commenced the process of preparation of their access arrangement proposal and the related consumer engagement early in 2016. During 2016 TG undertook a range of consumer engagement activities and processes.
- CCP 9 was established in September 2016.
- CCP9 members have participated as observers in most of the in most of the meetings of the TG's Advisory Group and Revenue Proposal Working Group over this period. TG also provided a briefing, at the request of CCP9, on their Revised Revenue Proposal.
- CCP 9 has held regular meetings with the Co-ordination Directors through the course of this review. Of particular relevance to the preparation of this submissions were:
    - A briefing on the draft decision by AER
    - A briefing on the Revised Proposal by TG
    - A teleconference requested by CCP9 with EMCa and AER to discuss the issues raised by TG in regard to the review of the Capex program
    - A briefing by the AER on their assessment of the revised proposal for Powering Sydney's Future proposed by TG.

3. Consumer Engagement

CCP9 has been closely monitoring the developments in the industry framework for effective consumer engagement that is being led by the ENA, AER and the Energy Consumers Association. The engagement process is being built around the principles of consumer collaboration with the networks in the development of their revenue proposals and tariff structures. CCP9's review of TG's consumer engagement since the publication of the draft determination reflects these trends towards respectful, transparent and collaborative decision making with all stakeholders including the regulatory bodies.

CCP9 notes that in its revised revenue proposal, TG's has also expressed interest in moving towards a more collaborative decision-making process. In this review of the customer engagement processes CCP9 has sought to contribute to TG's objective and further the overall industry reform by highlighting areas where TG could have benefited from a more collaborative approach and we note the comments from a number of stakeholders that they too are looking for these opportunities using approaches such as deliberative forums.

CCP9 also notes that TG's stakeholder groups have considerable expertise in renewable energy, demand management, energy efficiency as well as business and energy industry knowledge. This is an excellent base for TG to build on in the future. For example, in this review we have identified opportunities for collaboration on additional ways TG might tap into energy efficiency and demand opportunities outside the RIT-T process to improve reliability and reduce the pressure on expensive infrastructure programs.

Since the AER's draft decision, CCP9 attended, as observers, two meetings organised by TG during the development of its revised revenue proposal. Our observations in these meetings have been supplemented by a review of the submissions to the AER and further discussions with a number of these stakeholders.

Overall, TG's consumer engagement following the publication of the draft decision has been positively received by the stakeholders, particularly in the context of TG's decision to propose a modified Powering Sydney Future (PSF) project. Support for the modified PSF project was widespread amongst these stakeholders as they see the modifications as a practical response to the uncertainties around the forecasts of demand and cable reliability while still enhancing security of supply to meet Inner Sydney's growing population and new large infrastructure projects that are underway or in planning.

However, CCP9 also observed that some stakeholders remained uncertain about a number of the assumptions that TG has adopted in its modelling, particularly for replacement capex and the PSF proposal and for the AER to accept the outcomes of the engagement process. If TG wish to continue moving to working collaboratively with consumers and have AER place substantial weight on the outcomes, the information needs to be presented in a balanced manner, in an accessible form, with sufficient detail, and with sufficient time for stakeholders to analyse the information and consider their position. One option would be deliberative workshops with stakeholders that allow for deeper dives on specific issues.

CCP9's perhaps more fundamental concern is the impact that this approach has on consumers' perception of the regulatory process and their confidence in both TG and the AER. The consistent feedback received by the CCP9 is that stakeholders are looking for the AER and TG to come to an agreement on key assumptions early in the process so that stakeholders can focus on the application of these assumptions: "the revenue proposal should be about the application of the agreed parameters".

In line with a number of submissions from stakeholders CCP9 suggests that going forward, these issues can be better addressed through the use of mechanisms such as deliberative forums on key issues where consumers can more actively lead the process. Exploring ways to enhance energy efficiency and demand management provides an excellent first step on the next stage of TG's consumer engagement journey. The model used by Electranet and AGN – and proposed to be adopted by some of the NSW DNSPs in the current revenue reset – is the publication of a preliminary revenue proposal for review by stakeholders/public. CCP9 appreciates that TG has indicated it will consider this for its next reset.

CCP9 recommends:

- AER attends these important meetings, at TG's invitation, if only to clarify misunderstandings.
- TG consider adopting joint deliberative forums (or similar) which provide more opportunity for stakeholders to participate and contribute depth to the revenue proposal based on their experience.

3.1 Overview

Prior to the AER's draft decision, TG had an extended and comprehensive consumer engagement program that was widely regarded by stakeholders as a significant improvement on its previous consumer engagement processes. CCP9's focus in response to TG's initial revenue proposal was, therefore, on providing constructive feedback to TG that CCP9 had received as a result of its direct discussions with key stakeholders in the process, and CCP9's direct experience with successful consumer engagement programs conducted by other networks. CCP9 (and the AER) also made a small number of suggestions regarding the ongoing development of the TG's consumer engagement program.

It is pleasing to see that TG has carefully considered these suggestions and proposes to implement a number of enhancements to its program particularly with respect to managing communication with its range of stakeholders and more systematic monitoring and responding to stakeholders' perceptions of its engagement processes.

Following the publication of the AER's draft decision, TG has initiated a meeting with its Revenue Proposal Working Group (RPWG) and another meeting with its Advisory Council (TAC). The purpose of these meetings was to advise the two groups of the AER's draft decision and to obtain views on TG's proposed response in its revised revenue proposal (RRP).

Notably, TG accepted the majority of the AER's draft decision although it did not always agree with the AER's position. However, there remained significant differences between TG and the AER on the overall capital expenditure program (capex) and in particular between between the AER's draft position and TG on replacement capex (repex) and the Powering Sydney Future (PSF) project. The underlying issues with the repex related to the assessments of risks, while for the PSF the issues centred around forecast demand growth and the reliability of the existing Sydney city supply cable infrastructure.

The focus of TG's consumer engagement following the publication of the AER's draft decision has therefore been on the capital expenditure program and these topics were extensively covered in the RPWG meeting and the TAC meeting that followed the draft determination. CCP9 was an observer at these two meetings but the AER was not in attendance. TG also has had follow up discussions with a number of consumer groups to further gauge their responses to the draft decision. TG also undertook these discussions as part of its parallel RIT-T process.

CCP9, and the AER have had no involvement with these subsequent meetings although we have sought feedback from a number of these stakeholders before and after the publication of the revised revenue proposal. At the request of the AER, CCP9 has delayed its response to TG's revised revenue proposal[1] and this has provided further opportunity to consider the submissions provided by stakeholders to the AER. A number of CCP9's observations on TG's customer engagement process after the draft decision draw on these responses which we have found very useful, particularly given the limited opportunities to participate in TG's subsequent engagement with stakeholders. CCP9 thanks those participants who have shared their views with us in discussions and/or set out their views in their recent submissions to the AER

Before considering the AER's draft decision and TG's response with respect to customer engagement, CCP9 recognises that TG has made some significant modifications to its capex proposal, particularly the PSF project, in response to the Draft Decision. TG states that, in response to feedback it has received from its consumers it has modified its original PSF proposal and is now proposing a two-staged approach to implementing the PSF with the second stage likely commence in the 2023-28 regulatory period (subject to demand). This change has resulted in a total saving in its proposed capex of $100m for the 2018-23 regulatory period. As part of this, TG has also proposed to extend its demand management program for another year.

Section 4.2 of this advice to the AER discusses CCP9's views on the capex program, including the PSF. In this current section, CCP9's focus is on the customer engagement processes that TG has undertaken since the AER's draft decision. This will include CCP9's view on whether TG has effectively engaged with customers and its assessment of the support that customers have for TG's revised revenue proposal in the context of the information provided to them.

It must be said at the outset, that stakeholders generally indicated a positive response to TG's customer engagement following the draft decision and appreciated that TG had modified some aspects of its PSF project as a result of this feedback. Section 3.4.4 below provides a summary of

[1] The AER requested the CCP9 to delay its response to allow further investigation of the revenue proposal in general and the capex proposals in particular.

submissions to illustrate this appreciation. CCP9 concludes that TG has clearly made significant efforts to discuss its response to the AER and to garner support for its revised proposal.

CCP9 has identified some areas of the process and content of the revised revenue proposal that have raised concerns. In particular, CCP9 considers that TG has not fully explained its forecast assumptions, nor clearly presented reasonable alternative assumptions. CCP9 accepts TG was disappointed in aspects of the Draft Decision and expressed that. However, stakeholders would have better served if the basis for the AER's draft determination had also been explained. CCP9 observations and feedback from consumer representatives indicated this was not always the case. We observed this in the RPWG and consider it was reflected in the tone of some sections of the revised revenue proposal. In this situation, it is difficult for CCP9 to conclude that stakeholders have had the opportunity to make an informed judgement on what can be complex process and content issues.

At times in its revised revenue proposal, TG reported outcomes of the stakeholder meetings that implied a consensus view amongst participants. While there was a degree of high level agreement at the 'round-table' and relatively informal process in the RPWG and TAC it does not always deliver a clear picture of the individual views of all the representatives around the table. It is important that the 'minority' views are captured and reported in the revised revenue proposal. Subsequent submissions have indicated some divergence of views after stakeholders have had time to consider the issues further.

Overall, CCP9 considers that these aspects of the more recent customer engagement do not represent best practice engagement and leave questions around the extent to which any conclusions on the degree of support for key aspects of the program can be made. We recognise though that this may reflect the limited time available after the draft decision. That said, it can leave consumers feeling like they are 'piggy-in-the-middle', or are somehow encouraged to 'take sides' between the AER and the business and to do so without a clear understanding of both views. It is in these circumstances that at least some consumer advocates have looked to independent advice from third parties and have come to different conclusions on the capex program including the PSF. Moreover, while it is helpful for TG to encourage stakeholders to provide submissions to the AER, the challenge for the utility is deciding the extent to which it should support and inform or support, inform and guide.

CCP9 understands that the revenue determination process can be difficult for all parties and it is not always feasible to effectively exchange material with stakeholders and with the regulator in a timely way (and vice versa). Nor is it an easy task to communicate the complex detail of regulatory proposals and the AER's decisions to stakeholder groups. Nevertheless, CCP9 suggests that it would be useful for TG to present a consistently balanced view on these matters. In CCP9's view, it is essential that consumers have confidence in the regulatory process and the outcomes of this process, particularly as the industry as a whole moves towards a more collaborative regulatory decision-making process.

In this submission, CCP9 will provide some examples of these instances, so that TG can consider its approach in further proposals, including any future RIT-T processes arising, inter alia, from its multiple contingent projects. CCP9 is also speaking to the AER regarding some aspects of its process that may pose difficulties for, and even exacerbate the difficulties facing, the business and for consumers.

CCP9 notes the very useful feedback provided by consumer in their submissions to the AER on future engagement approaches that may enhance this aspect of consumer engagement. The aim here is to strengthen and extend the collaborative approach that would allow exploration of all the assumptions and options for TG's expenditure program, including a more balanced representation of the AER's preliminary positions. The concept of a 'citizen's jury' or 'deliberative forums' are some of the ways in which consumers and the business can genuinely work together to resolve issues and agree outcomes. The current joint program on effective consumer engagement being conducted jointly by the Energy Networks Association, the Energy Consumers Australia (ECA) and the AER will no doubt provide additional examples for TG of excellence in collaborative decision-making.

Having reviewed the submissions from consumers, CCP9 suggests that TG and consumers have the opportunity to work very productively together to develop strategies around energy efficiency and demand management, and to consider ways these activities might be funded. This approach would go beyond the existing formal RIT-T process while feeding into both the revenue proposal and the RIT-T process. Inner Sydney is a real opportunity given the rate of redevelopment of the region and the high costs of renewing or expanding infrastructure.

Notwithstanding the concerns with some aspects of TG's recent customer engagement, CCP9 also notes and welcomes the fact that TG has accepted many other aspects of the AER's draft determination. Moreover, TG has consistently adopted an open approach to sharing developments in the energy market and sought the views of its consumer representatives on these market developments and on how TG could most effectively respond to these. TG's approach to this has been clearly appreciated by its consumer representatives throughout the last 12-18 months and CCP9 encourages TG to continue with this aspect of its customer engagement.

3.2 AER's Draft Decision

The AER recognised that TG has made significant improvements in its consumer engagement processes over the last four years and that this is reflected in the positive feedback provided to participants to CCP9 and in TG's own research (e.g. TG's annual survey of community 'trust' in the business). The AER further noted that it was pleased with TG's consumer engagement program as reflected in CCP9's observations, namely:[2]

- TG made an earlier start to the process enabling trust and knowledge to develop amongst the range of stakeholder representatives and has established a sound framework and structured process to select participants, locations, topics, priorities and communication channels.
- The structure of the customer engagement program appears to be sustainable and is supported by the Board, CEO and senior management.
- TG has provided clear and continuous information to stakeholders with a focus on plain English, transparent and accessible material, including information on how stakeholders have influenced TG's revenue proposal.

The AER's draft decision also highlighted a number of areas for further improvements. The AER noted that: "In recent years we have seen a number of businesses raise the bar on consumer engagement

[2] See AER, *Draft decision TG transmission determination - Overview*, 28 September 2017, p 40.

in developing regulatory proposals."[3] For example, the AER cites with approval the leadership of Australian Gas Networks, ElectraNet and TasNetworks in ensuring that the voice of the consumer becomes an integral component of a network's regulatory proposal and the AER encourages TG to consider the approaches adopted by these very different businesses.[4] While 'no one size fits all', there are things to be learnt from the approaches adopted by all of these businesses.

The AER also provides some specific recommendations to TG. For example, the AER confirms CCP9's initial view that:[5]

- TG consider ways in which it can more consistently move from informing and sharing information with customers to involving consumers in its decision making, or even collaborating on approaches to priority issues.
- TG's proposal would have benefited from opening the proposal to challenge from stakeholders and, in particular, challenge sessions around the assumptions that underpin a number of TG's forecasts.
- TG could have done more to respond to concerns that consumers have around operational and capital investment efficiency and productivity, in order to sustain lower prices.
- TG's current communication, which is generally valued by customers, was considered by some as "too much' and they "couldn't follow all of it". This highlights the complex issue facing networks, ,because of the different levels of knowledge, interest and time.[6].

The AER notes that the first two observations are particularly relevant to the PSF project. CCP9 had indicated to the AER that it would like to see additional evidence of consultation around key elements such as the demand forecasts and the risks assessment as these are key components of the new and replacement capex proposals. The AER considers this reflects its own concerns based on the evidence available to it when making its draft decision.

The third observation by the AER relates to consumers' concerns with ensuring TG's operating and capital expenditure allowances are efficient and are driving improved productivity, just as their customers must face continued pressure to improve their productivity.

The feedback from customer stakeholders expressed at the RPWG and TAC meetings and directly to CCP9 indicates that stakeholders are very concerned with the continued increase in the regulatory asset base (RAB) and wish to ensure that the AER's final decision is consistent with prudent and efficient expenditures. As one participant in the RPWG highlighted, in their business, which operates in a competitive market, asset risk analysis must also include assessment of priorities and least cost mitigation and innovation strategies. It is important to consumers that the regulated businesses demonstrate the same discipline of capital rationing and risk mitigation.

[3] Ibid, p 41.
[4] Ibid, p 41.
[5] Ibid, pp 41-42.
[6] Consumer representatives have previously indicated to the CCP that they constantly face resource constraints and must allocate their time over multiple industries and businesses.

3.3 TG's Revised revenue proposal

TG's revised revenue proposal provides a summary of its conclusions on the outcomes of both the RPWG and TAC meetings that followed the publication of the AER's draft determination. TG concludes (inter alia) as follows:[7]

> *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 concerns for customers with reliable supply into the CBD a priority for many customer representatives.*
>
> *…*
>
> *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, TG saw good alignment…*

TG also recognised the additional importance of customer engagement across a variety of community organisations and consumer representatives, industry representatives, and government in a period of significant change in the market.[8]

> *With the level of uncertainty that we are currently seeing in the energy sector across Australia, TG 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.*

In particular, TG states that it has worked closely with the TAC to develop its response to the Finkel Report and to develop potential solutions to the development of large-scale renewable zones in NSW. These solutions would seek to address the TAC's concerns with the investment risk of stranded assets if these developments do not proceed and also the impact of these developments on the regulatory asset base (RAB).

CCP9 has directly observed the extent to which TG effectively communicates with its stakeholders on developments in the industry at large and how these developments impact on consumers. Stakeholders have clearly appreciated TG's approach in these matters. CCP9 specifically acknowledges TG's work with the TAC on the Finkel Report and the large-scale renewable energy zones. TG has recognised consumers' concerns and has committed to continuing to work with the TAC to develop more cost-effective solutions and to reduce TG's (and consumers') exposure to investment risk.

In its revised revenue proposal, TG also reported on the meeting it held with the RPWG in late October 2017 following the AER's draft determination. Again, TG provides a detailed table that sets

[7] TG, *Revised revenue proposal*, 1 December 2017, p 18.
[8] Ibid, p 21.

out TG's assessment of the feedback it received from the RPWG, and the actions TG has taken in response to the RPWG.[9]

Although TG did not always agree with the feedback received from the AER and CCP9, TG has nonetheless taken a positive approach to this feedback in the revised proposal. For instance, CCP9 is pleased to see that TG commits to continuing to develop its customer research program to: "ensure that it is best practice and is informed by implementing the feedback of our stakeholders".[10] TG specifically states in its revised proposal that it has proactively responded to suggestions from the AER and CCP9, including the following actions:

- Reviewing customer engagement programs conducted by other networks and including suitable aspects into its forward planning
- Seeking further feedback from the TAC on where TG sits on the IAP2 spectrum of engagement and is now responding to the challenge of moving to the 'empower' end of the spectrum where possible
- Ensuring that TG invites challenge to the assumptions in TG's modelling, particularly around the Powering Sydney Future program
- Accepting the recommendation of CCP9 to develop a more formal and transparent framework to measure levels and effectiveness of engagement
- Highlighting areas where TG has engaged with customers on strategic energy market issues and committing to further investigation of options "to ensure that any decisions are made in the best interests of consumers"[11]
- Recognising consumers' concerns that the capital and operating expenditure proposals are efficient
- Commitment by TG to further examining its engagement framework surrounding RIT-T investment to "ensure that best practice engagement is embedded into the process frameworks".[12]

It is notable that in responding to these matters raised by the AER and CCP9, TG has stated that it has sought and received further feedback from its TAC and has undertaken a number of modifications to its approach and its programs as a result of this feedback. For instance, TG states that based on feedback from the TAC, it has further examined how non-network options can be used to address network constraints. Working with the TAC on these more strategic issues is a very positive step and CCP9 would anticipate that TG's future revenue proposals, customer engagement and other stakeholder activity will greatly benefit from this experience.

TG also provided detailed response to the AER's and CCP9's specific comments on its expenditure proposals including the PSF program. Both the AER and CCP9 were concerned that the key assumptions that underlie these expenditures including cable reliability, peak demand forecasts, non-network alternatives, energy efficiency and the value of customer reliability (VCR), were not always adequately explained to its customer representatives. In response, TG has outlined multiple instances where it has invited critical feedback from stakeholders on these assumptions.

[9] Ibid, Table 3.1, pp 23-25.
[10] Ibid, p 26.
[11] Ibid, p 29.
[12] Ibid, pp 29-30.

CCP9 acknowledges the extent of TG's interaction with stakeholders including discussions with stakeholders outside the formal RPWG and TAC meetings and stakeholders appreciation for that engagement. However, we have some concerns about aspects of TG's approach to customer engagement as discussed in the following section of this submission, which sets out CCP9's assessment of a number of aspects of TG's customer engagement program. However, these concerns are not intended to discourage TG from direct engagement with customers and their representatives. Because we felt that where we have concerns we should be as specific as possible, we go into some detail in the sections below. We do want this to distort the key message: stakeholders have complimented TG on the improvement in customer engagement, appreciate this, and would encourage TG to continue to enhance its customer engagement. CCP9 supports this feedback and would add that this has enhanced TG reputation and provides the basis for moving to a collaborative approach to regulation. CCP9 also recognises that TG has committed to further enhancements of its program and we welcome TG's positive response on this.

CCP9 appreciates that TG has responded to the recommendations by the AER and CCP9 with respect to its consumer engagement program. CCP9 considers that working with its RPWG and with the TAC to address the consumer engagement matters raised by CCP9, will provide the opportunity for TG to continuously develop its customer engagement approach and will also provide the opportunity for stakeholders to be active participants in TG's future strategic direction and operational decisions.

However, CCP9 still has some concerns with the customer engagement process it has observed following the draft decision, particularly around TG's modelling assumptions and its representations of the AER's draft decision. CCP9 encourages a more constructive, balanced and open dialogue with its consumers on these matters, which in turn will enhance the quality of the feedback it receives from its consumers and its impact on the AER's final decision. CCP9 also notes the feedback to it from some consumer representatives for the AER and TG (and perhaps AEMO) to 'get in the room together' and resolve as many issues as possible before the revenue proposals (preferably) or at least before the draft decision. This highlights the need for the AER and TG to work together to build a better working relationship. Key elements will be better communication and higher levels of trust on both sides.

Before moving to the following section, however, CCP9 would stress that its comments in response to TG's initial proposal were designed to be constructive and we also recognised that CCP9 was involved in TG's customer engagement process at a later stage than was desirable. We have communicated this concern to the AER while recognising the administrative issues that had resulted in this unsatisfactory outcome.

CCP9 wishes to emphasise that its recommendations are made in good faith and on the basis of attendance at RPWG and TAC meetings and on direct feedback from consumers. Our experience was that there were significant differences amongst participants in the assessment of various aspects of TG's consumer engagement program and perhaps these differences may not have been adequately captured through evaluations reported by TG.

3.4 CCP9's Assessment of the draft decision and revised revenue proposal

3.4.1 Summary of CCP9's observations

CCP9 has indicated above that based on CCP9's own observations and feedback from stakeholders, TG has made significant steps to improve its customer engagement program in the lead up to its regulatory proposal. CCP9 also communicated its positive views to the AER and in the public forums that followed the publication of TG's revenue proposal (April 2017) and the publication of the AER's draft determination. Moreover, while CCP9 noted certain limitations in TG's customer engagement program, CCP9's comments were made in the context of the overall support by consumers of TG's progress in this area.

As noted above, it was pleasing to see TG's feedback on CCP9's proposals in its revised proposal. CCP9 appreciates TG's clarification of a number of matters and TG's commitment to adopt a number of the recommendations particularly around adopting a more formal measurement process in assessing the effectiveness of its customer engagement program and identifying opportunities for further improvement.

CCP9 also notes TG's response to the suggestion that, in the future, TG would seek to move on the IAP2 engagement spectrum from "inform" to "involve" and collaborate". TG states that feedback from the TAC indicated that it was mostly at the "involve" level, with some areas at the "collaboration" level. There was also encouragement for TG to towards the "empower" level of the spectrum wherever possible. TG states that it has "accepted this challenge and will work to move further along this path".[13] This is certainly an encouraging development and strongly supported by CCP9.

More generally, CCP9 is pleased to see that TG has responded to a number of concerns of customers, the AER and the CCP with respect to the PSF. That is, TG has modified the scope and timing of the commencement of the PSF and proposed to expand its demand management program for an extra year as part of this. TG has 'split' the project into two stages thus enabling greater flexibility to respond to changes in demand and future developments in the demand management market and technology generally.

Notwithstanding these positive developments, however, there are aspects of TG's recent approach to stakeholder engagement that have raised significant concerns with CCP9. At the centre of this is the relationship between TG and AER. Our concerns point strongly to the need for a better relationship between the AER and TG with more effective and timely communication of information - in both directions.

In particular, while it correct for a network to criticise the regulator's decisions where they consider the decision is flawed, CCP9 considers that discussing these with the RPWG (in particular) it is also important that the network provides a balanced assessment of the regulator's decisions. In CCP9's view, effective customer engagement requires this and, in its absence, claims that consumers support certain proposals are not as convincing as they might otherwise be.

The revised proposal strongly criticises aspects of the AER's draft decision and supporting reports of its consultants. While it is expected that there will be differences of view and that these should be

[13] TG, *Revised revenue proposal*, 1 December 2017, p 28.

expressed, CCP9 was surprised by the robustness with which these differences were presented. The revised proposal also makes claims about "strong" support by consumers. Subsequent submissions indicate that this support was not universal. This is in part due to stakeholders having further time to consider and analyse the issues but it may also reflect misunderstandings of the stakeholders positions at the time of the first discussions and/or the firmness of these positions. CCP9's discussions with stakeholders who had been further consulted by TG reinforced this. These two issues are further discussed below, and CCP9's expectation is TG (and the AER) will carefully consider these matters going forward.

However, CCP9 also points to areas where there are opportunities for TG to move along the IAP2 spectrum towards collaboration and empowerment. CCP9 has highlighted some of these areas throughout the following sections. As an example, however, the increased flexibility in the reliability standards set by IPART opens the door to productive and collaborative discussions with stakeholders. These discussions could revolve around how TG could better work in collaboration with its stakeholders to promote the wider adoption of energy efficiency, design innovation and various small and larger demand management actions, particularly in the Inner Sydney area. These actions would better ensure reliability in the short run and reduce or postpone the need for expensive capital upgrades in the long run. Win-win. This does not replace the RIT-T, but would certainly enhance the overall outcomes for all parties.

