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Consumer
Challenge
Panel

CCP Sub-Panel No. 9

12/05/2017

AER Board
Mr Adam Petersen, Co-ord Director – TransGrid Determination – 2018-23
Australian Energy Regulator
By email: adam.petersen@aer.gov.au Cc: ccp@aer.gov.au

Dear Paula,

Re: TransGrid Determination – 2018-23

Please find attached our submission in relation to the above network determination/access arrangement.

Kind Regards,

Eric Groom
Chair CCP 9

Consumer
Challenge
Panel

Submission to the Australian Energy Regulator (AER)

Consumer Challenge Panel Sub-Panel 9

Response to proposals from TransGrid for a revenue reset for 2018-19 to 2022-23

Sub-Panel CCP 9

Eric Groom

Bev Hughson

Andrew Nance

Click here to enter Sub-panel member name.

12/05/2017

Executive Summary

CCP 9 has considered the proposal of TransGrid 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 CCP 9 and our recommendation as follows:

CONSUMER ENGAGEMENT

CCP 9 has concluded that TransGrid has generally reflected on the feedback from stakeholders on their previous customer engagement (CE) processes and made further and substantial enhancements to its CE program for the regulatory reset. All stakeholders that CCP 9 has spoken to noted these improvements and expressed a growing level of trust in TransGrid's communications.

CCP 9 summarises the positive features of TransGrid's revised CE program as follows:

- Establishing a sound CE framework at the start of the process. The framework included better alignment of the structure of CE program and more structured process to select participants, locations, topics and communication channels;
- Ensuring that the structure was sustainable and could continue to be effective beyond the regulatory proposal stage;
- An early start to the process enabling the building of trust and knowledge;
- Commitment by the Board, CEO and senior managed to the CE program facilitating culture change across the organisation;
- Similarly, a commitment of significant and ongoing organisational time and resources to the CE program;
- Clear and continuous provision of information to stakeholders on key stages in the process and how stakeholders have influence TransGrid's decisions;
- A focus on plain English, transparency and readily accessible communication material

CCP 9 also highlights a number of areas that TransGrid should further consider. They are:

- Some stakeholders expressed concern that they were not sufficiently engaged in the more strategic areas or in critiquing the assumptions in the modelling. Given the sound base of knowledge and trust that TransGrid has successfully developed over the past year, it is appropriate for TransGrid to consider ways in which it can more consistently move from the 'inform' to the 'involve' and 'collaborate' CE approach (as set out in the IAP2 Engagement Spectrum).
- CCP 9 would like to see a more structured approach adopted to the process of evaluation and review of the CE program. We understand that TransGrid does collect and respond to feedback, however, this process would be improved by building review and measurement mechanisms into the framework.

- CCP 9 and TransGrid's stakeholders would like to see TransGrid adopt a more proactive approach to the changing energy market and to the risks and opportunities that face the network businesses over the next few years. For instance, TransGrid's plan might include more **proactive** pursuit of energy efficiency and demand management opportunities that benefit all parties (outside the DMIA process);
- CCP 9 and TransGrid's stakeholders would like to see TransGrid respond to consumers' concerns around operational and capital investment efficiency and productivity in order to drive and sustain lower prices. There is a risk in TransGrid's current plan that TransGrid rests on the laurels of existing efficiency improvements where stakeholders are sending a strong message that they want sustainable price reductions through greater efficiency.
- CCP 9 sees significant scope for enhancement of the CE program around the RIT-T process, in particular the $330m Powering Sydney Future project. CCP 9 understands that TransGrid has already gone beyond the strict consultation requirements in the NER for RIT-T projects. However, there is scope to further develop best practice CE in advance of the regulatory framework, including its engagement with potential non-network solution providers.

Recommendations:

a) Overall, CCP 9 recommends that the quality of TransGrid's CE program should be a positive factor in the AER's assessment of the revenue proposal in 2018/19 – 2022/23
b) However, CCP 9 recommends that CE by TransGrid in its PSF project has some limitations and suggests that the underlying assumptions in this project should be carefully reviewed by the AER.
c) Having built a base of trust and knowledge, TransGrid could consider how it can move more consistently along the IAP2 Spectrum from 'Inform' to 'involve' and 'collaborate'.
d) TransGrid could be more open to sharing and inviting challenges from stakeholders to the assumptions that underpin a number of their forecasts.
e) TransGrid could build into its process a formal and more transparent framework for measurement and ongoing improvement of their CE process.
f) TransGrid could further consider how it can expand the principles of best practice CE to include decisions on its contingent projects and, more particularly, the RIT-T process.
g) TransGrid could undertake a more detailed review of risks of their plans from the consumer perspective.

Further recommendations specific to the PSF RIT-T process are set out in B.3 below

LONG TERM INTEREST OF CONSUMERS

Our approach to considering the long term interests of consumers is based in the National Electricity Objective (NEO). The NEO is an economic efficiency objective that is often described in terms of three dimensions: productive, allocative and dynamic efficiency. There are a number of issues in the NSPs proposals which show or raise the prospect that the proposals are not in the long-term interest of consumers.

1. Capital Expenditure

A substantial Capex program is proposed. This is dominated by replacement expenditure (REPEX) and the Powering Sydney's Future project. The main areas of concern are the efficiency and prudency of this expenditure given current and future energy market uncertainties. Dynamic efficiency is a key challenge for the energy sector but our view that it is unlikely to be promoted under the current proposal.

Recommendations:

a) There is a role for the AER, working in collaboration with the NSPs, ENA, and stakeholders to provide further guidance on the role of, and techniques for, scenario analysis and option values in long term capex planning to reduce the risk of stranded assets being borne by consumers.
b) In assessing the proposed replacement capex that can be considered *prudent* the AER should test the sensitivity of key assumptions in TransGrid's risk-based capex model to assess if the scale of the program (the proposed REPEX of $961m).
c) AER should clarify the likely impact of the rule change to apply the RIT-T to REPEX as part of the Draft Determination.
d) If generation-based contingent projects are proposed, the triggers should include provision for review if there is a review of the arrangements for pricing of access for generators.
e) The AER should present impacts on revenues and prices both 'with' and 'without' contingent projects included in the draft and final determinations.
f) The AER should accept TransGrid's overall forecasts of overall electricity usage and demand.
g) The AER should seek further information from TransGrid on how they have critically reviewed Ausgrid's bulk supply point forecasts, and considered these forecasts in the light of the publicly available and committed plans of bodies such as the Sydney City Council.
h) The AER should ensure that TransGrid's RIT-T proposal for PSF project adequately considers the risks in demand forecast and the opportunities for non-network solutions to meet the peak requirements.
i) The AER undertake an independent review of the forecasts taking into account the multiple programs, including the SCC program to improve energy efficiency for both new and existing buildings and infrastructure
j) The AER should review the VCR assumptions used in the PSF with the presumption that the VCR should be based on the applicable reliability standards. Furthermore, the AER should carefully monitor and participate in future jurisdictional reviews of reliability standards.
k) The AER should consider the consumer and stakeholder engagement process conducted by TransGrid for the PSF RIT-T to determine if there is appropriate consultation on the forecasts and potential non-network options.
l) The AER should closely review the assessment of the non-network opportunities and consult widely, especially with potential providers of non-network options, in undertaking this review.

2. Operating Expenditure

Transgrid has a proposed an increased Opex allowance after several years of improved efficiency and lower expenditure. Choices made in the application of the expenditure guidelines and the Efficiency Benefit Sharing Scheme (EBSS) may not be in the consumer interest. Consumers can reasonably expect that TransGrid will continue to strive to improve efficiency but the projected opex does not show the continuing improvement that TransGrid has achieved in recent years.

Recommendations:

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 onto account the impacts on the EBSS.
c) In reviewing TransGrid's proposed opex, AER should include consideration of past trends in real opex and opex/MWh in determining the trends in TransGrid's future efficient costs. This would support 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.

3. Rate of Return & Tax

TransGrid has proposed an approach to the estimating the rate of return that is largely consistent with AER's current approach except that an increase in the Market Risk Premium (MRP) is proposed. TransGrid has also used a gamma (the value of imputation credits of 0.25 rather than 0.4, as used by the AER. The changes to the MRP and gamma are not supported. When a wider range of market evidence is considered, including recent transaction data, the current approach to the WACC and the parameters used by the AER – including the MRP - appear to more than meet market expectations.

Recommendations:

a) AER should not accept TransGrid's proposal for a MRP of 7.5%
b) As part of the next review of the Rate of Return Guideline, the AER should review its approach to the estimation of tax expense.

4. Incentive Mechanisms

In the absence of competition, incentive mechanisms provide a critical component of the regulatory framework. However, these are complex schemes that are difficult for consumers to understand. The proposal is missing an overview of how these mechanisms have, and will, contribute to the promotion of the NEO.

Recommendations:

a) AER to clarify the EBSS carryover period (4 years or 5) for the 2018-23 period
b) AER to review the operation of the incentive schemes over the current regulatory control period and into the 2018-23 period and provide a plain-language description in the preliminary determination

5. Tariffs

TransGrid has proposed no changes to its Pricing Methodology from the current Regulatory Control Period. The proposal states that stakeholders continue to the support the current approach which was developed via comprehensive engagement.

Recommendations:

a) AER should seek further evidence of continued support for TransGrid's Pricing Methodology.

More detailed consideration of these issues is set out in CCP 9 advice below.

BACKGROUND

- This advice was prepared in accordance with the Schedule of Work agreed upon between sub-panel 9 working on the TransGrid/Electranet/Murraylink revenue resets and Adam Petersen, the Co-ordination Director for the review.
- This advice relates to the TransGrid revenue resets. Separate advice has been provided on a the Murraylink proposal as it raised a number of distinct issues. Separate advice will also be provided on the Electranet proposal due to the revised timetable for that review.
- TransGrid commenced the process of preparation of their access arrangement proposal and the related consumer engagement prior to the commencement and the reset and undertook a range of consumer engagement activities and processes in 2016-2017.
- CCP 9 was established in September 2016.
- Members of CCP 9 attended meetings of TransGrid's Advisory Council, as observers, in November 2016 and March 2017 and thejoint TransGrid/AusGrid public forum on the Powering Sydney's Future project on 28 November.
- In addition to this CCP 9 members met with TransGrid (in person or via conference calls) on:
  - 1 November 2016
  - 21 and 25 November 2016
  - 7 April 2017
  - 27 April 2017, and
  - 4 May 2017

  During these meetings we discussed their consumer engagement processes, the key elements of their proposals (i.e. high-level drivers, priorities, issues and challenges for the business and how these issues were reflected in the proposal), and their key consumer issues.

- CCP 9 also met with a number of individual stakeholders who had participated in various aspects of TransGrid's consumer engagement processes to better understand their experience with TransGrid's customer engagement programs.
- On April 11 CCP 9 participated in the public forum convened by the AER in Sydney. The presentations by TransGrid and CCP 9 are available on the AER web-site.
- CCP 9 has held regular meetings with the Co-ordination Director and other members of the AER team for the review since October 2016.
- A series of meetings have been held with most of the AER specialist teams involved in the reset. These meetings have provided an opportunity for the sub-panel to better understand some of the technical issues involved as well as for the Panel and AER officers to exchange view on issues associated with TransGrid's proposal.

Role of the CCP

The objective of the Consumer Challenge Panel (CCP) 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.

CCP 9 is focussed on promoting the consumer interest during the development of revenues and prices for the TransGrid 2018-23 Regulatory Control Period (commencing 1 July 2018). Further information on the Panel is available at www.aer.gov.au/about-us/consumer-challenge-panel

ADVICE

A. Consumer Engagement

A.1 Summary and Recommendations

CCP 9 has reviewed the customer engagement (CE) programs included in the proposal by TransGrid. We have considered whether the CE programs are 'fit for purpose' and meet the expectations of the AER, stakeholders and the CCP for 'best practice' CE.

In conducting this review, CCP 9 has looked at the material provided in the proposals and multiple associated documents.

A.1.1 TransGrid Customer Engagement Program

CCP 9 has attended a number of TransGrid's workshops and met on several occasions with TransGrid executives and staff. CCP 9 has also talked to a number of stakeholders who are represented on TransGrid's formal CE Advisory Council and Revenue Proposal Working Group.

CCP 9 has concluded that TransGrid has generally reflected on the feedback from stakeholders on their previous CE processes and made further and substantial enhancements to its CE program. All stakeholders that CCP 9 has spoken to noted these improvements and expressed a growing level of trust in TransGrid's communications.

CCP 9 summarises the positive features of TransGrid's revised CE program as follows:

- Establishing a sound CE framework at the start of the process. The framework included better alignment of the structure of CE program and more structured process to select participants, locations, topics and communication channels;
- Ensuring that the structure was sustainable and could continue to be effective beyond the regulatory proposal stage;
- An early start to the process enabling the building of trust and knowledge;
- Commitment by the Board, CEO and senior management to the CE program facilitating culture change across the organisation;
- Similarly, TransGrid has committed significant and ongoing organisational time and resources to the CE program;

- Clear and continuous provision of information to stakeholders on key stages in the process and how stakeholders have influence TransGrid's decisions;
- A focus on plain English, transparency and readily accessible communication material

Based on the discussions with stakeholders and review of the extensive CE material provided by TransGrid, CCP 9 suggests the following matters for TransGrid to consider in its future CE planning:

- Some stakeholders expressed concern that they were not sufficiently engaged in the more strategic areas or in critiquing the assumptions in the modelling presented to them. Given the sound base of knowledge and trust that TransGrid has successfully developed over the past year, it is appropriate for TransGrid to consider ways in which it can more consistently move from the 'inform' to the 'involve' and 'collaborate' CE approach (as set out in the IAP2 Engagement Spectrum).
- CCP 9 would like to see a more structured approach adopted to the process of evaluation and review of the CE program. We understand that TransGrid does collect and respond to feedback during its CE programs, however, this process would be improved by building more formal review, measurement and feedback mechanisms into the framework.
- CCP 9 and TransGrid's stakeholders would like to see TransGrid adopt a more proactive approach to the changing energy market and to the risks and opportunities that face the network businesses over the next few years. For instance, TransGrid's plan might include more **proactive** pursuit of energy efficiency and demand management opportunities that benefit all parties (outside the DMIA process);
- CCP 9 and TransGrid's stakeholders would like to see TransGrid respond to consumers' concerns around operational and capital investment efficiency and productivity in order to drive and sustain lower prices. There is a risk in TransGrid's current plan that TransGrid rests on the laurels of existing efficiency improvements where stakeholders are sending a strong message that they want sustainable price reductions through greater operational and capital efficiency.
- CCP 9 sees significant scope for enhancement of the CE program around the RIT-T process, in particular the Powering Sydney Future project. TransGrid's proposal suggests that this program will cost some $330m so it is essential that both the electricity users and potential proponents of non-network solution are provided with realistic opportunities for engagement. CCP 9 understands that TransGrid has already gone beyond the strict consultation requirements in the NER for RIT-T projects. However, there is scope to further develop best practice CE in advance of the regulatory framework.

Recommendations:

Overall, TransGrid has conducted a very extensive CE process that has been well received by its stakeholders. While some stakeholders are clearly interested in having a more proactive role in reviewing the initial assumptions that underpin many of TransGrid's expenditure plans, the view is generally that TransGrid conducted an open and transparent CE process with one caveat.

CCP 9 's caveat is that we are not yet satisfied that TransGrid has conducted adequate CE around the Powering Sydney Future (PSF) plan. To be clear, TransGrid has complied with, and at times gone beyond, the current regulatory consultation requirements of the RIT-T[1] process to date.

[1] Regulatory Investment Test – Transmission.

However, the PSF project is the major single component of TransGrid's proposed capital investment program. Moreover, it is of vital importance to the long term interests of electricity consumers given the possible competing requirements of securing a reliable supply while avoiding excess investment and long term costs to consumers. It is also important that TransGrid's approach to the RIT-T does not, in practice, discourage or limit opportunities for non-network solutions to emerge.

Recommendations 1 – 2 are directly relevant to the AER's assessment of the regulatory proposal; recommendations 3 – 7 relate to matters that TransGrid might consider in its future CE programs.

1. TransGrid's CE program should be considered as a positive factor by the AER in its assessment of TransGrid's overall regulatory proposal.
2. The AER review TransGrid's RIT-T process for PSF to assess whether the CE process associated with this has proactively sought all options for non-network solutions and whether TransGrid has adequately considered all the factors that may impact on future demand growth in the Sydney CBD.
3. Having built a base of trust and knowledge, TransGrid consider how it can move more consistently along the IAP2 Spectrum from 'Inform' to 'involve' and 'collaborate'.
4. TransGrid could be more open to explaining to stakeholders the assumptions that underpin a number of their forecasts and inviting challenges to those assumptions.
5. TransGrid build into its process a formal and more transparent framework for review, measurement and feedback to drive ongoing improvement in its CE processes.
6. TransGrid further consider how it can expand the principles of best practice CE to include best practice consumer engagement in its decisions on the proposed contingent/RIT-T projects.

    TransGrid undertake a more intensive CE process regarding both the benefits and risks to consumers of its expenditure plans and the uncertainties in its demand forecasts.

A.2 Conceptual Framework for Effective Consumer Engagement

A.2.1 Overview

The National Electricity Rules (NER) set out the obligation for regulated electricity network service providers (NSPs) to incorporate in their proposal a description of how the NSP has engaged with electricity consumers and sought to address any relevant concerns identified by that engagement.[2]

The NER also requires the AER to develop a Consumer Engagement Guideline (CE Guideline).[3] The AER published the CE Guideline in November 2013[4] following an extensive literature search and multiple consultations/workshops with the networks and consumer representatives, many of whom have had extensive experience in working with industrial, small business and residential electricity consumers.

While the CE Guideline provides a framework of 'best practice' customer engagement (CE), each NSP has the responsibility to develop a CE program that is tailored to their particular circumstances and customer base. A transmission NSP such as TransGrid, or a regulated interconnector service provider such as Murray Link, face different challenges in engaging customers than a distribution NSP.

[2] NER, rr 6.8.2(c1)(2) and 6A.10.1(g)(2).
[3] NER, r.6A.2.3 (a)(2)
[4] See AER, *Better Regulation, Consumer Engagement Guideline for Network Service Providers*, November 2013; and AER, *Better Regulation, Explanatory Statement, Consumer Engagement Guideline for Network Service Providers*, November 2013.

The CCP is tasked with assessing the CE program for each NSP. In particular, CCP 9 understands that each NSP will need to tailor their program as noted above. Nevertheless, there are some common issues that must be addressed by all NSPs as part of their CE program. CCP 9 looks to NSPs to demonstrate:

- Who, how, when and on what issues the NSP has engaged with its customers;
- How this engagement has influenced the NSP's revenue proposals;
- How do stakeholders assess the quality and relevance of the engagement process; and
- Is there a systematic process for ongoing review of CE and continuous improvement?

CCP 9 also considers it important to distinguish two underlying, albeit interrelated, themes, namely:

- The quality of the CE process; and
- The extent to which the NSP responds to, and is seen to respond to the feedback from their stakeholders in their regulatory proposal.

A key element that links the two themes is the commitment of the businesses Board and executives to the process. CCP 9 expects NSPs to progressively move along the engagement spectrum of 'inform' to 'consult', 'involve' and 'collaborate' (see section A.2.3 below) and this can only be achieved in an environment of trust and where the senior management of the business are fully committed to the CE program and prepared to adjust their proposal in response to consumers' concerns.

The following sections provide a brief summary of the AER's CE Guideline, the IAP2 Spectrum and the Energy Network Association Handbook on CE. While these are the main sources that influence the CCP 9's assessment process, there are many other sources of information for NSPs to draw on to assist them in designing an effective CE program tailored to their needs.

The CCP 9 therefore does not believe there is any reason for an NSP to not develop such a program even when there circumstances are challenging. This proposition is fundamental to CCP 9's assessment of both the TransGrid and Murraylink[5] revenue proposals

A.2.2. AER Consumer Engagement Guideline

The AER's CE Guideline drew on other established bodies and resources such as International Association of Public Participation (IAP2), Ofgem, Australian standards for stakeholder engagement (e.g. AA1000SES), the Institute of Social and Ethical Accountability and the World Bank Ladder of Consumer Participation.

The CE Guideline is not mandatory, although there is an obligation under the NER to set out how CE outcomes have been incorporated into an NSP's proposal.[6] In fact, the CE Guideline is deliberately developed around high level 'best practice' principles which can be applied to each component of the CE process namely setting priorities, delivery of CE, outcome of CE and evaluation of the CE program.

Figure A.1 below illustrates these relationships between CE objectives, principles and components as set out in the AER's CE Guideline.