3.4.2 RPWG meeting on the draft proposal (October 2017):

General observations

The RPWG meeting covered an extensive range of issues arising from the AER's draft decision and was well supported by presentations from TG's management and staff. There was also active participation by stakeholders and many questions put to TG to explain their position. This is consistent with CCP9's observations in previous meetings. What was new in CCP's view, however, was TG's 'tone' towards the regulator and TG's explanation of the decisions of the regulator in the absence of representation from the AER at the meeting.

CCP9 was concerned with this development. In CCP9's view, these types of remarks have the potential to detract from what was otherwise a useful and dynamic meeting with significant consumer input. In particular, it does not build consumer confidence in the regulatory process as indicated by a number of comments made to CCP9 after the RPWG session. Nor does it assist CCP9 coming to clear conclusions on consumer support for TG's revised revenue proposal when the stakeholders' comments of support are made in the absence of a balanced representation of the AER's reasoning.

As an example, one representative, commented to CCP9 that some of TG's comments at the RPWG meeting (e.g a comment that the "AER has a target and retrofits the assumptions") were "a bit staggering". Another stated that while they might agree or disagree with the AER's figures, they were concerned with "disparaging language", which in turn "speaks to a broader underlying issue that is not productive". The representative further explained: "you can't say you believe in robust/technical debate and make disparaging comments about the regulator".

There was also concern by representatives that while frustration with the AER's draft decision might be "understandable", it is better to focus on the underlying issues in the decision. It was noted, however, that the AER "does not present arguments in a way to bring the parties together".

A useful recommendation to address this issue was also put forward. It was suggested that the AER and TG work together at the earliest possible stage so that by the time the proposal is submitted there are few/no surprises. The suggestion was then made that: "the revenue proposal should then be about the application of agreed parameters" rather than a dispute about the parameter values. This collaboration would also give more confidence to consumers in the outcomes and CCP(supports these comments.

In addition to CCP9's concerns set out above, CCP9 observed some important gaps in the explanation of the AER's reasoning to the consumer representatives. A number of examples are provided below in anticipation of TG's further considering how it approaches these matters with consumers.

Example 1: The interaction of demand forecasts and reliability assumptions

The demand forecast is an important element of the assessment of the timing of the PSF project as it interacts with forecasts of asset reliability to estimate the overall congestion costs of "doing nothing" and of various options for replacement of the transmission assets/cables.[14]

TG placed much emphasis on the 'failure' of the AER to utilise the latest AEMO 2017 forecast of demand growth for the Sydney PSF region, noting that AEMO's forecast was revised significantly upward before the draft decision was published. However, the AER's draft decision refers more to TG's reliance on Ausgrid's 2016 'development forecast' of maximum demand and the AER noted that this forecast was "higher than alternative forecasts by AEMO and BIS Shrapnel"[15] while recognising the AusGrid forecast also included forecasts of additional 'spot load' demand.

A more open and 'collaborative' discussion by TG with its stakeholders (who were very clearly interested in and concerned about the demand forecast) would place less emphasis on which AEMO forecast the AER relied on and when, and place more emphasis on explaining to the RPWG members that:[16]

- AEMO's updated Sydney connection point forecasts were not provided until July and September 2017, and given this, it was perhaps understandable that the AER did not have time to evaluate this updated forecast and include it in their draft determination – however, CCP9 considers that the AER too, could have made this point clearer in its draft decision.
- The BIS Shrapnel forecast of the Sydney region was more geographically relevant than AEMO's forecast and its was prepared specifically for TG's RIT-T process. The BIS Shrapnel forecast

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[14] Currently, TG has significant capacity in its network of cables to supply inner Sydney including the CBD (approximately 3,000 MWh and in TG/AusGrid forecasts, demand is not expected to exceed this capacity up to 2035/36. However, when combined with the expected deterioration in the cables, the outcome is more problematic with a stated cost of some $2.6B per annum (assuming no action before 2036/37 and the assumed VCR).

[15] The BIS Shrapnel forecast was prepared for TG and included as an attachment to the "RIT-T- Project Specification Consultation Report". In this report, BIS Shrapnel forecasts a long term average growth rate for electricity demand to 2046 for central Sydney of 0.9%/pa, lower than the long term growth used by TG of 1.5%pa. AEMO's updated 2017 forecast was too late for inclusion in the draft determination and would not change the thrust of the AER's observation as it was similar to BIS Shrapnel.

[16] Note, further discussion by CCP9 on the demand forecast for the PSF is included in a separate section on the PSF project. It is raised here in the context of highlighting the importance of providing a clear explanation of the issues and alternatives to the RPWG before seeking endorsement from the RPWG (or the AER) on the project.

showed a long-term growth rate of 0.9%pa, much lower than the AusGrid's development forecast of 5-6% in the first years, and extended to decline to an average growth of 1.5%/pa over the longer term.

- Sydney City has aggressive GHG reduction targets and associated plans to achieve these targets despite its expectation of significant growth in commercial and residential buildings.
- While neither AEMO or BIS Shrapnel forecasts included TG's forecast of 340MWh of 'spot loads' between 2016 and 2023, not all these spot load are equally 'certain'[17] and the impact that these new loads would be partially offset by reductions in other loads.[18]
- The impact of such a significant growth forecast in Sydney city area on forecasts for other Sydney LGA regions[19] and whether proposals such as the PSF would therefore mean resources are directed away from these other areas.
- Whether this difference in peak demand forecasts would have a significant impact on the fundamental question of whether the full PSF proposal is required on or before 2023.

As an example of this last point, in a May 2017 report to the AER, Dr Biggar considered the combined impact of AusGrid's 2016 peak demand forecast (top 5th percentile) and TG's forecast of declining reliability (assuming no remedial action in the interim). Dr Biggar produced the chart below to illustrate the interaction between forecast demand and reliability and it is clear from this that the importance of variations in the demand forecast can only be assessed in a broader context.

CCP9 considers discussion around this type of information is of central importance to consumers' assessment of TG's proposal and to the development of the collaborative approach that TG is seeking to establish in the future. For instance, further discussion on the City of Sydney's GHG emissions forecast,[20] and how this relates to AusGrid's forecast, BIS Shrapnel and AEMO would have been a productive and collaborative exercise for the RPWG members.

Moreover, TG has invested considerable and very valuable effort in developing RPWG members understanding of its business. As one participant in the RPWG noted, the RPWG needs to know more about the interaction of the 4 areas of demand forecast, cable availability, cable ratings and non-network. Dr Biggar's report, which does not appear to have been referred to by TG in the meetings or in the revised revenue proposal, provides an important opportunity (and <u>first</u> step[21]) in further understanding the basis of the PSF forecasts.[22]

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[17] TG does say its revised proposal that it adjusts for this uncertainty but does not appear to explain on what basis it makes these adjustments and to what extent it adjusts the forecasts.

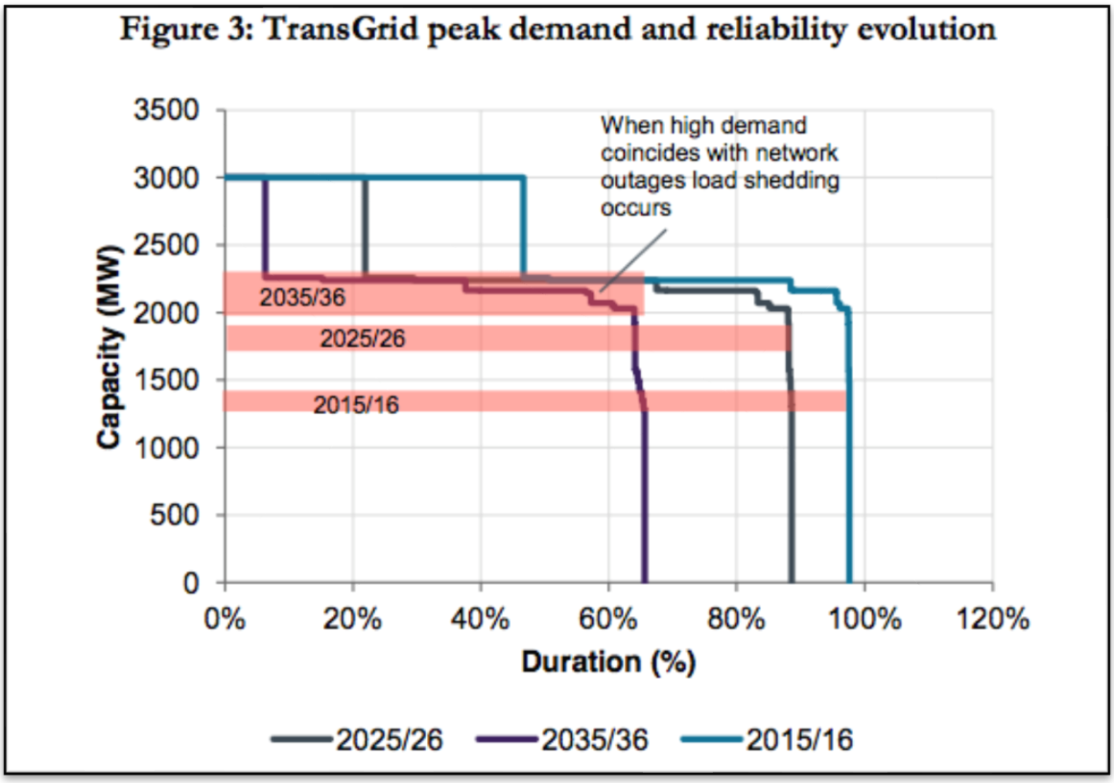
[18] Around half of the 340MWh spot load forecast referred to known projects currently under construction; other projects were in planning stages only or not even planned. The net impact is important because in the city area, a new building generally replaces an old building or factory, and the older building is likely to be less efficient than the new building, given for instance, the changes in energy efficiency and building standards. The new standards will have a significant effect on reducing average energy usage as discussed further in CCP9's separate assessment of the PSF project.

[19] TG had accepted the overall AEMO forecast for the greater Sydney area, which means that forecasts for other connection points in the greater Sydney area must be negative. CCP9 has sought clarification of this issue from the AER.

[20] See City of Sydney: *State of the Environment*, June 2016. The report indicates a target of 70% reduction over 2006 in GHG emissions by 2030 (p 10).

[21] Subsequent steps include the assessment of the value of the unserved energy.

[22] CCP9 notes that in a subsequent report prepared by JWH Consulting for the Energy Consumers Association, the author considers Dr Biggar's report as a "very good report". While CCP9 cannot verify every element in Dr



Source: Dr D Biggar, *An assessment of the modelling conducted by TG and AusGrid for the Powering Sydney Future Program,* May 2017. Note, the chart assumes that TG does 'nothing' to its system over the 20 year period and adopts TG's assumptions about peak demand growth and cable reliability including the full inclusion of "corrective actions" outages as well as "forced" outages. Changing these parameters further pushes out the period of congestion overlap. See Biggar, pp 16 -23.

Overall, CCP9 considers the focus on the AER's use (or otherwise) of the latest forecasts served to confuse rather than to clarify consumer stakeholders' understanding of the demand forecast and its role in the scope and timing of the PSF. The strong message from customers was that they wanted the TG, the AER and AEMO to sit down together and 'sort it out' – and preferably before the revenue proposal.

CCP9 considers that there were important elements of the AER's decision on the demand forecast and its interaction with reliability forecasts that could have been more objectively explained to stakeholders in the RPWG. TG's approach appeared to confuse rather than clarify the different demand forecasts and the impact of these differences on the timing and scope of the PSF given TG's assumptions on reliability of its infrastructure over the period. Consumers considered this was an area that would have been better resolved between the AER and TG through constructive dialogue before the regulatory proposal.

Biggar's report, we would endorse this view that it clearly explains the interactions of the forecast components within the context of TG's own forecasts and reliability assumptions.

Example 2: The importance of supply security to Sydney

Similarly, there was considerable discussion at the RPWG on the special importance of security of supply to the Sydney city and CBD regions This has been a continued theme and has certainly served to raise concerns about the reliability of supply over the next 5 years. This concern about supply security then feeds into a second concern about whether the AER has adequately recognised the level of risk and its importance to consumers in the draft determination.

CCP9 has looked at the draft determination with this question in mind. CCP9 concludes that the AER clearly stated that its issue is with the modelling input assumptions and therefore with the proposed timing and scope of the project rather than whether the project should proceed at all. Specifically, the AER stated in the draft determination:[23]

> ***We consider the key issue is whether the timing and scope of the upgrade is reasonable rather than whether an upgrade to the network is necessary****. Based on the information available, we are not satisfied that TG has demonstrated that the* ***key assumptions it has relied on to quantify the benefits of the project are reasonable.*** [emphasis added]

The stakeholder responses reported by TG seem to not reflect this assessment and similar statements made by the AER in the draft decision. For example:[24]

> *Feedback from customers to TG highlighted that there was a different appetite for risk regarding the security of supply to the Sydney CBD between TG and the AER's approach to the Powering Sydney Future project with consumers viewing the AER's appetite for allowing risk for the CBD being significantly higher than TG's.*
>
> …
>
> *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 clear articulation of the risk that would be acceptable to take with the security of supply to Sydney's CBD.*

In CCP9's view the quotation from the AER above indicates that the AER has not "denied" the project, or adopted a "different appetite for risk". Rather, the AER clearly accepts the necessity that at some point a form of the PSF will be required. Nor has the AER rejected TG's overall approach to assessing the risks to the assets in the PSF area. TG assesses risk based on modelling the probability of failure (PoF), the likelihood of a consequence (LoC) and the consequence of failure (CoF) and the AER accepts this as a reasonable risk assessment framework.[25]

However, the AER has – appropriately – questioned whether TG has provided sufficient evidence to support its assumptions in the calculations of each of these parameters. In addition, and reflecting the uncertainties around the different demand forecasts, the AER has provided the opportunity for

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[23] AER, *Draft decision TG transmission determination*, Attachment 6, p 6-96.

[24] TG, *Revised Revenue Proposal*, December 2017, p 31.

[25] TransGrid's Revised Proposal also reference a request from the RPWG that CCP challenge the AER decision 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. (p30). The CCP9 does not have a record of this request.

TG to further justify its assumptions in its overall capex modelling and/or to submit the PSF as a contingent project. The feedback from stakeholders summarised by TG above leaves an impression that the AER had 'denied' the project and did not recognise the risks. However, in addition to the quote from the AER set out previously, the AER stated:[26]

> *Our review of the economic analysis indicates that the* ***identified reliability risks are likely to be overstated such that the scope and optimal timing of the expenditure in the 2018-23 regulatory period has not been established.*** *On this basis we have not included proposed capex for this project in our substitute estimate of total capex.* ***We recognise however that the scope and timing for this project is affected by the significant uncertainty in regard to future demand in inner Sydney and CBD as indicated by the range of different demand forecasts****. Furthermore, given that this demand uncertainty may influence the scope and timing of this project* ***we consider that this project could be considered as a contingent project to manage this uncertainty while ensuring that customers do not fund the project before it is necessary.*** *We expect TG will address the key issues we have identified and* ***provide further information to support its proposed*** *'Powering Sydney's Future' project as part of its revised proposal.*

CCP9's view is that with a project of this size and implication on the RAB and where the risks will be transferred to customers, it is absolutely necessary for the AER to interrogate every assumption that underpins the project. Consumers expect no less. CCP9 does not suggest needs to be an advocate for AER but where it wishes to engage with customers to seek their views to inform and support their response it is better if customers can reach their views from a reasonable understanding if both TG and AER's views.

In CCP9's view, the AER's draft decision is carefully worded and conditional. It indicates that the AER expects "TG will address the key issues we have identified and provide further information to support its proposed [PSF project]. CCP9 considers that this apparent approach of propose-respond through long reports over many months may not be the best way of resolving these issues. Could these issues have been resolved in a more timely and less confrontational manner through a collaborative process involving the network, the AER, and other stakeholders (including AEMO) that commenced prior to the submission of TG's initial reset proposal?

CCP9 recognises that following the draft determination and TG's meetings with stakeholders, TG has come closer to a position that recognises the risks consumers face when the infrastructure is 'over-built' for the foreseeable needs of the region.

The revised revenue proposal proposes implementing a two-staged approach, with the option to implement stage 2 in the subsequent regulatory period(s) and then only if conditions warrant this development. CCP9 discusses this option in Section 4.2.3 of this submission. Many stakeholders saw this as a workable compromise. However, CCP9 remains concerned that their agreement may have occurred without having a balanced view of the assumptions and range of reasonable alternative solutions. A 'deep-dive' into the forecasts and the opportunities for small scale efficiencies and demand management may have assisted both TG and customer representatives in the process.

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[26] AER, *TG draft decision*, September 2017, Attachment 6, p 4.

CCP9 considers that a collaborative approach to customer engagement would, at this point, focus attention of stakeholders on the question of timing and scope of the project and the reasons why the AER might support or challenge these outcomes. TG might seek a collaborative approach with its stakeholder groups by working through the different views including the AER's views on each of the key assumptions of demand, cable reliability et al. From CCP9's perspective, the outcome of this more deliberative process would be more convincing, particularly given the extensive knowledge base it can draw on in the RPWG and TAC.

Example 3: Value attached to loss of supply in Inner city

The issues around the discussion on demand management have been cited above. In a collaborative approach it would also be important to explain to the stakeholders the values set in the supply/demand modelling for unserved energy (USE) and the associated value of customer reliability (VCR) and how these values implicitly capture the importance of electricity supply to Inner Sydney.

In the case of TG, the NSW independent regulator, IPART, advises the Minister of the appropriate reliability values. In 2016, IPART recommended a reliability standard of non-catastrophic failure rate of a maximum of **0.6 minutes per year**[27] and a **VCR of $90/kWh** for Inner Sydney.[28] This is equivalent to a N-2 standard for Inner Sydney including the CBD. The AER has not disputed this assessment and thus, the AER implicitly acknowledges the higher level of value placed on reliability in Inner Sydney, including the CBD.[29]

In its initial proposal submitted to the AER (and which the AER refers to in its draft determination), TG used two values for VCR for its PSF project, namely: $170/kWh for the CBD and $90/kWh set by IPART for the rest of the Inner Sydney region. This $170/kWh assumption is one of the components of the assessment of risk that that the AER – **correctly**- challenged in its draft determination, as this figure is almost double IPART's reliability assessment for Inner Sydney.[30]

A collaborative approach to consumer engagement would involve TG explaining this proposal and the AER's decision to consumers and, in particular, explain why it chose a figure for VCR for the CBD that was much higher than IPART's recommended standards. The fact that the AER has accepted IPART's VCR figure may have given consumers more reassurance that the AER was cognisant of the special status of Inner Sydney and implicitly accepted a value for USE that is more than 2.6 times the

[27] See IPART, *Supplementary final report electricity transmission reliability standards*, November 2016, p 20.
[28] Ibid, Table 3.3, p 23.
[29] Note, however, that consumer organisations such as the EUAA have previously submitted to IPART that the VCR of $90/kWh is too high and "potentially mean more network investment that consumers have to pay for and bear the market risk for" (Ibid, p 13) . IPART has recommended to the Minister, that a further review of this value for the VCR is warranted prior to the next regulatory reset for TG. See Ibid, p 5.
[30] AER, *Draft decision TG transmission determination*, Attachment 6, p 6-100 to 6-101. Although TG has now adopted a single value of $90/kWh, the AER's draft decision was prepared in response to the initial values of $170/kWh for the CBD and $90/kWh. The AER implicitly accepted the use of $90/kWh for VCR and 0.6 minutes/pa for USE as these values are set by the Minister on the advice of IPART as the regulator of reliability standards in NSW.

average for NSW (see below) and an average of 0.6 minutes of interruption per year for the 2018-23 regulatory period.

As part of this, TG could also have explained to the consumer stakeholders that a VCR of $90/kWh ($90,000/MWh) is significantly greater than the average NSW VCR figure of approximately $34/kWh,[31] or the NEM market price cap of $14.2/kWh ($14,200/MWh for 2017-18). At $90/kWh there is also significant scope for additional demand management/energy efficiency at lower cost, which aligns with the concerns of several stakeholders over whether TG had taken sufficient account of the opportunities for further efficiency and demand management and local energy supply (trigeneration, solar etc).

A collaborative consumer engagement approach may have provided opportunities for consumers and TG to explore further opportunities for additional efficiency and demand management where the total community costs of these activities would be lower than $90/kWh (or $90,000/MWh).

Moreover, IPART also notes that it is the estimated VCRs of small and medium commercial customers in the Inner Sydney rather than large customers that drive the higher VCR for the inner city region. IPART states that: "**this is likely to reflect the fact that large customers have backup supply arrangements**".[32] Such information is known to TG and would have also been a useful contribution to the discussion on how TG might further support investments in back-up supply that add to security of the network at lower cost, particularly in the context of the expected 'spot loads'. It is not clear at all what the trade-off between encouraging these new loads (including funding options) to install back-up generation and whether this would have (as IPART recognises) an impact on the forecast risk assessment.

The above comments by CCP9 are just examples of a number of such instances where a collaborative approach to reviewing the AER's draft decisions may have helped consumers make more informed and balanced judgements.

CCP9 considers that the AER has taken account of the special importance of the Inner Sydney/CBD region. Moreover, the importance of reliable supply in this region is captured in the reliability settings provided by IPART and which the AER must accept as a basis for evaluation of the options. However, this does not and should not preclude the AER challenging the assumptions made by TG and the evidence that TG has used to support these assumptions. The discussion on supply security highlights the importance of the AER working with the networks early to agree on forecasts, data requirements etc. It also highlighted to CCP9 that there are many opportunities for TG to work collaboratively with its stakeholders to maximise non-network opportunities in the Sydney region given IPART's assessment of a VCR of $90/kWh ($90,000/MWh) for Inner Sydney. A deliberative forum is one way, but not the only of progressing this discussion as part of a maturing customer engagement program.

[31] ibid, Table 3.2, p 22.

[32] Ibid, p. 78. IPART's view that a number of the large customers will have back up supply (which enable voluntary reduction in load) does not appear to be addressed in TG's forecasts for peak demand. At $90/kWh ($90,000/MWh) it would be useful for TG to encourage these options wherever feasible. Would, for instance, the WestConnex project benefit from having its own back up supply arrangements? And should TG actively support this given its view on VCR for the region? CCP9 considers that the RPWG could have made a useful contribution to this discussion.

CCP9 has shared some of its concerns discussed above with the AER. In particular, CCP9 (as agreed to by the RPWG) has passed the message to the AER that the RPWG strongly urged the AER, TG (and AEMO) to come together to resolve the 'technical' issues arising from the draft decision. Consumers did not want to be 'piggy-in-the-middle' of what appears to some to be a "destructive argument" and one that they felt was better resolved by these parties than by consumers.

CCP9, therefore, was very pleased to observe a more constructive approach by TG at the November 2017 TAC meeting. CCP9's observation is that the presentation of information to consumers was more balanced. In the meeting consumer representatives were appreciative that TG had sought to move towards a compromise proposal and there was broad support for the revised option. We considered this represented good progress towards a potential resolution and agreement between the AER and TG on PSF. That said, these are complex issues presented on the day. Hence consumer representatives required further time to analyse and consider their position. Subsequently, the ECA and PIAC questioned the timing of the need for the first cable.

In that context some of TG's comments in its revised proposal, particularly with respect to the AER's draft decision on TG's capex proposal, were surprising. To assist the AER and TG understanding CCP9's concerns, a number of TG's comments in the revised proposal are discussed below.

3.4.3 Revised revenue proposal & customer engagement

CCP9 reiterates that it was pleased to see that TG's revised proposal reflects its willingness to further explore the issues raised by the AER, CCP9 and its consumer representatives. The outcome reflects the modification of a number of parameters in the revised revenue proposal, including the rate of return, the value of imputation credits and some aspects of the PSF proposal.

Overall the revised revenue proposal is clear and well set out. In particular, it is clear which aspects of the AER's draft decision TG has accepted and which remain in dispute. Most of the areas in dispute related to the capex proposal and while TG has compromised on the scope of the PSF, it has not accepted other aspects of the AER's draft determination for capex. The examples below relate to how TG has addressed these areas of dispute in the revised capex proposal.

CCP9 also notes that in making these comments we also recognise that CCP9 has had limited direct exposure to TG's more recent customer engagement activities. The comments below are therefore based on the revised revenue proposal, submissions on the revised proposal and discussions with some stakeholder representatives. Nevertheless, CCP9 regards each of these information sources as relevant to the assessment of TG's customer engagement strategy.

The claims made and the tone of key sections of the revised revenue proposal, will all feed directly into consumers' confidence with the decisions of both TG and the AER. CCP9's ultimate focus is on looking for ways that the regulator, consumers and the businesses can better collaborate in the future to deliver proposals in the long-term interests of consumers. Confidence in, and respect between, all parties is at the heart of this objective.

Example 1: TG's claims regarding "errors" in the AER's draft decision and/or the EMCa expert report.

As reported in the revised proposal TG's advised the AER in August 2017 that: "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 conclusions". [33] This is a substantial issue.

The AER has strict publication deadlines and, CCP9 is advised that given the time the information was received the AER was limited to seeking feedback on confidentiality issues rather than 'factual errors'. Nevertheless, CCP9 considers that the consumer engagement would have benefited from the AER responding to as many of these 'errors' as possible so that time was not wasted on these issues. Overall, this situation raises an important question as to nature of the engagement between AER and TG in this period and the communication of timelines.

However, the question of the nature and substance of the points on which TG considers there were errors is also important. TG cites as an example of the errors that the EMCa report and the AERs draft decision stated that the total network risk implied in TG's proposal was $1.6 trillion. TG indicates that the actual value should be $1.6 billion; TG has mention this "error" 6 times in its capex section - **in bold**. CCP9 has sought, but has not yet received confirmation of these figures from the AER. Clearly, if there were an error, then is was a matter that the AER should have responded to quickly, as we indicated above. However, the advice to CCP9 was that, in fact, if this were an error it does not have a material effect on the AER's draft decision.

Similarly, TG made strong reference to the apparent contradictions between the draft decision and the EMCa report, quoting in support of this extracts from the AER's draft decision and extracts from the EMCa report. TG notes that the AER stated: "EMCa found it … bias in …risk methodology: inadequate justification and overstated project risk cost parameter assumptions (includes probability of failure…)." TG then compares this with EMCa's assessment that on balance, EMCa considers that "TG has applied a reasonable process and that application of this process is likely to produce a reasonable outcome of the PoF "[probability of failure]. [34]

CCP9 considers that the apparent contradiction has been overstated as the quotes come from different sections of the reports and are made in different contexts. The quote taken from the AER's draft decision specifically referred in the footnotes to pages 83 and 91 of the EMCa report, while TG has quoted from another page in the EMCa report (p 26). For example, page 83 and p 91 of the EMCa report, stated (respectively):

> *P 83: We consider that the systematic issues identified in our review reflect a bias towards over-estimation of forecast expenditure. The impact of this bias is demonstrated in the replacement and security & compliance expenditure projects that we reviewed…(at para 388)*
>
> *P91: In reviewing the proposed projects and programs, we consider that the IT capex forecast is over-stated, based on evidence of:*
>
> - *Insufficient justification for the estimated PoF, during operation, at end of life and post investment;*

[33] See for example: TG, *Revised revenue proposal*, December 2017, p 44.
[34] See Ibid, p 45.

- *Inadequate justification for the LOC parameters and what appear to be high CoF assumptions; and*
- *Inadequate option analysis, including unrealistic base case options and lack of consideration of IT asset life extension strategies.*

CCP9 suggests that care must be taken in linking two different quotes from a complex and multifaceted report and it would be useful for consumers if TG had better aligned the references. Certainly, CCP9's agrees that EMCa and the AER found that many of TG's processes and models reasonable (if some are still developing), but it is not inconsistent for the AER and EMCa to also state they have issues with the assumptions that go into TG's modelling.

Moreover, CCP9 has highlighted in its previous submission that we have received feedback from some consumers that they were concerned about the assumptions in the TG's models (rather than the models themselves) and, in particular, the extent to which these assumptions were adequately discussed with the stakeholder groups.

TG's revised revenue proposal would be enhanced from a consumer perspective by recognising these concerns and exploring these assumptions and alternative views openly with its stakeholders. Furthermore, TG does not appear to have directly addressed the assessments by Dr Biggar (referred to above), in its discussions with consumers even though Dr Biggar's critique is very relevant to any open assessment of the proposal.

Example 2: Assessment of the Bushfire risk

Bushfire risk is justifiably a highly sensitive topic with consumers and it is important that discussions on this topic draw on data not emotions. TG's proposed capex for "environmental risk management" is $200m over the 2018-23 period, and a large portion of this is directly associated with TG's stated intent to reduce bushfire risk. The AER made substantial reductions to dollars associated with managing this risk, based on its own risk assessment approach.

The revised revenue proposal sets out a chart with the heading "**Input values used out of context to support program-wide cuts".**[35] TG then illustrates how it has used a 'starting point' cost of $400m (based on 10% of the damages assessed from the 2009 Victorian fires). TG then modifies this $400m , by the probability of an asset failure (PoF) and the likelihood of a consequence (LoC). TG states that this process reduces the consequence cost of a tower failure from $400m to an average of $2.9m <u>per transmission line</u>.[36]

However, the use of a <u>starting point</u> of 10% of the total Black Sunday costs is not the issue that was emphasised in the EMCa report. The issues highlighted by EMCa included:[37]

- TG appears to assume that the consequence of a falling transmission structure or conductor would lead to a fire of the magnitude and destruction of the Victorian 2009 bushfire.
- In determining the LoC, EMCa could not find evidence that TG adequately accounted for the likelihood that a broken transmission structure/conductor will start a fire.

[35] Ibid, p 39
[36] Ibid.
[37] See EMCa, *Revise of aspects of TG forecast capital expenditure*, June 2017, p 21 and 58.

These are reasonable questions for the AER to ask TG, and TG's headline fails to give credence to this.

In summary,the issue appears more complex than presented to stakeholders. As noted above, consumers have clearly indicated to CCP9 that they did not welcome this particularly on technical issues such as risk assessment and would prefer the AER and TG to resolve these matters through early discussions.

Example 3: TG's comments that consumers have endorsed its revenue proposal

In its revised revenue proposal, TG has provided a table titled "**Key feedback from the RPWG**". The table provides a summary by TG of RPWG feedback on various issues and the actions that TG has or will take in response. In principle, this is a very good approach and many of the items listed in the table are consistent with CCP9's observations at the RPWG.

However, CCP9 is concerned that for 3 or 4 items listed there are differences between the short summary in the table and recollections of some participants. This is not unusual but highlights the need for care and verification in the preparation of such summaries. For example, CCP9 agrees with PIAC where PIAC notes that some statements are "only partly accurate", including:[38]

- The RPWG questioned on what basis the AER rejected the need for Powering Sydney Future and put to TG that the AER must come up with alternative triggers and project timings…
- RPWG commented that AER's decision on Powering Sydney's future showed a different appetite for risk…
- The RPWG wanted to understand the differences between TG's and the AER's approach to WACC. There was uncertainty as to whether the AER had been consistent with its own Guideline.

PIAC concludes that while the RPWG did discuss the AER's and TG's views on PSF triggers, PSF risk and rate of return, the framing in TG's revised revenue proposal suggests that the RPWG were in uniform agreement when this was not necessarily the case. PIAC states that in its view:[39]

> *The RPWG did not agree unanimously that the AER should be responsible for alternative triggers and project timings for the PSF, nor that it was their responsibility for declaring their risk appetite. In both cases, RPWG members suggested that TG and the AER should engage in open dialogue to develop mutually acceptable decisions. Finally, the 'uncertainty as to whether the AER was consistent with its own guidelines' with regards to WACC was voiced mostly by TG and not RPWG members.*

CCP9's observations accord with PIAC's views on this. CCP9's observations were that in many of the instances listed, the matters were discussed and the RPWG sought further explanations but that no specific conclusions were drawn stated by all the participants. Rather, CCP9's main observation was that RPWG members encouraged open dialogue between TG and the AER to resolve these issues (as PIAC suggests).

CCP9 also notes TG's statement regarding the AER's response to TG's proposal on the recover of Network Support Control Ancillary Service (NSCAS) costs. TG stated in Table 3.1 that:[40]

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[38] See PIAC, *AER draft determination and TG revised proposal*, January, 2018, pp 3-4, for the full text and references.

[39] Ibid, p 4.

[40] TransGrid, *Revised revenue proposal*, December 2017, Table 3.1, p 25.

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.

In the same table, TG sets out the "actions taken by TransGrid" in response to feedback. TG states in the table that its response was as follows:[41]

TransGrid agrees with the RPWG that expecting TNSPs to provide prescribed services for free is unsustainable and unreasonable.

Although the NSCAS draft decision was clearly a matter that TG was deeply concerned about, CCP9 did not observe any significant consensus by RPWG on this issue. CCP9's observation was that TG expressed strongly its view that it was "gifting the assets" and that it would cost more for customers if TG were to "turn off" the offer (of the service to the market).

More importantly, however, CCP9's observation was that the AER's reasoning was not adequately explained making it more difficult for stakeholders to make an informed decision. . Hence it is difficult for CCP9 to conclude there was significant support across the group for the real issue or principle.

It is CP9's understanding that operating costs in regard to NSCAS will be recovered. The point at issue is the recovery of capital costs. TG's view is that the assets should be rolled-in on the basis of depreciated costs and the AER considers that the assets should be rolled in at zero value as the original capital costs have already been more than fully recovered. AER considers that to charge customers again in the form of a return on and return of capital would represent a form of 'double dipping'.[42]

CCP9 considers this is an important issue of principle for consumers to debate and that the issue goes beyond the specific NSCAS issue. The question of principle is that if a network has more than recovered the total cost, including financing costs of an asset providing an unregulated service to the market, should it be able to recover its depreciated cost again if/when the asset is rolled into the regulated base and also receive a regulated return for doing this.

CCP9 would, however, agree with TG's observation that: "all members [of the RPWG] seemed perplexed by the AER's decision".[43] .

[41] Ibid.
[42] See AER, *TG draft decision*, Attachment 6, September 2017, p 6-53 to 6-54.
[43] TG, *Revised revenue proposal*, December 2017, p 107.

The implication we would draw for future customer engagement plans is that moving towards genuine collaboration with consumers in developing a revenue proposal, requires transparency, balance and provision of all the relevant facts and alternative views.

> Given the importance of the capex decisions and the extent to which the assumptions are disputed, CCP9 recommends that TG adopts a conservative approach to reporting back on the support it receives and the views of customers. This is particularly the case when the feedback is qualitatively assessed rather than quantitatively. CCP9 would also encourage TG to look at ways it can more reasonably represent the views of the AER to stakeholders particularly in the absence of the AER being there to explain its position. CCP9 for instance has observed instances where the AER's reasoning is not fully explained leading consumers to conclusions they might not otherwise have made. However, it is not TG's role or responsibility to be an advocate for the AER or fill in gaps in reasoning.
>
> CCP9 is looking to networks to move to a more collaborative approach not just with consumers but also with the AER and we observe that consumers generally support this. A prelude to this, is that the networks ensure that they adopt a balanced approach to presenting the AER's decision and engage consumers in working proactively on ways to address the AER's concerns.

3.4.4 Stakeholder submissions on the draft decision and revised proposal

CCP9 appreciates the thoughtful submissions provided in response to the revised revenue proposal. The discussion below, however, is restricted to areas in the submissions that are relevant to the customer engagement assessments. The submissions demonstrate the potential for collaborative engagement with consumers over issues such as energy efficiency, small-scale demand management, small-scale/local generation.

While stakeholders' views are mixed, most submissions support TG's latest proposal to implement the PSF in two stages with the option to postpone or cancel the second stage. CCP9 would like to more confident that in forming these conclusions, stakeholders were fully aware that there were other options that may further reduce the consumer's risk of funding stranded assets for 40 to 50 years. Section 3 of this submission considers a number of these alternatives.

Energy Consumers Australia (ECA) Submission.

In terms of consumer engagement process, the ECA notes that in addition to participation in the RWPG and the TAC, ECA has had direct contact with senior staff regarding the PSF project in particular. ECA acknowledges the "responsiveness and willingness to engage through this process and in particular the opportunity to comment on the initial and revised proposals." The ECA also appreciated that TG has revised some aspects of its proposal in response to consumers' views, and that in most areas TG's proposal is aligned with the AER's draft determination. [44]

The one significant area of disagreement between the AER and TG relates to the capex program and the long-term impact of this program on consumer prices. The ECA highlighted the challenges facing

[44] ECA, *Submission to TG revenue determination*, December 2017, p 3.

consumers with rising energy prices and notes that it is critical that affordability must be core to any assessment of network expenditure and investments going forward. Relevantly, the ECA states:[45]

> *Now more then ever, there is a need for network businesses, the AER and other stakeholders to forensically scrutinise augmentation and asset management plans, and to consider alternative 'non-network' solutions, to ensure that consumers are not required to spend a dollar more than is necessary to get the energy services they need.*

ECA commissioned expert advice from JWH Consulting to inform its contribution to the process. JWH concludes that: "this process indicates that TG has over-estimated the reliability risks facing the network and the AER's assessment of its capex plans in the 2018-23 period should stand".[46] ECA supports this conclusion including stating that, in relation to the PSF, a delay of five further years is appropriate even for a single cable option.[47]

The ECA also notes JWH has confirmed at least some of the errors in the ECMa report that were identified by TG, while also noting that the errors were not material and did not fundamentally change the validity of the AER's reasoning. [48]

The ECA made some recommendations with respect to these errors and conclusions, which CCP9 strongly supports. They include:[49]

- It would be preferable if these errors could be addressed through ongoing dialogue between the AER, networks and consumers prior to the draft determination. Or, given time constraints, the AER deal explicitly with these matters in its final determination.
- The AER consider whether it could publish a supplementary correction or discussion document prior to the draft determination to assist stakeholders in commenting on these issues.

The ECA has also identified the importance of 'turning the page' and developing more productive and collaborative processes to support the network revenue allowances. The ENA is currently working with the AER and Energy Networks Australia (ENA) on what it says is "a new, more flexible and deliberative process to develop revenue proposals".[50]

CCP9 supports these recommendations and the drive towards collaboration and a more flexible and deliberative process to develop revenue proposals. As CCP9 noted above, an important component of developing a more collaborative approach is to develop respect and trust between all parties and the early acknowledgement of errors by either party is an important part of that process.

PIAC's submission.

PIAC states that TG has engaged extensively with PIAC in the preparation of their revised proposal including the RPWG and bilateral meetings. PIAC also states that in general, this has been a positive process with TG senior staff being available and willing to provide transparent and timely

[45] Ibid, p 2.
[46] Ibid, p 2.
[47] Ibid, p 4.
[48] Ibid.
[49] Ibid, p 5.
[50] Ibid, p 2.

information. Moreover, PIAC describes the quality of information provided as being consistently of "high quality; clear, accurate and accessible".[51]

PIAC also notes that there has been a "measurable impact" of TG's consumer engagement, including revision to aspects of the rate of return and the value of imputation credits. PIAC concludes that this process is a "good example of genuine, responsive consumer engagement". [52]

CCP9 has already identified that PIAC did have a number of areas of concern with TG's statements on the RPWG meeting and the level of consensus amongst RPWB members on some issues. PIAC also raises a number of other important points relevant to customer engagement and the revised revenue proposal.

In particular, PIAC's submission states that it is concerned with the tendency to over-value reliability. While PIAC is satisfied with the TG's overall approach to assessing risk, it notes that the accuracy of the process relies on credible inputs and assumptions. PIAC further notes the EMCa's and the AER's assessment that TG overstates the likelihood and consequence of risk. While TG rejects the AER's conclusions, the views of the AER and the EMCa have been largely endorsed by JWH consulting whose paper prepared for the ECA (see above) concluded that the AER's draft decision was a better estimate of the forecast capex than TG's revised proposal. A similar case is put with respect to replacement capex.[53]

Given the competing claims of TG and the AER, PIAC also suggests that fundamental issues like demand forecasting, cable availability and sensitivity analyses "remain highly uncertain". Therefore the optimal timing and scope of the project as a whole remains uncertain. PIAC therefore concludes that it is "prudent for the PSF to be implemented at some later date, either through a contingent project or inclusion in the capex allowance for a subsequent regulatory period." [54]

PIAC also supports TG in using the contingent project mechanism for the renewable energy integration transmission contingent projects that were proposed by TG. PIAC also generally supports TG's proposed trigger mechanisms for the renewable energy integration projects although PIAC remains concerned that the proposed mechanism would allow some cases to proceed without necessarily completing a RIT-T.[55]

CCP9 considers that PIAC's submission provides a clear signal that there is an opportunity for TG to extend its current engagement and to work collaboratively on the PSF and the contingent projects/RIT-T processes in terms of whether the projects should proceed, when they should proceed, and what is the least cost option (including environmental and social costs) to meet the agreed objectives.

PIAC has also made a suggestion that in future, TG could broaden its consumer engagement to encompass not only consumer advocates but also consumers in general. Like the ECA, PIAC has suggested that developing a 'deliberative forum' process may be useful to achieving this outcome.

[51] *AER draft determination and TG revised proposal*, January, 2018, p 3.
[52] Ibid.
[53] PIAC, *AER draft determination and TG revised proposal*, January, 2018, pp 5-6.
[54] Ibid, p 46.
[55] Ibid, pp 7-8. See also CCP9's comments on Snowy Hydro's submission.

The Energy Users Association (EUAA) Submission

The EUAA is a member of the TAC and considers that the TAC process has kept the EUAA well informed and it has been able to provide input into the 2018-23 revenue proposal. The EUAA commends TG noting that: "their ongoing commitment to stakeholder engagement via the TAC and welcome the openness and frankness of our discussions". [56]

The EUAA expresses its support for the revised PSF proposal put to the AER in late 2017. The EUAA states that the revised proposal "represents a reasonable compromise between maintaining reliability and security of supply … and minimising costs for consumers." [57]Moreover, the EUAA considers such "compromises" will become increasingly necessary in the future and they "welcome the approach taken by TG in this instance".[58]

CCP9 notes these conclusions and agrees with the EUAA that in an increasingly complex network, compromises between cost and reliability will need to be made. However, they need to be made on the basis of access to the right information and in a manner that ensures all stakeholders and the AER can live with the outcome. The value of collaborative work with consumers is that these compromises can be made on the basis of better assessments of the risks (including forecasts of demand and asset failure rates) and the long-term interests of consumers in efficient energy prices and consistent with the policy and legal requirements underpinning of the NEO, NEL and the NER.

NSW Government, Planning & Environment submission

The NSW submission is focused largely on the PSF project. The submission stresses that security and reliability of supply to Sydney is "of the utmost importance" given its contribution to both the NSW and Australian economies.[59]

The submission also provides estimates of population and dwelling increases over the next 25 years for inner Sydney (Sydney LGA) including expected population growth of 72% between 2011 and 2036.[60] The submission notes the large-scale projects underway or in the pipeline in Inner Sydney that will add some 110 MW to the load in Inner Sydney.[61] The NSW Government also plans other substantial infrastructure projects over the next 10-20 years. The submission concludes that the economic risks of a potential transmission cable failure in the central Sydney are significant and the economic importance of Sydney CBD should not be understated.[62]

Having said this, the NSW Government's submission then acknowledges the important role of the AER in promoting efficient investment and supporting the long-term interests of consumers. It states that:[63]

> *As the PSF project will likely have significant cost implications for consumers, it is important that the need for the network investment is firmly established.*

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[56] EUAA, Letter to the AER re TG 2018-23 revenue proposal and Powering Sydney Future, 8 January 2018. P 1.
[57] Ibid.
[58] Ibid.
[59] NSW Government, Planning & Environment, "Letter to Ms Conboy re the AER's draft decision on TG's revenue proposal", 11 January, 2018, p 1.
[60] Ibid, pp 1-2.
[61] Ibid, p 2.
[62] Ibid, pp 2-3.
[63] Ibid, p 3.

CCP9 acknowledges the importance of secure supply to Inner Sydney and the prospective growth in housing and 'spot loads'. With respect to the importance of reliable supply, CCP9 has noted previously that this is captured in the modelling by the VCR of $90/kWh and the AER has accepted this input. We have also noted that this VCR is approved by the Department on the advice of IPART and is equivalent to the previous N-2 standard. It is also clear that there is significant overcapacity in the current cables relative to demand and there are untapped opportunities for extending efficiency and demand management.

Part of a collaborative approach to responding to the Government's concerns is to be actively pursuing ways in which the Government could work with TG and the City of Sydney to ensure these non-network opportunities are fully developed allowing future expansions of the network in Sydney to be postponed or reduced and thereby reducing costs to consumers in the longer term.

City of Sydney submission

The City of Sydney (City) submission states that its particular interest is in the PSF project. The submission recognises the difficulties of forecasting future electricity demand given the sustained increases in wholesale prices, and the progress being made in demand management and in local generation.

Given these uncertainties, the City also states that it "welcomes the constructive way in which TG and the regulator have collaborated since the draft determination to address key concerns raised by stakeholders such as the CCP and the City". [64] These concerns included ensuring greater flexibility in the investment program given the uncertainty of future demand, extending the life of existing assets where possible (with appropriate compensation to TG) and acknowledging the increasing role for demand management accompanied by greater incentives for this.[65]

The City therefore commends TG for responding to stakeholder concerns in promoting a "new and better option for the rollout of the PSF, namely the staged approach to the rollout. The City considers this deals with load uncertainty, mitigates the risk to security of supply, and is cost effective for consumers while maintaining the incentives to undertake demand management initiatives. However, the City mentions two matters that still need consideration, albeit they cannot be fully addressed through the current regulatory review process, namely:[66]

- The growing role of locally generated and consumed power is not adequately recognised in electricity forecasts (including, but not only TG).
- It is desirable that both TG and AusGrid modify their tariff structures to remove embedded transmission charges from network tariffs for transport of electricity solely within distribution networks. The City considers this issue may be addressed during the tariff setting process that follows the regulatory decision.

Overall, the City supports TG's revised revenue proposal generally, and supports the staged development of the supply to the City centre including the revised PSF program. The City also recognises the benefit to the revenue proposal as a result of the regulator's scrutiny and the input from stakeholders on the original proposal.

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[64] City of Sydney, *TG – Regulatory Determination – Revenue Allowance – 2018-2023*, p 1.
[65] Ibid, p 1-2.
[66] Ibid, p 2.

CCP9 considers the City of Sydney is yet another stakeholder who has set out a pathway for TG to further expand its collaboration with consumers. The City is at the forefront of driving the 'green revolution' for Inner Sydney with strong GHG reduction targets and a desire for innovative solutions (including but not only tariff reforms). Given the revised reliability standards recommended by IPART (which includes greater flexibility for networks to meet the reliability standards with demand management), and given IPART's assessment of the VCR of $90/kWh ($90,000 MWh), there is a very significant opportunity for TG to work with the City to expand its demand management and efficiency programs and reduce the pressure on TG to invest in large scale infrastructure developments.

Sydney Business Chamber (SBC) Submission

The SBC's submission endorsed the proposed two-stage solution outlined by TG in its revised revenue proposal, specifically the capital expenditure on a new 330kV cable to reinforce supply in the inner city. The SBC agrees that Inner Sydney is facing the "dual issue" of increasing demand combined with deteriorating assets and that this comes at a time of significant spending on Sydney's transport infrastructure during the 2018-23 period.[67] The SBC also states that it would not only be economically damaging, it would be unlikely that a quick restoration would be possible without impacting on other States and the National Electricity Market generally.

The SBC concludes that it not only supported the two-stage solution proposed by TG but TG will also be incentivised to remain within its capex budget and deliver the first stage of the project as planned because of the AER's capital expenditure sharing scheme.[68]

The SBC submission highlights to CCP9 the importance of promoting a good understanding of the relationships between demand forecasts, cable failure rates and customer reliability measures such as IPART's VCR. The SBC is also in an excellent position to work in collaboration with TG and others to identify efficiency and demand management opportunities that will further protect the reliability of the existing network system at a lower cost than reinforcement/replacement during the current regulatory period. These collaborative approaches and innovative solutions will underpin economic activity and growth in a modern "global" city.

Other stakeholders' submissions

Snowy Hydro submission

Snowy Hydro states that it has seen "first hand", TG working closely with consumer representatives and market participants to ensure TG's revenue proposal responds to community and market participant concerns. Snow Hydro considers that TG's modification of the PSF program is an example of TG responding to consumer concerns and the two-stage option represents a reasonable compromise for all stakeholders. Snowy Hydro also outlines the work it is undertaking with TG on the development of transmission for the Snowy 2.0 program and argues that this contingent project program does not need a RIT-T process as a trigger. Snowy Hydro suggests that the AER still has a responsibility to assess the efficiency of the capex in the contingent project.

[67] Sydney Business Chamber, *Submission on TG's revised proposal*, 7 December, 2017, p 1.
[68] Ibid, p 2.

While CCP9 understands the arguments put by Snowy regarding the RIT-T process trigger, it is also important that the process encourages effective consumer engagement and demand management options where applicable.

Energy Network Association (ENA) submission

The ENA submission is focussed on the operation of the CESS rather than the revised revenue proposal as a whole. However, CCP9 recognises that the CESS will be a particularly important protection for consumers given TG's capex plans, including the PSF. A proper review of the ENA proposal is therefore in consumers' long-term interests.

CCP9, therefore, and without prejudice, encourages the AER to further examine this issue in consultation with consumers who have a strong interest in "getting the CESS right".

AusGrid submission

AusGrid's short submission is focussed on the PSF. AusGrid strongly supports the revised two-stage solution (installation of a new single 330kV cable) and believes it addresses the concerns of stakeholders that were expressed during the RIT-T consultation process for the project. AusGrid states:[69]

> *Deferring the installation of a second cable until 2028, will not only bring down the costs of the project but will provide the flexibility to act earlier or later, or not at all, depending on whether loads grow at the predicted rate and whether additional demand management opportunities become available.*

[69] AusGrid, *Submission to TG 2018-23 Determination*, 12 January 2017, p 1.

AusGrid also notes that the installation of the 330kV cable will enable AusGrid to address environmental issues posed by ageing oil filled cables. In addition, the incorporation of 40-60 MW of non-network capacity over a four-year program will advance the scale of non-network solutions across the city of Sydney and complement the demand management projects that AusGrid has underway in the same area.

CCP9 has had the opportunity to consider the public submissions and these have assisted our understanding of the various stakeholder perspectives. In general, consumer advocates have expressed their appreciation of the ongoing efforts by TG to listen to the concerns of customers and to engage these customers in the development of the their revised proposal. Consumers also appreciated that TG has adopted the AER's draft determination with respect to WACC and operating costs, thus avoiding the distraction of legal disputes and processes.

The remaining area of dispute between the AER and TG (with consumers in the middle) concerns the capex program. The uncertainty around some of the assumptions in the revised revenue proposal, including the PSF project, has resulted in some stakeholders seeking an independent review of the capex. This review has concluded that while there are errors in the AER's draft determination, in the absence of further justification by TG, the AER's conclusions on capex are generally supported (including, but not only, the assessment of the timing and scope of the PSF).