[5] See for instance, CCP 9's submission to the AER on Murraylink's revenue proposal for 2018/19-22/23
[6] NER, r.r 6A.6.6(e)(5A); 6A.6.7(e)(5A); 6A.10.1 (g)(2)

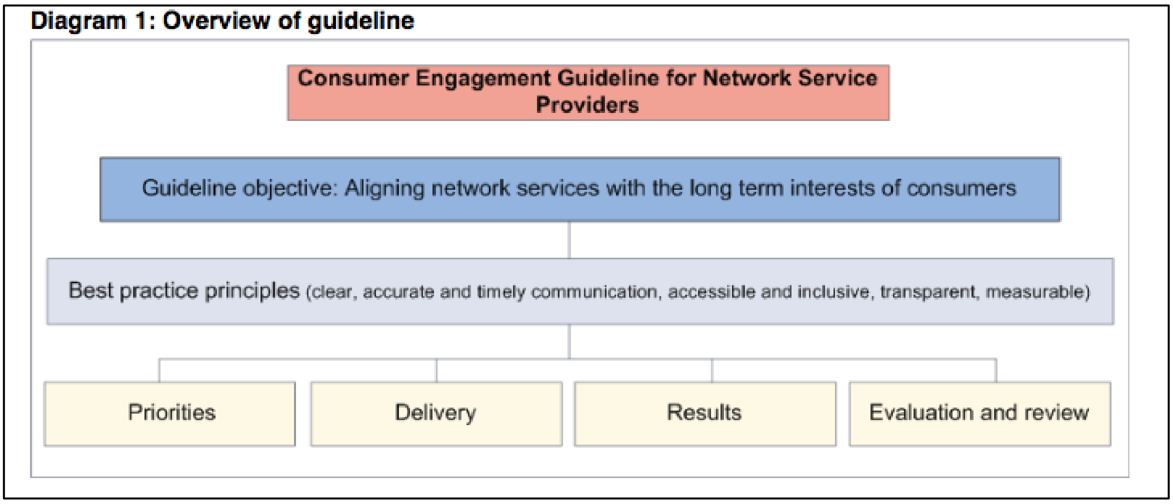
Importantly, while the CE framework illustrated below sets out the AER's basic expectations for all NSPs, the CE Guideline also recognises that CE is an evolving process and that the details of the process and the issues addressed within the CE framework must reflect the unique circumstances of each business and its customers.

An important feature, therefore, of effective customer engagement is the early identification of areas where consumers may provide meaningful input from both the network's and the consumers' perspectives. The AER identifies a number of areas for initial consideration such as:

- Making price and reliability trade-offs;
- Setting and designing tariffs;
- Understanding demand 'hot spots' and exploring associated impacts; and
- Exploring alternatives to capital investment

However, it is important that NSPs also identify and respond to the specific concerns of their stakeholders.

Figure A.1: AER's Consumer Engagement Guideline Framework



Source: AER, *Consumer Engagement Guideline*, November 2013, p. 7.

The AER summarises its perspective on the role of CE in the regulatory determination process as follows:[7]

> *…While the guideline is not prescriptive, we anticipate* ***all service providers will make an effort to adopt the guideline****…We will consider whether and how well a service provider considered and responded to consumer views, equipped consumers to participate in consultation, made issues tangible to consumers and obtained a cross-section of consumer views.* [emphasis added]

CCP 9 considers that the AER's CE Guideline provides the minimum standard for a NSP to seek to achieve, while providing the flexibility for a NSP to adapt to their individual circumstances.

[7] AER, *Explanatory Statement, Customer Engagement Guideline*, November 2013, p. 22

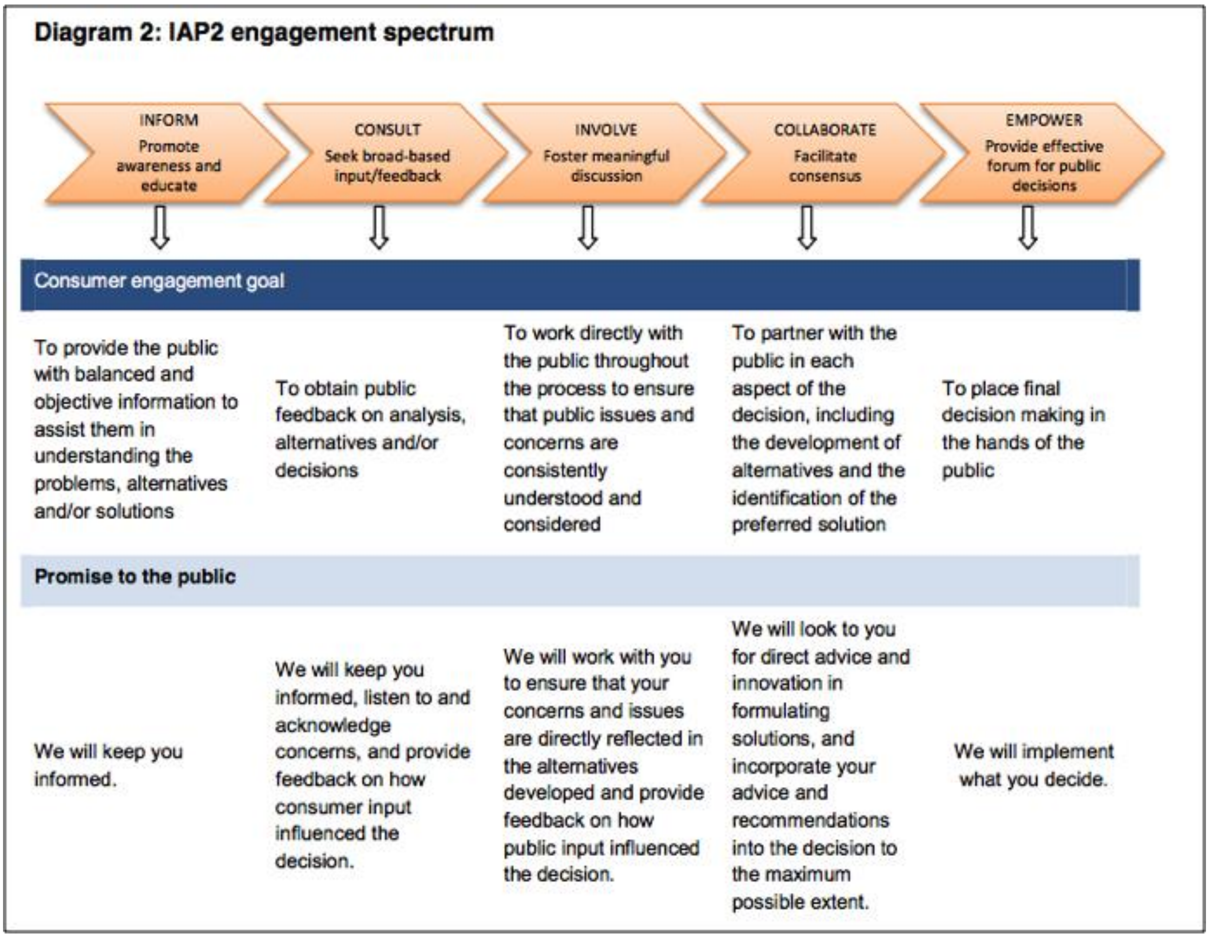
A.2.3 IAP2 engagement spectrum

The IAP2 engagement spectrum provides a further useful contribution to the design and assessment of a CE program. The focus of the IAP2 spectrum is on the CE goal(s) and on matching 'style' of the engagement to these goals.

As illustrated in Figure A.2, the CE spectrum ranges from ' inform' to 'empower' with the place on the spectrum corresponding to the goal or objective of the engagement program. There is, therefore, no one correct style of engagement, it all depends on the objectives of the CE program. Moreover, a CE program may start at one level (e.g. 'inform') and move over time to levels requiring greater mutual participation and sharing.

In terms of the effective engagement of NSPs with their consumers over the course of a preparing a regulatory proposal, it is most likely that the initial CE will need to focus on the 'inform' end of the spectrum as most CE participants will have limited knowledge of the energy industry. Similarly, there is likely to be very limited understanding of the processes involved in economic regulation and the decision trade-offs to be made in the design of tariffs, capital investment, reliability etc.

Figure A.2: IAP2 engagement spectrum and associated goals and promises to the public



A.1.4 Energy Networks Australia/CSIRO – Customer Engagement Handbook (July 2016)

The ENA/CSIRO Customer Engagement Handbook ('Handbook') is a useful source of guidance to NSPs in that it is designed to specifically address the challenges faced by energy networks in implementing an effective CE program. In addition, the Handbook reflects the AER's view that:[8]

> *… the energy industry is undergoing a "profound, customer-driven transformation, and that this requires a sincere and transparent approach to create a dialogue with energy customers so that the system can deliver the services they value.*

The Handbook was developed following an extensive research program that involved input from the network businesses, CSIRO social science experts, consumer advocacy and other experts and stakeholder representatives. The Handbook also includes a range of 'case studies' that illustrate good practice and/or the challenges faced by networks in conducting effective CE programs.

As stated in the Handbook, it was designed to: "provide practical, industry-endorsed guidance that supports energy network businesses to foster transparent dialogue with their customers".[9]

The Handbook overlaps many of the features of the AER's Guideline although its emphasis is slightly different. It summarises effective customer engagement as including the following elements, including illustration of 'best practice' customer engagement as summarised below:[10]

- It involves a dialogue, i.e. a two-way flow of information;
- It aims to build mutual trust;
- It is strategic and planned, tailored to meet the requirements of each business;
- It recognises the scale of participation, consistent with the 'promises' that can be made to participants; and
- It is conducted 'responsibly'.

A.1.5 Conclusions on the key elements of effective CE.

Having considered the three programs, CCP 9 concludes that there are a number of key elements to a successful CE program for a NSP. From <u>a CE process</u> perspective, these elements include:

- To clarify, in advance, the objectives of the CE program and the "who, what, when and how" of the program.
    - Who should participate in the CE program and how are they selected;
    - What topics should be addressed, in what order and with which participants;
    - When should the process start and what should be the optimal frequency and timing of different kinds of contacts;
    - How should the CE be best conducted to meet needs of the business and attendees
- Measuring outcomes and open honest feedback to both internal and external stakeholders covering both the strengths and weaknesses of the program
- The importance of early engagement with both internal and external stakeholders;
- The building of confidence and the development of trust through 2-way and transparent communication;

[8] Ibid, p. 8.
[9] ENA, *Customer Engagement Handbook*, July 2016, p. 2. The Handbook provides considerably more detail on each of these elements of best practice and this detail has informed the CCP 9 in its review.
[10] Ibid, see pp. 12 – 17 for details.

- The requirement for long-term organisational commitment and resourcing, including the visible participation by senior management in the process
- Keeping other internal stakeholders informed, engaged and participating when feasible.

Over time, an effective CE program will benefit both the business and the customers, particularly as customers move from passive 'price taking' consumers to active 'pro-consumers'.

The CCP 9, however, must stress that no matter how good the CE process may be, what ultimately counts is the extent to which the outputs of the CE process are genuinely reflected in an NSP's regulatory proposal, tariff design and strategic investment decisions.

To achieve this outcome, NSPs will also need to move through the engagement spectrum from 'effective informing' to 'effective involvement' and ultimately to 'effective collaboration' (at least for some issues).

A.2 TransGrid's Consumer Engagement Program

A.2.1 Overview of TransGrid's CE Program

TransGrid's CE program for the 2018/19 -22/23 regulatory period represents a very significant advance both conceptually and in practice from TransGrid previous CE activity, notwithstanding the very real challenges facing a transmission company in engaging the broader community in its regulatory proposal.

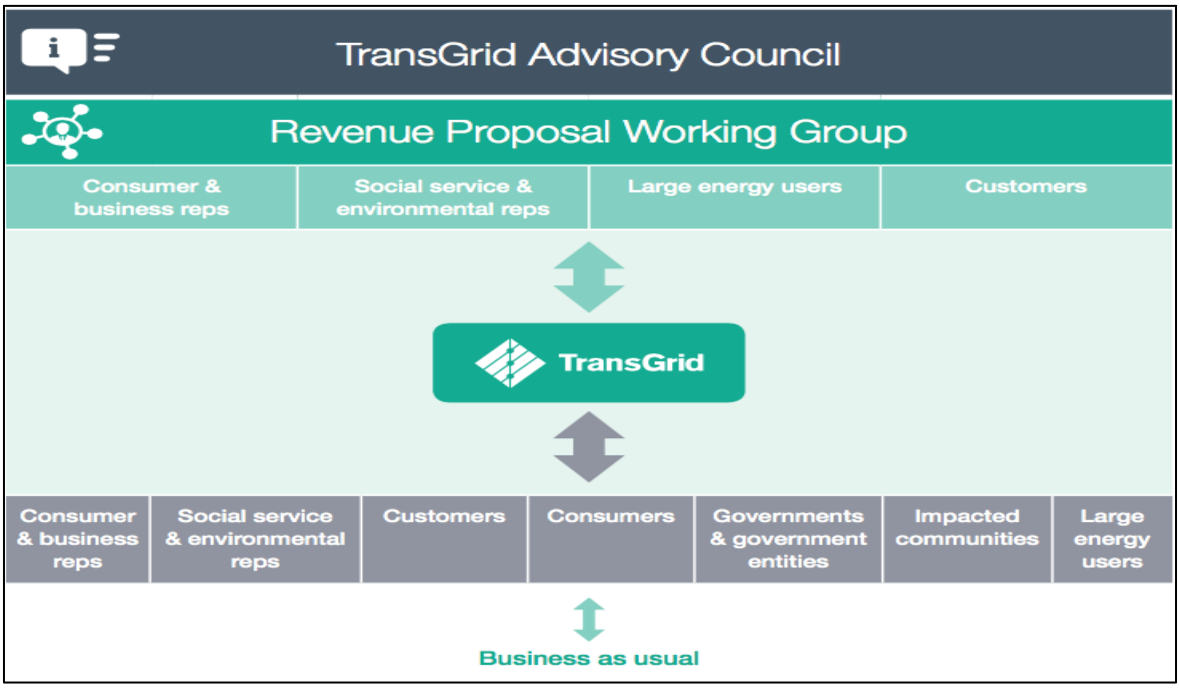
The development of a clear vision, and a set of objectives, principles and drivers by TransGrid, as set out in Figure A.9 facilitated these improvements. Moreover, it appears that this framework was effectively communicated to and agreed by TransGrid's stakeholders.

In addition, TransGrid has made an important distinction at the outset of its CE program between 'customers' and 'consumers', where 'customers' referred to electricity users and generators directly connected to the transmission system and 'consumers' included all other electricity end-users.

By distinguishing these two groups, TransGrid was able to more effectively identify key stakeholders from both groups and to tailor their CE program to the quite different requirements and interests of the two groups. The program also recognised that stakeholders' needs vary according to location in NSW and TransGrid has conducted CE activities in a range of metropolitan, urban and regional areas in NSW, although it is not clear how these differences are reflected in TransGrid's investment decisions and regulatory proposal.

TransGrid's overall CE framework is summarised in Figure A.3 below.

Figure A.3: TransGrid's Customer Engagement Framework



Source: TransGrid Revenue Proposal 2018/19-2022/23, Appendix C, p. 3

TransGrid's CE program also, and importantly, extends beyond the boundaries of the regulatory reset process as illustrated in Figure A.3 above. Key elements of the CE program were put in place before the regulatory process commenced with input from TransGrid's Advisory Council and TransGrid intends to continue these activities beyond the regulatory period. TransGrid correctly recognises that it is important to maintain the goodwill and the knowledge base that they have so carefully built up over the last year.

The CE program has also included participation in TransGrid's tariff planning process and in the Regulatory Investment Test – Transmission (RIT-T) processes associated with major investment proposals. Both tariffs and RIT-T processes occur parallel to, but essentially outside, the regulatory revenue decisions. However, each process will have a significant impact on some or all energy users in the states.

For example, decisions on tariff structures affect the relative costs of electricity supply to city, urban and regional consumers and to consumers with different load characteristics. Large capital investments subject to RIT-T requirements represent an increasing component of TransGrid's capex and have major impacts on the electricity costs to consumers over the medium to long term. Given this, it is essential that TransGrid fully engage with customers in these processes as well as the regulatory revenue determination process. CCP 9 has seen some evidence that TransGrid's CE plans are progressing in these key customer contact areas.

The CCP also notes that TransGrid has been active in the development of state regulation[11] and in long-term vision for the Australian network[12], and has initiated or participated in a number of industry/consumer forums including the NSW Energy Forum that was attended by a range of energy

[11] For example, TransGrid has actively contributed to the development of NSW transmission reliability standards conducted by IPART, and has communicated these developments with stakeholders.
[12] For example, TransGrid, *Network Vision 2056,* and TransGrid's participation in the ENA Road Map.

experts, state and local governments, consumer and industry representatives, energy utilities and other network operators.

These forums are an important addition to the CE program and provide TransGrid with an insight into the broader views of the community on emerging energy issues that are relevant to TransGrid's current and future investment plans. Active engagement in these broader community issues provides the basis for open and relevant communication with TransGrid's various stakeholders. Figure A.4 illustrates the scope of the CE activities u.

Overall, therefore, CCP 9 considers that TransGrid has established a very coherent framework for its CE program that recognises and responds to the needs of different stakeholders and provides for both continuity (through the Advisory Council) and focus (through the Revenue Proposal Working Group).

A more detailed analysis of the merits of TransGrid's CE program and the views of its stakeholders is set out in Section A.2.4 and A.2.5. However, it is also instructive to consider the current program in the context of the response to TransGrid's previous CE program. This will be briefly discussed in Section A.2.3 below.

Figure A.4: TransGrid engagement activities to 2016

Policy	Plans	Projects	Locations	Methods
Reliability standards	Transmission planning	Powering Sydney's Future	Sydney	Deliberative forums
Demand Management Innovation	Regional project and network updates	TransGrid's Revenue Proposal	Wagga Wagga	Workshops
Pricing methodology	Five year business plan	NSW transmission reliability standards	Cooma	Information sessions
Improvements to community consultation practices			Tamworth	Online surveys
			Taree	Briefings
			Orange	Website
			Parramatta	Enewsletters
			Dubbo	Written communication
			Batemans Bay	Social media
			Wollongong	Blogs
				Q&A sessions
				Webinars
				Quantitative surveys

Source: TransGrid, *Connecting with you, TransGrid Stakeholder Engagement* 2016, p. 5.

A.2.3 Previous Assessment of TransGrid's Consumer Engagement (2014/15-2017/18 Regulatory Proposal).

The CCP (Sub panel 6) made a number of observations around TransGrid's CE program for the current regulatory period (2014/15 to 2017/18).[13]

For example, CCP Sub-Panel 6 noted that TransGrid had put considerable resources and expenditure into talking with a range of customers and energy consumers over a period of a year and that TransGrid considered this had provided them with greater understanding of the priorities and

[13] AER, Consumer Challenge Panel (CCP6 Sub Panel), "Submission on the TransGrid Revenue Proposal", 8 August 2014, p.p 3 - 4.

expectations of NSW energy users. Consumers too expressed appreciation that the CE process had improved over prior years.

However, this observation was qualified by CCP 6. In particular, CCP 6 was concerned that, based on the IAP2 Engagement Spectrum, TransGrid's CE activity had been at the "Inform" level of participation. CCP 6 expected that in the future TransGrid would seek to engage consumers at the "involve" and "collaborate" levels including a more thorough 'Willingness to Pay' analysis to quantify the costs and risks around competing expenditure priorities.

There was also a view by some stakeholders that some elements of TransGrid's consumer CE program had been "push polling" driven and that the cost and price implications of consumer preferences had not been transparently communicated to stakeholders.

The various comments from CCP 6, customers and customer representatives indicate that, notwithstanding progress in TransGrid's CE program, stakeholders and the CCP had some reservations and that 'trust' was still an important issue to stakeholders. Another (and perhaps related) issue was a lack of confidence that TransGrid would, in practice, respond to the issues raised by customers particularly with regard to efficiency and pricing.

For example, Norske Skog (a very large electricity user in regional NSW) stated in a submission to the AER, that: [14]

> *NSA considers while TG has conducted a customer engagement process,* ***TG has paid scant attention to the customer feedback gathered from its consumer forums i****n its revised revenue proposal except for the adoption of demand based charging for the postage stamp component. NSA estimates TG has adopted no more than 10% of customer recommendations and expectations and is certainly not addressing and meeting the main concern of a more efficient and lower cost transmission network for NSW customers. …****NSA questions the ongoing benefits to NSW customers of such a program*** *and recommends that no funding be allocated to this activity, again on the basis that there has been no return on investment for NSW customers.* [emphasis added]

Similarly, a consumer representative body, the Total Environment Centre (TEC) responded to the Draft Decision/Revised Proposal with the following commentary relating to consultation on the RIT-T process in particular: [15]

> *We also concur with the CCP (through our own experience with TransGrid's recent Mid North Coast and Far North Coast proposals) that its* ***past performance in regard to its RITs and Requests for Proposals are largely tokenistic, and that the new regulatory proposal gives little reason to believe that this is likely to change in the near future.*** [emphasis added]

More generally, there was a view that TransGrid was focussed on 'informing' customers about its plans and priorities rather than seeking genuine 'collaboration' to optimise their expenditure program in the long term interests of consumers.