Other stakeholders and some consumer advocates, however, provided support for the revised PSF program (the "two-stage" solution), and see this change as a sign that TG is listening to the concerns of customers and building in flexibility in response to the uncertainty over the forecasts. Several stakeholders encouraged TG to continue to pursue demand management opportunities as non-network solutions also provide flexibility and reduce overall long-term costs to consumers.

An underlying theme across a range of submissions was the importance of TG continuing to work with its stakeholders, including the AER, in an open and transparent manner, whether this is on the revenue reset, tariffs, demand management opportunities or resolving future supply issues.

CCP9 appreciates the contributions these submissions make to the process. We are encouraged by the many opportunities this provides for TG to move further along the IAP2 spectrum and to establish genuine collaboration with its stakeholders to address the challenges ahead while also focussing on long-term affordability. Cooperative engagement with the regulator will also be a key to this progress. Consumer collaboration in the process requires that consumers have confidence in the network business, the regulatory process and the regulator as the ultimate arbiter in delivering a fair and balanced outcome for investors and customers.

4. Revenues and Tariffs

4.1 Overview of Draft Decision and the Revised Proposal

The AER draft decision proposed a 8.5% reduction from the maximum allowed revenue (MAR) proposed by TG. The largest and most contentious change was the 40% reduction in the capex program, which resulted in an end-period RAB that was 9% below that proposed by TG. This in turn contributed to the 7% and 5% reductions in the return of and on capital (relative to the TG proposal).

The other large percentage reductions were in the allowances for taxes and payments under the EBSS and CESS incentives. However, Opex was also 8% lower than TG's proposal.

TG's Revised Proposal reduced the MAR by only 4.6% compared to the original proposal. This was around half the reduction proposed in the draft decision. Capex remains the most contentious area and the proposed capex in the Revised Proposal was only 5% lower than in the original revenue proposal. As a result, at the end of the regulatory period the RAB is 9% higher in the revised proposal than in the draft decision. The difference between the return of and on capital in the revised proposal and the draft decision reflects the difference in the proposed capex and revisions to inflation forecasts and interest rates for up-dated data.

Table 4.1: Comparison of Costs and Revenues (nominal $m)

Revenues and Costs (Nominal $m, total for 5 years to 2022-23)					
	Proposed	Draft Decision (DD)	Revised Proposal (RP)	Difference (%)	
				DD cf Proposal	RP cf Proposal
Revenue Building Blocks					
- Opex	1018.5	940.9	983.9	-7.6	-3.4
- Depreciation	678.1	630.5	635.1	-7.0	-6.3
- Return on Capital	2233.5	2124.2	2211.1	-4.9	-1.0
- Tax	247.9	168.5	171.1	-32.0	-31.0
- Adjustments	91.5	44.7	71.7	-51.1	-21.7
- Total Revenue	4269.8	3908.8	4072.9	-8.5	-4.6
Capex	1784.63	1069.7	1696.3	-40.1	-4.9
RAB (closing 2022-23)	7512.1	6812	7438.3	-9.3	-1.0

Sources: PTRM spreadsheets (Asset and Revenue Summary Sheets) submitted with Revenue Proposal, Draft Decision, and Revised Revenue Proposal

4.1.1 Main differences between Draft Decision and Revised Proposal

TG has accepted many of the revised revisions in the draft decision except for the forecast capex. The key differences in the major components are summarised below.

- **Capex**. AER draft decision reduced the proposed capex program by $715m though excluded the PSF project and substantially other capex, particularly replacement capex. In its revised proposal, TG proposed an alternative approach on PSF that staged the project and reduced spending in the current period but largely rejected the other changes. Capex in the revised proposal is $627m above the Draft Decision capex.
- **Opex**. TG has accepted most of the revisions to opex in draft decision except for cost of complying with licence conditions on IT security, where they have provided further information
- **WACC.** TG have accepted the revisions to the WACC proposed by the AER.
- **Tax (Gamma).** TG have accepted the value for gamma (0.4) proposed by AER.
- **Incentive payments.** TG accepted some of the proposed changes to the calculation of the EBSS but not the final year adjustments for 2013-14 and 2017-18. TG have proposed new modifications to the CESS calculation that were not in either the original proposal or the draft decision.

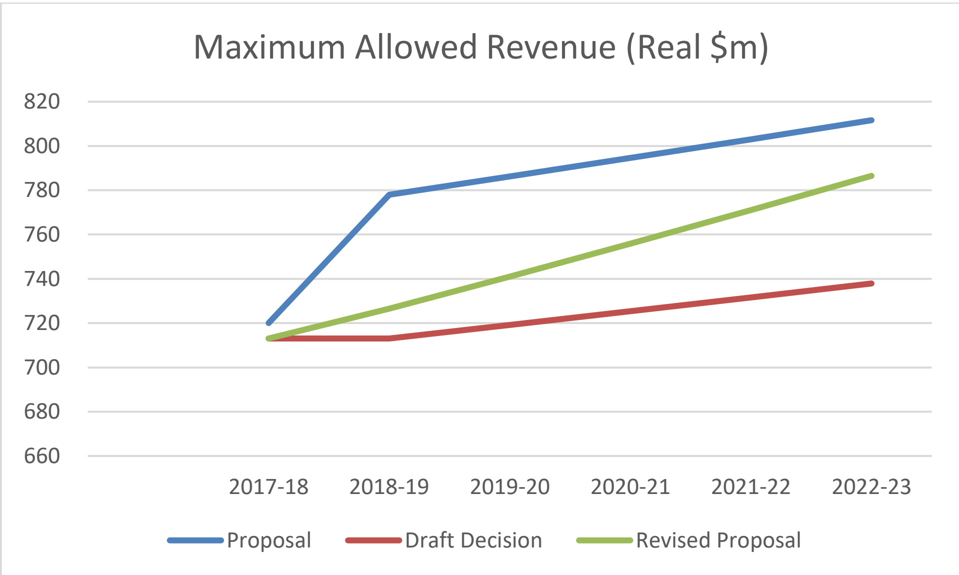
4.1.2 Outcomes for consumers

Only a few very large industrial customers are supplied directly from the transmission system. For other customers transmission cost are a small part of the total electricity bill. For most customers transmission charges are around 11% of the total cost of electricity. Hence, even large changes have an indirect and small impact on the final cost of electricity for consumers. That said, given the rapid rises in energy bills that have placed budget stress on a significant number of households and businesses, every part of the bill counts.

Regulatory revenues and average prices have fallen during the current regulatory and revenues and prices for 2017-18 are below the average for the regulatory period (2014-18). Thus, while maximum allowed revenues will increase in real terms during the regulatory period the average revenue for 2018-23 will below that for 2014-18 in real terms. The average MAR for 2018-23 under the draft decision is 5.9% below the MAR for 2014-18 in real terms and 8.4% the average MAR proposed by TG. The average MAR in TG's revised proposal is 4.2% above MAR in the Draft Decision but below the average for 2014-18.

Although the average MAR for the regulatory periods declines under the Draft Decision and Revised Proposal the MAR rises during the period from 2017-18. Under the draft decision annual revenues increase by 3.5% in real terms during the regulatory period, while the increase under the revised proposal would be 10 3% in real terms.

Figure 4.1: Annual Maximum Allowed Revenue (Real $m)



The average prices that consumers are expected to pay (in $/MWh) are a function of the MAR and the forecast energy sales. It should be noted that while MAR is lower under the draft decision and revised proposal than in the original proposal, the forecast energy sales are also lower. This partially offset the effect of the lower MAR on prices.

The table below summarises the MAR, forecast sales, and average prices (in real terms) for TG's proposal, the Draft Decision, and the Revised Proposal.

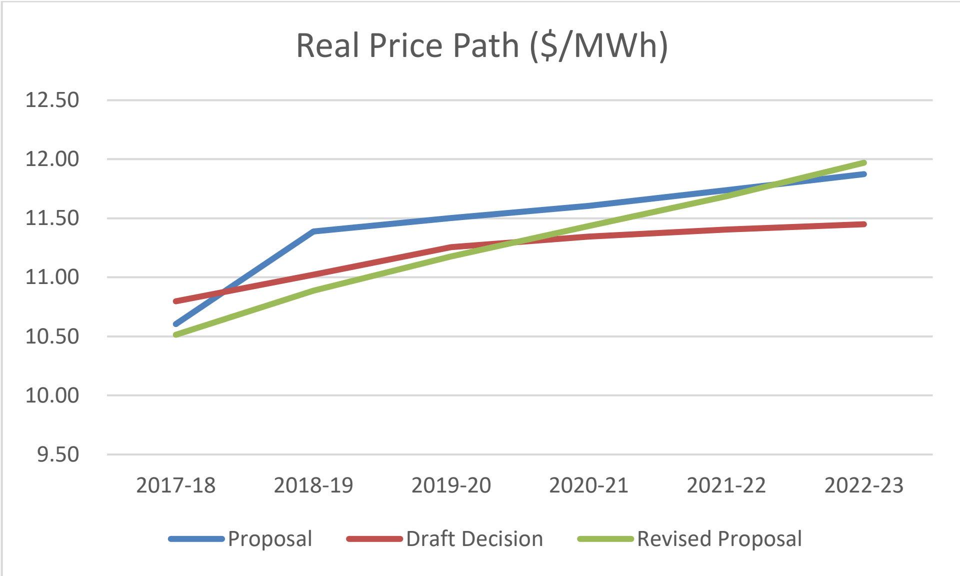
Table 4.2: Revenues and Prices in Real Terms

		2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
Proposal							
Forecast Energy	GWh	67,900	68,302	68,345	68,460	68,411	68,352
Maximum Allowed Revenue	$m Real	720	777.9	786.2	794.6	803.1	811.6
Annual Percentage Impact on Revenues	%		8.04%	1.07%	1.07%	1.07%	1.07%
Price Path	$/MWh Real	10.60	11.39	11.50	11.61	11.74	11.87
Annual Percentage Impact on Prices	%		7.40%	1.00%	0.90%	1.14%	1.15%
Draft Decision							
Forecast Energy	GWh	66,039	64,681	63,888	63,933	64,152	64,445
Maximum Allowed Revenue	$m Real	713	713.1	719.2	725.4	731.6	737.9
Annual Percentage Impact on Revenues	%		0.00%	0.86%	0.86%	0.86%	0.86%
Price Path	$/MWh Real	10.80	11.02	11.26	11.35	11.40	11.45
Annual Percentage Impact on Prices	%		2.10%	2.11%	0.79%	0.52%	0.40%
Revised Proposal							
Forecast Energy	GWh	67,819	66,727	66,303	66,101	65,976	65,703
Maximum Allowed Revenue	$m Real	713	726.5	741.0	755.9	771.0	786.5
Annual Percentage Impact on Revenues	%		1.88%	2.00%	2.00%	2.00%	2.00%
Price Path	$/MWh Real	10.51	10.89	11.18	11.44	11.69	11.97
Annual Percentage Impact on Prices	%		3.55%	2.66%	2.32%	2.20%	2.43%

Sources: PTRM spreadsheets (Revenue Summary Sheet) submitted with Revenue Proposal, Draft Decision, and Revised Revenue Proposal

Under the draft decision average prices increase by 6% in real terms during the period, compared to 12% under TG's original proposal. Prices under the revised proposal actually increase more quickly (13.9%) than under the TG's original proposal due to the lower forecast energy sales (In 2022-23 sales under the revised proposal are 3.9% less than in TG's original proposal).

Figure 4.2: Average Prices in Real Terms



There is a high likelihood that prices will increase more quickly than forecast. As discussed in the capex section, the proposed capex included in the RAB and revenue building blocks does not include contingent projects that total $2.0-4.9 billion. To the extent these proceed prices will increase in the current period and the RAB will increase, perhaps significantly, adding to prices in future periods. The other risk for consumers is the potential rise in interest rates which are at historically low levels. Increases during the current period will add to prices through increases in the cost of debt under the annual adjustment. But the more significant increase would come through the reset of the WACC at the next revenue reset.

4.2 Capital Expenditure and RAB

4.2.1 Draft Decision

The Draft Decision (p6-23) provided an alternative estimate of total Capex of $992.2 million - $645.7 million (or 39 per cent) lower than TG's forecast of $1 638.0 million. The key components of the draft decision were:

- Load driven capex (augmentation expenditure) reduced by 81 per cent from $517.4 million ($2017-18) on the basis of:
  - 'Powering Sydney's Future' (PSF) augex reduced by 100 per cent from $331.7 million
  - Economic benefits driven augex reduced by 51 per cent from $61.9 million to $30.4 million
  - Reliability and Security driven augex reduced slightly from $41.2m to $41.0m
  - Connection driven augex reduced by 79 per cent from $36.0 million to $7.5 million
  - Localised demand driven augex reduced by 15 per cent from $21 million to $17.8 million
- Replacement driven capex (repex) reduced by $203.9 million or 21 per cent from $961.8 million to $757.9 million ($2017-18) – this includes security and compliance related expenditure.

- Non-network driven capex reduced by 13 per cent from $158.8 million to $137.7 million ($2017-18) on the basis of ICT capex being reduced by 20 per cent from $102.7 million to $81.8 million.

- The inclusion of unregulated NSCAS assets in the RAB at zero value instead of the $25.7m proposed.

The Draft Decision also proposed changes to the trigger events for TG's proposed Contingent Projects.

4.2.2 Revised Proposal

TG's revised proposal includes a staged approach to PSF which reduces the capital expenditure forecast by $78.6m as shown in TG's Revised Proposal Table 4.6:

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**

In relation to the other elements of the Capex program, TG largely rejects the reductions of the AER Draft and is highly critical of the AER and its consultants EMCa.

The revised capital expenditure forecast is provided in TG's 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.

Setting aside the PSF component, the revised forecast of $1,281.6 compares to the equivalent $1,280.6m in the original proposal and $992.2m in the Draft Decision.

The number (and potential value) of Contingent Projects has also increased from the original Proposal (and the August update).

4.2.3 Assessment

Overview

Overall it has been challenging for consumers to engage on the Capex program. The reviews by the AER have involved large volumes of material provided by TG under information requests that were not made generally available. The timing of the requests and the responses have not been conducive to a process with which consumers can engage. Neither TG nor the AER can escape criticism in this regard.

Repex (TG Section 4.5)

TG has stated that the $191m reduction in the Asset Replacement Program component of this category '… *relies upon a range of analytical errors and misunderstandings'* (Table 4.7, p62). Reference is made to written notification of concerns by TG to the AER in August, however this is not in the public domain and CCP9 does not have a specific view on this correspondence. CCP9 does however accept that there is a difference between a robust methodology & model and the appropriate selection of inputs to that model.

TG proposed a 11% increase in repex in 2018-23, compared to the current period (2014-18) which, in turn was an 8% increase from the 2009-14 period[70]. Increases of this magnitude are considered unusual for repex and place a strong obligation on the proponent to provide strong supporting planning and analysis. The AER, and its consultants EMCa, identified significant concerns with TG's implementation of the risk-based planning modelling. The Draft Decision proposed a reduction in repex of 21%, which will provide a level of repex that is consistent with the level of repex that TG has estimated to be necessary in the 2015-18 regulatory control period. TG did not accept the reduction in repex in its revised proposal and pushed back on the assessment of its planning in strident terms.

Throughout the Chapter, TG repeatedly refers to *'factual errors'*, *'misconceptions'* *'misunderstandings'*, *'misleading'*, *'lack of rigour'*, *'lack of quality control'*, *'misrepresent'*, *'incorrect or inapplicable analysis and misinterpretation of our information'*, *'loosely based on analysis which is not credible or fit for purpose'* and similar language. It should be of significant concern to consumers that such an apparent impasse exists at this point in the regulatory process.

Given the wide gap in the views of the parties, a number of which appeared to involve matters of fact or understanding of TG's planning model we requested a briefing by EMCa to seek their response to the comments by TG. The briefing was held by teleconference on 18 January 2018 with AER staff also participating. CCP9 considers that many of the comments by TG are tangential to the assessment of repex. The discussion with EMCa focussed on the key issues of fact and interpretation that appeared most relevant to the assessment of the proposed repex:

1. The approach to estimating risk and its consequences
2. The estimation of the cumulative reduction in risk from the repex program,
3. The period until restoration of loads.

EMCa indicated that they had not yet reviewed the comments in TG's revised proposal in detail to assess whether the comments would impact upon EMCa's assessment and conclusions.

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[70] from AER Draft Decision Attachment 6, figure 6-7, expressed in $2017-18 (i.e. in real terms)

CCP9 understands that the general methodology (risk-cost) employed by TG is similar to that of other TNSPs. The key difference is the application of extreme consequences discounted by a moderating factor reflecting an estimate of the likelihood of consequence. Our understanding is that this introduces the need to select input parameters that are not based on empirical measures of historic events (as would be the case if the risk-cost method was based on less extreme events with more likely consequences), rather they often rely on estimates that are unable to be validated. As noted above, EMCa had not yet reviewed TG's comments on this in detail and did not respond to the specific comments (e.g on the assessment of bushfire risk). However, we note that Energy Consumers Australia (ECA) commissioned an expert review of the publicly available information from JWH Consulting which acknowledged some of the errors identified by TG but did, in the reviewer's view, did not appear to be material in the overall assessment of repex.

The example of the bushfire risk was discussed in section 3.4.3, which highlighted that on further analysis the extent to which there was a misinterpretation of TG's approach approach appears uncertain.

Overall, we are inclined to agree that the approach runs the risk of biasing the investment program towards greater expenditure than necessary.

A key point raised by TG is that EMCa (and the AER) have erroneously concluded that the business is exposed to $1.6 trillion of risk per annum when the data used actually values pre-investment risk at $1.6 billion. CCP9 is not in a position to replicate EMCa's analysis but points out that while this appears to be an unusually large number, TG's own analysis of the benefits of Powering Sydney's Future (i.e. the avoided risk of unserved energy of not investing in PSF) is $7 billion in the central case of each of the options analysed and around $75 billion in the high case (see PACR November 2017 page 4 and 48: *"Net benefits are greatest in the central and high scenarios, where options are estimated to deliver between $7 billion and $75 billion of net benefits"*.

We agree with the ECA submission that the estimation of the cumulative risk reduction does not affect the project-level assessment, but we accept that it may inform the assessment of the overall level of repex. The assumptions on the restoration of loads are important inputs in the evaluation of repex projects. EMCa did not resile from their assessment in regard to either of these issues but indicated that they would need to examine TG's comments in detail.

Robust, reasonable estimates of efficient repex requirements are important in balancing the consumers long-term interest in reliable supply while avoiding paying for excessive and inefficient costs. CCP9 considers:

- The level of increase in repex proposed by TG is significant and this places an obligation on TG to provide 'water-tight' supporting analysis. An alternative presumption is that the true level of required repex is likely to be more in line with past trends
- We support the concern's expressed by AER and EMCa, and supported by JWH Consulting, that the approach to assessment of risk may result in biased estimates

- TG's responses in its revised proposal and prior communications with AER need to be carefully and objectively reviewed by EMCa and AER before it can be concluded that the repex proposed in the AER's draft decision is flawed
- The level of disagreement between TG and AER/EMCa is of concern and the parties should seek to work together in a collaborative manner to seek to reduce the extent of disagreement so that consumers to be confident that the level of expenditure is sufficient, but no more than that, to efficiently maintain reliability of supply. In saying this we do not wish to imply in any way that we consider that the proposed repex in the draft decision is too low.

CCP9 would be happy to assist in the process to resolve the differences of view on the capex forecasts if all parties consider that would be helpful.

Augex (TG Section 4.6)

Setting aside PSF, the proposed augex of $185.7m was replaced with an estimate of $96.6m (Table 6-6), a reduction of 48%.

TG summarises this category (excluding PSF) in Table 4.21 (reproduced below) and shows an increase of $25.8m from the original proposal:

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.

Expenditure on Dynamic Voltage Support was rejected in the Draft Decision based on uncertainty of need. These investments relate to the connection of renewable generation and TG's revised proposal argues for the inclusion. Given the link to the connection of generators, CCP9 is not convinced that consumers should bear the cost of these projects as part of the ex-ante capex allowance. Why isn't the full or partial cost of these projects allocated to the connecting generators? Alternatively, why is this not included in the scope of the various contingent projects that relate to the connection of generation in NSW?

The revised proposals transfers ten projects from the Network Capacity Incentive Parameter Action Plan (NCIPAP) to this expenditure category after being rejected from the NCIPAP in the AER's draft decision. These projects are outlined in Table 4.16 and total $20.9m. Nine of the ten projects are categorised as providing reliability benefits and one is categorised as improving market efficiency. The economic benefits do not appear to be re-stated in the revised proposal and there is no accompanying discussion of whether the reliability improvements are ones that consumers are willing to pay for, or to meet compliance obligations. CCP9 recommends AER review this expenditure in light of the above.

Reliability driven capital expenditure is outlined at 4.6.2 and Table 4.18 and shows an increase of $7.4m from the original proposal *"… caused by a delay to the Mudgee project*." (p87). No further information is provided about the Mudgee delay and CCP9 would expect the AER to seek further justification. Further, the TG discussion refers to the discretion of IPART and CCP9 is of the view that it would be appropriate to seek IPART's opinion on this rather than TG and the AER being left to interpret the requirement.

Connection driven capital expenditure is outlined at 4.6.3 of TG's revised proposal. The Draft Decision reduced this category from \$36.0m to \$7.5 and the revised proposal seeks to restore this to \$36.5m (Table 4.19, p91). The costs are driven by a small number of potential new large loads (19, p87). It is unclear to CCP9 why the costs are being allocated to consumers at large rather than being allocated to the connection costs of the project proponents. It seems likely that such costs could be recovered from location specific network tariffs for these customers rather than from other customers, but this should be clearly articulated in the rationale for the expenditure. TG asserts that by discounting the combined cost estimate by 40% and allocating 60% of the total to the ex-ante capex allowance that this '… balances the costs to consumers but includes some risk for TG' (p91). CCP9 is of the view that this does not represent a balanced sharing of risks.

In relation to Powering Sydney's Future (PSF), The AER Draft Decision was to reject the capital allowance proposed for PSF in its entirety as not being sufficiently justified in the 2018-23 Regulatory period. The AER instead proposed that TG could request that it be treated as a contingent project, noting that "An earlier version of Powering Sydney's Future was proposed as a contingent project in TG's 2014 regulatory proposal. In our draft decision, we proposed rejecting the contingent project because we did not consider that the demand forecast TG submitted its proposal supported the need for the proposed contingent project. TG subsequently removed the project from its revised proposal" (footnote 270, page 6=96) TG's revised proposal was to split the project into two stages that involved completing the civil works and ducting for two cables then installing and commissioning a single cable only in the upcoming RP. This reduced the capex proposal by around 24% from \$331m to \$252m.

In principle we consider this to be an improvement of the previous proposals put forward. It provides greater flexibility with a smaller up-front commitment. This is particularly important given uncertainties around demand and the technological changes impacting on the NEM. The ENA/CSIRO Network Transformation Roadmap[71] provides an excellent summary of the trends and possibilities for Distributed Energy Resources (DER) and pricing reform to reshape the electricity landscape and avoid substantial investment in traditional network infrastructure. The Roadmap refers to over \$1.4 billion in avoided network investment by 2027 and average network bills 10% lower than 2016:

> *"The next decade to 2027 is likely to see a step change in the rapid adoption of new energy technologies, driven by falling costs and global carbon abatement measures. This decade provides a limited window of opportunity to reposition Australia's electricity system to deliver efficient outcomes to customers"*

The proposed two-stage approach allows for a more adaptive approach to be taken over time. There is no necessary commitment to the second stage, but the lead time for the second cable is reduced. It may be that demand does not grow as quickly as expected, or distributed resources grow more quickly, in which case the second cable can be deferred further or not built at all. However, it is not sufficient that the proposal is just a better option than those previously proposed, it also needs to be shown that it is required and better than other options that could be considered.

[71] http://www.energynetworks.com.au/electricity-network-transformation-roadmap

AER afforded CCP9 the opportunity to be briefed by the AER's Capex team and to review the submissions of other consumer representatives (see below). We appreciated that briefing but would suggest that given the importance of this project and the limited remaining time for the AER's consideration of the project, that the AER should provide similar briefings for TG and other stakeholders.

We note that Energy Consumers Australia (ECA) commissioned an expert review of the publicly available information from JWH Consulting which suggested that "*the correct timing [of the single cable] is more like 20126/27*." ECA consequently did not support the PSF in the 2018-23 Regulatory Period. This was a position supported by the Public Interest Advocacy Centre (PIAC).

The Energy Users Association of Australia (EUAA) supports the revised PSF proposal as a "*reasonable compromise between maintaining reliability and security of supply in the Sydney metropolitan area and minimising costs for consumers*". The City of Sydney submission also supported the staged approach:

> *"Forecasting future electricity consumption and hence getting this timing right is challenging given recent sustained increases in wholesale energy prices, along with progress on demand management and local power generation, all of which tend to drive down demand for transmission services. At the heart of the issue is the optimal trade-off between security of supply, costs and flexibility."*

It is important to acknowledge that some investment is inevitable. The oil-filled Ausgrid cables must, at some point, be replaced and a high-capacity Transmission connection is likely to provide the economies of scale to deliver an efficient solution. The efficient scope and timing of the investment is determined by a combination of the reliability of these cables and growth in demand in the region served. Both of these include significant uncertainties. CCP9 is of the view that expenditure on the PSF project is a risk management exercise. The Australian Standard for Risk Management[72] defines risk as the "*effect of uncertainty on objectives*". In this case, the objective must be the reliable supply to the Sydney CBD at an efficient cost. Consequently, CCP9 is of the view that a staged approach is reasonable, and that subsequent stages may not be required, depending on demand in the region over time. CCP9 is not of the view that no expenditure is a prudent response to the inevitability of replacing these oil-filled cables. However, the revised proposal for $252m is also a significant investment and has not yet been sufficiently justified.

CCP9 encourages the AER to consider an alternative investment program that manages risk for consumers (in terms of balancing the risks of un-served demand in the CBD and the risk of un-necessary growth in the Regulatory Asset Base and consequently increased costs for consumers at large). In our view this would involve a comprehensive Demand Management Program in order to manage demand risk and a reasonable allowance for pre-construction costs that would allow for rapid implementation of a single-cable construction program in the subsequent regulatory period <u>if</u> the need is demonstrated five-years hence. The appropriate investment at that point would be determined based on updated understanding of cable reliability and demand growth. For example, the investment could be a single cable operated at 132kV rather than 300kV (such as in Option 5 of

[72] AS/NZS ISO 31000:2009 Risk Management – Principles and guidelines, section 2.1

the Regulatory Investment Test where the cost of converting two cables from 132kV to 330kV was costed at $79m – see PACR Table B-8, page 59).

IT expenditure (TG Section 4.7)

The Draft Decision recommended a $21.1m reduction in forecast IT capex, reducing the proposed $102.7m by 20% to $81.8m. TG's revised proposal seeks to restore this to $102.2m (Table 4.23, p95).

CCP9 is concerned by the size of the proposed IT spend and the apparent lack of linkages to increased capabilities or increased efficiencies. As outlined in the CCP9 submission to the original proposal (page 22) consumers had expressed to us "… *that TG has not made the case for increased replacement capital expenditure and IT investment, and has not adequately demonstrated where cost savings will be made to reflect the expected efficiencies gains of new capital equipment and IT systems*". This remains the case.

Further, such significant expenditure by all network businesses is, in our view, worthy of specific benchmarking of this expenditure category. ElectraNet, for example, has forecast $47.3m in IT capital expenditure over the 2018-23 regulatory period.

Contingent Projects (TG Section 4.8)

The revised proposal now includes 9 contingent projects. From the five in the original proposal: "… 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." (page 95)

The Revised Proposal would have benefited from a consolidated summary of these projects. The consumer interest is best served when a comprehensive picture of proposed and potential expenditure is presented. A summary table is provided below that shows the range of expenditures proposed by TG:

		Low ($m)	High ($m)
1	New South Wales to South Australia Interconnector (NSI)	$ 279	$ 1,074
2	Reinforcement of Southern Network	$ 60	$ 393
3	Reinforcement of Northern Network (QNI Upgrade)	$ 63	$ 141
4	Support South Western NSW for Renewables	$ 89	$ 470
5	Broken Hill	$ 52	$ 177
6	Reinforcement of Southern Network in Response to Snowy 2.0	$ 831	$ 1,228
7	Support Central Western NSW for Renewables	$ 120	$ 455
8	Support North Western NSW for Renewables	$ 500	$ 945
9	Renewables development in the Mt Piper to Wellington area	$ 37	$ 37
		$ 2,031	$ 4,920

Not all of these projects will proceed and not all will ultimately cost as much as anticipated but it is important for consumers to consider this potential for several billion dollars in Capital Expenditure when forming a view on more detailed aspects of TG's proposed Capex Program. To put this potential in context, the Revised Proposal includes $1.6 billion in capex and the AER Draft Decision was for just under $1.0 billion.

CCP9 has raised a number of issues with the treatment of Contingent Projects in the context of ex-ante Regulatory Determinations and the ability of consumers to engage in the related Regulatory Investment Tests. A submission to the AER Board can be found under the heading 'General Advice' at www.aer.gov.au/about-us/consumer-challenge-panel/statements-and-advice.

CCP9 notes that a number of the contingent projects relate to the connection of generation. Related processes include the Australian Energy Market Operator's inaugural Integrated System Plan (ISP) due in mid-2018 (www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan) and the AEMC's Market Review into Coordination of generation and transmission investment (www.aemc.gov.au/Markets-Reviews-Advice/Reporting-on-drivers-of-change-that-impact-transmi#). CCP9 notes that the AEMC announced a delay in the release of an options paper from November 2017 to February 2018 to allow the AEMC "… to consider related developments in the energy sector, including the Integrated Grid Plan which is currently being developed by AEMO …"[73]. CCP9 remains concerned that the timing of this work by the AEMC and AEMO is challenging for the Regulatory Determinations required for TG, MurrayLink and ElectraNet for the 2018-23 Regulatory Period commencing 1 July 2018.

CCP9 has made specific recommendations regarding the presentation of the potential impact on revenues and prices in our submission (dated 31 January 2018) on ElectraNet's Revised Proposal. In this we have acknowledged the imprecision of pricing impacts and suggested presenting the range of plausible outcomes in terms of the impact on the TNSPs' Regulatory Asset Base (RAB) in order to allow consumers to put the scale of the projects in perspective.

Network Support and Control Ancillary Services (NSCAS, TG Section 4.10)

The key issue in this expenditure category is an issue related to TGs proposal to include NSCAS assets into the Regulatory Asset Base (RAB) at a value of $26m. The Draft Decision agreed that the assets could be added to the RAB but at a value of $0 rather than TG's proposed 'depreciated asset value' of $26m.

The background to the issue and AER's rationale is provided from page 6-50 of the Draft Decision. TG successfully tendered (to AEMO) for a service agreement that commenced in February 2013 and continues until it expires on 30 June 2019: *"Under the service agreement, AEMO procured 800 MVAr of absorbing reactive support from TG, using reactors at Murray Switching Station (Murray) and Yass Substation (Yass)."* (AER page 6-50).

TG's methodology for including the NSCAS as a prescribed service *"… results in a depreciated value of $25.7 million for these assets which TG proposes to be transferred into the RAB*." (page 6-53) The Draft Decision did not agree that this reflected 'prudent and efficient costs': "*This is because TG has recovered more than the depreciated value of the assets under the service agreement with AEMO … by the time TG service agreement with AEMO expires on 30 June 2019, the unregulated revenue stream for these assets will total approximately $67 million. This indicates that the value of these assets have been more than fully recovered over the period of the services agreement.*" (AER page 6-53)

TG's revised proposal states (page 106):

[73] AEMC News article dated 21 November 2017 available from www.aemc.gov.au/News-Center/What-s-New/Announcements/Update-on-review-of-coordination-of-electricity-ge

“*TG 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, TG 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”* (emphasis added).

CCP9 is of the view TG’s methodology does not reflect efficient costs and that it has already made a risk weighted return on its investment. It appears that TG tendered for the service at a price that either reflected an ability to profitably recover its investment over the contract period or priced on the basis that ‘conversion’ to a regulated asset was a likely outcome. Such a situation highlights the issues for competitive elements of the market to compete with incumbent monopolies and the potential for consumers to pay twice (the ‘double dip’ referred to by the AER at their page 6-50). TG was only able to offer the NCAS service at the price it did due to the ability to house the assets within its regulated assets (i.e. the substations in question).

Inclusion in the RAB and the provision of NSCAS as a prescribed service allows TG to recover any operating costs associated with the service. TG’s assertion that “**In effect, the AER is proposing that TG provides this service for free for the next 35 to 40 years”** (emphasis in original, page 106) is not accepted by CCP9 and we support the AER’s Draft Decision.

Recommendations:

a) TG and AER/EMCa should work together in a collaborative manner to seek to reduce the extent of disagreement so that consumers to be confident that the level of replacement capital expenditure is sufficient, but no more than that, to efficiently maintain reliability of supply. CCP9 would be happy to assist in the process to resolve the differences of view on the capex forecasts if all parties consider this helpful
b) AER review augmentation capital expenditure in light of the absence of discussion of whether the reliability improvements are ones that consumers are willing to pay for, or to meet compliance obligations
c) Seek IPART’s opinion on the discretion afforded by the reliability framework in relation to Reliability capital expenditure forecasts (rather than this be interpreted by TG or the AER)
d) AER review TG’s approach to connection driven capital expenditure, in particular the statement that the approach balances the costs to consumers but includes some risk for TG
e) AER seek to provide briefings to key stakeholders on the assessment of PSF
f) Consider an alternative investment program that includes a comprehensive Demand Management Program in order to manage demand risk and a reasonable allowance for pre-construction costs that would allow for rapid implementation of a single-cable construction program in the subsequent regulatory period if the need is demonstrated five-years hence.
g) The IT capital expenditure be linked to productivity or capability improvements and AER to consider benchmarking of this significant expenditure category between NSPs.
h) Consider the contingent project triggers in light of AEMO’s Integrated System Plan and seek consistency with the approach for other TNSPs. Consider presenting a range of plausible impacts on TG’s RAB of a proportion of the contingent projects in order for consumers to understand the potential scale of the investments proposed.
i) Reject the addition of NSCAS assets to the RAB at a value above $0

4.3 OPERATING EXPENDITURE

The AER applies a 'base – trend– step' change approach to determining with the network's proposed operating expenditure (opex) satisfies the opex objectives set out in the NER or NER and if not, what, what alternative estimate should replace the network's proposal. In undertaking this review, the AER's focus is on the overall proposal rather than individual projects although it may consider these individual projects in coming to its decision.

The key elements of the AER's review of the network's opex proposal have been set out in the AER's 2013 Forecast Expenditure Guideline[74] (Expenditure Guideline) and include the following assessment stages:

- Assessment of the revealed opex in the base year (the last year in which there is audited data) to test whether it is 'materially inefficient'. The assessment of efficiency includes, inter alia, the benchmarking of the performance of the business compared to its peers;
- Trend the base opex forward to provide an estimate of the final year(s) opex in the current regulatory period and then forecast trend opex for each year of the new regulatory period. The trend opex estimates (rate of change per year in real dollar terms) for the new regulatory period include assessment of three elements:
    - Input price growth: labour and non-labour price growth
    - Output growth: energy delivered, ratcheted maximum demand, weighted entry and exit connections and circuit line length[75]
    - Productivity growth
- Step changes, which are the components of the opex estimate that are not adequately compensated for in the base year opex or in the rate of change. Step changes can be positive or negative and should apply only to 'exceptional circumstances, that may change the network's fundamental opex requirements. Two examples cited by the AER include a material change in the business' regulatory environment and an efficient and prudent capex/opex substitution opportunity.
- Category specific costs, which are costs that are forecast independently from base opex and are not subject to an EBSS. The AER has typically included forecasts for debt raising costs, demand management incentive allowance (DMIA) and guaranteed service level (GSL) payments as these costs can vary significantly from year to year and do not readily fit within the base-trend-step approach.

As discussed below, the AER has applied the approach set out in the 2013 Forecast Expenditure Guideline and outlined above to the overall assessment of TG's initial opex proposal. In its revised proposal, TG has adopted the same approach to forecasting its expected opex.

[74] AER*, Expenditure forecast assessment guideline for electricity transmission*, November 2013.

[75] These output specifications are specific to the transmission businesses. They have been modified after the Draft Determination in November 2017 following detailed assessment by the AER's advisors, Economic Insights. The changes are discussed in later sections.

4.3.1 Draft Decision

The AER did not accept TG's initial opex proposal of $947.7m ($2017-18). The AER's draft decision estimated an efficient opex of $873.3m ($2017-18) as consistent with the opex criteria in the NER.[76] The table below summarises the components of TG's initial proposal and the AER's Draft Determination.

Table 4.3 TG Initial Proposal and AER's Draft Determination: Operating Costs ($m, 2017-18)

	TransGrid	Our alternative estimate	Difference
Based on reported opex in 2016–17	868.7	862.9	–5.8
2016–17 to 2017–18 increment	–26.6	–26.4	0.2
Output growth	4.8	2.7	–2.0
Price growth	26.1	15.0	–11.0
Productivity growth	–2.6	–5.0	–2.4
Step changes	37.3	7.8	–29.5
Category specific forecasts (DRC)	40.1	15.8	–24.2
Total opex	**947.7**	**873.0**	**–74.7**

Source: TransGrid, *Revenue proposal, Opex Model*, 31 January 2017; AER draft decision opex model.
Note: Numbers may not add up to total due to rounding.

Source: AER, *Draft Decision TG Transmission Determination*, Attachment 7, Table 7.2, p 7-19.

AER DD: Base year opex assessment

The AER agreed with TG's proposal to use 2016-17 as the base year. The AER also concluded that TG's base year opex (was "not materially inefficient" having regard to the application of the Efficiency Benefit Saving Scheme (EBSS) and the results of the AER's transmission benchmarking study for 2015-16. The AER states that:[77]

Our benchmarking indicates that TG is operating relatively efficiently when compared to other service providers in the NEM…Having considered the results of our benchmarking, and the limitations of it, we are satisfied that TG's estimate of opex in 2016-19 is not materially inefficient.

AER DD: 2017-18 opex assessment

TG adopted a forecast for opex for 2017-18 based on its forecast rate of change applied directly to the base year opex. TG also included an estimated efficiency saving of 4% in 2017-18 to reflect its business efficiency and restructuring initiatives. The AER did not accept TG's approach and instead, relied on the approach set out in the AER's 2013 Expenditure Guideline. This approach is set out in the extract below.

[76] NER, cl. 6A.6.6(c).

[77] AER, *Draft Decision, TG transmission determination,* Attachment 7, p 7-21. The AER also highlights that the transmission benchmarking on which it relies is "relatively new and relies on a limited data set". (ibid).

AER's formula to estimate opex for 2017-18[78]

$$A^{*}_{2017-18} = F_{2017-18} - (F_b - A_b) + non - recurrent\ efficiency\ gain_b$$

Where:

- $A^{*}_{2017-18}$ is the best estimate of actual opex for 2017–18
- $F_{2017-18}$ is the allowed opex forecast for 2017–18
- F_b is the allowed opex forecast for the base year
- A_b is the amount of actual opex in the base year
- $non - recurrent\ efficiency\ gain_b$ is the non-recurrent efficiency gain in the base year.

The AER was also concerned that using TG's approach would result in an inconsistency between the EBSS calculation and the estimate of the final year opex for the purposes of the forecast opex from 2018-19 to 2022-23. The AER states that:[79]

By estimating higher opex in 2017-18 in its opex forecast than in the EBSS, TG has proposed EBSS rewards for efficiency gains that it would not pass on to consumers through its opex forecast.

However, the AER has concluded that it is satisfied with the quantum of TG's estimate of the final year opex in its opex model ($168.4m ($2017-18)) although the AER has updated this figure using the AER's estimate of inflation for 2017-18 ($167.3m ($2017-18)). The AER, however, has also qualified its acceptance of TG's proposal by requiring TG to use the same estimate in its EBSS calculation.

CCP9 supports the AER's DD and agrees that it is important that TG use the same opex for its 2017-18 forecast and for its EBSS calculation. While CCP9 can see some merit in TG's proposed approach to estimating 2017-18, we also believe there is a benefit in the AER retaining a consistent approach across all its decisions. Overall, therefore, CCP9 prefers the AER's simpler and more transparent approach.

AER DD: Annual rate of change 2018-19 to 2022-23

There are significant differences in the rate of change included in TG's initial proposal and the AER's DD reflecting different approaches to forecasting input prices, output and productivity growth. The AER adopted the approach to forecasting the rate of change as set out in its 2013 Expenditure Guideline resulting in a forecast rate of change of 0.51% per annum. TG's initial approach resulted in a rate of change of 1.2%. the differences in the annual rate of change are cumulative and after five years result in significant differences in total opex forecast. The sections below summarise the AER's DD in response to TG's initial proposal .

[78] AER, *Draft Decision, TG*, Attachment 7, p 7-21 to 7-22.
[79]

Forecast Input price growth

The AER's standard approach is to:

- Forecast labour price growth using the average of the most up to date NSW public and private utilities wage price index (WPI) forecasts from Deloitte Access Economics (DAE) and the BIS Shrapnel
- Non-labour price growth using the forecast change in the CPI.
- Weighting of labour and non-labour of 62% and 38% respectively.

TG's initial proposal differed with respect to the forecasts used for labour price growth and the weighting of labour and non-labour costs. TG relied on the forecast by BIS Shrapnel of Australian private utilities WPI for NSW (which was higher than the public/private WPI at the time) and did not include the DAE forecast. TG also used its own internal data to determine the weighting of labour and non-labour (71% and 29% respectively) in its opex proposal.

The AER did not accept these variations in approach proposed by TG. The AER did not consider TG's reasoning to use the private utilities WPI for NSW as reasonable as it expected over time that the public and private sector wages would converge. The AER also argued that the weightings were based on benchmark allocation between labour and non-labour (using an earlier industry study by Pacific Economics Group (PEG))[80] rather than specific company allocations. The AER states that: [81]

- The benchmark weightings from the PEG study provide an incentive to use the most efficient mix of labour and non-labour inputs;
- The opex criterion that a forecast must reflect a realistic expectation of cost inputs, does not per se require the AER to take account of specific management resource decisions;
- Under TG's proposal, the higher labour weighting will always yield a higher opex forecast (as labour costs increase faster than non-labour).
- The AER's benchmark weightings were consistent with the weightings that were used to forecast productivity growth; using different input weights to forecast price growth and productivity growth would yield a biased opex forecast.

Forecast output growth

In its initial proposal, TG proposed an approach to forecasting output growth that was not consistent with the approach outlined in the Expenditure Guideline. TG calculated output growth as commissioned augmentation capex (augex) as a proportion of the replacement value of the network. TG then applied an economy of scale factor of 0.47%.

The AER did not accept TG's proposed approach. The AER highlighted, inter alia, that TG's approach relied on assumed growth in input measures (augex), not output measures as required in the Guideline and consistent with the view that these measures should reflect services provided to

[80] Pacific Economics Group, *TFP Research for Victoria's Power Distribution Industry,* December 2004.
[81] See AER, *Draft Decision TG*, Attachment 7, pp 7-26 to 7-29.

customers. Moreover, TG's approach implies that there is a one-to-one relationship between augex and opex[82] but TG provided no evidence to support this claim.

The AER's replacement forecast of output growth was consistent with the measures and weights used in the AER's 2014 transmission benchmarking analysis conducted by the AER's consultants Economic Insights (EI).[83] The relevant output measures and weights used to forecast output growth are:

- line length (28.7%)
- energy throughput (21.4%)
- ratcheted maximum demand (22.1%)
- voltage-weighted entry and exit connections (27.8%).

The AER accepted TG's forecast of each of these four output measures. The overall average annual output growth based on these forecasts and the weightings (above) was 0.1% (i.e. average 0.1% per annum). In comparison, TG's methodology resulted in an annual average growth rate of around 0.2%.[84]

However, the AER highlights that at the time of the DD it was currently reviewing its economic benchmarking of transmission NSPs with a focus on refining the specifications and outputs. The AER intends to take the recommendations of this review into consideration in its Final Determination (FD). The results of the review was published in November 2017 and TG has incorporated the measures and weights identified in this review in its revised proposal (see XXXX). The AER will also need to consider this review as part of its assessment of the productivity growth rate as discussed in the next section.

Forecast Productivity Growth Rate: Shift in the productivity frontier for transmission networks

In its initial proposal, TG proposed an approach to assessing productivity growth based on various independent productivity measures. All of these measures indicated declining productivity for the transmission network sector. As a result, TG proposed to use a productivity factor of 0% per annum. After adjusting for economies of scale for output growth calculated by TG, TG's implied productivity growth was 0.1% per annum.

The AER did not accept TG's initial proposal and applied a productivity growth forecast of +0.2% based on the analyses by EI of trends in in opex productivity across the transmission industry from 2006 to 2016. The AER argued in the DD that TG's sample of studies were not directly relevant. For instance, two of the studies considered multi-factor productivity (rather than opex partial factor productivity) and were based on trends in the utility industry as a whole rather than the electricity transmission industry.

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[82] Before allowing for the economy of scale factor of 0.47%.
[83] Economic Insights, *Economic Benchmarking assessment of operating expenditure for NSW and ACT electricity TNSPs*, November 2014. <u>These output measures and weightings have been updated by EI as per EI's November 2017 report.</u>
[84] Based on Table 7.3, p. 7-23.

TG's third study relied on trends in opex partial factor productivity for Australian distribution network companies calculated in EI's 2005-06 to 2014-15 distribution benchmarking report. The AER argued in its DD that this latter study was also not relevant to assessing productivity trends in the transmission industry. Notably, all the studies relied on by TG used data only up to 2014-15.

Summary of Rate of Change

As a result of the AER applying the approach set out in the 2013 Expenditure Guideline in its DD, the total amount allowed for the rate of change over the five years was around $12.7m ($2017-18). This was less than half the amount claimed for the total rate of change by TG in its initial proposal of $28.3m ($2017-18)

CCP9 supports the AER's approach in its DD to assessing the input price changes and output growth rates. However, CCP9 considers that:

- It appropriate to update the ratio of labour and non-labour costs in line with the findings of the November 2017 EI economic benchmarking study;
- The weightings and output measures recommended by EI in its November report should be adopted by the AER in its FD; and
- EI's revised productivity trends (2006 – 2016) indicate a continued decline in the industry opex partial factor productivity levels, and suggests that the AER will adopt a productivity value of 0%/pa in its FD (rather than +0.2%/pa). It is extremely concerning that opex, and total factor productivity in the industry continues to decline despite the massive capital investment that has occurred since 2008. This issue is discussed further below.

Step Changes

In its initial proposal, TG proposed two step changes, namely:

- $37.3m ($2017-18) to manage off-easement vegetation risk; representing 4.1% of TG's total opex forecast; and
- An estimate of $14.4m ($2017-18) relating to remedying the non-compliance issues that were identified in the audit review report for IPART.[85]

In its DD, the AER rejected the off-easement vegetation risk step change and has accepted only part ($7.8m ($2017-18)) of the opex costs relating to non-compliance issues. The AER concluded that granting the vegetation management and the full costs arising from the audit non-compliance would not be consistent with arriving at a total opex allowance that reasonably reflects the opex criteria.

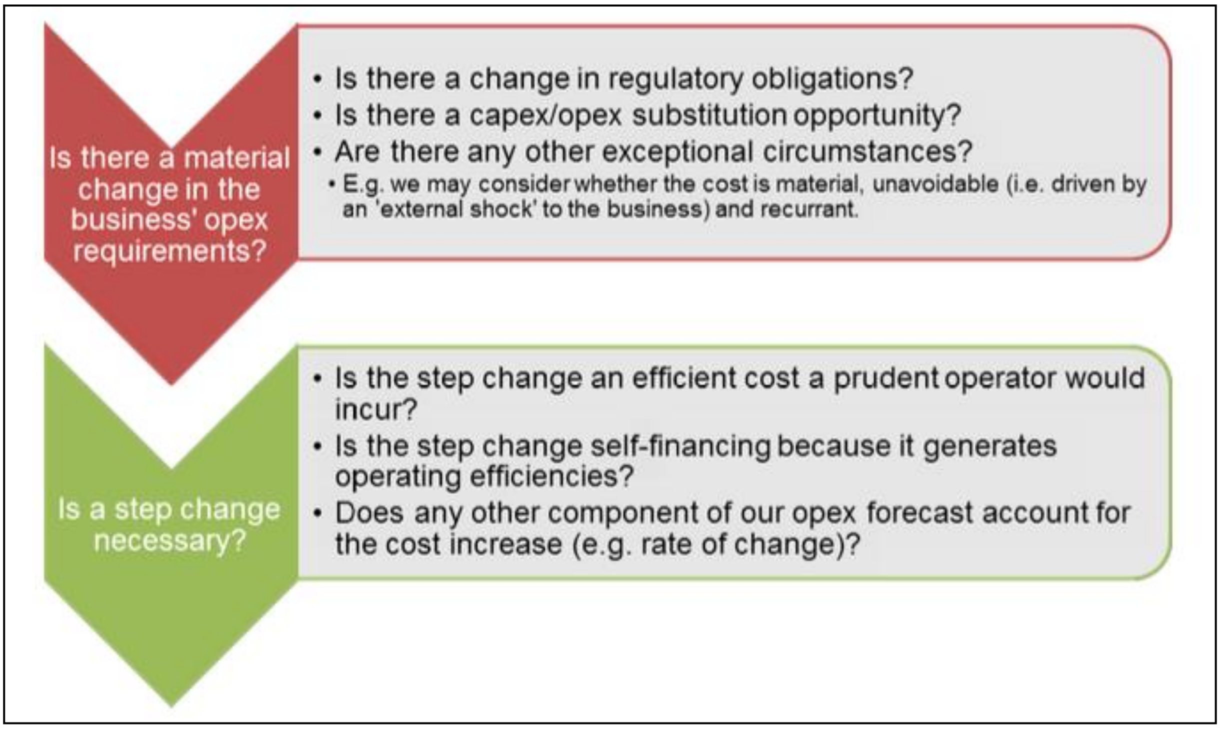
The starting point for AER's assessment was a systematic consideration of whether there was a material change in the business's opex requirements and whether a step change was necessary and the associated costs were prudent. Other than for exceptional circumstances, the AER envisages it

[85] In its initial proposal, TG signaled the issue but did not include a specific amount as it was not clear what was required for compliance. TG advised the AER in July 2017 that it estimated a step change of $14.4m ($2017-18) to achieve compliance with the conditions of the licence.

will only approve a step change for prudent and efficient expenditure arising from a change in regulatory obligations or a prudent and efficient capex/opex substitution.