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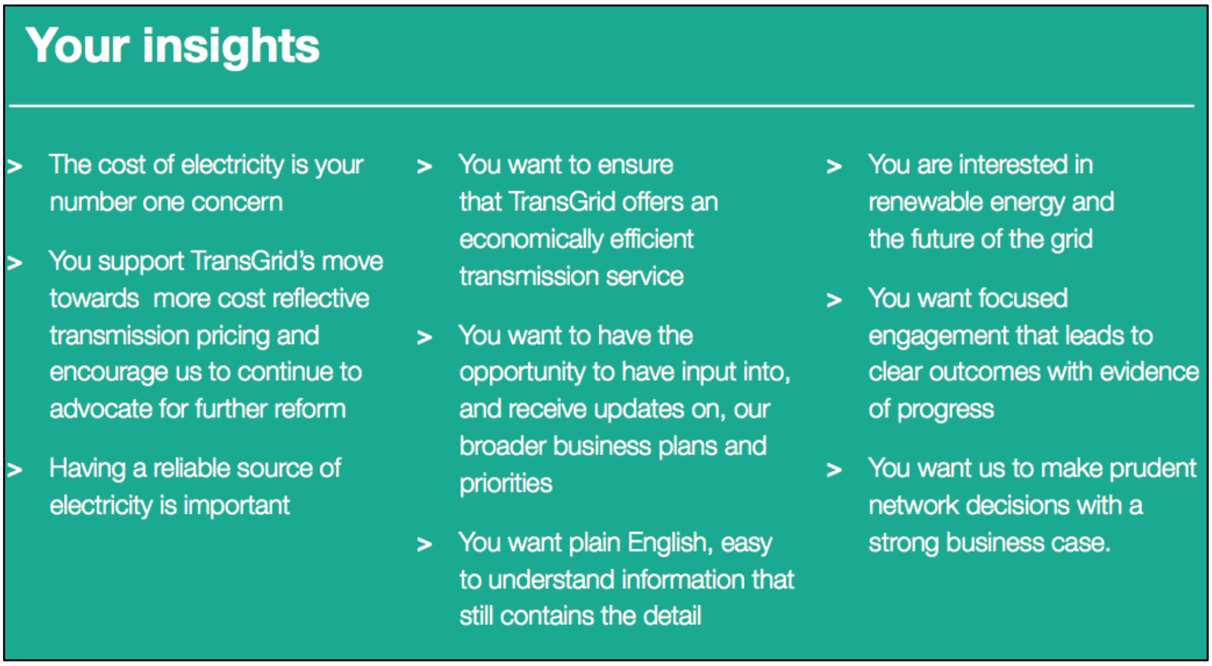
[14] Norske Skog Albury Mill, "Response to the AER's TransGrid Draft Determination and to TransGrid's Revised Application". 4 February, 2015.

[15] Total Environment Centre, "TransGrid Revised Revenue Proposal 2014-19 Submission to the AER", February 2015, p. 5

Given these comments, CCP 9 is pleased to observe that TransGrid has taken on board these comments as summarised by TransGrid in Figure A.5 below. In its CE planning for 2016 and beyond, TransGrid has also set out how it considers it has addressed each of the 'insights' identified in the assessment of the previous CE program and some indication of 'where next' in the 2018/19 -22/23 period.[16]

Figure A. 5: Stakeholder feedback to TransGrid



Source: TransGrid, *Connecting with you, TransGrid Stakeholder Engagement* 2016, p. 3.

As noted above, the current CCP recognises the value of this analysis by TransGRid as a result its previous CE program as a prelude to the current 2018/19 – 2022/23 regulatory proposal.

However, the question remains as to whether TransGrid's regulatory proposal represents an adequate response to these concerns. As discussed below, CCP 9 considers that TransGrid has continued to make very good progress on some of these issues but we remain concerned about other areas, particularly some aspects of the capital and operating expenditure plans and the continued promotion of a higher WACC value, particularly having accepted the AER approach and parameters in the current regulatory decision.

In doing this, we urge TransGrid to pay particular attention to the comments from stakeholders cited above. A CE plan only has an ongoing life, if the participants believe that the regulatory proposal genuinely addresses their priorities and concerns.[17]

[16] For details, see TransGrid, Connecting with you, TransGrid Stakeholder Engagement 2016, p.p. 8 – 15. TransGrid presented the details in the form of "what we heard", "What we did", and "Where next" which provides a readily accessible illustration of how TransGrid intended to utilise stakeholder feedback in their future plans and priorities.

[17] To be clear, this does not mean that TransGrid has to adopt all views; consumer views may be conflicting and TransGrid has to operate within the constraints of technical and financial limitations and externally imposed reliability, safety and employment standards.

The following sections will summarise the responses to CCP 9 from some stakeholders and CCP 9's own assessment of the strengths and limitations of the current CE approach. CCP 9's assessment will also include a more specific assessment of TransGrid's CE program for the RIT-T project, Powering Sydney's Future. As noted previously, this is a very major capital investment project that forms part of TransGrid's proposal but subject to a separate process of customer consultation.

A.2.4 Participant Assessment of TransGrid's current CE program for 2018/19-2022/23

CCP 9 was involved relatively late in the roll out of TransGrid's CE program. To some extent this limits CCP 9's direct assessment of the CE program and places more reliance on the written material available from TransGrid and the feedback we have received from TransGrid and from stakeholders both at the formal stakeholder meetings and in a number of 'one-on-one' meetings with stakeholders over April and May 2017.

CCP 9, therefore appreciates the efforts made by TransGrid to provide access and briefings to the CCP and also the additional time granted to us by a number of individual stakeholders. We appreciate the insights that these meetings have provided to us.

With specific reference to TransGrid's **CE program,** the CCP 9 members have:

- Attended a joint Advisory Council/Working Group meeting in November 2016 and February 2017. At the November meeting, TransGrid provided the CCP with the opportunity to talk directly and in confidence to attendees on their views regarding TransGrid's customer engagement process

- Attended a workshop conducted by TransGrid and Ausgrid on Powering Sydney Future (November 2016)

- Presented and sought feedback at a Public Forum in March 2017 on CE issues;

- Conducted phone interviews with a number of participants in TransGrid's Advisory Council and Revenue Proposal Working Group

- Discussed in detail the lessons and opportunities for future CE activities with relevant TransGrid staff.

A number of consistent themes for stakeholders emerged from the CCP 9's review and the discussions with stakeholders both at the formal meetings and subsequent discussions.

These themes should be considered in the light of the widespread view that there was a 'trust deficit' existing in the relationship between TransGrid and its stakeholders following the initial regulatory processes in 2014, as discussed in Section A.2.3 above.

The CCP 9 considers that the turn around in this 'trust deficit' between 2014 and the current proposal represents a major achievement by TransGrid and should be acknowledged by the AER in their assessment. Importantly, improving trust provides the basis for ongoing involvement and more collaborative decision-making between TransGrid and its stakeholders.

The positive themes emerging from CCP 9's discussions with stakeholders include the following stakeholder assessments of the CE program:

- TransGrid's CE program represented a significant advance on its previous communication with customers. Particular noteworthy was TransGrid's willingness to share information and "put everything on the table";
- The material provided to stakeholders as part of the process was generally clear and the content well explained with sufficient detail to understand and critique the proposal;
- The presence of the CEO and/or senior executives at all major stakeholder meetings demonstrated commitment of the organisation to the CE process and gave added confidence that stakeholder suggestions would be 'acted on';
- The early commencement of the project provided time for stakeholders to build up trust and consolidate their understanding of the key concepts and trade-offs;
- The opportunity that TransGrid provided to stakeholders to have one-on-one discussions with TransGrid, greatly assisted stakeholders in gaining a better understanding of the regulatory proposal given the different level of knowledge at the start of the process;
- Providing regular feedback on what actions were taken - or not taken - and why, in response to issues raised by stakeholders. This feedback provided further encouragement for stakeholders to invest scarce time in the process;
- The presence of the AER at the meetings was valuable for stakeholders. AER expert staff were able to fill in gaps and ask challenging questions through the process which benefited the process as a whole;
- There was a general view that TransGrid's tariff review process was effective and that TransGrid responded appropriately to the views of most stakeholders given the limitations under the Rules.

Other areas of the CE program received a mixed response. For instance:

- Some stakeholders reported finding the meetings covered "too much information" and they "couldn't follow all of it". Others found the information "clear" and "sufficient", illustrating the challenge in targeting information to stakeholders with different interests and knowledge of the industry;
- Some stakeholders felt that TransGrid's program was "too ambitious" and it was not always clear what TransGrid wanted from the attendees; particular concern related to the presentation of many numbers/tables – these stakeholders questioned how they were meant to follow these in the context of a workshop. However, others considered that more detail should be provided to understand the assumptions and links in TransGrid's models and forecasts.
- Some stakeholders valued the approach of having fewer but longer 'whole day' workshops and appreciated the mix of attendees at the meetings. Others found the whole day workshop too demanding on their time.

Notwithstanding that overall, the response of stakeholders was very positive; a number of different stakeholders highlighted the following concerns with TransGrid's regulatory proposal:

- TransGrid's proposal will not achieve net price reductions over the regulatory period that the stakeholders considered necessary, particularly in the context of the very significant price rises across the NSW networks in 2010-12 period that have harmed both households and businesses;

- A number of stakeholders were not convinced that TransGrid's capital investment proposal is efficient. They consider that TransGrid's approach to capital investment is still not as disciplined as the non-regulated competitive market because they can be assured of passing costs onto consumers. They also consider that TransGrid 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
- A number of stakeholders are critical of TransGrid's forecast operating costs. The expectation is that all businesses should be improving productivity and that it was not appropriate to forecast zero productivity improvements in the forecast based on historical data;
- At least some stakeholders did not consider that TransGrid made a case for a higher market risk premium (MRP) given stable market conditions and/or that the special benefits to TransGrid under the regulatory framework (such as the revenue cap and the annual inflation of the asset base) should be reflected in a lower beta value;
- Overall, TransGrid has some way to go before its proposal reflects the expenditure discipline that stakeholders experience when operating in the competitive market -. If "costs increase in one area, then savings should be made in another" area;
- There was a concern that TransGrid was focussed on providing information. While this was appreciated, stakeholders considered that TransGrid should now be moving towards a deeper level of engagement of their stakeholders in the process. As an example, one stakeholder noted that TransGrid demonstrated to stakeholders its new asset replacement model and how that model now drove its replacement capital expenditure. However, replacement capital expenditure grows in the proposal, and stakeholders would have preferred to spend more time working with TransGrid on the assumptions that went into the model.
- Some stakeholders were critical of the RIT-T process, considering that it was too "narrow" and "deterministic" and focussed on engineering solutions where more innovative thinking was required.
- There is interest in further exploring with TransGrid, the risks and opportunities provided by the changing energy market and new policy and program settings such as the NSW Climate Change Policy,[18] the National Energy Productivity and the ENA Road Map.

While CCP 9's summary of stakeholder views is clearly based on the limited contact CCP 9 has had with TransGrid's stakeholders, it is important to share these findings with TransGrid as they provide an opportunity for future development of the CE program.

In addition, it suggests that there is value in TransGrid undertaking an independent review of its CE process to address stakeholders concerns and priorities.[19] This includes assessment of whether stakeholders' concerns (identified above) around overall costs and the need for continued productivity improvements in capital and operating costs are sustained, and if so, have they been adequately addressed in the regulatory proposal. It will also be important for TransGrid to consider

[18] NSW Climate Change Framework was released in late 2016 setting out an aspirational objective to achieve net zero emissions by 2050. The plan includes proposals regarding standards for new commercial buildings and tenanted homes, with an initial $500 million 'Environmental future funding package'.
[19] CCP 9 notes that TransGrid did undertake an independent assessment of its 2014/15 CE program. CCP 9 will seek further feedback from TransGrid on the value of this process.

how it moves further along the IAP2 Spectrum towards deeper involvement and collaboration, particularly in the development of the assumptions that underpin its expenditure forecasts.

TransGrid's response to stakeholder comments

TransGrid has responded to CCP 9's concerns that were raised at the Public Forum in March 2017 and again in CCP 9's subsequent discussions with TransGrid.

In the first instance, TransGrid highlighted the improvements in customer satisfaction as measured in regular annual surveys. TransGrid also highlighted that its CE spreads well beyond the regulatory proposal including consultations with communities affected by its capital projects and its support of various community programs.

When considering future CE developments that are more specific to the regulatory proposal, however, (rather than BAU), TransGrid considers that the CE process can be further improved by better targeting of messages: "the right conversations, with the right people at the right time". Better targeting will assist TransGrid in maintaining relevance and responsiveness to stakeholders.

TransGrid has also provided CCP 9 with a more detailed and specific summary of how its CE observations ('insights') are reflected in the revenue proposal for 2018/19-2022/23 as set out in Figure A.6.

Figure A.6: TransGrid's summary of how engagement influenced the revenue proposal

Customer and Stakeholder Insights	TransGrid Response
Customers commented on, and made recommendations to change TransGrid's proposed approach to output growth for forecasting operating expenditure	TransGrid changed its approach to adopt the suggested recommendations. This has reduced the output trend and is reflected in a lower operating expenditure forecast of $1 million
Customers said they want TransGrid to invest in maintaining its assets to maximise their life. In doing this, customers wanted to ensure that investments are made at the right time and in the long term interest of customers and consumers to minimise cost impacts	TransGrid has heard and responded to feedback and improved the asset management strategy and risk framework. This proposal is centred on a capital program that is, efficient, innovative and in the long term interests of consumers
Customers advised that TransGrid needs to provide reasonable explanation and justification for costs relating to the step change for hazard trees within the next period	TransGrid has reflected this feedback and provided further detail as Appendix D to the revenue proposal
Customers recommended that TransGrid focus more on the proposed WACC number rather than the approach itself	TransGrid has ensured that it is transparent in regards to the proposed WACC of 6.6%. Details of the WACC and expenditure are included in the front of both the Executive Summary and the Overview Paper for the revenue proposal, in addition to the later more detailed proposal chapters
Customers were concerned that the Productivity Commission's Productivity Update for 2016 data could have been distorted as it included the water sector	In response, TransGrid looked for an alternative forecast and subsequently identified that the AER's DNSP report, which includes a substantially larger data set to the AER's TNSP report, might be a suitable alternative
Customers suggested that TransGrid clarify its messaging on IT efficiencies as it created uncertainty around the potential for service impacts resulting from cost reductions	In response to this feedback, TransGrid improved and clarified the information in its proposal
Customers told TransGrid that there is a perception that transmission networks don't actively pursue non-network alternatives and that the process during a RIT-T can be seen as a "tick box" exercise	TransGrid recognises that this is an established concern for stakeholders and is working hard to satisfy customers that wherever it is most cost-effective for customers, a non- network solution will be pursued.

Source: TransGrid, *Consumer Challenge Panel,* 4 May 2017. p.8.

A.2.5 Customer Engagement and the Regulatory Investment Test (RIT-T)

CCP 9 has highlighted its concerns about the CE associated with the RIT-T process noting, in particular, that these large projects have potentially a very significant impact on the long-term costs to consumers and the risks associated with future redundancy of the large asset builds.

In CCP 9's view, it is more important than ever that RIT-T projects are subject to appropriate levels of consultation and engagement around both trade-offs and opportunities for non-network solutions.

Section B.3 of this submission discusses this issue further in the context of TransGrid's proposed contingency projects and, in particular, the Powering Sydney Future (PSF) project.

The discussion below is focussed on TransGrid's CE around the PSF project as this contributes some $330m to TransGrid's proposed capex for the 2018/19-2022/23 regulatory period. However, the discussion is relevant to all very large RIT-T level projects.

CCP 9 recognises that the current regulatory framework for RIT-T projects does not oblige a transmission NSP to go beyond issuing key reports for consultation. As noted below, CCP 9 also recognises that TransGrid has, to date, gone beyond these strict, but rather limited, regulatory requirements for consultation in its RIT-T process for the PSF. However, CCP 9 encourages TransGrid to take this process further as discussed below.

Powering Sydney's Future and Customer Engagement

CCP 9 has taken a particular interest in the RIT-T processes including the evaluation of options and the approach to CE throughout the RIT-T process.

Our concern is heightened by the fact that a number of the projects subject to a RIT-T are very large, whether included in the regulatory proposal's expenditures or included as contingency projects to be considered at some future date. As such, they represent a significant portion of new capital expenditure and have a long-term influence on the size of the regulatory asset base. Such projects also introduce a significant new risk for consumers given the uncertainty in the current energy market and the growth of viable non-network solutions and energy efficiency options. In addition, the RIT-T process is a very important step in 'opening the door' for the 'non-network solution market', although this is an area of limited success to date.

However, without an effective CE strategy that goes beyond the requirements in the NER this potential for non-network solutions may not be fully realised, increasing risks to consumers over the longer term of having to pay for what have effectively become redundant assets.

The future risk of these projects has been transferred from the business to the consumers and it is only reasonable for consumers to have a meaningful involvement in the decision making.

The PSF project is of particular interest to CCP 9 because of its size and its inclusion in TransGrid's regulatory proposal (some $330m).[20] The project is designed to identify the optimal mix of new network investment and non-network options to supply the Inner Sydney Area in order to address the two challenges of aging infrastructure and forecast growth in peak demand in this region.

The PSF project, which is a joint project between TransGrid and Ausgrid[21], forms a very significant component – approximately 20 per cent - of TransGrid proposed capital expenditure for the regulatory period. Given this level of expenditure, the project must not only pass the immediate regulatory test of prudent capital expenditure, it is also subject to the formal RIT-T process under the NER, a process that places some limits on the AER's discretion. [22] As a result, the final project design and costs are not yet known. For example:

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[20] CCP recognises that this figure may change in the final assessment, depending on various factors including non-network options. For instance, in the PADR, TransGrid suggests that non-network options may allow the deferment of capital investment for at least a year.

[21] Ausgrid is the local distribution network service provider for the Inner Sydney area. Both TransGrid and Ausgrid consider that a significant portion of the inner Sydney network that was built in the 1960s and 1970s requires replacement. Ausgrid has also indicated to TransGrid that it expects peak electricity demand in the inner city area to increase significantly over the next 10 years (having declined between 2010 and 2014 and risen again through to summer 2017) due to renewed construction and economic activity.

[22] The COAG Energy Council has recently concluded a review of the RIT-T (COAG Energy Council, *Review of the Regulatory Investment Test for Transmission*, February, 2017) and suggests a number of improvements

- The final economically and technically viable non-network options that might be available to TransGrid to meet forecast peak system demand over the regulatory period are not yet known;
- The selection of the optimal capital expenditure option, route selection and the timing, including the option to stage the implementation of the expansion, is still under review.

The requirements for the RIT-T process are set out in the NER[23] and further explained in the AER's RIT-T Guideline.[24] The Rules include a number of stages in the process where a RIT-T proponent must make material available and where the RIT-T proponent must seek submissions from market participants, AEMO and "other interested parties". They are:

- Project Specification Consultation Report (PSCR), published in October 2016
- Project Assessment Draft Report (PADR), published in May 2017; and
- Project Assessment Conclusions Report (NB: submissions are not sought on the Conclusions Report. However, affected parties can raise a dispute to the AER before the AER's final determination.

The AER also recommends in its Guideline that the relevant documents be included on the proponents website, along with the closing date and requirements for submissions.[25]

Given the importance of the PSF project and the RIT-T process in general, the CCP is pleased to note that TransGrid has gone beyond the strict Rule requirements in the preparation of the PSCR and the PADR. For example, the list below illustrates a number of key stakeholder contact points and planned consultations, noting that TransGrid has also undertaken one-on-one meetings with interested parties:

- October 2016: TransGrid commenced consultations on the PSCR with its Advisory Council and Revenue Proposal Working Group, covering the need for the project and the potential solutions and alternative options.

- November 2016: TransGrid and Ausgrid initiated a "Powering Sydney's Future Forum" along with further industry consultation and a non-network dedicated forum to inform and advise non-network proponents. TransGrid extended the period for submissions from December 2016 to February 2017 in response to requests from potential applicants.

- May 2017: published the PADR on-line and advised interested parties of next steps. Also commenced consultation on preferred cable routes using a variety of communication channels.

- June 2017: publication of summary engagement report highlighting feedback from stakeholders; and submission of preliminary Environmental Assessment (PEA and Route Options Selection Report

- August 2017: online publication of the PACR document including consideration of feedback through the PADR process.

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including a review of the AER's RIT-T application guidelines, improvement in accessibility of information and increasing the AER's level of oversight for the RIT-T process (p. 8). The Council is also suggesting rule changes that strengthen the link between the economic regulation framework in Chapter 6A of the NER and the RIT-T. (see p. 30).

[23] See NER, r.r 5.16.4 – 5.16.5.

[24] AER, *Regulatory investment test for transmission application guidelines*, Final, June 2010.

[25] See for instance, Ibid, p.p. 45, 46 and 48. .

Notwithstanding the progress TransGrid has clearly made in its consultation process around major projects, CCP 9 notes that a number of these steps (council meetings, community notification) can be regarded as standard 'good practice' for large-scale projects.

In most cases, these consultations come after the decision is made on the project specifications. While it is recognised that these latter BAU consultation processes are most important, they do not go to the heart of CE as understood in the context of this submission. That is, they do not go to the issues of stakeholder engagement in the assumptions made in the model, the risks transferred to customers and the flexibility of the plan to changing circumstances and consumer behavior.

The question then becomes whether the processes of publishing and seeking submissions on PSCR and the PADR constitutes effective CE in line with the 'best practice' CE processes built around the regulatory proposal in general.

CCP 9 considers it does not. As noted, we do acknowledge that TransGrid has gone further than most to engage consumers and industry. We would like to see this process further developed with more public examination of the assumptions and non-network options. For example, CCP 9 would like to have seen additional evidence of consultation around the 'strategic' aspects such as a more critical evaluation of Ausgrid's peak demand forecast and the risks around this forecast?

Similarly, CCP 9 would like to better understand the extent to which TransGrid has proactively pursued non-network solutions. CCP 9 notes, for instance, that in its recent PADR TransGrid identifies a number of potential non-network actions where it received no proposals (or no 'viable' proposals). This included grid scale energy storage, energy efficiency and power factor correction.[26] Was there an option for TransGrid to more actively pursue proposal in these areas? Could TransGrid simplify the proposal framework and reduce/share risk with the providers. CCP 9 does not have a view on what these mechanisms may be, however, would welcome evidence of TransGrid pursuing these matters further.