Figure 4.3 below provides a useful guide to the AER's approach to assessing step changes and has been carefully considered by the CCP in its assessment of the proposed step changes.

Figure 4.3: Step change assessment



Source: AER, *Draft Decision TG determination*, Attachment 7, Figure 7.7, p 7-40.

Off-easement vegetation risk

The AER noted that TG has an ongoing obligation to manage its assets in an appropriate way including safety requirements and that there have been no new regulatory obligations imposed on TG with respect to these obligations. The only change has been a change in regulator from the NSW Department of Trade and Investment to IPART. While an independent audit conducted in 2015 found that TG's electricity network safety management system was compliant, an audit conducted under the new IPART compliance guideline in 2016 found areas of non-compliance. TG also argued that there had been a 'sustained' increase in off-easement tree events in recent years.

The task facing the AER was therefore to determine if these matters constituted a change in regulation and/or exceptional circumstances. While the AER noted that it was prudent and efficient for TG to re-asses its compliance program in these circumstances, the AER also concluded that this did not justify a step change. The AER stated:[86]

However, we are not satisfied there is a case to include a step change for off-easement risk management in our total opex forecast. ***A new regulatory obligation does not drive this cost.*** *Nor have we identified any other exceptional circumstances to warrant a step change.* ***We do not consider there has been a substantial change in TG's operating environment that would require a***

[86] AER, *Draft Decision TG*, Attachment 7, p 7-41.

***step change** for our forecast total opex to reasonably reflect the opex criteria. Further, TG overstated the costs it faced.*

*We therefore consider the proposed cost driver is a "business-as-usual expense" for TG to manage **within its total opex forecast**. Including the step change proposed by TG would lead to a forecast of total opex that is above efficient levels.* [emphasis added]

IPART has confirmed to the AER that TG's obligation to manage bushfire risk has remained unchanged since the introduction of the new Regulation and change in the relevant regulator.[87] In addition, TG indicated to IPART that it had completed the rectification of the non-compliant matters identified in the 2016 audit by the end of 2016. As a result, the costs of rectification were included in the base year 2016-17. Moreover, the non-compliance items related to a deficiency in the systems for demonstrating compliance rather than in the failure to adequately address bushfire hazards.

CCP9 notes that, notwithstanding the analysis above, the AER did conduct further investigations into the step change proposal to assess whether the costs were material enough that they could not be offset by other efficiencies or expenditure deferrals. The AER concluded that there was no evidence of a long-term pattern of increased off-easement tree incidents (other than cyclical factors) and that TG's proposal was neither prudent nor was it cost effective – risks could be managed in better ways than complete removal of the trees and the proposed unit costs of tree removal were overstated. Finally, TG's proposal did not include any reduction in other costs that might be expected to occur if increased falling trees were an issue, such as reduced maintenance costs.

CCP9 supports the AER's analysis of the proposed step change for vegetation management and the AER's decision to reject this claim. If falling off-easement trees are an increasing issue (and in the view of CCP9, the evidence provided does not support a *new and permanent* trend), then TG's first step is to rationalise other opex activity and to seek the most cost efficient method of managing the risk. CCP9 would expect to see savings in other areas to offset this cost and/or higher rewards under the STPIS scheme and EBSS.

Compliance with licence conditions

Since December 2015, TG has been subject to a transmission operator's licence that includes annual audit reviews by IPART of compliance with the conditions of the licence. At the time of submitting their initial regulatory proposal, TG was aware that it had compliance issues and that IPART was reviewing these issues.

In its subsequent audit review report for 2015-16 (published in May 2017) IPART reported that TG had not complied with two of the 'critical infrastructure' conditions during 2015-16.[88] These two non-compliance incidences related to the fact that TG's contractor (based outside Australia) had a degree

[87] IPART, *Letter to the AER-TG Revenue Determination 2018-2023*, 29 May 2017, p 1.

[88] See IPART, *Annual licence compliance report 2015-16*, October 2016, see addendum. The critical infrastructure licence conditions were new conditions that applied to what was termed critical infrastructure following the sale of TG. These new conditions (conditions 6, 7 and 8) require that TG's transmission system can only be operated and controlled within Australia (condition 6.1(b)), and that it holds data on the quantum of electricity delivered and personal information solely within Australia, and that this data is accessible only from within Australia (condition 7.1(a)).

of influence over TG's transmission system in 2015-16 and could access electricity load data from overseas in 2015-16. However, IPART also noted that TG had provided evidence to the auditor that since the end of 2015-16, it had complied with, or taken steps to comply with, the critical infrastructure licence conditions.

TG submitted a step change proposal to the AER on 5 July 2017 for $14.2m ($2017-18). The AER rejected this proposal in its DD but did allow some $7.8m ($2017-18) step change. The AER's DD also stated that this decision might change in the FD when more information is available following the submission of the 2016-17 audit report to IPART in August 2017 and IPART's report to the Minister on TG's compliance.

CCP9 notes that the audit report has since been submitted to IPART and confirmed that there were some limitations with the requirements set out in the licence conditions and the costs of implementing these requirements.[89] CHECK CONFIDENTIALITY. Subsequently, the NSW Government with input from the Federal Agencies and TG has drafted revised licence conditions that are expected to be completed prior to the AER's FD in April 2018. TG states that:[90]

The business needs and the amount of the allowance for the step change differes between existing licence conditions and the final version of the revised licence conditions and the timing of any approval by the State and Commonwealth. Once signed by the NSW Minister, the amended licence conditions will take effect prospectively and not retrospectively. The Program of Work developed in conjunction with the Federal Agencies includes a transition plan containing the expected implementation steps required to be undertaken and forms part of the amended licence conditions.

In its revised proposal, TG has submitted two costings, namely $13.9m ($June 18) for the 'existing licence conditions' and $8.0m for the 'proposed licence conditions'.[91]

CCP9 has considered the 2016/17 audit report on TG's compliance with the critical infrastructure requirements and on this basis considers that the AER should revisit the estimates of the step change in the DD. In particular, while the revised licence conditions will reduce the costs relative to compliance with existing licence conditions, there are likely to be ongoing compliance costs that are directly related to the implementation of the regulatory changes and are not currently captured in the base year.

Category specific forecasts

TG's initial proposal suggested debt-raising costs of $40m ($2017-18) based on a methodology that included an additional 'liquidity' allowance amounting to some additional 11.9 basis points on the cost of debt. That is, in addition to the transaction costs of issuing bonds, TG proposed additional costs for related obligations that included refinancing maturing debt at least three months ahead of

[89] Hivint, TG Critical Infrastructure Licence Conditions 2016/17.

[90] TG, *Revised Revenue Proposal 2018/19-2022/23,* Appendix B-IT Step change licence conditions 1217 Public, December 2017, p 2.

[91] Ibid, Tables 1 and 2.

the debt maturing and meeting formal requirements with respect to liquidity to meet short term cash requirements. [92]

These additional liquidity and refinancing of debt costs increased TG's proposed debt raising costs by some $24m ($2017-18).

In its DD, the AER again adopts a benchmarking approach to assessing the efficient debt raising costs rather than a service provider's actual costs to ensure consistency with the forecast of the cost of debt in the rate of return building block. More specifically, the AER rejected TG's proposed liquidity and refinancing costs. The AER's DD allowed a debt raising cost of $15.8m ($2017-18) using its established methodology that includes only transaction related costs of issuing bonds. The AER argues in the DD (and in previous determinations on the same issue) that the any liquidity and refinancing costs are adequately compensated for by the favourable timing assumptions in the PTRM.[93] The AER concluded that:[94]

For these reasons we consider there is no need for an additional explicit allowance for liquidity costs, as service providers are already implicitly and sufficiently compensated for such costs.

CCP9 considers that the AER's DD to reject the proposed liquidity allowance is reasonable and consistent with the opex criteria given that any liquidity costs are more than compensated in the PTRM. This conclusion is based on the AER's assessment of the cash flow biases in the PTRM and on the precedence established in all previous decisions on the cost of debt. However, CCP9 considers that given more recent changes to the PTRM, it is worthwhile for the AER to review this cash-flow bias particularly as this bias currently appears to favour the networks in the order of more than 1.8% of revenue (see AER, DD, Attachment 3, p 3-393).

4.3.2 TG's Revised Opex Proposal

TG's revised proposal is summarised in Table 4.4 below (excluding debt raising costs). The revised proposal is some $30m ($June 2018) less than the original proposal. In addition, TG has included the AER's debt raising cost methodology in its revised proposal, although with considerable reservations. The total reduction including the changes to the debt raising costs is some $44m ($June 2018).

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[92] For details regarding this calculation, see AER, *TG Draft Determination*, Attachment 3, September 2017, p 3-390.

[93] There appear to be two elements to this conclusion. Firstly, the PTRM assumes that revenues are received on the last day of the year and secondly, the PTRM has been modified (in 2007) to recognise capex in the middle of each year which means that the PTRM in effect adds an additional half year of WACC to all capex in the year that it enters the capital base. The effect of this within the PTRM is to further heighten the favourable cash flow timing assumptions in the PTRM, an outcome that more than compensates for any liquidity costs (see Ibid, p 3-393).

[94] AER, *TG Draft Determination*, Attachment 3, September 2017, p 3-393.

Table 4.4: TG's proposed and revised opex proposals and the AER's Draft Decision ($m June 18) – excluding debt raising costs

	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.

Source: TG, *Revised Revenue Proposal*, 1 December 2017, Table 5.1, p 108.

TG has therefore accepted most of the elements of the AER's approach as set out in its DD. In particular, TG has accepted "the AER's preference for its own approach to estimating the trend and has adopted the AER's method."[95] TG has also accepted the AER's decision on the step change for off-easement vegetation management.

TG states that the primary drivers for the increase in its revised proposal over the AER's DD are:[96]

- 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 (published November 2017)
- Reconfirming the step change requirement to meet NSW licence conditions
- Correcting the AER's operating expenditure model errors including an error in the CPI calculation (which has been since corrected by the AER and by TG).

TG summarises the impacts of these factors in the following table extracted from its revised revenue proposal. The table illustrates TG's initial proposal, the AER's DD and TG's revised proposal.

[95] TG, *Revised Revenue Proposal 2018/19 -2022/23*, 1 December 2017, p 109.
[96] Ibid.

Table 4.5: TG's opex proposals and the AER draft decision

	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.

Source: TG, *Revised Revenue Proposal*, 1 December 2017, Table 5.3, p 115.

TG's Revised Proposal: base year opex and 2017-18 opex

TG has marginally updated the estimate of revealed costs for 2016-17 noting that the AER has confirmed the base year represents efficient costs and this is confirmed in the benchmarking studies cited by TG.

TG has also maintained its approach to estimating opex for the final year of the current regulatory period, 2017-18. While TG's approach differs from the AER's approach to estimating the final year, the outcomes are largely the same and represent a reduction of around 3% compared to 2016-17 revealed costs.

CCP9 considers that there are strengths and weaknesses in both approaches and that further investigation by the AER may be required to compare the two approaches to estimating the last year of the current regulatory period (for this and other determinations). Given that this figure is the starting estimate for the forecasts and the impact of errors in the initial starting point is cumulative over the forecast period, small differences in the starting estimate can have a more substantial impact across the five years. This will also require careful examination of the base year opex figures to ensure that they do not include one-off events that should not be carried forward.

However, CCP9 also recognises the importance of maintaining consistency between the estimate for opex in the revenue proposal and the estimate of opex used for the EBSS. As the AER notes, it is essential that they are calculated on the same basis.

TG's Revised Proposal: annual rate of change 2018-19 to 2022-23

TG highlights that: "when preparing this proposal [the initial proposal] we looked 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".[97]

TG now states that as the AER has again applied its standard approach, TG would accept the AER's preferred approach to the rate of change in the revised proposal.[98] The discussion below summarises TG's revised proposal with respect to the three elements of the rate of change calculation.

CCP9 notes that TG's revised proposal appears to rely on the draft benchmarking reports from EI and the AER. We understand the timing issues and expect that the AER's final decision on the rate of change parameters will be based on EI's final report published in November 2017 and the AER's Annual Benchmarking Report, also published in November 2017. The discussion below relates to the results in the draft benchmarking reports by EI and the AER.

Input price change

TG's revised proposal adopts the AER's "previously used methodology".[99] That is, TG updated the price change index using the average of the NSW EGWWS WPI forecasts from BIS Shrapnel (updated October 2017) and DAE (September 2017). TG has also updated the relevant CPI.

TG had strongly argued against the AER's 'benchmark' weightings indicating inter alia, that the study by PEG was out-dated and based on industry sectors that were not representative of the transmission industry. While the AER did not accept TG's proposed weighting, the AER did acknowledge that the weightings would be reviewed as part of the 2017 benchmarking study by EI.

TG states in its revised proposal that it has updated the weightings using the results from EI's 2017 transmission benchmarking study. As a result, the proportion of labour used in the revised proposal was 70.4%.

CCP9 supports the approach adopted by TG in its revised proposal although we expect that the AER will apply the most up-to-date forecast figures   CCP9 also supports the use of the revised weightings between labour and non-labour based on the most recent EI 2017 benchmarking study. CCP9 also refers the AER to the recently announced Enterprise Agreement between the Electrical Workers Union (ETU)and TG, which includes an agreement for 8% pay rise over four years (average 2% per year). The ETU representative stated that: "It's a reasonable outcome in a tough environment for the electricity sector. We're 100% privatised and our workforce is under pressure".

http://www.etunsw.asn.au/power-water-and-utilities/four_year-TG-eba-protects-and-improves-conditions)

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[97] TG, *Revised Revenue Proposal 2018/19 -2022/23*, 1 December 2017, p 116.
[98] Ibid.
[99] CCP9 notes that in its DD, the AER refers only to the average of the DAE NSW EGWWS WPI forecasts although previously it had used the average of the DAE and BIS Shrapnel forecasts. The DD does not provide any explanation of this change.

Output change

TG has accepted the AER's approach and has updated its forecast opex using the results of EI's 2017 benchmarking study. In particular, TG has:[100]

- Adopted the output measures using EI's 2017 benchmarking report; and
- Replaced connection points with the AER's NSW customer data used in the revised benchmarking analysis (2006-2016 customer data) and extrapolating customer numbers for the next regulatory period using ordinary least squares regression (OLS regression)
- method to establish a historical based customer growth rate.

CCP9 agrees with TG, that the AER should adopt EI's revised transmission output measures and weightings and also update the customer number forecast using the most recent customer data from the NSW distributors. However, CCP9 notes that we do not necessarily support the use of OLS regression methodology for forecasting the total NSW state customer numbers over the next regulatory period but rather, should rely on multiple established forecasting sources.

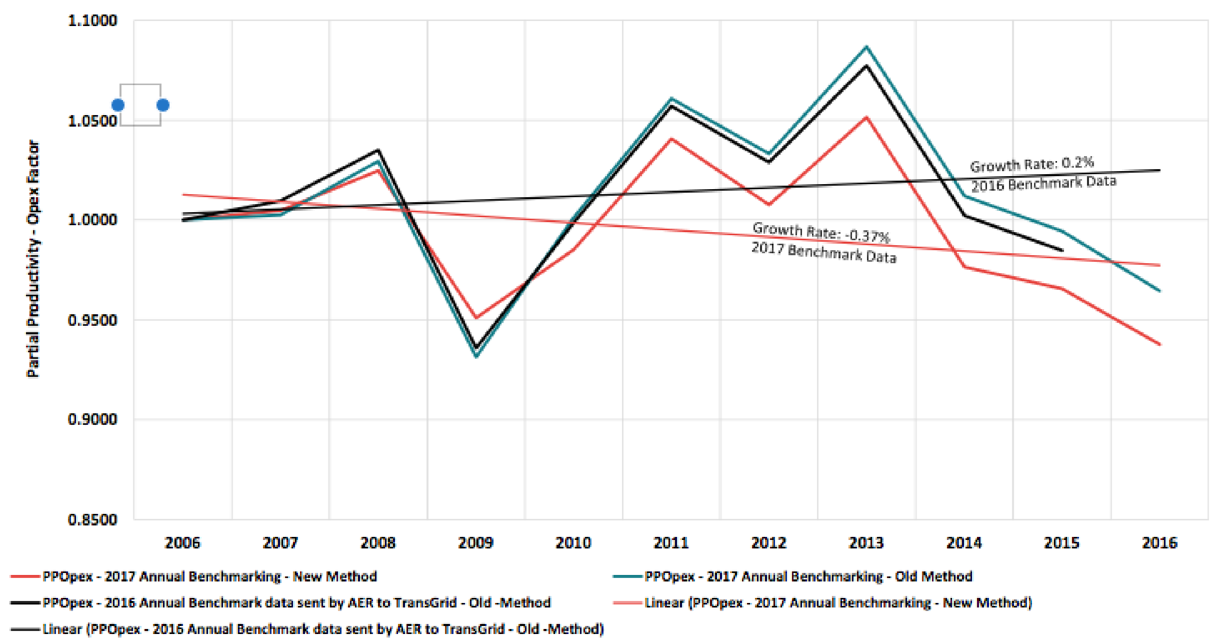
Productivity change

In the AER's DD, the AER rejected TG's proposal for a productivity change of 0% based on a number of productivity studies. The AER replaced TG's proposal with a positive productivity growth factor of 0.2% per annum.

However, as TG highlights in its revised proposal, EI's 2017 benchmark study, using the additional year data and amended output specification, indicated an industry wide decline in total multi-factor and opex partial factor productivity. Figure xxx below from TG's revised proposal illustrates the trends in opex productivity from the EI's 2017 analysis updated to include 2016 data and using both the older output specifications and weightings and the revised 2017 output specifications and weightings. On the basis of this updated information, TG's revised proposal includes a productivity change of 0%.

[100] See Ibid, p 118.

Figure 4.4: Comparison of AER 2016 & 2017 operating expenditure productivity benchmarks



Source: TransGrid using AER economic benchmarking data (2016 and 2017).

Source: TG, *Revised Revenue Proposal*, 1 December 2017, Figure 5.2, p 120. Note: this is based on TG's analysis of the draft AER/EI reports and results may differ from the EI November 2017 report. It is included here for illustration purposes only. 5NoteNote:

It is not clear from the chart above if TG has used the final November EI benchmarking report or the draft EI report, but in any case, the trends in productivity are very similar. That is, the latest data supports the view that there has been a continuation of the decline in the partial factor.

CCP9 therefore concludes that TG's revised proposal that includes a 0% productivity change figure is appropriate. However, we remain very concerned that the industry measures continue to show a decline in opex partial factor (and multi factor) productivity. There has been a significant growth in capex over the last 10 years, while the input measures have shown little or even negative growth. This outcome would explain the decline in capex partial factor productivity but does not explain the decline in the industry wide opex productivity. In normal competitive market circumstances, it would be reasonable to expect that replacement of assets and investment in IT would at the very least, result in improvements in opex productivity measures. The fact that it does not, and has not done so over an extended period of time, suggests that the opex productivity measure and/or the EBSS are not delivering the outcomes consumers should expect. See also discussion in Section 4.5.3 below.

TG's Revised Proposal: Step changes

TG has accepted the AER's DD that off-easement risk management costs do not fit the definition of step changes and has not included these costs in its revised proposal.

However, TG has indicated that:[101]

- if the current transmission licence conditions are retained, then it seeks a step change of $13.9m ($June 2018) for the next regulatory period.
- if the licence conditions are amended in accordance with the current proposals before the regulatory bodies, then TG would seek a step change of $8m ($June 2018).

TG further states that until the proposed licence conditions are ratified, its revised proposal includes the amount of $13.9m for the next regulatory period. This amount, while lower than the step change proposed in its original proposal, is till higher than the AER's DD amount of $7.8m ($2017-18).

CCP9 supports TG's decision to remove the step change for off-easement risk management costs. CCP9 notes the substantial reduction in the proposed step change if the proposed licence conditions are approved. The2016/2017 independent audit of compliance with the critical infrastructure conditions in the transmission licence conditions suggests that full compliance with the current licence conditions will result in significantly greater costs and some risks to the business continuity and efficiency of operations. CCP9 therefore accepts that there will be a step change required as the additional costs for compliance appear to be incremental and ongoing. However, we cannot comment on whether the proposed costs are efficient. Nor are we in a position to assess whether TG has overstated the cost of implementing the current conditions (should that outcome eventuate) in its proposal.

TG's Revised Proposal: Category specific opex changes (debt raising costs)

As noted above, l the AER reduced the allowance for debt raising costs by some $24m. In its revised proposal, however, TG restates its view that its proposed debt raising costs of $40m are: "an accurate estimate of the benchmark costs for an efficient business". TG continues to maintain that the AER's approach is "out of date" and does not recognise the increased costs businesses face in raising debt post the GFC. TG also believes that the AER is incorrect to claim timing of the PTRM calculations offset these costs. In particular, it argues that these liquidity and refinancing costs are not working capital; a fact which the AER recognises but does not acknowledge in its assessment.

However, TG's revised proposal adopts the AER's DD and proposes a debt raising costs of $16.5m ($ June 18). TG states:[102]

Nevertheless, TG 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.

CCP9 generally supports the AER's reasoning on this matter and understands that networks have generally adopted the AER's approach of considering transactional costs only. CCP9 has noted previously, however, that the AER could usefully update its analysis of benchmark transactional costs and also consider the so-called compensating cash flow biases in the PTRM as these biases appear to be quite significant and in favour of the networks.

[101] See ibid, p 121.
[102] Ibid, p 121.

4.3.3 Assessment

Overall, CCP9 is pleased to see the greater degree of accordance between the AER's DD and TG's revised proposal. CCP9 understood that in its initial proposal, TG was seeking to introduce what it saw as innovation in the AER's approach.

CCP9 has outlined some elements of its response to the AER's DD and to TG's revised proposal. In this section, CCP9 will focus on the following areas:

- Has the AER adequately addressed the issues raised by CCP9 in its response to TG's initial proposal?
- What are the findings of the most recent transmission benchmarking study and how might they impact on the AER's FD?
- How effective are the current opex productivity measure and EBSS incentives in delivering continuous improvements in the operating costs of the transmission businesses (including but not only TG)?

Has the AER responded adequately to the issues raised by CCP9?

CCP9 made the following recommendations to the AER in response to TG's initial proposal: [103]

a) The same forecast should be used for projecting the final year opex for both the EBSS and the forecasting of opex in the next regulatory period.

b) The choice of the approach to forecasting opex for the final year should be guided by which method can provide the best forecast and the quantification of the significance of the errors in the forecast of the final year opex on prices and revenues taking into account the impacts of the EBSS.

c) In reviewing TG's proposed opex, the AER should include consideration of past trends in real opex and opex/MWh in determining the trends in TG's future efficient costs. This would support the inclusion of a positive productivity growth factor.

d) Due to the likely asymmetric operation of step changes, the AER must maintain a stringent test for accepting step changes and the standards for quantifying the net impact of changes.

The AER's DD has confirmed its intent to ensure that the same forecast should be used for the final year opex as used in the EBSS. This means that irrespective of the preferred approach (which deliver similar outcomes in this instance), TG must apply the same opex for its EBSS calculations. However, CCP9 considers that the AER has not adequately considered the cumulative impact of any errors in the final year or the impact of this on the EBSS outcomes over the regulatory period.

CCP9 also considers that the AER has not paid sufficient attention to the historical trends in real opex and opex/MWh (etc) in forecasting the future opex allowances. Real operating expenditure has been declining over the last four years but this is in the context of limited growth in key outputs (including

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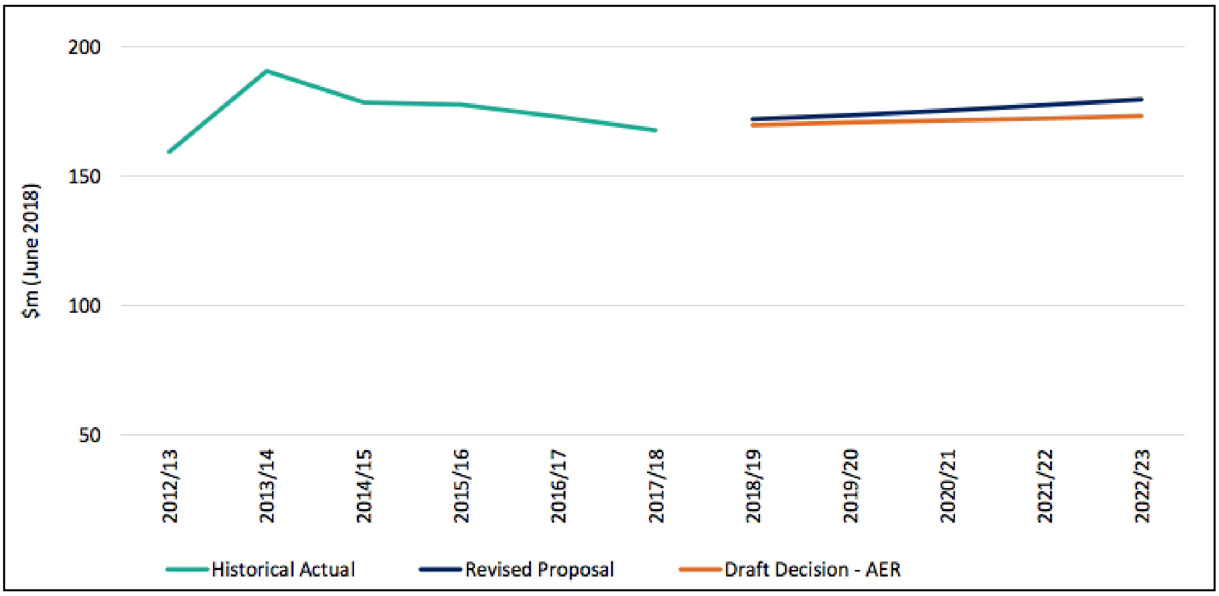
[103] Consumer Challenge Panel subpanel 9, *Response to proposals from TG*, 12 May 2017, p 66.

negative growth in the energy not served (ENS) measure), and significant increases in augmentation and replacement capex in previous periods.

Figure 4.5: Comparison of operating expenditure forecasts, $m June 18



Source: TG, *Revised Revenue Proposal*, December 2017, Figure 5.1 p 110.

As CCP9 noted in its response to TG's initial proposal, there is no reason why this trend of declining real opex should not continue, whereas both the AER and TG (in their revised proposal) are proposing small increases in real opex costs as illustrated in Figure xxx below from TG's revised proposal. CCP9 stated:[104]

The reductions in real opex achieved by TG did not represent catch-up efficiencies, as TG was considered to already be efficient. They were the outcome of TG's continuous efforts to improve its efficiency and reduce costs through for example better risk-based system to improve asset planning and management and improvements to business services. It is reasonable to expect such continuous improvements will continue in the next period.

In general, we do not accept TG's claim that it has already captured all the possible efficiencies. In a competitive market, improvement in efficiency is – necessarily - a continuous process and the same disciplines should apply to the regulated monopoly networks. Moreover, recent investments – and proposed investments in asset renewal and systems should assist TG in achieving a similar continuous improvement outcome. Nor does CCP9 accept that the operating environment, including regulation, has changed sufficiently in the last few years to warrant the reversal of the trend to reduction in real opex.

In CCP9's initial submission, we also highlighted the concern expressed by members of TG's Advisory Council that unregulated businesses were under continuous pressure to pursue productivity improvements to remain competitive and it is reasonable that the regulator should place the same

[104] Ibid, p 64.

discipline on TG,[105] irrespective of whether TG was regarded as 'efficient' in the context of the AER's benchmarking studies.

CCP9 does, however, recognise that the AER has conducted a careful analysis of TG's proposed step changes and made clear that there must be substantial evidence of a real and sustained increase (or decrease) in costs arising from the proposed step change. For this reason, CCP9 supports the AER's DD on vegetation management. The transmission critical infrastructure licence conditions are still uncertain (as discussed above). However, CCP9 expects the AER to very carefully examine the nature and quantum of the proposed step changes in accordance with the recommendations above.

What are the findings of the November transmission benchmarking study and how do they impact on the AER's final decision?

CCP9 notes that TG and its consultant, Frontier, have made significant criticisms of the 2016 transmission benchmarking study and have sought to introduce outcomes from other benchmarking studies irrespective of their relevance to the AER's opex forecasting and benchmarking framework and in the absence of transparency about the assumptions and measures used by some of the reports.

Nevertheless, it is widely accepted that the AER's benchmarking of transmission was still in an immature state. CCP9 is therefore pleased that the AER and industry stakeholders have invested significant resources over the past year in developing the AER's transmission benchmark process. There has also been a continued process of improving the data quality. While still a 'work in progress', the November 2017 benchmark report by EI therefore represents a significant improvement in the quality and consistency of the input data and the AER's capacity to benchmark transmission services.[106]

The new specification, which as noted above has received broad support from stakeholders, is set out in EI's November 2017 report. It includes five output measures and four input measures to be used in the calculation of Total factor productivity (TFP) and multilateral total factor productivity (MTFP):[107]

<u>Output measures (</u>numbers in brackets represent cost weightings in the form of percentage of gross revenue)

- Energy throughput (23. 1%)
- Ratcheted maximum demand (19.4%)
- End-user numbers (19.9%)
- Circuit length (37.6%)
- (minus) Minutes off-supply (weight based on current AEMO VCRs capped at a maximum absolute value of 5.5% of gross revenue)

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[105] Ibid.

[106] Economic Insights, *Economic Benchmarking Results for the Australian Energy Regulator's 2017 TNSP Benchmarking Report*, 6 November 2017. (EI, *Economic Benchmarking Results*, November 2017).

[107] Ibid, p 6.

Input measures

- Opex (total opex deflated by a composite labour, materials and service price index)
- Overhead lines (quantity proxied by overhead MVAkms)
- Underground cables (quantity proxied by underground MVAkms)
- Transformers and other capital (quantity proxied by transform MVA).

While the AER acknowledges the limitations of the transmission benchmarking, such as the relatively small number of small Australian electricity transmission and concern about whether exogenous environmental factors can be adequately captured, the AER also concluded in November 2017 as follows:[108]

That being said [i.e.the limitations of the benchmarking], we consider that the benchmarking analysis presented in this [November 2017] report is reasoned and comprehensive. We have collected data on all major inputs and outputs for transmission businesses, and we consider the dataset used is robust.

CCP9 agrees with the AER's conclusions and supports the use of EI's updated analysis in its final determination for TG in the regulatory period 2018-23.

However, CCP9 would also add:

- The inputs and output specifications and definitions have been developed over the course of 2017 and there has been extensive consultation with transmission businesses and other stakeholders in the process
- The process of developing the benchmark specifications, the methodology used to derive the time-series index is been transparent and can be replicated by third parties. Concerns raised by some stakeholders (including TG) regarding the small sample size are addressed by using index values rather than absolute values.
- There was reasonable agreement amongst service providers on the key inputs and outputs to be used with the possible exception of using customer numbers. In particular, the following changes were made after consultation with stakeholders:[109]
    - Replaced voltage-weighted connections by the number of end-users
    - Placed a cap on the weight given to the reliability output variable (being 5.5% of gross revenue) to prevent distortion of results from 'one-off' large scale events
    - Updated the output cost share weights of the other four output variables

[108] AER, *Annual Benchmarking Report, Electricity transmission network service providers*, November 2017, p 20.
[109] For details see Economic Insights, *Economic Benchmarking Results for the Australian Energy Regulator's 2017 TNSP Benchmarking Report*, 6 November 2017, pp 2-3.

- Collection of additional data in the economic benchmarking regulatory information notices (EBRIN) to assist future development of important variables.[110]

- The EI November 2017 report provides analysis of 2006 to 2016 data using both the new and the previous input and output specifications.

For these reasons, CCP9 believes that TG's concerns with the transmission benchmarking may be overstated or at least outdated. The results of the new benchmarking analysis provide useful and relevant information that can be used by the networks and consumers alike to assess trends in performance. Similarly, the results provide information to the AER and this information needs to form part of its decision-making beyond merely estimating a value for the 'rate of change in industry wide productivity'. For example, the report provides important information on the trends in both the industry and individual total and partial productivity (for opex and capex), including:

- The percentage contribution of different inputs and outputs to total factor productivity, including the contribution of different capital investment segments and overall opex
- Changes in total and partial factor productivity with and without redundancy payments
- Total and partial factor productivity trends for both the transmission industry as a whole and individual transmission companies
- Changes in productivity measures between 2006-2016, and for two sub-periods 2006-2012 and 2012-2016 with the sub-periods broadly corresponding to the period of high capital investment growth and high output growth (2006-20120 and the period of lower capital investment growth but also lower or even negative growth in outputs.

CCP9 considers that the regulated transmission industry as a whole has not responded effectively to the regulatory incentive regime. The AER now has sufficient information from the RIN data and from EI's 10 year analysis of industry and firm specific trends in total and partial factor productivity to undertake a review of the effectiveness of the incentive schemes and the overall expenditure forecasting approach

How effective are the current opex productivity measure and EBSS incentives in delivering continuous improvements in the operating costs of the transmission businesses?

A high level examination of the trends in productivity in the transmission industry as a whole and in TG in particular illustrates the difficulty in turning the transmission industry around under the current incentive mechanisms and regulatory framework. A fundamental problem is that the rigidity in these arrangements means that the industry is not receptive to the market signals and changes in consumer behaviour as seen in the continued decline in TFP and the Opex and capex PFPs.

[110] Specifically, EI recommended that the EBRIN data collection include the MVA rating of each TNSP entry and exit point to eventually allow the assessment of relevant operating environmental factors (OEFs)

For example, Table 4.5 below taken from EI's November 2017 report illustrates the changes in industry level inputs, outputs, TFP and PFP indexes, 2006 to 2016 (using EI's new specification for inputs and outputs).

The opex PFP index feeds directly into the AER's assumption on rate of change in productivity growth. The table demonstrates that between 2006 and 2012, the opex PFP index was slightly positive and reasonably consistent with the AER's use of a productivity rate of change of 0.2% per annum. However, since 2012, annual growth rate in the industry-wide opex PFP has turned negative (-1.8% per annum) despite the implementation of the EBSS scheme across the transmission businesses and the significant growth rate in capital expenditure in the previous period (2006-2012) which should flow through (at least in part) to opex savings in future regulatory periods. By 2016, EI reports that opex PFP was some 6% below its 2006 level.

Such an outcome for opex productivity is neither adequately explained by the industry, nor would it be a sustainable outcome in a competitive market facing static or declining demand. It also fails to meet consumers' reasonable expectations that in paying for significant growth in capital investment in one period, there will be a dividend in the future in lower operating costs.

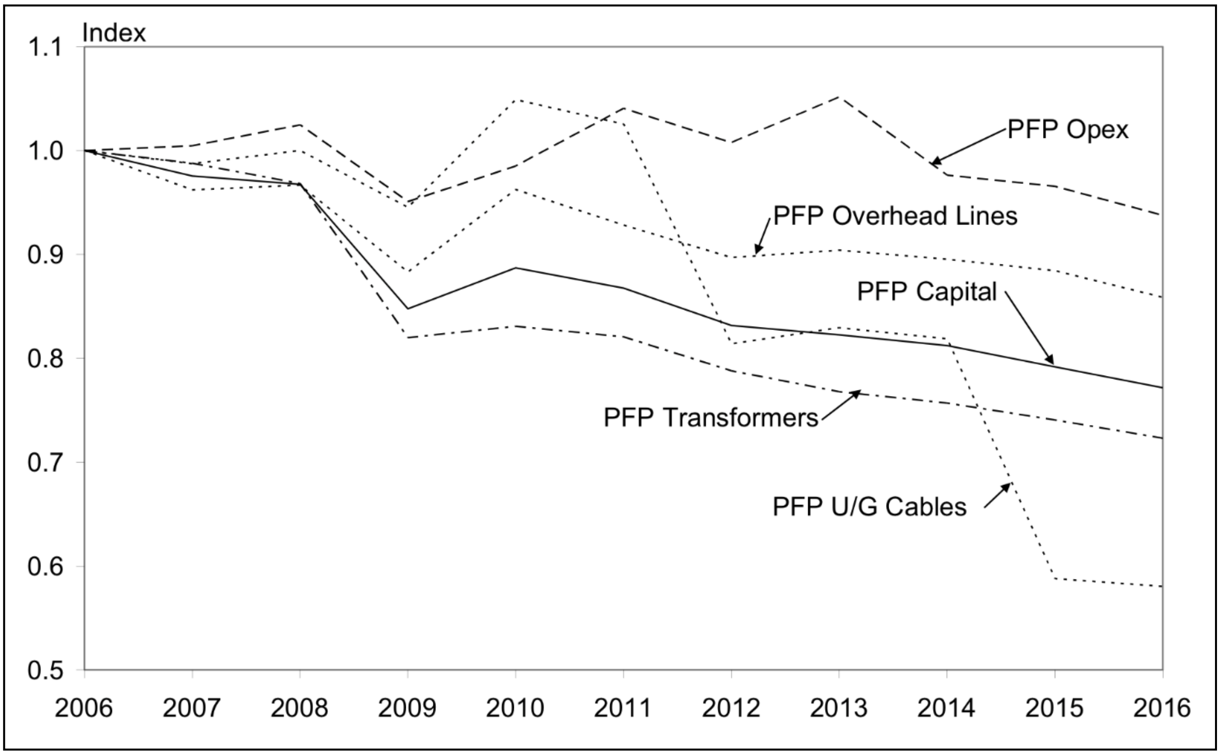
Table 4.5: Industry-level transmission output, input, and total factor productivity and partial productivity indexes, 2006-2016 (new specification)

Year	*Output Index*	*Input Index*	*TFP Index*	*PFP Index*	
				Opex	*Capital*
2006	1.000	1.000	1.000	1.000	1.000
2007	1.007	1.023	0.984	1.005	0.976
2008	1.022	1.038	0.985	1.025	0.968
2009	0.971	1.107	0.877	0.951	0.848
2010	1.054	1.152	0.915	0.985	0.887
2011	1.060	1.161	0.913	1.041	0.868
2012	1.056	1.204	0.877	1.008	0.832
2013	1.059	1.205	0.879	1.051	0.823
2014	1.064	1.247	0.853	0.976	0.812
2015	1.063	1.273	0.835	0.966	0.792
2016	1.050	1.291	0.813	0.938	0.772
Growth Rate 2006–16	0.49%	2.56%	–2.07%	–0.64%	–2.59%
Growth Rate 2006–12	0.91%	3.09%	–2.19%	0.13%	–3.07%
Growth Rate 2012–16	–0.14%	1.76%	–1.90%	–1.80%	–1.87%

Source: *Economic Benchmarking Results, November 2017*, Figure 2.1 , p 8.

Figure 4.6 below illustrates the PFP indices for the transmission industry as a whole

Figure 4.6: Industry-level transmission partial factor productivity indexes 2006-2016



Source: EI, *Economic Benchmarking Results, November 2017*, Figure 2.4, p 12.

The EI November 2017 report also provides an analysis of each of the transmission businesses. For example, the EI report produces the same analysis for TG (and each of the other transmission businesses). Table xxx below illustrates that in the period 2012-16, TG's opex PFP declined by an average of 1.09% per annum. Excluding redundancy payments, the opex PFP still declines at the rate of -0.8% per annum.[111] Overall TFP declined at the rate of -2.34% per annum in the same period (-2.27% excluding redundancy payments).

[111] See EI, *Economic Benchmarking Results*, November 2017, Table 5.15, p 57.

Table 4.6: TG output, input, and total factor productivity and partial productivity indexes, 2006-2016 (new specification)

Year	*Output Index*	*Input Index*	*TFP Index*	*PFP Index Opex*	*PFP Index Capital*
2006	1.000	1.000	1.000	1.000	1.000
2007	0.999	1.033	0.967	1.025	0.942
2008	1.013	1.010	1.003	1.112	0.959
2009	1.003	1.100	0.912	1.106	0.841
2010	0.997	1.172	0.851	0.980	0.799
2011	1.019	1.184	0.860	1.081	0.784
2012	1.011	1.249	0.809	1.004	0.741
2013	1.000	1.198	0.835	1.093	0.751
2014	0.996	1.275	0.782	0.912	0.734
2015	0.995	1.300	0.765	0.973	0.696
2016	0.971	1.317	0.737	0.961	0.666
Growth Rate 2006–16	–0.30%	2.76%	–3.05%	–0.40%	–4.07%
Growth Rate 2006–12	0.18%	3.71%	–3.53%	0.06%	–5.00%
Growth Rate 2012–16	–1.01%	1.33%	–2.34%	–1.09%	–2.67%

Source: EI, *Economic Benchmarking Results, November 2017*, Table 5.13, p 53.

However, notwithstanding these declines in opex and capex PFP and in TFP (as illustrated in Table xxx above), the AER's process still regards TG's base year 2015-16 as 'not materially inefficient' and builds up its opex forecast from that starting point. Moreover, in the AER's DD, TG receives a positive EBSS carry-over payment of $15.3m ($2017-18)[112] in addition to its opex allowance for 2018-23.

TG also receives a CESS carry over payment of $26.5m ($2017-18),[113] again in the face of declining capex PFP. It is not at all clear how TG's capex proposal and approved capex allowance for 2018-23 responds to this incentive payment.

Recommendations:

h) CCP9 supports AER's proposed opex in its draft decision with the amendments proposed by TG in its revised proposal subject to the recommendations below.
i) Given the cash flow bias identified in the draft decision the AER should separately review the cash flow assumptions in the PTRM.
j) Given that this figure is the starting estimate for the forecasts and the impact of errors in the initial starting point is cumulative over the forecast period, small differences in the starting estimate can have a more substantial impact across the five years, the AER carefully examine the base year opex figures to ensure that they do not include one-off events that should not be carried forward.
k) The base year estimate for opex use in forecasting opex should also be used for the EBSS.

[112] AER, *Draft Determination TG*, September 2017, Attachment 9, p 9.6
[113] ibid, Attachment 10, p 10-7.

l) CCP9 agrees with TG, that the AER should adopt EI's revised transmission output measures and update the customer number forecast but forecasts of customer numbers over the next regulatory period should rely on multiple established forecasting sources
m) AER should update its analysis of benchmark debt transactional costs
n) CCP9 remains very concerned that the industry measures continue to show little, if any, productivity growth and considers that the regulated transmission industry as a whole has not responded effectively to the regulatory incentive regime. The AER should separately undertake a review of the effectiveness of the incentive schemes and the overall expenditure forecasting approach

4.4 Rate of Return, Inflation and Tax

4.4.1 Draft Decision

The AER Draft Decision proposed a WACC of 6.5% (nominal vanilla), consistent with the AER's Rate of Return Guideline, and slightly lower than the 6.6% WACC proposed by TG. The difference reflects a lower Return on Equity (ROE) of 7.2% (compared to 7.5% proposed by TG) due to the retention of the market risk premium (MRP) of 6.5% rather than the MRP of 7.5% proposed by TG. The MRP was the only parameter in the nominal WACC where TG proposed a variation from the Rate of Return Guideline. The lower MRP (compared to TG's proposal) more than offset the increase in the risk free rate (RFR), due to changes in bond yields, from 2.24% in TG's proposal to 2.68% in the AER's Draft decision.

Consistent with its Rate of Return guideline and TG's proposal, the AER adopted the transition to the trailing average starting from 2013-14. This resulted in an estimated return on debt of 6.01% based on a benchmark credit rating of BBB+ and term of 10 years.

The estimate for inflation expectations in the draft decision is 2.5%, compared to TG's proposal of 2.39%. This change reflected updated data rather than a change in approach as TG had accepted the AER's approach to the estimation of inflation expectations.

Finally, the AER used a gamma (value of imputation credits) of 0.4, consistent with the Rate of Return Guideline, in estimating the allowance for tax expense, compared to TG's proposed gamma of 0.25.

4.4.2 Revised Proposal

In preparing its Revised Proposal TG accepted the AER draft decision in regard to the WACC and its components, the estimation of inflation expectations, and the value of gamma used in estimating tax expense.

The only two parameters on which there had been a difference between TG's original proposal and the AER Draft Decision were the value of the MRP and the gamma. In each case TG has accepted the AER Draft decision but note that:

- TG considers that the 'proper application' of the methodology in the Rate of Return Guideline would result in an MRP estimate of 7.0%
- An estimate of gamma of 0.34 can be calculated using the ATO statistics method

4.4.3 Assessment

CCP9 supports the application of the AER's application of the Rate of Return Guideline and, as a consequence of this, the proposed WACC of 6.5%. CCP9 also welcomes TG's acceptance, with reservations, of the AER's draft decision. In doing so, CCP9 notes that it also has reservations – albeit different ones – in regard to the AER Draft Decision.

- It considers that AER's current approach and values for key parameters have resulted in WACCs that have systematically erred on the high side, but that this is best considered through the current review of the Rate of Return Guideline.
- It supports the CCP submission to the Rate of Return guideline.

Why we have accepted the AER's proposed WACC of 6.5%

While we consider that AER's approach resulted in WACC's that have erred on the high side we support the application of the Rate of Return Guideline as AER has done in the draft determination. The AER developed the Rate of Return Guideline through an extensive process of consultation and research. While the Guideline is non-binding, it created a reasonable expectation that the AER would apply the Guideline unless there was strong persuasive new evidence and/or a substantial change in circumstances such that a change in approach and parameters was necessary to achieve the ARORO and NEO. That is, in layman's terms, there is a high burden of proof on those requesting a variation in approach or parameters from those in the rate of Return Guideline

We find it disappointing that some NSPs have been selective in their approach and not respected the role of the Rate of return Guideline in promoting certainty and consistency of regulation, consistent with best practice principles of regulation and NSPs past requests for greater certainty. Hence, we wish to recognise and support TG's decision to accept the AER's Draft Decision on the WACC and value of gamma, which we consider properly implements the Rate of Return Guideline.

In our submissions to the AER on the TNSPs proposals, we argued that:

1. Market evidence, such as market value to RAB ratios, suggests that the allowed rates of return have exceeded the expected rates of return required by investors
2. Indicators of investment climate and uncertainty/risk do not support an increase in the MRP, which is the risk premium for investing in equities compared to risk-free investments.

However, we accept that these issues are best considered in the review of the Rate of Return Guideline and that while there is evidence that could support a lower WACC it does not meet the burden of proof required to support a change in approach at a revenue reset covered by the current guidelines.

Why we consider that the proposed WACC errs on the high-side

As the CCP submission to the Review of the Rate of Return Guideline argues:

> Market evidence on the attractiveness of the sector for investors suggests that the current approach, as implemented by the AER has more than met the requirements under the NEO and ARORO to provide the utility with the opportunity to earn a fair return. In particular:
>
> - Acquisition values do not support the view that the allowed ROR is less than fair for investors – indeed they are more likely to be consistent with the allowed return exceeding investor expectations;

- Commentaries from brokers and rating agencies provide a positive assessment of the regulatory regime for investment; and
- Existing investors do not appear to be seeking, on balance, to reduce their exposure to the sector[114].

The winning bidders in the most recent electricity network transactions, the long-term leases of the TG network (2015), the Ausgrid network (2016) and the Endeavour network (2017), paid 1.6, 1.4 and 1.6, respectively, times the RAB. These multiples are significantly above the RAB multiples commonly seen internationally. The multiples are also above the RAB multiple of 1.15 paid for the Sydney Desalination Plant.

Acquisition or market values need to be treated with caution. A premium is not proof of an overly generous regulatory regime, but it provides some information on the relativity of allowed returns and investor expectations. A very conservative interpretation of the RAB multiples in the acquisitions of TG, Ausgrid and Endeavour is that they provide strong evidence that the combined allowances for the cost of capital and tax under the AER's current framework and recent decisions are not too low and probably exceed investors' expectations for the required return on investment. This is discussed further in various CCP submissions.[115]

Brokers and rating agencies appear to regard the regulatory regime and the rates of return offered as positive features of the investment environment. For example, in its report on Hastings Infrastructure Fund after the purchase of TG, Credit Suisse commented that TG was "*governed by a generous regulatory regime which still by design errs on the side of over-incentivising*."[116] In its presentation for investors Jemena noted that both Moody's and Standard and Poor's referenced the maturity and strength of the regulatory regimes in providing the underpinning for the regulated businesses cash flows.

If the ROR offered were less than fair one would expect to see investors seeking to reduce their exposure to the sector. This could occur though an increase in gearing as the investor converts equity into debt or a reluctance to invest. In regard to gearing, the Frontier Economics study on beta did not suggest any significant change in gearing was occurring:

> "*We note that the average leverage is reduced by the inclusion of AGL and Alinta – both of which had maintained low leverage in order to preserve borrowing capacity to enable them to acquire assets during a time of industry consolidation. But for these two firms, the mean leverage is again very close to the 60% gearing assumption adopted by the AER*." [117]

This apparent stability in gearing is occurring at a time when the RABs continue to increase – see for example the proposed 17% increase in TG's RAB in the TG proposal. The generally moderate levels of debt of the regulated utilities and sound credit ratings do not suggest that this increase in equity

[114] CCP Submission, Review of the Rate of Return Guideline, p18
[115] See CCP submissions on Profitability Measures, the Review of the Rate of Return Guideline, and the TG and Murraylink Revenue Proposals for 2018-19 to 2022-23.
[116] Credit Suisse, *Spark Infrastructure Group, Equity Research,* 25 November 2015 at p1
[117] Jemena Electricity Networks (Vic) Ltd 2016-20 Electricity Distribution Price Review Regulatory Proposal Revocation and substitution submission, Attachment 6-6 Frontier Economics - Estimating the equity beta for the benchmark efficient entity at p10

exposure to the sector is due to a lack of capacity to borrow more. For example, SGSPAA has a rating of Moody's: A3 (Stable) / Standard & Poor's: BBB+ (Stable), has maintained a stable gearing of around 50%, which is below the metric for maintaining investment grade debt of 65%, while its RAB is increasing (for example, SGSPAA projected increases in the RAB for its Electricity and Gas networks in Victoria of 6.6% p.a. and 3.7% p.a., respectively, over 2015-2020).[118]

Overall the evidence suggests the regulatory regime errs on the side of generosity for the NSPs rather than parsimony.

Recommendation:

CCP9 accepts the proposed WACC of 6.5% (nominal, vanilla) and recommends that in its final decision the AER updates the proposed WACC for changes in interest rates but does not otherwise change it.

CCP9 supports the AER's Draft Decision to use a gamma of 0.4 and the AER's current methodology for estimating inflation expectations (2.5% based on current data).

4.5 Incentive Schemes

4.5.1 Draft Decision

The AER has three standard incentive mechanisms: the Efficiency Benefit Sharing Scheme (EBSS) and the Capital Expenditure Sharing Scheme (CESS) which are designed to provide stronger and more neutral incentives for efficiency in opex and capex; and the Service Target Performance Incentive Scheme (STPIS) that seeks to balance the TNSP's incentives to reduce costs or improve services. The AER's draft decision proposes to:

1. *Approve EBSS carryover amounts of $15.3 million from the 2014-18 regulatory period.* This is $47.1 million less than the carry-over amount of $62.4 million claimed by TG.
2. *Continue the application of the EBSS.*
3. *Approve CESS carryover amounts of $24.3 million from the 2014-18 regulatory period.* This is almost 10% less than the carry-over amount of $26.5 million claimed by TG
4. *Apply the CESS for the 2018-23 period.* The CESS covers all capex except priority projects approved under the STPIS.
5. *Apply the STPIS for the 2018-23 period* covering unplanned outages and market impacts.