Section B.3.2.4 includes further discussion and recommendations regarding TransGrid's CE process on the PSF project.

A.2.6 CCP 9 Conclusions and Recommendations

Having considered the feedback from TransGrid's stakeholders, examined the previous review of TransGrid's CE, and the considerable material provided by TransGrid to its customers and to CCP 9, CCP 9 comes to the following conclusions.

CCP 9 has highlighted above TransGrid's major achievement of in building much greater trust between the business, stakeholders and the community in general. There are other very strong features of TransGrid's CE approach, features that establish an excellent basis for future development of CE by TransGrid and the transmission industry more generally. They include:

- *A strong CE framework.* The framework clearly sets out objectives, principles and plans and the supporting structures to deliver these objectives.

[26] For instance, TransGrid's PADR identifies a number of non-network areas where it received no proposals or no 'viable' proposals, including grid scale energy storage and energy efficiency and power factor correction. Was there an option available to TransGrid to more actively pursue proposals in these areas? See TransGrid & Ausgrid, RIT-T: *Project Assessment Draft Report, Powering Sydney's Future*, May 2017, p. 31.

- *The commitment by the Board, the CEO and senior management to the program*. The senior staff at TransGrid have clearly made themselves available to attend workshops and follow up on issues raised by consumers at various stages in the process. The commitment by senior executives to the process is fundamental to changing the culture of the organization and TransGrid is to be congratulated for the level of commitment to the process.

- *A review of the past CE program and other feedback from consumers*: In 2016, at the commencement of the current CE program, TransGrid reviewed the feedback from stakeholders in order to: "help us evaluate and develop our engagement program for 2016". A summary of this feedback and response to it is set out in a public document, "Connecting with you – TransGrid Stakeholder Engagement 2016".[27] In terms of the CE program as a process, the document concludes:

  > ***Engagement: Where next?*** *TransGrid is gearing up for our 2016 engagement program, and this time around we are going to ensure that we focus on the tangible areas of influence that stakeholders are interested in. As a result of your feedback, we've set up an Advisory Council, to work with us on our engagement program and ensure that stakeholder views influence our business* direction.

- *The commitment of significant and ongoing organisational time and resources to the CE program*. TransGrid has committed significant resources to building and maintaining its CE program and has recognised the benefits that effective CE can bring to the organisation and its ability to respond effectively to a rapidly changing energy environment.

- *A clear and continuous provision of information to their stakeholder representatives on how they have influenced the decisions*. A major challenge for a CE program is to maintain the interest and motivation of customer representatives over the longer term. It is essential, for instance, that representatives can see where and how their advice has been considered by TransGrid in the decisions it has made. The TransGrid documents clearly set out the actions taken by TransGrid in response to the issues raised by stakeholders during the regulatory determination CE process.

- *A focus on plain English and readily accessible communications with stakeholders*. TransGrid's written material is well set out, and complex ideas are also well explained. Information on TransGrid's website about its CE program is straightforward and readily accessed on TransGrid's web site.

Notwithstanding the many positive features of TransGrid's program and the associated improvement in customers' views of TransGrid, there are a number of areas that warrant further development. These include the following issues:

- *Moving toward involvement and collaboration*: TransGrid needs to consider how it can move the CE process further along the IAP2 spectrum from information to collaboration. It would appear that some progress has been made in the area of tariff design and stakeholders appear more satisfied that TransGrid has demonstrated a collaborative approach in its tariff review process.

  However, as noted above, stakeholders also expressed some frustration with the consultation on *both the* regulatory proposal and RIT-T process. In particular, there was a view that TransGrid was focused on 'informing' stakeholders but was not yet prepared to undertake genuine collaboration and debate around the fundamental assumptions in the proposals and RIT-T.

[27] TransGrid, *Connecting with you; TransGrid Stakeholder Engagement* 2016. This document, usefully sets out TransGrid's findings from its past CE in the form of "What we heard", "What we did" and "where next".

- *A more structured evaluation and review process*: From the material available to the CCP, there appears to be a need for a more substantive program of evaluation and review. It is clear that TransGrid has measured and responded to feedback from its customers at various stages and that it continuously monitors overall perceptions of TransGrid and its services.

  However, CCP would prefer to see a more structured approach to the evaluation, measurement and review of different elements of the CE program. For example, Figures A.7 and A. 8, which set out the key stages in TransGrid's CE program for both 2016 and 2017, do not include distinct marker points for review and evaluation of the key stages of CE.

- *Improving CE in the RIT-T* process: The CCP remains concerned with the CE process surrounding the RIT-T processes. It is essential in an era of uncertain growth in network-supplied energy that future investment in the network is subject to the tightest risk assessment. For example, non-network options may allow TransGrid to postpone or scale down investment providing time to obtain more clarity in future growth and network requirements. It is essential therefore, that the CE and stakeholder communication process around the RIT-T goes beyond the CE prescribed in the Rules and seeks to proactively pursue options that can safely and cost effectively allow TransGrid to postpone commitment to large scale investment projects. This issue is further discussed in section B.3.2.3.

- *More proactive response to the changing energy market*: More generally, CCP 9 would like to see more evidence that TransGrid is responding to stakeholders requests for TransGrid to work with their stakeholders to respond more proactively to the risks and opportunities arising in the future network. It is not clear, for instance, if TransGrid is actively pursuing ways in which it can facilitate non-network options and energy efficiency in constrained areas of the network.

- *Stronger focus on improving efficiency and productivity to ensure sustainable lower prices*: Stakeholders have expressed a strong view that TransGrid has not fully listened and responded to their concerns with price pressures and with the apparent absence of a strong productivity target and continuing risk of inefficient investment in the forward looking plans. CCP considers these are valid issues and there is room for TransGrid to respond more effectively in its regulatory plans to these genuine concerns.

Figure A.7: TransGrid Engagement Activity Timetable 2016

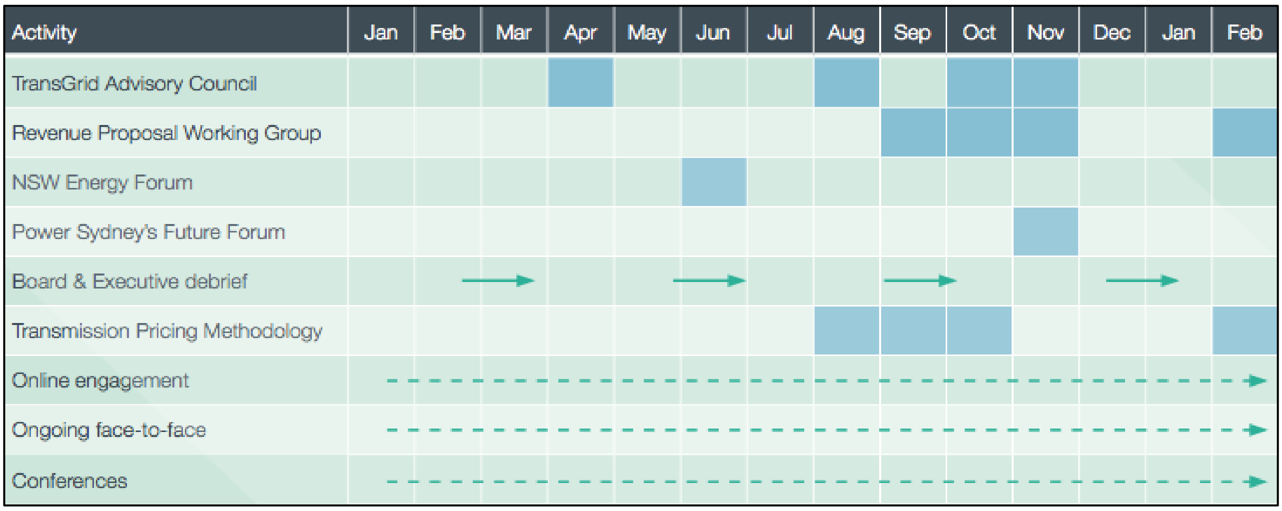
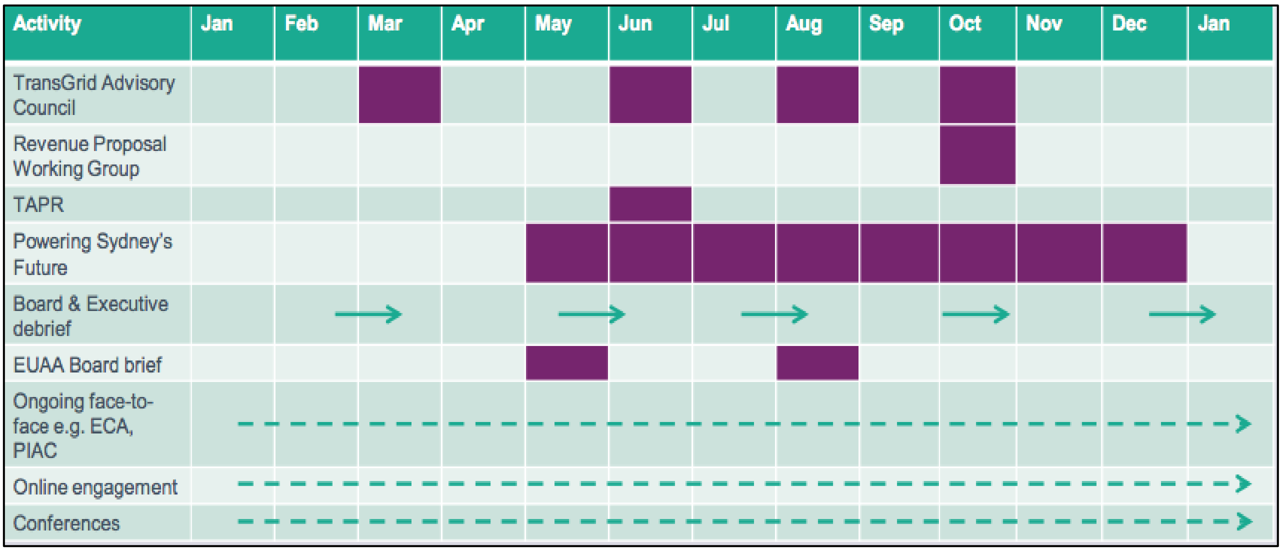


Figure A.8 : TransGrid Engagement Activity Timetable – 2017



Source: TransGrid, *Presentation to the Consumer Challenge Panel*, 4 May, p. 9

Recommendations

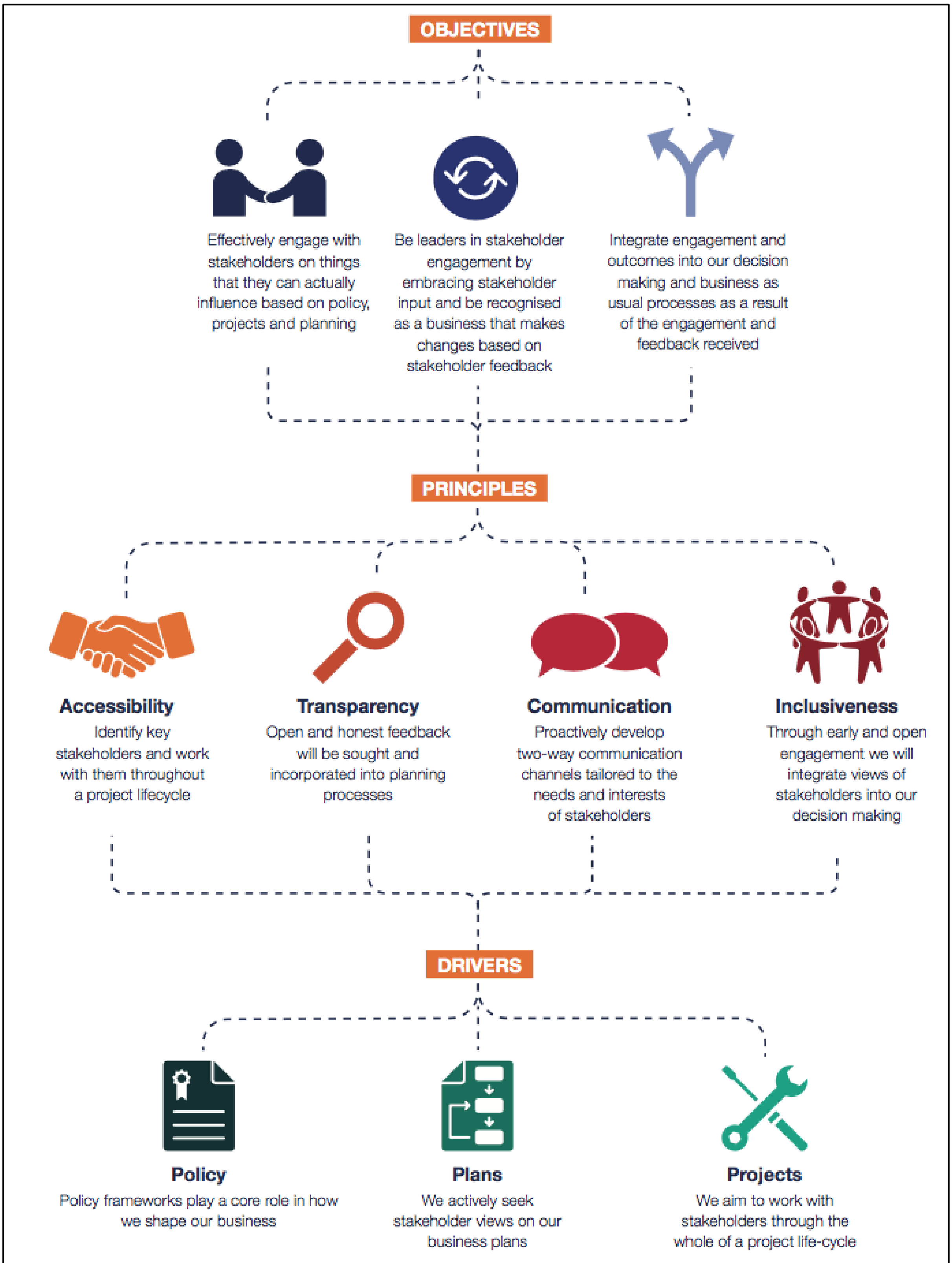
a) Overall, CCP 9 recommends that the quality of TransGrid's CE program should be a positive factor in the AER's assessment of the revenue proposal in 2018/19 – 2022/23

b) However, CCP 9 recommends that CE by TransGrid in its PSF project has some limitations and suggests that the underlying assumptions in this project should be carefully reviewed by the AER.

c) Having built a base of trust and knowledge, TransGrid could consider how it can move more consistently along the IAP2 Spectrum from 'Inform' to 'involve' and 'collaborate'.

d) TransGrid could be more open to sharing and inviting challenges from stakeholders to the assumptions that underpin a number of their forecasts.
e) TransGrid could build into its process a formal and more transparent framework for measurement and ongoing improvement of their CE process.
f) TransGrid could further consider how it can expand the principles of best practice CE to include decisions on its contingent projects and, more particularly, the RIT-T process.
g) TransGrid could undertake a more detailed review of risks of their plans from the consumer perspective.

Figure A.9: TransGrid Customer Engagement: Objectives, Principles and Drivers



Source: TransGrid, *Stakeholder Engagement Summary Report to inform TransGrid's 2018/19 to 2022/23 regulatory period*, 2017, p. 2

B. Long Term Interests of Consumers

B.1 National Electricity Objective: Framework for Assessing the Proposal

As noted earlier, role of the Consumer Challenge Panel (CCP) 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.

Our approach to considering the long term interests of consumers is based in the National Electricity Objective (NEO). The NEO is an economic efficiency objective that is often described in terms of three dimensions: productive, allocative and dynamic efficiency. The AER's Issues Paper also discusses the NEO and its interpretation at Section 3.1 (p9-10). A point of contention is whether the long term interest of consumers includes consideration of externalities. Consideration of these externalities is consistent with the principles of economic efficiency, but the current interpretation of the NEO by the AEMC does not appear to include externalities.[28]

In reviewing the regulatory proposals we have asked the following questions:

- Does the proposal promote Productive efficiency?
  - In the absence of competitive market forces, is there evidence of improved productivity? Efficient costs, incentive schemes, risk-reflective rate of return are all relevant.
- Does the proposal promote Allocative efficiency?
  - The pursuit of allocative efficiency refers to the alignment of TransGrid's regulated services with consumer preferences. Consumer engagement, network pricing reform and value of reliability matters are relevant.
- Does the proposal promote Dynamic efficiency?
  - Is the proposal consistent with the ENA/CSIRO Network Transformation Roadmap?
  - How does the proposal fit with contingent projects being advanced through RIT-T processes?

Our summary views on the three dimensions of economic efficiency in relation to this regulatory proposal follow:

<u>Productive Efficiency</u>

The pursuit of productive efficiency for an Electricity Transmission Network Service Provider is compromised by the absence of competitive market forces. We also acknowledge that the

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[28] See, for example, the Total Environment Centre submission to the Finkel Inquiry at http://www.environment.gov.au/submissions/nem-review/total-environment-centre.pdf

productivity benchmarking of TNSPs is not yet a mature activity and methodological changes are likely[29]. However, in our view, past trends in real opex and real opex/kWh are indicative of the scope for improved efficiency from TransGrid over the 2018-23 period. At the last review AER concluded that TransGrid's operating costs were efficient. Since 2014 TransGrid has continued to make improvements in its asset management and maintenance and business processes that have reduced its costs. CCP 9 considers that it is reasonable to expect that TransGrid can continue to make efficiency improvements in the future, as businesses in competitive markets seek to do. Hence, in the absence of strong information to the contrary it is reasonable to expect that TransGrid can continue to reduce opex in real terms.

Allocative Efficiency

The pursuit of allocative efficiency refers to the alignment of production with consumer preferences. In the context of regulated energy infrastructure, this refers to issues such as pricing and the provision of regulated "services" only up to the point of consumer's willingness and capacity to pay. In order to form an overall view on allocative efficiency, we have considered:

- Consumer engagement to elicit preferences
- Pricing reform
- The use of Value of Customer Reliability (VCR) estimates in expenditure decisions

In our view, TransGrid's CE program has contributed to this objective however, there is no new progress proposed on pricing reform. The consideration of alternate VCR values in the PSF RIT-T is also a small step in the advancement of Allocative Efficiency. Overall, our view is that the TransGrid Proposal should do more to advance Allocative Efficiency during the 2018-23 regulatory control period.

Dynamic Efficiency

The pursuit of dynamic efficiency for a regulated energy business relates to how efficiently the business can innovate and navigate the inevitable changes appearing in the energy markets. The ENA and CSIRO released the Network Transformation Roadmap on April 28th 2017[30]. In our view, this Roadmap represents the state of the art in the pursuit if dynamic efficiency for an Electricity Transmission business such as TransGrid. TransGrid has prepared a Network Vision 2056 (Appendix A to the RP), participated in the NTR process and articulated a framework [RP, p24]:

- Flexible Planning
- Scalable operations
- Efficient Asset Management

TransGrid also identify important changes in their operating environment for the 18/19-22/23 RP as [RP p23]:

- More decentralised and intermittent generation
- Changes in Electricity Consumption Patterns
- Regulatory and market framework changes

[29] The AER is currently conducting a review of Transmission Benchmarking www.aer.gov.au/communication/aer-invites-submissions-on-review-of-transmission-benchmarking
[30] www.energynetworks.com.au/electricity-network-transformation-roadmap

- Driving business efficiencies

The AEMC is also conducting a Market Review of drivers of change that impact transmission frameworks[31]. The draft Stage 1 Report was released on 11 April 2017 and states:

> *"There appears to be a large degree of uncertainty regarding future patterns and drivers of generation and transmission investment."*

The review is linked to the previous work program "Optional Firm Access Design and Testing Review" that concluded in 2015. This previous work considered the potential for more commercial drivers for generators to fund Transmission Capacity (rather than full cost recovery from consumers under the network regulatory framework). In light of increasing uncertainty, this reallocation of risk back to those best placed to manage it (generators) is likely to be in the consumer interest. The implications for TransGrid's capex program – particularly some of the contingent projects – are not yet clear but will require specific consideration by the AER.

An example of evolving requirements, the AEMC published a directions paper for the System Security Market Frameworks Review on 23 March 2017 that identifies new requirements on Transmission Network Service Providers (TNSPs) to provide and maintain a defined operating level of inertia at all times. An interim measure allows the TNSP to contract with third party providers of Fast Frequency Response (FFR). The directions paper also proposed an approach for maintaining 'system strength' by clarifying obligations on TNSPs. The implications of this for the Regulatory Proposal are not clear.

The capex program proposed by TransGrid will see the RAB increase by 17% in nominal terms (or 4% in real terms). Technology is changing rapidly in a way that is fundamentally altering the way we produce and use electricity. The transmission system will still be required, but its role and the type and quantity of assets required may change. But once the assets are constructed and rolled into the RAB future customers will, under the current rules, continue to bear the costs of the assets, irrespective of their usefulness.

Our summary view is that TransGrid's expenditure proposal does not adequately address the uncertainties and consequentially allocates too much risk to consumers.

B.2 Overview of the Revenue Proposal

B.2.1 TransGrid's Proposal

B.2.1.1 Outcomes for current period

Average prices for TransGrid's transmission services will fall by 7% on average over the 4 years to 2017-18 under the AER's current determination. This reflected a reduction in TransGrid's total revenue requirement of 14.6% (in real terms). The AER's decision assumed, on the basis of its analysis of the then proposed capex and opex, that TransGrid could achieve substantial reductions in capex and, to a lesser degree, opex over the regulatory period. The allowed capex was 25% below the proposed capex and the allowed opex was 7.3% below the proposed opex. In its proposal TransGrid has indicated that it will 'beat' the assumed efficient costs for the period – that is, its actual spending on opex and capex will be lower than the AER's allowances.