The difference in the carryover amounts under the EBSS are due to:

1. Carrying forward the incremental loss made in 2013-14 for an additional year in adopting a carryover period of 5 years rather than 4 years for the 2014-18 regulatory period (reduction of $13.1 million)
2. Correction of an error in the inflation adjustment (-$10.8 million)
3. Correction of opex amounts to match determined opex and adjustments to provision and superannuation liabilities (-$9.0 million)
4. Alignment of opex allowance in 2017-18 with EBSS calculation (-$8.4 million)

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[118] Jemena, *Investor Update,* June 2016, downloaded from: www.jemena.com.au/getattachment/About/investors/investor-information/SGSPAA-Investor-Presentation-June-16-Roadshow.pdf

5. Correction of opex excluded from EBSS coverage (-$5.9 million)

4.5.2 Revised Proposal

In its revised proposal TG has:

1. Accepted the application of the EBSS but does not accept the adjustments in the estimation of the carryover from 2014-18 due to the use of a 4 year carryover period and alignment of the opex allowance in 2017-18 with the EBSS calculation.
2. Accepted the application of the CESS, but with modifications to the calculation of the carryover that it considers better aligns with the intent of the CESS. These increase the carryover from 2014-18 to $33.7 million.
3. Accepted the application of the STPIS with the parameters proposed in the draft decision.

4.5.3 Assessment

CCP9 considers that incentives to improve efficiency is in the long-term interest of consumers as long as it is not at the expense of service quality and supports the application of the EBSS, CESS, and STPIS as proposed in the AER's draft decision.

Incentive mechanisms and the long-term interest of consumers

The set of performance incentives are in the long-term interest of consumers if they are successful in promoting larger efficiency improvements.

In the absence of the EBSS and CESS, the TNSPs' incentives to pursue efficiency improvements diminishes through the regulatory period. As a result, reductions in costs that could be achieved in the last years of a regulatory period may be foregone or deferred to the subsequent period. Under the revealed costs approach, where costs in the last year of one regulatory period form the basis for assumed costs for the first year of the next, this results in higher prices for consumers.

The EBSS and CESS are intended to:

1. Equalise the incentives to improve efficiency across each year of the regulatory period
2. Equalise the incentives to improve efficiency through reductions in opex and capex.
3. Provide a fair sharing of efficiency benefits between the TNSPs and consumers

Equalising the incentives over the regulatory period provides a stronger incentive for the TNSP to reduce costs in the latter years of the regulatory period. If the TNSP responds to this these incentives the costs at the end of the period will provide a base for future prices. This should provide a benefit that more than offsets the increment to prices in the next regulatory period under the EBSS or CESS to provide the incentive to the TNSP.

Equalising the incentives between Opex and Capex removes a potential distortion in the TNSP's that could lead a utility to inefficiently substitute opex for capex or vice versa. Again this should result in lower revealed costs that provide the basis for future prices.

It is important to note the differences in incentives for costs that are not set using the revealed preference approach and hence the coverage of the EBSS and CESS.

One concern is that in strengthening incentives to reduce costs it also strengthens the incentives to reduce costs through reductions in service standards not just efficiency improvements. The concern is that there may be cases where the increased costs (or loss of value) for consumers from reductions in service standards may exceed the reduction in costs for the TNSP. The STPIS provides a mechanism for protecting against this and is an important component of the incentive framework from eth consumers' perspective. However, it is subject to the constraints on measuring service performance and the limitations on the revenue at risk.

Under the current approach some costs – most notably debt costs and tax expense – are set using a benchmark without reference to actual costs incurred. Debt costs are based on the yield for benchmark corporate bonds. These may vary from actual costs incurred but there is no adjustment or reset at any point to actual costs incurred (in contrast to most opex and capex). Tax expense is based on an estimate of taxable income based on the allowed revenue requirement and the statutory tax rate. The forecast tax expense may vary from tax paid – indeed it appears to systematically exceed actual tax paid – but there is no adjustment or reset at any point to actual costs incurred (in contrast to most opex and capex). This means that for debt and tax costs the utility retains 100% of the benefit of any reduction in these costs and that the consumers do not benefit. This has two important implications:

1. **The incentives for the utility to minimise debt costs or tax costs are more than 3 times as strong as the incentive to achieve opex and capex efficiencies.** Unfortunately, this means that if there are limited management resources, it would be rational for the TNSP to prioritise minimising tax, to the detriment of other taxpayers and without benefit to consumers or economic benefit through more efficient resource usage, and minimising debt costs.
2. **Costs which are based on benchmarks alone and do not use the revealed cost approach at the revenue reset should not be included in the EBSS or CESS.** The utility already retains 100% of any reduction in these costs. Inclusion in the EBSS would 'double count' these benefits to the detriment of consumers who would have to fund the incentive payments with no benefit through a reduction in the cost base for the determination of future prices.

Calculation of the carryover under the EBSS

In its Draft Decision the AER made five adjustments to the calculation of the carryover amount from the 2014-18 determination:

1. Carrying forward the incremental loss made in 2013-14 for an additional year in adopting a carryover period of 5 years (reduction of $13.1 million)
2. Correction of an error in the inflation adjustment (-$10.8 million)
3. Correction of opex amounts to match determined opex and adjustments to provision and superannuation liabilities (-$9.0 million)
4. Alignment of opex allowance in 2017-18 with EBSS calculation (-$8.4 million)
5. Correction of opex excluded from EBSS coverage (-$5.9 million)

Adjustments (2), (3), and (5) were accepted by TG. These adjustments are not controversial and supported by CCP9 without further discussion. CCP9 also supports adjustments (1) and (4), but as these are controversial we explain our reasoning below.

Adjustment of the carryover period

The change from a regulatory period from 4 years to 5 years has raised had unintended consequences for the EBSS and the calculation of the carryover amounts. In its 2015 final determination the AER had adopted a 4-year carryover period for gains and losses under the EBSS for the 2014-18 regulatory period. In April 2016 TG alerted the AER to the potential for this to provide the perverse outcome where TG could be better off by increasing its expenditure in 2016/17 (the base year for the next regulatory period) – which was the effect the EBSS was intended to avoid. CCP9 notes that in doing so TG was arguably acting against its short term financial interest but in the long term interest of better regulation and efficient supply.

It is now common ground between the AER and TG that the proposed 4-year carryover period 2014-18 regulator period should be extended to 5 years. This necessarily involves changing the carryover period set out in a previous determination and applying it to years that have already passed (i.e. it has an element of retrospectivity).

As the AER points out applying a 4-year carry over period "would:

- not fairly share efficiency gains between TG and its network users
- create an incentive for TG to increase opex in the expected base-year, 2016–17
- reward TG for efficiency losses and penalise it for efficiency gains
- not provide a continuous incentive for TG to pursue efficiency gains." [119]

This arises because of the mismatch between the length of the carryover period and the length of the regulatory period. As the AER also demonstrates moving to a 5 year carryover period for the 2014-18 solves the problem of the transition from the 2014-18 to the 2018-23 regulatory periods but creates a new mismatch for the transition from the previous regulatory period to the 2014-18 regulatory period. In doing so, the change in the carryover period creates a windfall gain for TG in regard to the incremental efficiency loss in 2013-14. "This is because the incremental loss in 2013–14 would be carried forward for an additional four years by the opex forecast (until 2017–18), but the incremental gain in 2014–15 would be carried forward for an additional five years through the EBSS carryovers (until 2019–20)."[120] AER proposes to remove this windfall gain by carrying forward the efficiency loss in 2013-14 for an additional year (i.e. 2018-19). It is this adjustment that TG has not accepted.

The AER argues that its proposed approach "rewards efficiency gains and penalises efficiency losses, thus sharing gains and losses fairly. We have applied this approach in our draft decision because it is the only approach that is consistent with the objectives we must have regard to when we implement the EBSS."[121]

TG provided a report by Frontier Economics that argues against the AER's proposal to extend the carryover period for 2013-14 as well as the 2014-2018 regulatory period. In so doing Frontier Economics seeks to limit the consideration of any gains or losses from a the change to the period from 2014 on. For example, Frontier Economics assess the AER's approach in terms of whether it is necessary to achieve a "30:70 sharing ratio … **in the current RCP**"[122]. Frontier Economics does not consider the effect that the decision may have on the sharing of efficiency gains and losses in previous periods, specifically 2013-14.

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[119] AER Draft Decision, Attachment 9 – EBSS, p9-13.
[120] AER Draft Decision, Attachment 9 – EBSS, p9-14
[121] AER Draft Decision, Attachment 9 – EBSS, p9-15
[122] TG Revised Revenue Proposal, Appendix C Frontier Economics:The AER Modifications to EBSS

Frontier Economics also takes a narrow interpretation of the AER's objectives and the objectives of the EBSS.

Moving to a 5-year regulatory period created an intended consequence – or error – in the application of the EBSS that it is now agreed should be corrected by changing the carryover period. CCP9 considers that in seeking to correct this error through a retrospective change in the carryover period all impacts should be considered, including those arising from the sharing of gains/losses in 2013-14 that would impact on consumers in the 2018-23 regulatory period. It would be inappropriate and unfair if in correcting one error or unintended consequence another was created that resulted in a windfall gain/loss was created for some stakeholders (in this case, a gain for the TG and a loss for consumers).

Furthermore, the overarching obligation on the AER is the achievement of the NEO and the NEO is relevant to this decision. The NEO is:

> to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to – price, quality, safety, reliability, and security of supply of electricity; and the reliability, safety and security of the national electricity system.

In this case the decision on the treatment of efficiency gains in past years cannot affect the past decisions on investment, operation, and use of the electricity services. But a decision that imposes a windfall loss on consumers through higher prices and has no benefits in terms of efficiency, security or quality of service provision is clearly not in "the long term interests of consumers with respect to – price". The specific arguments put by Frontier Economics in regard to the AER's proposed treatment of 2013-14 efficiency losses and our responses are set out in the table below.

Table 4.7 Assessment of the Frontier Economics' Reasons

Frontier Economic's argument	CCP9 Response
As noted above, they are not necessary to achieve the objectives of the EBSS in respect of the current or forthcoming RCPs	The change impacts prices in the forthcoming RCP and retrospectively changes the sharing of efficiency losses from 2013-14. On both counts it is relevant to the EBSS and the long term interests of all stakeholders, most especially consumers
Modifications made now to sharing ratios that apply retrospectively to 2013/14 could not and will not affect TG'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	The change to the treatment of 2013-14 efficiency losses will not affect incentives, but the same could be said of all years prior to 2016-17. The EBSS is concerned with the fair sharing of efficiency gains in the long term interests of all stakeholders as well as the promotion of efficiency. The AER's proposed adjustment supports the objective of fairly sharing efficiency gains by offsetting a windfall gain/loss that is an unintended consequence of the shift to a 5 year carryover period.
The modifications seek to achieve a sharing ratio outcome that the AER has	The adoption of the 5 year carryover period represents a return to a consistent application of the 30:70 sharing ratio. To the extent that an

not pursued consistently. For example, if the upcoming RCP (2018/19 onwards) remained four years in length, as it was originally intended to be, the benefit-sharing ratio for the 2014/15 to 2017/18 RCP would be 25:75;	unintended consequence is to change the sharing ratio for 2013-14, it is entirely appropriate and consistent that this is also addressed.
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, [Frontier Economics] highlight again that the AER's modifications have not even been defined algebraically, as the existing EBSS has	The proposed change has the same effect as an extension of the carryover period and is described as such. Algebraic expression is not a prerequisite for a valid, correct decision. In terms of process, AER has given notice of and clearly explained its proposed change in its draft decision – the relevant place for it to do so – and provided an opportunity for all stakeholders to respond to this draft decision. The AER is obliged to consider these inputs prior to making its final decision and in doing so will have satisfied the requirements of due process.

Alignment of Opex allowance and EBSS calculation

As the actual opex in the final year (in this case 2017-18) is not known at the time the carryover allowances are calculated it must be estimated. In its proposal TG used a lower forecast for the opex in calculating the EBSS carryover than it used to forecast opex in future years. If the estimate used in forecasting opex is the best forecast, given the available information, of the opex in 2017-18, the use of a lower forecast for the calculation of the EBSS means that the TNSP may be rewarded for efficiency gains it is unlikely to achieve.

In its Draft Decision the AER used the same forecast for 2017-18 opex for calculating the EBSS carryover and forecasting future opex. This is consistent with the position we set out in our submission on TG's Revenue Proposal and which we maintain to be correct.

Using the same, best available, forecast of opex in 2017-18 for forecasting future opex and calculating the EBSS carryover is not only good common sense but also technically sound. Under the approach proposed by TG a forecast of the final year opex that it considers to be an inferior forecast would be used for calculating an efficiency carry forward, when an estimate that it regards as more accurate is available and used for forecasting future costs. It is not clear why this is proposed, and there appears to be a risk that it could create a windfall gain (in this case) or loss (in other cases)

In forecasting opex for the final year of the current regulatory period the objectives are to:

1. Determine/forecast actual expenditures in 2016-17 (base year) and 2017-18 as accurately as possible, subject to reasonable compliance and administrative costs
2. Preserve the efficiency incentives for the base year and final year of the regulatory period
3. Avoid opportunities for gaming or windfall gains and losses.

The forecast used to estimate the final year opex will affect the absolute size of the efficiency loss or gain carryover but not the incentives to pursue efficiency gains. The table below provides a simplified example that abstracts from non-recurrent efficiency gains to illustrate this:

Table 4.8: Example of Impact of Variations in Opex Forecast

	Biased Opex Forecast ($m)	Unbiased Opex forecast ($m)
Opex forecast	100	95
True expect opex	95	95
Loss/gain carried forward	5	0
Actual opex	92	92
Loss/gain carried forward	8	3
Change in loss/gain carried forward	3	3

In this simplified example the TNSP achieves an additional efficiency gain $3m in the last year it increases the carryover amount for the next 5 years by $3m, irrespective of which opex forecast is used.

The is not a novel outcome. It reflects the basic underlying principle of incentive based regulation – it is not the size of the X factor but the period for which revenues are is de-linked from actual expenditure that determines the strength of incentives.

However, as the table shows, the choice of the opex forecast affects the absolute size of the carryover amount and future prices. If the opex forecast used is biased up, the carryover amount is also biased up with no impact on efficiency. This creates a windfall gain that is not in the long term interest of consumers. The reverse would apply if the opex forecast were biased down - the TNSP would unfairly suffer a windfall loss without any efficiency benefit.

CESS

The AER's draft decision adopts the CESS as set out in version 1 of the capital expenditure incentives guideline to TG in the 2018–23 regulatory control period. Priority projects approved under the network capability component of the STPIS for transmission network service providers are excluded. The Draft Decision provided for carryovers from the CESS for the current regulatory period of $26.5m, which is slightly above the amount in the TG Revenue Proposal of $24.3m.

TG accepted the AER Draft Decision but proposed changes the calculation of the carryover amount that would increase it to $33.7m. The changes to the calculation involved:

1. Removal of any financing benefit in the year of over/under spend
2. Inclusion of capitalisation of half year of WACC on capex
3. Calculation of the financing benefit using the real WACC rather than the nominal WACC.

The changes proposed by TG were based on a report by Houston Kemp.

Approach to calculating the benefits under the CESS

The TNSP's revenues are calculated to provide a return of and on the forecast capex during a regulatory period (together with the recovery of the costs of existing assets and other costs). That is the future revenues attributable to the forecast capex equals the capex in net present value terms. When the TNSP spends less (more) than forecast it generates more (less) cash than expected and the benefit of this can be valued at the opportunity cost of funds for the TNSP. The alternative way of looking at the benefit to the TNSP is to note that the allowed revenues are larger than would have been allowed if the regulator had known in advance the actual level and timing of capex spent.

At the start of the next regulatory period the RAB is rolled-forward on the basis of the actual capex incurred so that the benefits (costs) for the utility of spending less (more) do not persist beyond that point, in the absence of the CESS.

As a result there are two alternative and valid questions that can be asked in assessing the benefit (cost) to the utility from spending:

1. what is the value to the utility of 'the additional cash flow from the savings in capex; or
2. what revenue was included in the revenue building blocks in regard to the capex not spent.

In principle both questions should result in the same or very nearly the same answer since the regulatory model is intended to equate future and current cash flows at the opportunity cost of capital for the TNSP.

The first question – the value of the additional cash flow – is a common commercial question that can be answered simply using standard financial techniques. For these reasons we consider this to be the preferred approach. The commercial value of the additional cash flows can be determined independently of the detailed joint workings of the PTRM, the RFM and the annual pricing adjustments which together determine regulated revenues.

The AER has stated that "We calculate the CESS payments taking into account the financing benefit or cost to the service provider of the under-spends or over-spends"[123]. This is consistent with the first question and the current approach to to the calculation of benefits under the CESS which reflects the financing benefit approach rather than the estimation of the building blocks within the PTRM/RFM.

The second question – what revenues were allowed for the capex not spent – would require that the calculation of the benefit reflects the calculations within the PTRM/RFM.

Benefit calculation in the current CESS model.

As noted above, the calculation of the benefits in the current CESS model reflects the cash flow approach. Once the revenue path has been set if the utility spends less on capital expenditure than allowed its net cash flows will be correspondingly higher. The value of the additional cash generated is measured by the opportunity cost of funds - assumed to be the WACC determined by the AER. All the calculations are done in nominal terms. The steps are in the CESS model are:

1. express the allowed capex in nominal terms
2. calculate the nominal capex savings as the allowed capex in nominal terms minus the actual nominal capex
3. estimate the value to the NSP of the extra cash flow in each as the additional cash flow times the opportunity cost of funds (assumed to be the nominal WACC). It is assumed that capex is evenly spread through the year so that in the year in which the savings are achieved the additional cash flow from the savings is available for only 6 months on average. Hence, a 6-month cost of funds is used for that year.

[123] AER, Attachment 10 – CESS | TG transmission draft determination 2018–23, p

4. since the savings occur in different years, the savings are converted to a common year (the last year of the regulatory period) in NPV terms. The nominal WACC is used as the discount (in this case accumulation) factor.
5. since the utility is to receive a benefit equivalent to 30% of the capex savings, the NPV of the nominal savings is multiplied by 0.3 and the amount calculated at (4) deducted from this. The residual is the carry-over amount under the CESS.

We have carefully reviewed the current CESS model which AER used in its draft decision and consider that correctly calculates the financial benefit in the current regulatory period of the increased cash flows arising from the capex savings.

The proposed Houston Kemp (HK) model

The HK analysis and model focusses on the second question: what revenue was provided in the current determination period in regard to the capex not spent.

The steps are in the HK model are:

1. express the allowed capex in nominal terms. *This is the same as in the AER CESS model.*
2. calculate the nominal capex savings as the allowed capex in nominal terms minus the actual nominal capex. Capitalised interest is then added to the underspend in each year using half the nominal WACC. Capitalised interest is added because that is how capex is treated in the PTRM and RFM.
3. no financing benefit is allowed for savings in the year they are incurred. In subsequent years the financing benefit is calculated using accumulated savings in previous years times the **real** WACC. The real WACC is used because the PTRM is designed to achieve an outcome equivalent to a real rate of return but it should be noted that this real return is on an indexed RAB.
4. since the savings occur in different years, the savings are converted to a common year (the last year of the regulatory period) in NPV terms. The nominal WACC is used as the discount (in this case accumulation) factor. *This is the same as in the AER CESS model.*
5. since the utility is to receive a benefit equivalent to 30% of the capex savings the NPV of the nominal savings is multiplied by 0.3 and the amount calculated at (4) deducted from this. The residual is the carry-over amount under the CESS. *This is the same as in the AER CESS model.*

The two approaches should, in principle, proved the same or very nearly the same answer. The fact that they do not raises a question as to whether there are errors in one or both models. As noted above, we consider that the current CESS model correctly values the financial benefit of the additional cash flows available to the TNSP. However, we have questions about the HK model, particularly in regard to the use of the real discount rate in valuing benefits in nominal terms without allowing for the indexation of the RAB.

Since the model is in nominal terms the returns on the capex savings must be calculated in nominal terms. The challenge is to do this consistent with the joint operation of the PTRM/RFM which use both a nominal WACC and indexed RAB. Following the recent inflation review it is common ground that:

1. The two models (PTRM and RFM) are interconnected and cannot be examined in isolation

2. Together the models provide a revenue stream equivalent to the real WACC on real (indexed) RAB. Under this approach the asset owner receives the nominal return in two forms: a nominal capital gain which maintains the real value of the RAB; and a real return on the RAB

While HK are correct to say the PTRM is designed to replicate the results with a real rate of return the interaction with the RFM is complex. The PTRM provides for an ex ante nominal WACC and avoids double counting of inflation through the adjustment to depreciation expense. Ex post the real rate of return is locked in via the formula for adjusting prices within the regulatory period and the interface with the RFM which indexes the RAB for future periods. This highlights the complexity of replicating the PTRM/RFM through the CESS model.

However, it is commonly agreed that the current model seeks to replicate the 'real return on real rate base approach' over multiple regulatory periods and that under this approach the nominal returns to owners comprise a nominal capital gain and real rate of return. On this basis the HK model appears to be incomplete in that it does not include the inflation component of the nominal returns allowed on the capex not spent. If so, this can be corrected by using the nominal WACC or including the nominal capital gain from the indexation of the RAB in the calculation

Summary of position

There are two valid approaches to estimating the benefit to the TNSP from capex savings: estimating the value of the cash flow gains and estimating the revenue allowed on the money not spent. Both should yield the same answer, but the former is more commercially focused and simpler to estimate.

The current CESS model correctly estimates the value of the additional cash flows, whereas HK have sought to modify the model to better approximate the revenues under the PTRM/RFM. However, this yields a significantly different value for the benefit and appears to overlook the compensation for inflation that is included in the nominal returns to owners.

Recommendations

The AER should examine further the reasons for the discrepancy between the HK approach and the current CESS model, which CCP9 considers correctly values the financing benefit from the increased cash flows.

Unless the two models can be reconciled or it be shown that the current approach does not correctly value the financing benefits of the improved cash flows, the current approach, as set out in the Draft Decision, should be maintained.

STPIS

In its Draft Decision the AER accepted TG's proposals for the STPIS with minor changes. TG's revised proposal accepts the Draft Decision proposals. CPP 9 also supports the Draft Decision.

Recommendation:

CCP9 supports the application of the EBSS, CESS, and STPIS as proposed by the AER.

5. Conclusion

In its submission on TG's Revenue Proposal CCP9 commended TG on the substantial enhancements to its CE program. All stakeholders that CCP 9 has spoken to at that time noted these improvements and expressed a growing level of trust in TG's communications. In its revised revenue proposal TG expressed interest in moving towards a more collaborative decision-making process. In this review of the customer engagement processes CCP9 has sought to contribute to TG's objective by highlighting areas where TG could have benefited from a more collaborative approach. Stakeholders have said that they too are looking for these opportunities and CCP9 has provided a number of examples where TG could expand its collaboration and build on the significant skills it has in its stakeholder groups.

Overall, TG's consumer engagement following the publication of the draft decision has been positively received by the stakeholders, particularly in the context of TG's decision to propose a modified Powering Sydney Future (PSF) project. Support for the modified PSF project was widespread amongst these stakeholders although some remained uncertain about a number of the assumptions that TG has adopted in its modelling, particularly for replacement capex and the PSF proposal. CCP9's perhaps more fundamental concern is that the way in which information was presented may have impacted on consumers' perception of the regulatory process and their confidence in both TG and the AER. In this submission we have provided suggestions that we hope will help TG build upon the improvements made to date to further improve its CE

In its Revised Proposal TG accepted most of the changes proposed by the AER. Overall, CCP9 is pleased to see the greater degree of accordance between the AER's Draft Decision and TG's revised proposal. In some cases, such as elements of the WACC, TG has not agreed with the AER decision but it has accepted these while expressing reservations. For CCP9 this illustrates an approach to regulation that looks beyond a 'zero sum, short term perspective' to a focus on long term relationships and common interests that can support more collaborative approaches that better serve the long-term interests of both customers and the utility.

The main area that remains unresolved is Capex and the PSF project. Overall it has been challenging for consumers to engage on the Capex program. The reviews of major programs such as Repex and Powering Sydney's Future by the AER have involved large volumes of material provided by TG under information requests that were not made generally available. The timing of the requests and the responses have not been conducive to a process with which consumers can engage. Neither TG nor the AER can escape criticism in this regard.

The level of disagreement between TG and AER/EMCa is of concern and the parties should seek to work together in a collaborative manner to seek to reduce the extent of disagreement so that consumers to be confident that the level of expenditure is sufficient, but no more than that, to efficiently maintain reliability of supply. CCP9 would be happy to assist in the process to resolve the differences of view on the capex forecasts if all parties consider that would be helpful.

In relation to PSF, CCP9 is not of the view that no expenditure is a prudent response to the inevitability of replacing these oil-filled cables. The staged approach set out in the revised proposal is a significant improvement on the previous proposal. However, the proposed investment of $252m is substantial and we consider it has not yet been sufficiently justified.

CCP 9 commends to the AER the issues raised in this advice and the recommendations made.

Signed

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