[31] http://www.aemc.gov.au/Markets-Reviews-Advice/Reporting-on-drivers-of-change-that-impact-transmi

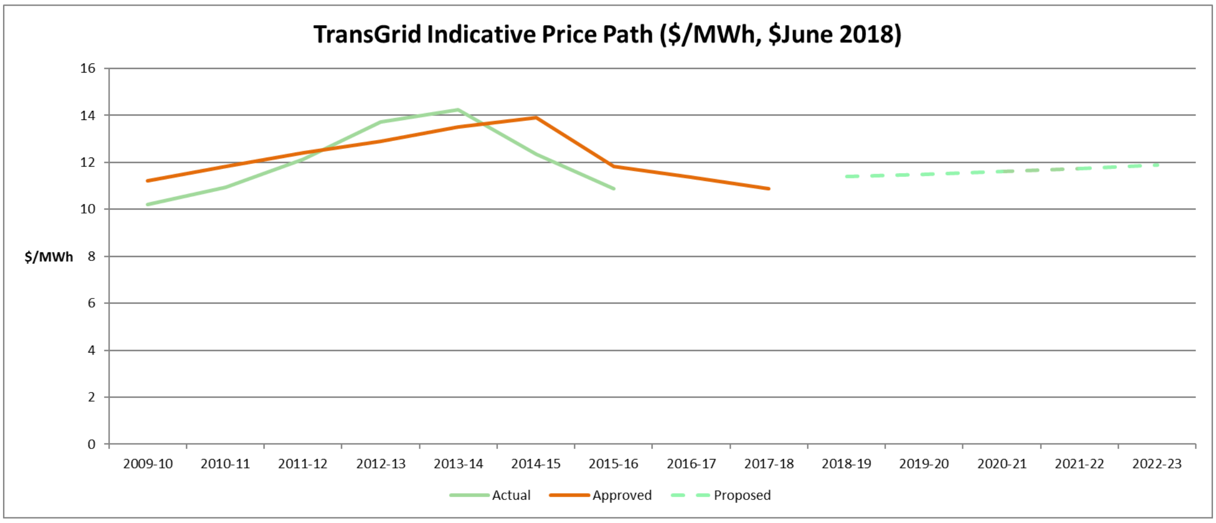
The outcomes in the current regulatory period are consistent with the regulatory regime – as implemented by the AER – operating in the long-term interest of consumers. The AER has rigorously examined costs to come to a judgement on efficient costs. Given the incentives provided, TransGrid has significantly improved its efficiency and reduced its costs. The lower costs achieved by TransGrid then provides the starting point for the costs next regulatory period starting in 2018, for the long-term benefit of consumers.

B.2.1.2 Projected revenues and prices

TransGrid's proposal will result in small real reduction of 2.5% in average transmission prices for the next regulatory period (i.e. this this is the change in the average price over the 5 years to 2023 with the average price in the 4 years to 2017-18). This reflects a 1.2% real increase in TransGrid's proposed revenue requirement from $785[32]m p.a. in the current regulatory period to $795m p.a..

However, the average price paid will increase in real terms in each year of the regulatory period – 7.4% in 2018-19 and around 1% in each of the following years[33]. Average transmission prices (in nominal terms) will be below the peak of 2013-14 until 2022-23.

Figure B.2.1 – TransGrid's Indicative Transmission Price Path



Source: AER

The increase in average transmission tariffs is more pronounced because:

1. the higher prices in 2013-14 (the first year of the current regulatory period) due to the interim price determination, resulted in a larger subsequent reduction in approved prices. Approved price in 2017-18 will generate revenues $61m below the average revenue requirement for the regulatory period.
2. Allowed revenues are not being fully recovered by current prices (the gap between actual and approved prices in the graph above) and the shortfall is to be recovered in the next period.

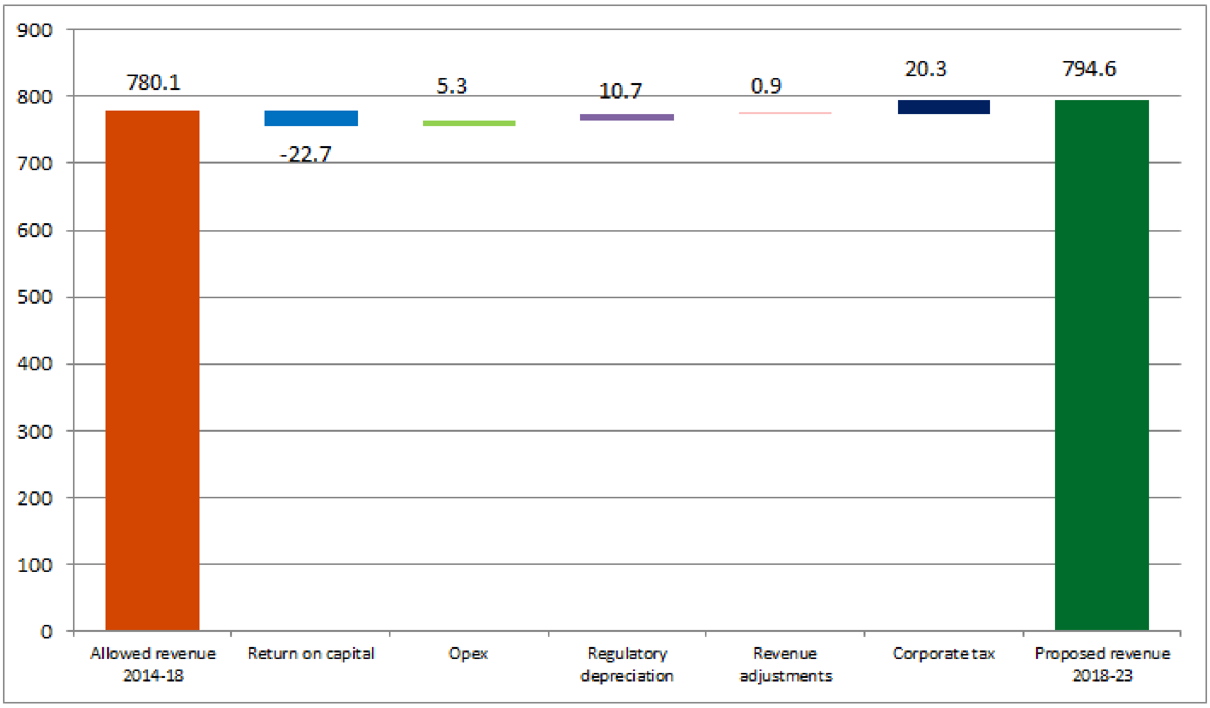
[32] This includes the latest updated debt allowance.
[33] TransGrid, *Proposed PTRM, Revenue Summary* sheet, row 55

B.2.1.3 Summary of key cost components and contribution to revenue requirement

The chart below summarises the key contributors to the increase in the annual average revenue requirement proposed by TransGrid. In brief:

1. Lower interest rates (partly due to lower inflation expectations) reduce the return on capital required
2. Opex is projected to increase following the reductions in recent years
3. The increased capex program will result in a rising RAB and increased depreciation
4. The benchmark allowance for corporate tax is expected to increase by an average of $20.3m p.a.. If it were not for this, the proposed revenue requirement would decrease slightly. Of this increase, almost $10m is due to TransGrid's use of a lower value of imputation credits, but the remainder is due to an expected increase in the benchmark tax calculation

Figure B.2.2 – Change in TransGrid's Proposed Average Revenue by Cost Component



Source: AER, *Issues Paper: TransGrid's Electricity Transmission Revenue Proposal, 1 July 2018 – 30 June 2023,* March, 2017, p5

The potential impacts on revenues and prices of the contingent projects proposed by TransGrid are not included in the proposed revenues or prices.

B2.2 Assessment of TransGrid's Proposal

In addition to the enhanced customer engagement discussed above, there are a number of positive elements in TransGrid's proposals:

- TransGrid has largely accepted and worked within the regulatory framework set out by the AER. There is, for example, far less disagreement around the WACC parameters than in past reviews.

- Following the substantial price reductions in the past period, the real increase in proposed prices is relatively small and the underlying real change in the average revenue requirement has of 1.9% reflects past efficiency gains.
- The use of contingent projects reduces the risks of consumers being asked to pay for projects in the current period that may prove not to be required or can be deferred to a future period.

However, there are various matters on which we have questions or where we believe that there are alternative assumptions or conclusions that would better serve the long-term interests of the consumer while also respecting the reasonable commercial interests of TransGrid:

- *The impact on future consumers of the current capex proposals.* The capex program proposed by TransGrid will see the RAB increase by 17% in nominal terms (or 4% in real terms). Technology is changing rapidly in a way that is fundamentally altering the way we produce and use electricity. The transmission system will still be required, but its role and the type and quantity of assets required may change. But once the assets are constructed and rolled into the RAB future customers will, under the current rules, continue to bear the costs of the assets, irrespective of their usefulness.
- *The impacts of prices of the rising RAB if interest rates rise.* The customers also bear the risk of future rises in interest rates. The lower WACC expected for the next regulatory period reduces the impact on prices of the increase in the RAB. But if interest rates were to return to their long-term average the higher RAB alone would increase average transmission tariffs by almost 3%.[34]

Together these two risks faced by customers highlight the importance of ensuring that opportunities to defer or reduce capex and pursing more agile non-network options where feasible and economic (having regard to the option value that they provide).

- *Scrutiny and impacts of contingent projects.* It is highly likely that at least some of the contingent projects will proceed during the regulatory period. Hence, it is important the potential price impacts of the contingent projects are recognised. CCP 9 is also concerned to ensure that the review and analysis of the contingent projects is no less rigorous than if the projects were included in the capex program included in the revenue requirement.
- *Scope for ongoing productivity improvements.* TransGrid has achieved significant reductions in real opex and opex/MWh in the last period but has not included similar improvements in their proposal for the next period. In competitive markets firms are required to continuously pursue productivity gains in all areas of activities. CCP 9 considers that stronger evidence is required to support the reversal in trends in real opex and opex/MWh proposed by TransGrid. In the absence of this, continuation of past trends provides a realistic reference point for expectations for future trend changes in opex.
- *The proposed WACC may be higher than required by the NEO and rate of return objective.* In particular, when a wider range of market evidence is considered, including recent transaction data, the current approach to the WACC and the parameters used by the AER appears to be more than meeting market expectations.

[34] Based on the $1,106m increase in the RAB in the current period and an increase in 10-year government bonds from 2.24% to the 10-year average of 4.3%.

- *The methodology for estimating the benchmark tax payments (before allowance for imputation credits) needs further consideration (but not for this review).* The estimation of tax obligations (before the application of Gamma) has not received the same attention, or been subject to the same level of challenge, as the WACC or benchmark opex and capex. In the case of TransGrid, the increased allowance for tax is the single largest component of the increase in the revenue requirement. CCP 9 recognises that the current approach has been well-established and should not be changed for the current review, and any single review. However, it would be appropriate for this to be considered as part of the next review of the Rate of Return Guideline.

B2.3 Recommendations:

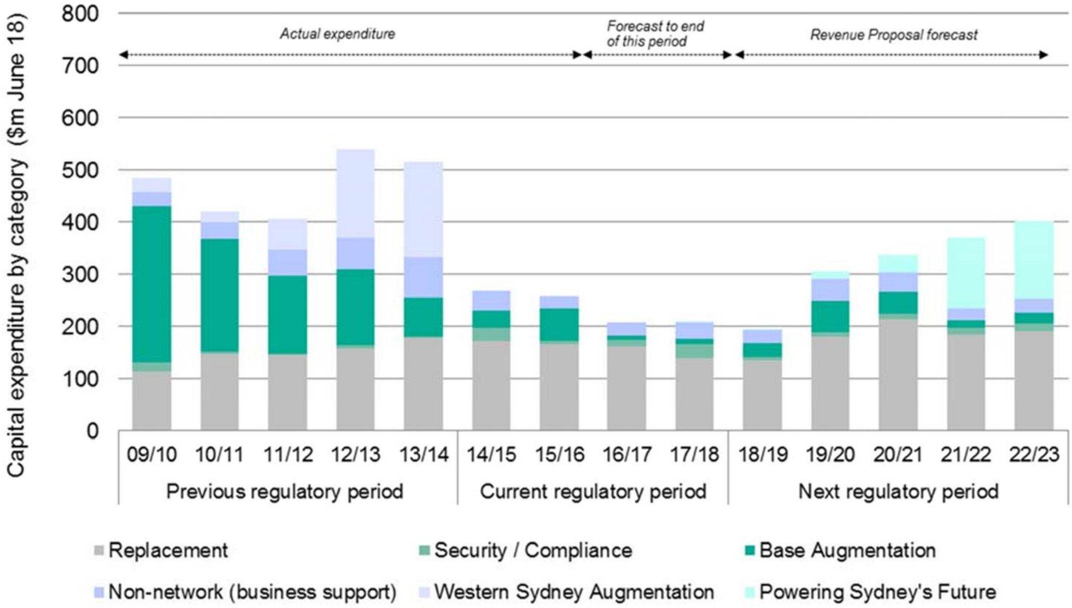
a) AER should ensure that contingent projects are subject to no less rigorous review than projects included in the Capex program.
b) In reviewing TransGrid's proposed opex, AER should include consideration of past trends in real opex and opex/MWh in determining the trends in TransGrid's future efficient costs. This would support inclusion of a positive productivity growth factor.
c) AER should not accept TransGrid's proposal for a MRP of 7.5%
d) As part of the next review of the Rate of Return Guideline, the AER should review its approach to the estimation of tax expense.

B.3 Capital Expenditure

B3.1 TransGrid's Proposal

The chart below summarises the level and composition of the proposed capex in the current and next regulatory period.

Figure B.3.1 – TransGrid's Proposed Capex Program



Source: TransGrid, *Revenue Proposal 2018/19-2022/23,* January 2017, p72.

B3.1.1 Capex in the current period

Expected capital expenditure for the current four year period is $946 million, or $236m p.a., significantly below the average annual capex in the prior period of $470, p.a. and also below the regulatory allowance determined by AER for the four years to 2018.

TransGrid suggested[35] two main reasons for this:

1. augmentation expenditure is at historically low levels due to the stable level of demand; and
2. the new investment and risk framework for capex planning.

The new planning framework resulted in the de-scoping or removal of planned capital investments with total savings of approximately $110m ($June 18) by providing the opportunity to focus capex on the most critical needs identified through the development of new asset health indices.

B3.1.2 Projected capex

TransGrid forecasts capex (in June 2018 $s) of $1,612m ($322m p.a.) over the five year period from 2018/19. While this is 36% higher than capex in the current period it remains lower than the average annual capex spending in the previous period. The increase relative to the current period is largely due to

1. the Powering Sydney's Future project; and
2. higher asset replacement needs in the next period.

The Powering Sydney's Future project is discussed in more detail below. While the remaining augmentation is low compared to augmentation spending prior to 2013-14, it is higher than in the period to 2017-18. Replacement expenditure is also higher based upon the latest asset condition information and analysis using the new risk model. TransGrid highlights a number of efficiency improvements made to date that have improved the efficiency of capex planning and delivery, such as new design and equipment standards.

The proposal also sets out 5 contingent projects estimated to cost between $543m and $2,274m in total. These projects are not part of the capex program of program of $1,612m but may be triggered during the regulatory period.

B3.1.3 Implications for RAB and future prices

TransGrid's RAB will increase by 17% in nominal terms (or 4% in real terms). As the chart below shows, this follows a period of relative stability in the RAB, but it will not match the rapid growth in the RAB in the period to 2014. The increase in the RAB will be larger than this to the extent that the contingent projects are triggered.

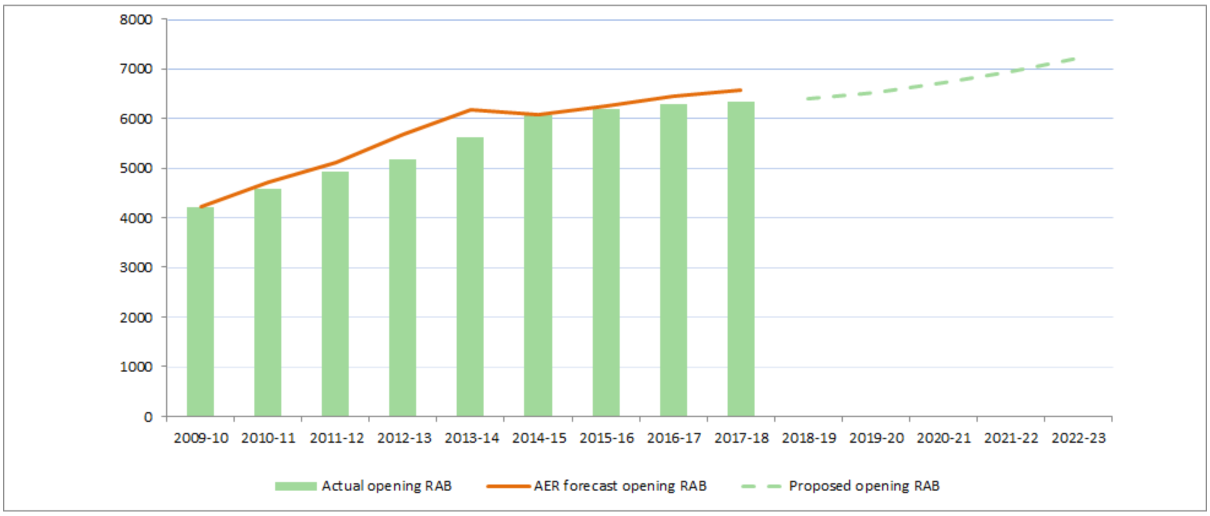
CCP 9 recognises that additional investment is required as demand grows, reliability standards increase or major asset replacements are required. Hence, a growing RAB may well be in the long-term interest of consumers. However, the concerns for customers are that:

1. the rising RAB puts upward pressure on prices, especially if interest rates return to their longer term averages

[35] TransGrid, *Revenue Proposal 2018/19-2022/23,* January 2017, pp72-73

2. these are very long-lived assets (some with lives of 50 years) which, once included in the RAB, customers will have to pay for irrespective of changes in technology or carbon policies that may substantially change the role of the transmission system and the usefulness of the assets currently being installed.

Figure B.3.2 – TransGrid's Projected Regulatory Asset Base (nominal terms)



Source: AER, *Issues Paper: TransGrid's Electricity Transmission Revenue Proposal, 1 July 2018 – 30 June 2023,* March, 2017, p7

Of the $1,106m increase in the RAB:

- $810m results from the indexation of the RAB. That is, this component maintains the real value of the assets.[36]
- $287m results from the projected capex ($1,785m in nominal terms) exceeding the depreciation of the existing assets of $1,487m.

The lower WACC expected for the next regulatory period reduces the impact on prices of the increase in the RAB. But if interest rates were to return to their long-term average the higher RAB alone would increase average transmission tariffs by almost 3%.

B.3.2 Assessment

B.3.2.1 Dynamic efficiency and future nature and role of Transmission

It is widely recognised that the electricity sector is going through a period of fundamental change driven by:

- Rapid technological change. New smaller scale generation, storage, and demand response options are becoming more economic leading to the increasing of distributed resources that can both compete with conventional supply options (including networks) and provide network support services.

[36] The regulatory framework for the electricity utilities uses a nominal rate of return on an indexed RAB. To avoid double-counting inflation, the indexation component of the RAB is deducted when determining the revenue requirement. This is intended to result in an outcome equivalent to a real return on an indexed RAB.

- Decarbonisation of energy supply. Substantial reductions in carbon emissions are expected, driven by policies aimed at reducing carbon emissions and the improving economics of low emission distributed resources.
- Demand uncertainty. In the context of these changes future demand (both in terms of maximum demand and the profile of demand during the day and variability during the year) is becoming more uncertain. A key concern is network utilisation being 'hollowed' leaving the costs of serving peak loads but more difficulty in recovering those costs.

These changes are likely to lead to major changes in the role of networks and their relationship with other market participants and customers. Recognising this the ENA, in partnership with the CSIRO has prepared and Energy Transformation Roadmap that sets out scenarios for the role of the networks in the future energy sector. The roadmap foresees a more customer-centred energy system that meets the objectives of system security and carbon abatement while still ensuring energy services remain affordable. The Roadmap envisages:

By 2050

- The sector will be net carbon neutral
- 45% of energy could be generated locally, with 2/3 of customers having some form of generation and storage
- 1/3 of customers could be stand-alone power system customers
- Networks could pay $2.5b to customers and market participants for network support
- Network charges could be 30% lower and $16b of network investment avoided.

By 2027

- Carbon emissions could be reduced by 40%
- 40% of customers will have on-site (distributed) resources such as solar generation and battery storage.[37]
- Networks could pay more than $1.1b to market participants and customers for network support

[37] AEMO forecasts that by 2024-25 there will be over 1000 MWh of residential battery storage in NSW as battery storage becomes more economic – see http://aemo.com.au/-/media/Files/PDF/Emerging-Technologies-Information-Paper.pdf

The roadmap still envisages a critical role for the networks but the assets required and the relationship with market participants and customers will change fundamentally, even within the next 10 years.

The Critical Role of the Integrated Grid

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 agility with which networks connect, integrate and incentivise new, lower carbon energy choices will directly influence the cost, fairness, security and reliability of the electricity system for customers. Urgent regulatory and policy changes will be required to maintain power system security, while reducing customer costs by enabling the efficient use of distributed energy resources, stand alone systems and micro-grids. Timely development of technical standards and new platforms will animate new distributed energy resource markets and permit more efficient customer services and participation.

The right balance can be achieved.

With a clear Roadmap, Australia's electricity sector can outperform current abatement targets, keep the lights on and deliver lower costs. Australia can increase the levels of both centralised and decentralised renewable and low emission generation sources enabled by transmission and distribution networks. Total system costs can be reduced by over $101 billion through network service platforms enabling distributed energy resources to participate in increasingly dynamic electricity markets. Together, the Roadmap activities can achieve a positive energy future for Australian energy customers enabling choice, lower costs, high security and reliability and a clean electricity system to 2050.

Source: ENA/CSIRO, *Electricity Network Transformation Roadmap: Final Report (Summary)*, April 2017, p3.

It is in this context that the proposed capex plans need to be considered. Major transmission assets such as underground cables, transmission lines, and substations have lives of 40-50 years. Using the Powering Sydney's Future project as an example, by 2027 major components of the project will be scarcely through one-tenth of their life, with 35-45 years of life remaining. Yet under the ENA Roadmap it is likely that economics of distributed resources and the amount of resources available will have changed dramatically, and with it the potential for network support services.

CCP 9 is concerned that under 'business-as-usual' there would be a significant risk of investment in assets that would be underutilised for much of their lives. Under the current electricity rules it is the customer rather than the utility that bears the cost of this possible asset stranding. Hence, it is critical from the perspectives of both the dynamic efficiency of the sector and the long-term interest of consumers that these long term changes are fully factored into planning. This requires:

- Integration of network planning with long term scenario analysis which extends beyond sensitivity testing for variations around 'business-as-usual' demand forecasts

- Within this identification of changing economics and role of distributed resources and the implications of this for the future use of assets
- Identification of the 'option value' of strategies that can defer or reduce the investment in very long-lived assets while still meeting system security requirements.

Together this suggests and increased focus on more agile, flexible option that allow adaptation as the we get better information on the likely future shape of the energy system. In this context – as the ENA/CSIRO roadmap sets out – there is a strong expectation the role of distributed resources in providing network support will increase rapidly in the medium to long term. It is not clear to CCP 9 that the current approach to the development of capex plans adequately captures these changes to the sector and their implications for long term capex planning. However, these are complex issues and CCP 9 considers that there is a role for the AER, working in collaboration with the NSPs, ENA, and stakeholders, to provide further guidance on the role of, and techniques for, scenario analysis and option values in long term capex planning to reduce the risk of stranded assets being borne by consumers.

B.3.2.2 Risk-based approach to Capex planning

Capital Expenditure on Asset Replacement (REPEX) proposed of $961m represents the majority of network capital expenditure proposed by TransGrid (Issues Paper p17,18). We also acknowledge that this is likely to remain the case for a while and are therefore supportive of a long-term approach to its management:

> *"The top down modelling indicates that replacement expenditure will likely remain at a higher level for at least the next four regulatory periods, as assets installed in the 1970s and early 1980s reach the end of their service lives." (RP p80):*

We also note that the AER has submitted a rule change (*Replacement expenditure planning arrangements*) in order to see the RIT-T apply to REPEX projects as well. A Draft Decision from the AEMC was released on 11 April 2017[38]:

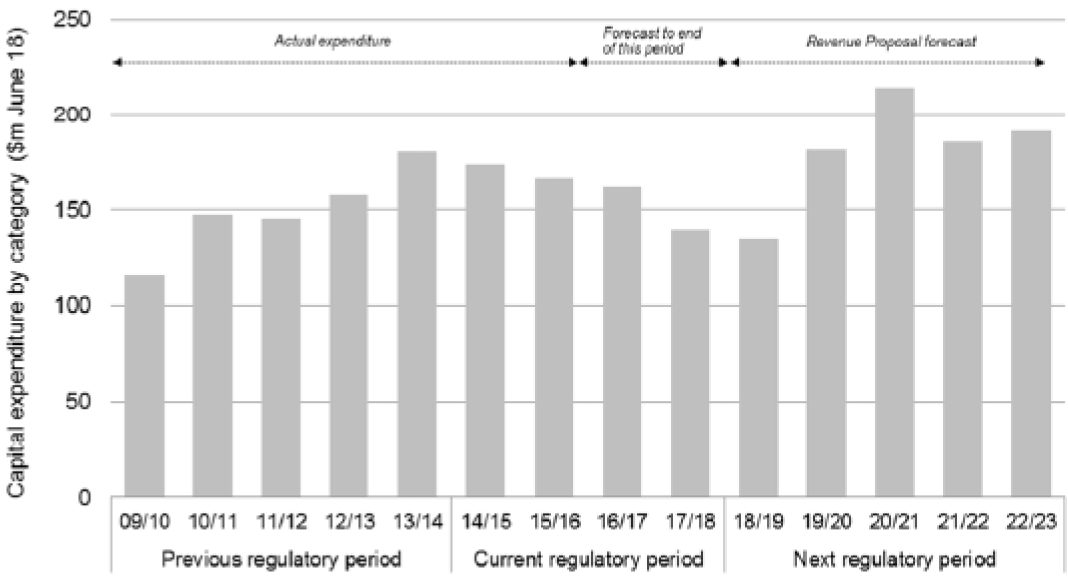
> *The draft rule requires electricity network service providers to include information on all planned network asset retirements and certain de-ratings in their annual planning reports. It also extends the current regulatory investment test framework for electricity transmission and distribution networks to include replacement expenditure.*

The Daft determination notes that the AER should complete consequential amendments to the RIT and guidelines by 31 December 2017. AER's final determination on TransGrid is due 30 April 2018.

As can be seen in TransGrid's Figure 5.7 below, REPEX has been an important component of capital expenditure each year. According to the AER Issues Paper (Table 2) the 2018-23 period expenditure represents a 7% increase over the current regulatory control period.

[38] AEMC Reference ERC0209 Replacement Expenditure planning arrangements www.aemc.gov.au/Rule-Changes/Replacement-Expenditure-Planning-Arrangements

Figure 5.7: Replacement capital expenditure trend ($m June 18)



It is important for consumers to understand that the AER final determination will not explicitly approve any of the individual projects that TransGrid identified in their capex proposal. Rather it will set an allowance based on the *prudent* and *efficient* capital expenditure necessary to meet current and future performance standards[39]. The lower REPEX in the current period is acknowledged by TransGrid (RP p72):

> *"TransGrid was able to de-scope and remove some replacement projects in this period following a review of the program against the new asset management process. This lower capital expenditure benefits consumers… TransGrid applied its new approach to risk, challenging existing investment proposals in light of updated asset condition information and other changes in circumstances. While there was a temporary pause in initiating new projects during the process change, projects in delivery were not affected and there was no impact on service delivery or risk. The result of the analysis was the de-scoping or removal of planned capital investments with total savings of approximately $110 million ($June 18)."*

TransGrid has provided a review of the capex program by aurecon (Regulatory Proposal Appendix E). The aurecon review considers both AUGEX (capital expenditure on network augmentation) and REPEX. The review also provides an overview of the methodology and some worked examples.

Our consideration of the REPEX proposal is based on our understanding of TransGrid's risk-based analysis method. Our view is that it is a theoretically sound approach, however, the formulation of the REPEX program is based on parameter selection (such as risk of failure and cost of failure) that is immature and inherently uncertain. The Network Asset Risk Assessment Methodology (RAM) includes a bottom up replacement forecast based on comparing a 'risk cost' vs a 'mitigation costs'. The REPEX forecast is the sum of the 'mitigation costs'. The approach is exposed to subjectivity in the estimations of both consequences and likelihood. Further, we note that Asset Health Index (HI) approach continues to mature (e.g aurecon p17, 18). Further, the aurecon review notes that they

[39] The capex criteria are set out in the National Electricity Rules cl 6A.6.7(c)

were not provided information regarding the impact on risk costs of the deferral of asset replacement (p23). The sensitivity of results (ie forecast cumulative REPEX) to parameter selection was also noted in a review of PowerLink's approach by consultants EMCa for the AER (aurecon p27) and in our view is likely to apply to TransGrid as well. As noted by aurecon (p27):

> *"The TransGrid approach to risk provides relatively consistent results where supply reliability is the dominant component of risk as the value of customer reliability provides a means of costing reliability. However, where the risk cost is dominated by safety and environmental risk, the results vary much more widely."*

The use of estimates of Value of Customer Reliability (VCR) is an important component of network regulation and a consistent approach is encouraged. The use of bespoke VCR values for inner Sydney and CBD to derive estimates of the value of un-served energy (USE) that are multiples of the state-wide average (see discussion at aurecon p39) however raises doubts as to the consistent application of VCR estimates. In our view sensitivity testing of results across a range of VCR estimates must be a component of risk-based asset management[40].

The Australian / New Zealand Risk Management Standard AS/NZS ISO 31000:2009 *Risk management – Principles and guidelines* defines risk as the *effect of uncertainty on objectives*. Effective risk management is therefore predicated on clarity over objectives and management of uncertainty. In response to the question posed by the AER Issues Paper[41], it is the view of CCP 9 that more comprehensive testing of sensitivities to key parameters (around VCR as well as Risk Costs) is warranted in order to assess whether the overall approach to REPEX (in terms of methodology and cumulative expenditure forecast) is both *prudent* and *efficient*. For example, the development of alternate scenarios could be used to demonstrate alternate risk costs based on different levels of expenditure.

The impact of the requirement for RIT-T on REPEX projects is an important consideration. It is not clear what proportion (by expenditure) of REPEX projects would be impacted however it is noted that TransGrid have included an additional $0.57m pa to the capital program as a consequence of the additional reporting and consultation requirements. CCP 9 does not support this inclusion as robust project evaluations and stakeholder engagement should already be included in the expenditure program.

Our summary view is that the risk assessment methodology is an appropriate approach to prioritising activities within an asset renewal and replacement program. The development of this risk-based approach has helped TransGrid improve its efficiency by optimisation of Repex and maintenance costs in the current period. In our view, further improvements are likely as TransGrid further develops and enhances its approach. In our view sensitivity testing of key assumptions is required in order to assess if the scale of the program (the proposed REPEX of $961m) can be considered *prudent*. The likely impact of the rule change to apply the RIT-T to REPEX should be clarified as part of the Draft Determination.

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[40] We note that the Power Sydney's Future PADR tests results using the AEMO VCR figures as well as the IPART/TransGrid higher figures for Inner Sydney and CBD.

[41] Capex Question, page 21: Do you consider that TransGrid's risk assessment methodology and its application have been sufficiently detailed to support its proposed replacement capex against the capex criteria? If not please identify any issues that may be relevant to an assessment of the proposed capex.

B.3.2.3 Contingent projects

TransGrid has proposed 5 contingent projects:

- NSW-SA Interconnector – pending the SA Electricity Transformation RIT-T being undertaken by ElectraNet (due mid-2017)
- Reinforcement of Northern Network
- Reinforcement of Southern Network
- Support SW NSW for Renewables
- Reliability of Supply to Broken Hill

The AEMC is also conducting a Market Review of drivers of change that impact transmission frameworks[42]. The draft Stage 1 Report was released on 11 April 2017 and states:

> *"There appears to be a large degree of uncertainty regarding future patterns and drivers of generation and transmission investment."*

The review is linked to the previous work program "Optional Firm Access Design and Testing Review" that concluded in 2015. This previous work considered the potential for more commercial drivers for generators to fund Transmission Capacity (rather than full cost recovery from consumers under the network regulatory framework). In light of increasing uncertainty, this reallocation of risk back to those best placed to manage it (generators) is likely to be in the consumer interest. The implications for TransGrid's capex program – particularly some of the contingent projects (the Reinforcement of Northern and Southern Networks and the Support SW NSW projects in particular) – are not yet clear but will require specific consideration by the AER. In our view, *the large degree of uncertainty regarding future patterns and drivers of generation and transmission investment* represents risks that are better managed by Generators and Transmission Network Service Providers under a revised framework. It is our recommendation that, if generation-based contingent projects are proposed, the triggers should include provision for review if there is a review of the arrangements for pricing of access for generators.

The Supply to Broken Hill contingent project is a particularly new development following on from the setting of an unserved energy allowance by IPART in December 2016. The information provided is explicitly preliminary but a non-network solution seems viable since current reliability is maintained via back-up generation capacity procured from Essential Energy. CCP 9 expects this project can be further developed prior to TransGrid's revised Regulatory Proposal (1 December 2017).

Overall, CCP 9 has mixed views on the role of contingent projects in an ex-ante regulatory determination. The provision of clear triggers and the scrutiny of an effective Regulatory Invest Test (the RIT-T) can ensure the prudency and efficiency of major projects. However, consumer engagement is fragmented by such an approach and understanding of the 'big picture' can be diluted as a result. It is our recommendation that in the draft and final determinations, the AER present impacts on revenues and prices both 'with' and 'without' contingent projects included.

B.3.2.4 Powering Sydney's Future

TransGrid has included an allowance of $330m, or 20% of the total proposed capex program, for the Powering Sydney's Future project. This is a joint project Ausgrid that responds to the need to:

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[42] http://www.aemc.gov.au/Markets-Reviews-Advice/Reporting-on-drivers-of-change-that-impact-transmi

1. Replace the capacity currently provided by aging transmission lines that will become increasingly unreliable. Three existing cables are scheduled to be retired in the near term while the reliability of eight other cables is expected to decline.
2. Meet the projected increase in demand in the CBD and inner metropolitan areas
3. Meet the new reliability standards set by the NSW Government.

TransGrid and Ausgrid are investigating six shortlisted options, each involving the construction for two new 330kV transmission lines. The options vary in terms of:

- Whether TransGrid's existing Cable 41 is remediated, operated without remediation (including at a lower voltage), or retired
- Ausgrid's eight oil-filled cables in the poorest condition are retired at once, or in stages
- Two new 330 kV cables are built together, or in stages.

All six options envisage the inclusion of non-network solutions of some type. By 2022/23 the requirement is for 60MW and this rises to 190MW by 2024/25.

In its revenue proposal TransGrid indicated that "Currently, the most promising solution to maintain supply to Sydney's inner metro and CBD is option 3 in the PSCR - Install two 330kV cables (route as in 1.) at once and retire Cable 41 - with a forecast cost of $331 million." TransGrid included a variant on this in the PADR where non-network solutions allowed the expenditures to be deferred by a year.

As illustrated in Figure B5.3.3 below, the PSF project is made more urgent by the pending retirement of a number of Ausgrid's inner city cables. CCP 9 understands, therefore, the importance that TransGrid places on the PSF project for ensuring a reliable supply of electricity to the Sydney CBD over the next decade or so.

However, CCP 9 is also concerned that the solutions envisaged by TransGrid provide a balance between ensuring secure supply and avoiding excess capital expenditure that NSW consumers will continue to pay for over the 50-year life of the assets.

Therefore, the questions that CCP9 have about the proposal concern:

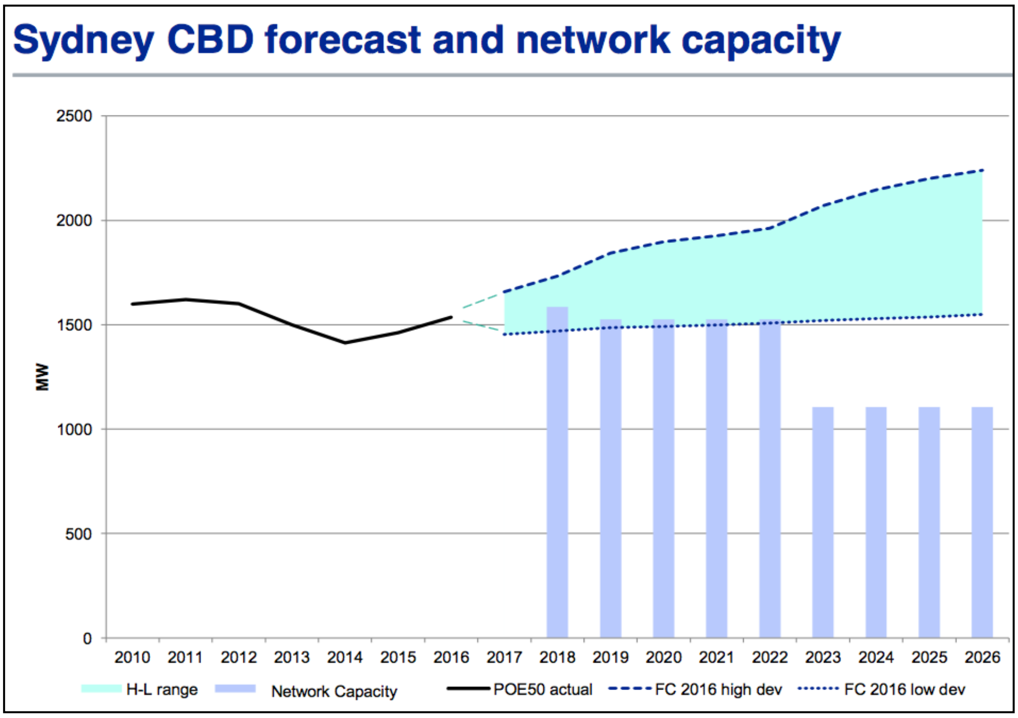
- The timing of the project;
- The size of the project;
- The assessment of the 'option's available to TransGrid; and
- In particular, the assessment of non-network options.

As part of considering these four questions, CCP9 has reviewed:

- TransGrid's forecast of demand for the CBD region
- The options considered by TransGrid as part of their capital planning and RIT-T process
- The customer engagement process undertaken as part of the project planning

CCP9 also notes that TransGrid has very recently published its Project Assessment Draft Report (PADR), the second stage of its RIT-T assessment of the project. Due to timing constraints, CCP9 has not had the opportunity to fully consider the PADR. However, it will form part of our ongoing assessment of the PSF project.

Figure B.5.3.3: Sydney CBD forecast and network capacity



Source: TransGrid, Revenue Proposal 2018/19-2022/23, p. 30

Demand forecasts

Overall NSW demand forecast:

TransGrid's forecast of both electricity usage and demand for NSW as a whole appears reasonable and is aligned with AEMO's forecast for NSW in its 2016 NEFR.[43] AEMO predicts little or no growth in usage and summer demand over the next 20 years despite a forecast of economic growth an population growth of some 30 per cent over the same period.[44] AEMO's reasons for this decreasing energy intensity include:[45]

- The increase in efficiency of electrical appliances will continue and offset the increasing use of electrical appliances
- Strong growth in PV (350% by 2035-36)
- Other new technologies are expected to reduce energy uses, including battery storage and mobile devices replacing stationary home equipment.
- the restructuring of the Australian economy continues to change towards less energy intensive industries

In addition, there are multiple Federal and state government's plans to reduce GHG emissions, with an emphasis on improved efficiency. This includes the Federal Governments National Energy Productivity Plan.

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[43] AEMO, *National Electricity Forecasting Report*, June 2016.
[44] See, Ibid, p 3.
[45] Ibid, p.p. 3 – 5.

These trends are reflected across all states and regions within states to various degrees. The also impact on both usage and peak demand. For example, AEMO forecast maximum summer demand in NSW to be stable across the period 2016-17 to 2035-36.[46]

CCP9 recommends that TransGrid's overall forecasts of overall electricity usage and demand is accepted by the AER.

Powering Sydney Future (PSF) - TransGrid forecast of Sydney CBD demand

Unlike NSW demand in general, TransGrid forecasts an increase in demand in the Inner Sydney area is forecast to experience an increase in peak demand. In turn the forecast of an increasing demand in turn, influences the timing and scope of the PSF project.

TransGrid notes, for instance, the increase in summer peak demand since 2014 with particular reference to the peak demand observed in the Sydney CBD on 10 February 2017.

Figure B.5.3.3 above illustrates the trends in Sydney CBD peak demand from 2010, including the inflection point in 2014 where the decline in peak demand appears to have turned around.

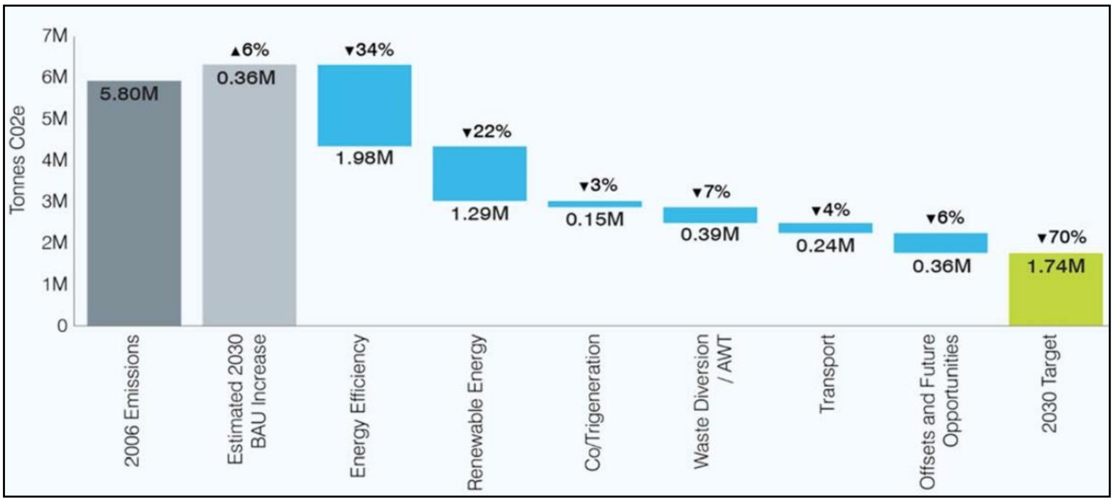
TransGrid claims that the actual peak demand in 2017 indicates that peak demand over the next 10 years is more likely to follow the high trajectory forecast as illustrated in Figure B.5.3.3. Moreover, TransGrid considers the high trajectory forecast is more consistent with their expectations for continued growth in the CBD.   In its recent RIT-T PADR document (May 2017) [47], TransGrid states:[48]

> Customer demand in the Inner Sydney area continues to increase due to renewed economic activity. This is evident in the Summer 2016/17 peak demand, committed new customer connections and anticipated customer connections. Figure 1.2 shows the historical peak demand for Inner Sydney and the forecast for the next 10 years. Of particular note is the actual demand that occurred on 10 February 2017, which was in line with the high forecast.

CCP 9 has reviewed the SCC's plans for greenhouse gas (GHG) emissions reductions for the period up to 2030. We have sought advise from TransGrid on how it reconciles its views on demand growth with the SCC's plans. In its recent report, SCC set out the following expected reductions over the 2006 emissions baseline.

[46] See Ibid, Table 1, p. 6.
[47] TransGrid, RIT-T: Project Assessment Draft Report, Powering Sydney's Future, May 2017.
[48] Ibid, p. 14

Figure B.5.3.4: Sydney LGA, GHG emissions target. Estimated contribution of initiatives.



Source: City of Sydney, Green Environmental Sustainability Progress Report, July to December 2016, Chart 4, p. 17.

While it is recognised that some measures will not have a direct impact on the electricity peak demand in the Inner Sydney area, it is clear that there is a commitment to a substantial reduction through sustainable energy efficiency programs. CCP9's conversations with the SCC also reinforced SCC's commitment to the program. For instance, SCC cited the following:

- SCC has had substantial success to date in reducing both their own and the city emissions. While the new targets are 'challenging' they are 'realistic; and 'achievable';
    - SCC has brought in considerable expertise to ensure that the targets/projects are achievable;
    - SCC has been working with developers et al to encourage energy efficiency and will continue to do so;
    - the City has increased its staff dedicated to ensuring the achievement of the GHG targets;
    - SCC continues to identify sites suitable for local generation.
- Large scale developments such as Barangaroo have focussed intensively on reducing energy demand, while other developers have indicated substantial emphasis on improved building energy efficiency.
- SCC's own research has indicated that there are clear limits to growth in the CBD and surrounds (e.g due to geology and aircraft flight paths), and that there is a move by developers towards quality rather than quantity in the high value CBD;
- There are also ongoing retrofits of existing buildings in the CBD which include improvements in energy efficiency (e.g. through installation of more efficient cooling systems)
- Energy prices have reduced from their peak, however, it is generally expected that that wholesale prices will increase over the period providing additional incentives for efficiency and local generation.

It is important to add that in identifying its commitment to its Sustainability plan, SCC made clear its concerns that the safety and security of supply to Inner Sydney was vital. The SCC recognises that the

PSF project needs to go ahead in some form to secure future supplies but is also concerned that the project is designed in a way that reduces the risk of over investment in assets that will be paid for by current and future users for many years. SCC is also concerned that overbuilding of network assets will result in 'crowding out' future demand management projects for many years.

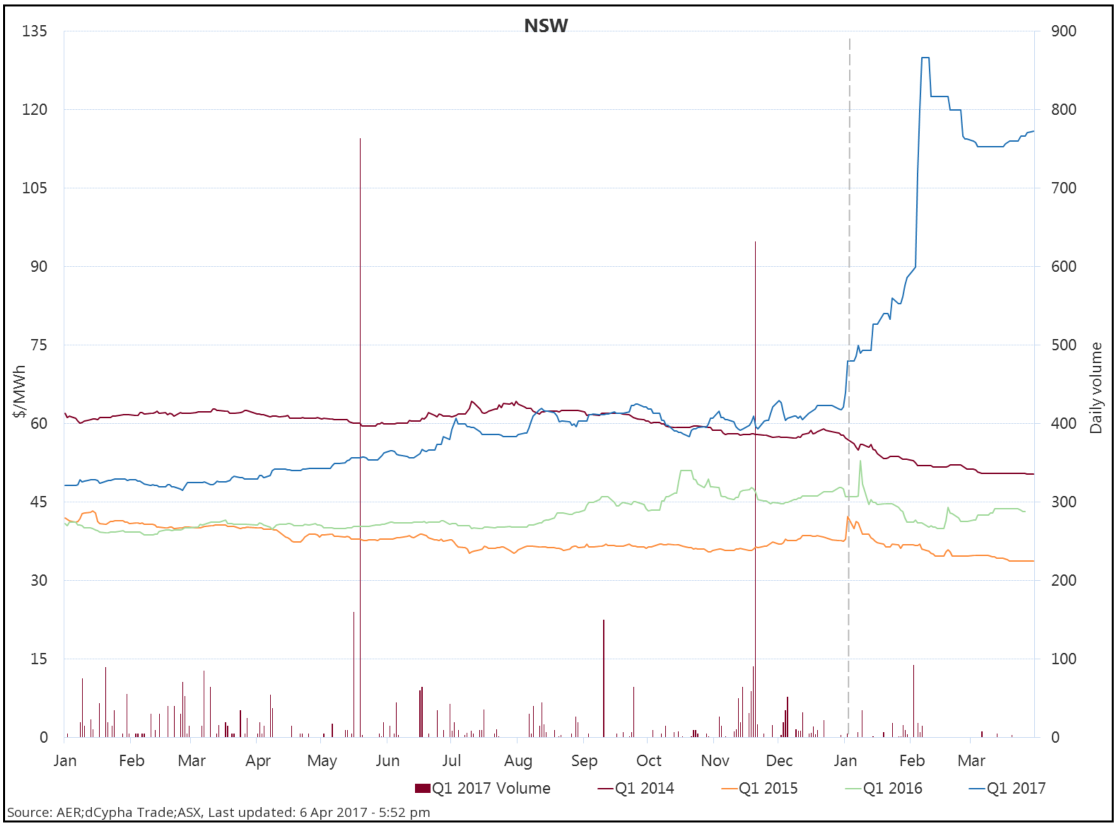
CCP 9 concurs with the trends identified by SCC and others. In particular, it is essential that TransGrid's forecast of demand does not just rely on some 'trend' observed in the last few years without assessing the basis for these changes and without any significant acknowledgment of the other factors that constrain the trend (such as limits to growth) or even reverse the trend (sustainability projects, price impacts etc).

CCP 9 notes the recent significant increases in wholesale electricity prices (and gas prices) that will over time flow through to energy consumers heightening their concerns for greater efficiency. For instance, Figure B.5.3.5 illustrates the increase in daily base contract prices for NSW, indicating substantial increases for 2017 Q1 contract prices compared to Q1 14, 15 and 16. Base future prices have also increased substantially (see AER website for further details).

Given the dynamics of the wholesale electricity and gas energy markets at this stage, it is likely that wholesale electricity prices will remain above prices prevailing in the Q1 2014-Q1 2016 period for some time. It is also not clear if distribution network prices will also increase over the next five years.[49]

[49] For instance, the outcome of the NSW networks appeal to the Australian Competition Tribunal and the AER's counter appeal to the Federal Court is not yet known but may have a significant impact on distribution prices in the period 2018/19 to 2022/23.

Figure B.5.3.5: NSW daily base contract prices and traded volumes (Q1)



Source: AER, *Wholesale market statistics, daily base contract prices*, accessed 10 May 2017. https://www.aer.gov.au/wholesale-markets/wholesale-statistics/new-south-wales-daily-base-contract-prices-and-traded-volumes-q1

As a final comment on the demand forecast, CCP9 understands that TransGrid's forecast of Inner City peak demand relies on the forecasts provided by Ausgrid of demand at bulk supply points. CCP9 does not have sufficient information to evaluate these forecasts but is concerned that in general, such 'bottom up' engineering forecasts tend to overstate demand in the future and fail to pay sufficient heed to factors that might mitigate growth over the regulatory period and beyond. It is important that such bottom up forecasts are tested against the overall forecasts of demand which are considerably more stable (notwithstanding forecasts of significant growth in the economy and population).

To the extent there is wide uncertainty in the published forecasts, CCP 9 believes there is opportunity to further explore non-network solutions that would reduce the long term exposure of consumers to redundant assets and effectively limit opportunities for commercially viable future non-network solutions. In saying this, CCP9 reiterates that we do not oppose the project per se and recognise the issues facing TransGrid in ensuring a safe and secure supply to inner Sydney.

CCP 9's concerns relate more to the size and timing of the project, and the extent to which the value of non-network options is appropriately considered.

CCP 9 recommends that the AER:

1. seek further information from TransGrid on how they have critically reviewed Ausgrid's bulk supply point forecasts, and considered these forecasts in the light of the publicly available and committed plans of bodies such as the SCC.
2. ensure that TransGrid's RIT-T proposal for PSF project adequately considers the risks in demand forecast and the opportunities for non-network solutions to meet the peak requirements
3. undertake an independent review of the forecasts taking into account the multiple programs, including the SCC program to improve energy efficiency for both new and existing buildings and infrastructure.

Assumptions on expected reliability and its costs

One of the key elements in network planning is the reliability standard that the network is required to meet and the value of customer reliability (VCR).

Under TransGrid's licence it must ensure complies with any reliability and performance standards issued by the Minister for the transmission system and IPART the economic advisor in regard to the standards. In 2015-16 IPART undertook a review of reliability standards and recommended standards based on two elements – the N-1 and N-2 standards and a probability of unserved energy to be used as a planning standard. For the inner Sydney area it set the expected unserved energy standard at 0.6 minutes p.a. at average demand based on a VCR of $90/kWh which was significantly higher than the AEMO average value for NSW of $34.15. Importantly IPART emphasised that non-network options were and equally valid means of achieving the reliability standards.

One of the key issues for the review and IPART had engaged Parsons Brinckerhoff (PB) to undertake a VCR study. The PB study estimated the VCR for TransGrid based on the AEMO values. They "found that there are several possible approaches to expressing VCRs for the transmission network. Firstly, VCR values are available from several sources. We found the information published by AEMO to be suitable as it grouped customers into 5 classifications – residential, commercial, industrial, agricultural and direct connected – that could be related to the transmission network." (p. iii). In their draft report, released on 31 May 2016, IPART noted some concerns with the AEMO estimates that were identified by the utilities and proposed that it should undertake estimation of the VCR in future. However, it adopted the PB recommendation that the AEMO values should be adopted for the determination of reliability standards in the current review.

On 9 September IPART published a report on the VCR by Houston Kemp (HK) that was commissioned by TransGrid. This report recommended that values that were significantly above the AEMO values be used in determining reliability standards for the inner metropolitan areas. HK was "engaged by TransGrid to determine **defensible** values of the Value of Customer Reliability (VCR) that can be applied to unserved energy estimates in both Sydney's CBD and Sydney's Inner Metropolitan (Inner Metro) areas, **drawing on existing, publicly available VCR estimates**." (p.1 emphasis added). The HK report was a re-interpretation of other results of other quantitative studies and did not provide new quantitative evidence. In reaching its judgements the HK report gave greater weight to an earlier Oakley Greenwood (OG) study. This study had also been reviewed by the PB report for IPART which concluded that "Whilst these values do not align with the AEMO values, we do not consider these values to provide any more certainty." (p.7)

The HK study adopts a mix of the OG study and AEMO results. It then scaled up those values on the basis of a qualitative assessment of factors that could mean that the estimated values may understate customers value of reliability. It should be noted that the PB report had set out other factors that could mean that the estimates overstate the value of reliability.

IPART subsequently adopted a VCR value of $90/kWh consistent with the Inner metropolitan value estimated by HoustonKemp rather than use the AEMO values. This was over twice the AEMO estimate for NSW. However, IPART adopted the inner metropolitan value for the CBD as well as the inner metropolitan area and this value was around half of the HK estimate for the CBD. IPART also noted that there could be other areas where it may consider a VCR above the AEMO value would be more appropriate.

CCP 9 has significant concerns about the decision to significantly increase the VCR for the inner metropolitan area. In reaching its decision IPART considered that the increase in VCR would not have a significant impacts on costs for customers because the current performance of the network was well within the resulting USE of 0.6 minutes p.a.. However, we support the ENA's view[50] that:

1. there should be a 'nationally consistent framework for transmission reliability standards and a robust methodology in measuring the VCR'
2. Estimating the VCR 'requires an adequately resourced, expert body with the commitment of funding to develop and update robust measures'
3. The estimation of VCR by state agencies with broader responsibilities and less specific expertise 'is unlikely to be efficient or to expedite the development of a robust nationally comparable framework for VCR'

In this case, the AEMO value was arrived at through substantial research on the values customers placed on reliability. While not disaggregated by region, the AEMO values were disaggregated by type of customer. The AEMO research and values were subsequently reviewed by PB who supported the use of these values. While it is acknowledged that HK was specifically asked to review the VCR for the Sydney CBD and inner metropolitan, it was essentially a review and reinterpretation of the research undertaken by others, rather than the result of new research on customer values of reliability.

TransGrid has stated that the increased reliability standard has not affected high-level decision on the PSF given the asset retirements planned and the forecast growth in demand. However, the specific impact of the change on the detailed design and staging of the options, and the opportunity for non-network options, is not clear. Furthermore, TransGrid and Ausgrid have assumed higher values for the VCR in its planning for PSF. The central estimates use a value of $170 for the for the CBD, based on the HK study. In its review of the VCR IPART had considered the evidence from the HK report and whether the higher rate proposed for the CBD should be used. Having considered this, it decided that a value of $90/kWh was applicable to both the inner metropolitan area and the CBD and set the reliability standards on this basis. CCP 9 endorses the view that NSPs should be able to recover the costs of meeting legal obligations and standards and notes that the STPIS already provides an incentive to improve service performance. However, proposals to use higher standards than required for network planning should be very closely reviewed, with the presumption that the

[50] ENA, Submission to [IPART's] Electricity Transmission Reliability Standards: and Economic Assessment Draft Report, July 2016, p1

planning should be based on the reliability standards set and determined separately. In this case the evidence used to support the VCR was already considered and not adopted in the setting of the reliability standard.

CCP 9 recommends that the AER should review the VCR assumptions used in the PSF with the presumption that the VCR should be based on the applicable reliability standards. Furthermore, the AER should carefully monitor and participate in future jurisdictional reviews of reliability standards.

Customer engagement on PSF

CCP9 has identified a number of issues relevant to customer engagement processes in the RIT-T process in general, and the PSF project in particular.

Our observations on the customer engagement process for the PSF RIT-T are necessarily limited. Moreover, we appreciate that TransGrid has undertaken a number of initiatives in this area that go beyond the strict requirements for consultation in the RIT-T process.

Nevertheless, the PSF is a major component of TransGrid's revenue proposal for 2017/18 -2022/23 and, therefore, CCP9 considers it appropriate to make some comment on our observations to date.

CCP9 has received feedback that raised some concerns with the RIT-T process for the PSF and we will pursue these further with TransGrid and other stakeholders over the coming months. In summary, these concerns relate to the following comments/observations made by stakeholders about both the PSF CE program and the project itself:[51]

- that the 2016-17 consultation process, particularly with potential providers of non-network solutions, was not as robust as the process conducted in 2014 when the PSF project was first mooted by TransGrid;
- TransGrid did not appear to be as interested in exploring non-network options or explaining its preferred options. Rather, TransGrid appeared to be focussed on a 'need for a solution' rather than 'nurturing' demand management (DM) options;
- TransGrid did not seem committed to growing DM, nor to exploring with stakeholders other solutions that might 'fill the gap' with less risk to future excess capacity and long term costs to consumers;
- TransGrid seemed to be seeking non-network solutions that provided guaranteed supply for 6 months of the year for 12 hours of the day – this appeared to be overly restrictive and limit non-network/DM options designed to address peak demand spikes;
- TransGrid has not properly considered the option that demand growth from 2014 to summer 2017 would stabilise given the multiple projects to improve efficiency and sustainability
- Similarly, TransGrid has not taken account of the increase in wholesale prices since 2016 when they were at historic lows

CCP 9 recommends that the AER consider the consumer and stakeholder engagement process conducted by TransGrid for the PSF RIT-T to determine if there is appropriate consultation on the forecasts and potential non-network options.

[51] To be clear, the comments from stakeholders on TransGrid's CE are specific to the PSF RIT-T project and not necessarily to the overall CE program associated with the regulatory proposal. In addition, CCP 9 has not had the opportunity to independently validate these claim and welcome further clarification from TransGrid on these views particularly with respect to such matters ad the 6 months/12 hours per day restriction.

Opportunities for non-network options

The ENA Roadmap sets out a vision for the future in which there is a rapid increase in distributed resources and increasing contracting for network support services. AEMO is projecting a substantial increase in the take-up of battery storage from the early 2020's which will also significantly change the economics of distributed renewable generation and the capacity to provide network support. The ENA roadmap envisages that by 2027 the networks will pay distributed resources $1.1b for network support. The most efficient use of these resources (and achieve the most efficient provision of energy services) would see the greatest penetration of distributed resources, and contracting for network support, in areas of the highest need for network investment – such as Sydney's inner metropolitan areas.

As part of the PSF TransGrid and Ausgrid sought and evaluated non-network proposals. This is reported in the PADR released in May 2017. CCP 9 has not had sufficient time to review the process for seeking non-network options and the assessment of the proposals received in preparing this submission. However, the level of non-network response by 2022-23 of 40MW and spending on non-network payments of $7-10m, appears low relative to the expectations for 2027 under the ENA roadmap.[52]

This is a critical project in defining the future role of non-network options. Therefore it is important that the process for seeking these options and their assessment is subject to extensive testing and review.

In this context we note that TransGrid considers that "requirements for a viable non-network solution for a replacement project can be different to that of a project driven by incremental demand growth. Typically, non-network solutions for incremental growth offer network support to supplement the available network capacity for the 30-50 hours per year in summer (or winter) when electricity demand reaches peak."[53] However, one of the drivers for the PSF is the forecast growth in demand.

TransGrid also states that "To maintain customer supply in the event of a failure of a network element, non-network support would be required to cover up to an 8 week disruption while repairs are completed. As demand for electricity peaks in summer, network support would be required for the 3 month period from December to February when the majority of energy at risk occurs. During this period, network support would be required for up to 12 hours per day from 8am to 8pm."[54] An important question is whether this requirement is too onerous.

The overarching issue is how the proposed planning process factors in, and responds to the anticipated changes in the sector and the implications of this for the current investment and future utilisation of these assets. Options of staging investment and increased use of non-network options can increase the agility to deal with these changes. For example, if greater use of non-network options could allow the investment to be further staged or deferred by 2-3 years instead of 1 year the decisions could then incorporate new information on:

1. Whether the recent increase in demand is going to continue or not

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[52] TransGrid, *RIT-T Project Assessment Draft Report, Powering Sydney's Future*, May 2017, p35
[53] TransGrid, *RIT-T Project Assessment Draft Report, Powering Sydney's Future*, May 2017, p.27
[54] TransGrid, *RIT-T Project Assessment Draft Report, Powering Sydney's Future*, May 2017, p.28

2. New information on the changing economics of new technologies such as battery storage and the economics of distributed resources.
3. Experience with contracting for non-network options and experiencing with risks on a portfolio basis rather than individual project basis.

CCP 9 recommends that the AER closely review the assessment of the non-network opportunities and consult widely, especially with potential providers of non-network options, in undertaking this review.

B.3.3 Recommendations:

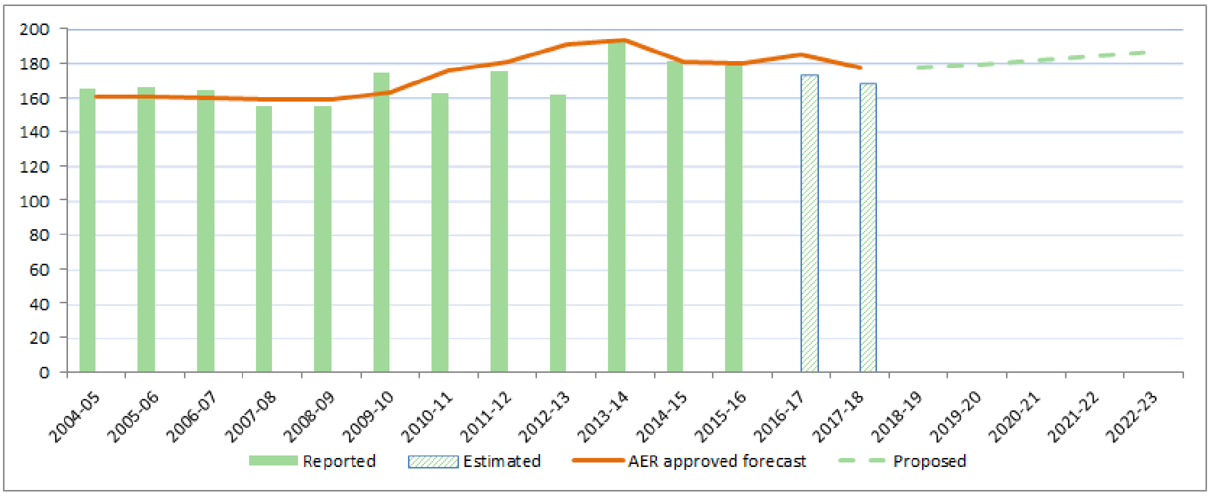
a) There is a role for the AER, working in collaboration with the NSPs, ENA, and stakeholders to provide further guidance on the role of, and techniques for, scenario analysis and option values in long term capex planning to reduce the risk of stranded assets being borne by consumers.
b) In assessing the proposed replacement capex can be considered *prudent* the AER should test the sensitivity of key assumptions in TransGrid's risk-based capex model to assess if the scale of the program (the proposed REPEX of $961m).
c) AER should clarify the likely impact of the rule change to apply the RIT-T to REPEX as part of the Draft Determination.
d) If generation-based contingent projects are proposed, the triggers should include provision for review if there is a review of the arrangements for pricing of access for generators.
e) The AER should present impacts on revenues and prices both 'with' and 'without' contingent projects included in the draft and final determinations.
f) The AER should accept TransGrid's overall forecasts of overall electricity usage and demand.
g) The AER should seek further information from TransGrid on how they have critically reviewed Ausgrid's bulk supply point forecasts, and considered these forecasts in the light of the publicly available and committed plans of bodies such as the SCC.
h) The AER should ensure that TransGrid's RIT-T proposal for PSF project adequately considers the risks in demand forecast and the opportunities for non-network solutions to meet the peak requirements.
i) The AER undertake an independent review of the forecasts taking into account the multiple programs, including the SCC program to improve energy efficiency for both new and existing buildings and infrastructure
j) The AER should review the VCR assumptions used in the PSF with the presumption that the VCR should be based on the applicable reliability standards. Furthermore, the AER should carefully monitor and participate in future jurisdictional reviews of reliability standards.
k) The AER should consider the consumer and stakeholder engagement process conducted by TransGrid for the PSF RIT-T to determine if there is appropriate consultation on the forecasts and potential non-network options.
l) The AER should closely review the assessment of the non-network opportunities and consult widely, especially with potential providers of non-network options, in undertaking this review.

B.4 Operating Expenditure

B.4.1 TransGrid's Proposal

The chart below summarises the level and composition of the proposed opex in the current and next regulatory period.

Figure B.4.1 – TransGrid's Proposed Opex (in June 2018 $s)

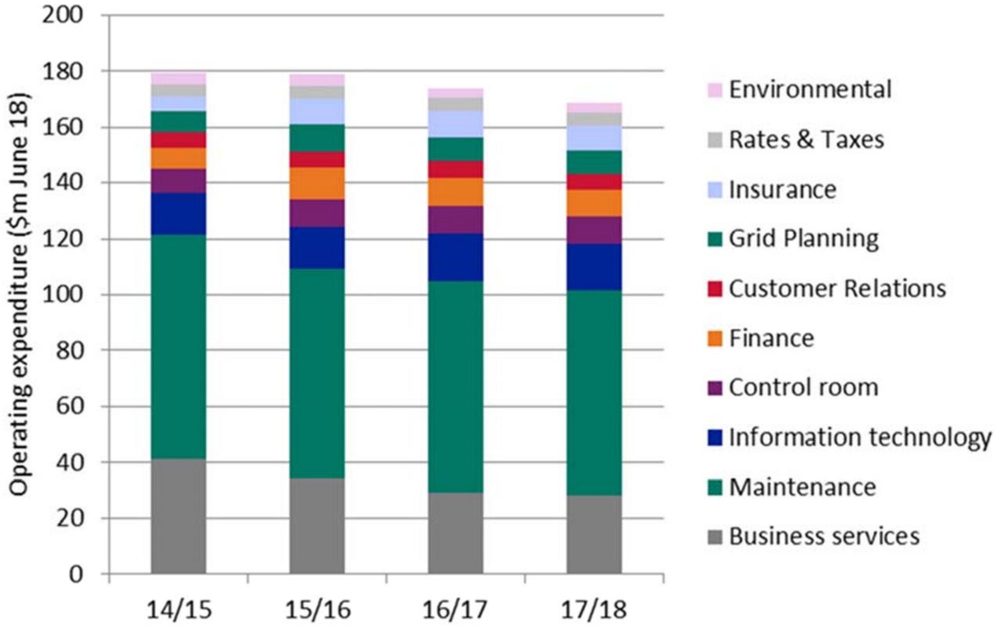


Source: AER, *Issues Paper: TransGrid's Electricity Transmission Revenue Proposal, 1 July 2018 – 30 June 2023,* March, 2017, p24

B.4.1.1 Opex in the current period

TransGrid expects to reduce its opex by 6% during the current regulatory period from $179m in 2015-15 to $168m in 2017-18. These reductions have been achieved primarily through efficiencies in maintenance and business services. TransGrid achieved a real reduction of spending on these services, which account for 2/3 of TransGrid's total expenditure, of $19m or 16%.

Figure B.4.2 TransGrid's Current Period Opex (in June 2018 $s)



Source: TransGrid, *Revenue Proposal 2018/19-2022/23,* January 2017, p152.

B.4.1.2 Projected Opex

In contrast to the steady real reduction in opex in the current period, TransGrid projects a real increase in opex of 11% from $168m in 2017-18 to $186m in 2022/23.

The factors contributing to the $19m increase in opex in this period are:

- a small amount of output growth. This increases the opex forecast in 2022/23 by $0.9 million ($June 2018).
- forecast labour price increases. This increases the opex forecast in 2022/23 by $9.7 million ($June 2018).
- Increased vegetation management costs[55]. This increases the opex forecast in 2022/23 by $7.5million ($June 2018).

TransGrid has allowed for a small scale factor in the allowance for output growth and a business efficiency adjustment to reflect cost savings in 2017-18, but has otherwise not included an explicit productivity adjustment.

B4.2 Assessment

In determining the opex allowances the AER:

1. Determines the TNSP's expenditure in the base year
2. Assesses the efficiency of the base year expenditure

[55] This cost increase and the increased debt servicing costs are step changes that have a similar impact on costs in each year of the period. Output growth and wage increases gradually add to costs through the period.

3. Determines the trend rate of change in costs. To do this the AER takes into account productivity trends, output growth, and specific price changes (e.g. changes in wage and salary costs)
4. Makes adjustments for step changes in costs and other costs not included in the base forecast.

B.4.2.1 Base year opex and EBSS

The starting point for the opex projections is the establishment of the base year Opex. The process for this set out in detail in the Expenditure Forecasting Guideline.[56] TransGrid has proposed a variation on this approach and the two approaches are summarised in the table below.

Figure B.4.3 Process for Establishing Base Year Opex

Step	Application of AER Approach	TransGrid Proposed Approach
Establish base year opex using latest year for which full audited data is available	Use audited opex for 2016-17 (subject to efficiency assessment)	***Same.***
Estimate Opex for the final year of the regulatory period as the basis for projections in the next period.	Estimate 2017-18 opex by adding: 1)the difference between the allowances for the 2016-17 and the 2017-18 to actual reported opex for the 2016-17 2) any non-recurrent efficiency gains (or losses) in the base year	Estimate 2017-18 opex by adding: 1)**the current estimate of the change in opex between 2016-17 and 2017-18.** 2) any non-recurrent efficiency gains (or losses) in the base **year – set at zero**
Estimate final year Opex for the EBSS	Estimate for 2017-18 opex for the calculation of the EBSS using the same methodology as above	Estimate for 2017-18 opex for the calculation of the EBSS **using the AER methodology.**

The objective is 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.

Given this the relevant questions are:

1. What would be the obligations on AER in reviewing the proposed change in costs between 2016-17 and 2017-18?
2. Is TransGrid's proposed approach likely to yield a better estimate of actual costs in 2017-18?
3. If so, should the same estimate of 2017-18 opex be used for the EBSS.
4. Will the incentives to reduce costs in 2017-18 and beyond be reduced?

A specific issue raised in the current case is the nature of the efficient gains in the base year and how this should be treated under either the AER approach or the approach proposed by TransGrid. As

[56] AER*, Expenditure Forecast Assessment Guideline for Electricity Transmission*, 2013, p24-5

Figure B.4.1 shows, the allowed opex increased in 2016-17 and then fell in 2017-18 to the trend value. This reflected the effect of the allowance for one-off cost in 2016-17. TransGrid's opex was in line the allowed opex for the first two years. In 2016-17 TransGrid is projected a further reduction in costs in line with the previous two years rather than a step change. This raises the question of the extent to which the efficiency gain in 2016-17 is a one-off efficiency gain due to the avoidance of the allowed one-off cost rather than an ongoing efficiency gain.

Review of cost changes projected for 2017-18

Under the AER approach the calculation of the 2017-18 costs from the 2016-17 costs is automatic except for the consideration of any non-recurrent efficiency gains (or losses) in the base year. Under the TransGrid's approach, 2017-18 opex would be estimated using the latest information on trends in unit costs, outputs and other relevant factors. Given that:

1. the assessment of the efficiency of current costs uses the base year costs rather than the 2017-18 opex, and
2. costs in the next regulatory period are calculated from the 2017-18 costs

there appears to be an opportunity for TransGrid to benefit from forecasting a larger increase in costs for 2017-18. Under this approach it will therefore be important for AER to carefully and critically review the escalation of costs under TransGrid's proposed approach.

Under the AER approach the AER has to consider whether the efficiency gains in 2016-17 are one-off gains or not in estimating the adjustment for 2017-18. In this case, key question would be whether the efficiency gain is due to the avoidance of the one-off cost. If so, it would appear to be a one-off efficiency gain that should be reversed out. While the TransGrid approach allows for the adjustment of one-off efficiency gains it is not clear how or when this would apply under its approach.

Overall, the AER's approach is administratively simpler and less burdensome.

Accuracy of estimate of 2017-18 costs

In principle, the TransGrid approach provides the opportunity to use more up-to-date information in estimation the change in costs in 2017-18. Given this, if the estimates are unbiased it should in principle yield more accurate estimates of the costs in 2017-18. This is important because under the methodology for calculating opex allowances, errors in the estimation of the opex in the final year of the previous period affect the allowed opex in each year of the following regulatory period. For example, if the rate of change of costs in 2017-18 was over-estimated by 200 basis points, the allowed opex in each of the following years would be higher than would otherwise have been determined by 200 basis points.

This should not affect the decision on whether to use a methodology that uses more recent data since the errors can go in either direction. But it does highlight the importance of carefully scrutinising the proposed adjustments.

In practice, the AER also allows the consideration of more recent information in regard to whether the efficiency gains in the base-year are one-off gains or not. In this current case, if the gains in 2016-17 are predominantly one-off efficiency gains there may be little difference in practice between the two options.

Basis of the estimates of the final year (2017-18) opex for the EBSS

TransGrid propose that the final year (2017-18) opex should still be estimated using the current (AER) approach to projecting the 2017-18 opex for the EBSS calculations. TransGrid commissioned advice from Frontier Economics who were asked to examine "whether it would be 'functionally correct' to use the alternative methodology raised by TransGrid for forecasting opex in the following RCP while continuing to use the existing methodology for final year estimation (i.e. final year expenditure estimate = final year allowance - base year underspend) for the EBSS calculation." [57]

Frontier Economics were not asked to consider whether, if the approach to forecasting opex for the final year was changed for the purposes of calculating the opex in the next regulatory period, that same approach should also be used for the estimation of the final year costs for the EBSS. In principle, it would seem that it should and that this would reduce the potential for distortions arising from the mismatch between the final costs used for the two purposes. Under the approach proposed by TransGrid an estimate of the final year opex that it considers to be an inferior estimate 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).

Impact on incentives

Frontier Economic's report presented examples that examined the potential impacts on revenues in the next regulatory period and the cash flows for the TNSP under various scenarios including:

- the impact of the alternative methods of forecasting final year opex
- impacts of bring forward or deferring expenditure under the alternative forecasting methods
- impacts of increasing actual base year opex under the alternative forecasting methods.

From this Frontier concluded that "use of the alternative opex forecasting methodology alongside the existing EBSS formula would not, by comparison to the use of the AER's existing methodology (the 'Base case'), create perverse incentives for TNSPs to engage in inefficient behaviours, such as:

- Unnecessarily increasing opex in the base year ('Boost base year opex') or
- Unnecessarily bringing-forward opex from the year following the base year into the base year ('Bring-forward opex')."[58]

However, the scenarios do not appear to include scenarios where the forecast increase in costs in the final year is over-estimated or under-estimated relative to actual costs incurred in that year and in the subsequent period. It would seem likely that this would show an incentive to err on the side of lower rather than higher forecasts, while retaining the incentive to pursue efficiencies in actual opex.

CCP 9 considers that 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. 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 onto account the impacts on the EBSS.

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[57] TransGrid, *Revenue Proposal 2018/19-2022/23,* January 2017, Appendix J: Frontier Economics, Prescribed operating expenditure forecast starting point p1.

[58] TransGrid, *Revenue Proposal 2018/19-2022/23,* January 2017, Appendix J: Frontier Economics, Prescribed operating expenditure forecast starting point p16

B.4.2.2 Assessment of efficiency of base year opex

In its expenditure forecasting guideline the AER indicating its preference to adopt the 'revealed cost' approach to assessing base opex. "If actual expenditure in the base year reasonably reflects the opex criteria, we [AER] will set base opex equal to actual expenditure for those cost categories forecast using the revealed cost approach."[59] In commenting on the draft guideline users proposed caution in adopting the revealed cost approach. For example, UnitingCare Australia expressed "concerns about the interpretation of revealed cost as the process for determining base OPEX, specifically with regard to interpretations of efficiency of current expenditure."[60]

However, CCP 9 accepts that it may be reasonable for the AER to conclude that it does not have sufficient evidence to conclude that TransGrid's base year opex is materially inefficient given:

1. AER accepted that TransGrid's base year opex for the current determination was efficient
2. TransGrid forecasts that its opex in the current period will be below the target set by AER
3. The available benchmarking data is not conclusive but provides some evidence that TransGrid's performance is comparable to, or better, than its peers.

Benchmarking TNSPs is more difficult than benchmarking DNSPs due to the limited data set. However, TransGrid generally performs well the measure of opex partial productivity and some of the opex KPI's used by AER. TransGrid also cites several other industry studies of operating cost performance to provide further evidence that TransGrid is efficient.

CCP 9 recognises that benchmarking is difficult, especially for TNSPs where there are fewer comparators. In assessing the information value of benchmarking studies we consider that the transparency of the data and models and replicability of the analysis are important. In the absence of this, it is difficult to assess the strengths and weakness of the benchmarking and the value of the results. We encourage the AER to continue benchmarking TNSPs, and further developing its multi-factor productivity and partial productivity measures. All benchmarking has its flaws in terms of data quality, limited peer comparators, and incomplete models. The advantage of the AER's benchmarking is its transparency and replicability. The AERs benchmarking has been subject to rigorous review and critiques by stakeholders and legal review. Inevitably this has identified some weaknesses but this does not mean it does not have value when used in conjunction with other information. Furthermore, such public review help AER continue to improve its benchmarking.

B.4.2.3 Productivity trends

In its expenditure forecasting guideline the AER proposed to consider the following in assessing forecast productivity:

In its proposal TransGrid has incorporate a small scale factor in allowing for output growth. In its view:

1. it has incorporated all efficiency gains achieved, or expected to be achieved, in the current period in the base opex

[59] AER*, Expenditure Forecast Assessment Guideline for Electricity Transmission*, 2013, p24
[60] UnitingCare Australia, *Submission on Draft EFA Guideline*, 2013, p3
AER*, Expenditure Forecast Assessment Guideline for Electricity Transmission*, 2013, p24

2. there are limited future opex savings that it can identify, give the efficiencies built into the base opex
3. measures of productivity improvement in the sector, or more broadly defined industry groups, support an assumption of zero or negative productivity change

CCP 9 understands that the underlying principle of incentive-based regulation is the utility should be given strong incentives to reveal its efficient costs. This can be argued to reduce the importance of assessing the scope for trend improvements in efficiency since the benefits will be passed on to consumers at the next regulatory period. However, CCP 9 considers that it is important that the allowed opex costs reflect the estimated efficient costs of providing services through the regulatory period, not just in the first year. This is also consistent with the obligations on the AER under the NER which do not limit the requirement to consider efficient costs to the first year of the regulatory period.[61]

Other than the small scale factor, TransGrid assumes zero productivity improvement in the next regulatory period. As members of TransGrid's Advisory Council argued, unregulated businesses are under continuous pressure to pursue productivity improvements to remain competitive and it is reasonable that the regulator should place the same discipline on TransGrid. CCP 9 considers that this is a practical and reasonable expectation.

CCP 9 also considers that past trends in real opex, opex/MWh or opex/MW, or other business-focussed KPI's provide relevant information about the scope for future achievable trends in opex. It would be reasonable, and consistent with good business practice, if such trends were used to challenge forecast of future costs. The reductions in real opex achieved by TransGrid did not represent catch-up efficiencies, as TransGrid was considered to already efficient. They were the outcome of TransGrid's continuous efforts to improve its efficiency and reduce costs through for example better risk-based systems to improve asset planning and management and improvements in business services. It is reasonable to expect that such continuous improvements will continue in the next period.

In essence, past trends in real opex have information value in projecting future trends and should be considered alongside other more complex measures such as estimates of total factor productivity or partial factor productivity in the sector and the economy more broadly. While a simpler measure, trends in real opex/MWh are also a measure of historical productivity performance and the consideration of these trends use would be consistent with the AER's Expenditure Forecasting Guideline.

In proposing a zero productivity assumption TransGrid has cited:

1. The Productivity Commissions estimates which show a reduction in productivity of the electricity, gas, water and waste (EGWW) services over the period from 1989-90 to 2014-15 of 1.2%
2. As study on Productivity in NSW by David Buckland & Harley Smith, NSW Trade & Investment, published 18 September 2014 which estimated a decline in NSW utility productivity of approximately -1.86% p.a. between 1995 and 2013 using a multi factor productivity measure.

[61] NER, clauses 6A.6.6(c), 6A.6.7(c).

The difficulty such studies have in measuring productivity is in properly accounting for outputs. The utility sectors are characterised by large, lumpy investment that provide capacity for future customers as well as current customers and improve the reliability/quality of services. Examples of this are large transmission augmentation projects and desalination plants. Studies such as these find it difficult to incorporate these components of outputs in the analysis. This can be seen in the difference between the results for the EGWW sector between the period up to 1999 and the period post 1999 when there was a substantial increase in investment to increase capacity and replace ageing assets (i.e. provide service for future customers) and improve the reliability of services (i.e. improve quality). Mining shares the characteristics of lumpy investment for future capacity and the Productivity Commission estimates for the mining sector show a similar pattern of a significant decline in measured productivity when the sector was investing heavily in future capacity.[62]

TransGrid also notes the decline in productivity in the DNSPs of 1.8% p.a. in AER's benchmarking of the distribution networks and indicates that it considers greater weight should be given to this study than the comparable TNSP study, citing a critiques of the study from Frontier Economics. It should be noted that similar criticisms have been made of the DNSP study. That said, CCP 9 considers that:

1. The AERs productivity studies were undertaken in a thorough professional manner using models and estimation techniques consistent with good practice.
2. Questions of the reliability of data have been raised but the studies used the best available dataset for the Australian networks and in the case of the DNSPs the decision to include some overseas data and its manner of incorporation was also consistent with good practice
3. Alternative models, data choices and estimation techniques can be used but the choices made were neither biased nor outside good practice.

In summary, we are not convinced that the criticisms of the TNSP study are substantially different from those that have been made of the DNSP study, nor so severe as to justify no weight being given to the information. Given this we consider that the TNSP productivity analysis is more relevant to TransGrid than the DNSP study and should be given some weight. We also consider that AER should give weight to historic trends in real opex and real opex/MWh in assessing future trends in opex.

B.4.2.4 Step changes: Vegetation management

TransGrid has proposed additional costs of $37m over the period to 2022-23 due to increased vegetation management related to trees outside its easement that could affect its lines. TransGrid has stated that this is a new obligation resulting from a clearer statement of its obligations under existing safety regulations.

In principle, the TNSP should be able to recover the efficient costs of meeting legally binding obligations and regulations. That said, customers can be reasonably concerned that state-based regulations and licence conditions should not add to the costs of electricity supply unnecessarily.

We have not been able to review this proposed additional cost in detail but it is important that before the request for a step change in costs is accepted:

- The current obligations and how this new obligation arose are clarified. If it is to be accepted as a step change TransGrid should demonstrate that it is a legally binding obligation.

[62] Another factor in the decline in mining productivity was probably an increase in output from existing marginal (i.e. less efficient) mines.

- The proposed expenditure should be the most efficient means of meeting the obligation.
- Potential savings to current costs are identified and taken into account. This requires the consequences of the costs currently incurred because vegetation outside the easements are not managed. How does TransGrid currently manage this risk (e.g. does it currently undertake any vegetation management outside its easement, or incur insurance costs related to this risk)? If vegetation management is undertaken outside easements at present, has the cost of this been offset against the new obligation? Have incidents with trees outside the easements caused interruptions to supply and/or additional network maintenance and management costs?

The information asymmetry between the networks and the regulator and the even greater information asymmetry between the networks and other stakeholders create a significant risk of asymmetry in the allowances for step changes. Changes in that increase costs are more likely to be identified by the utility than the regulator or other stakeholders are likely/capable of identifying changes that reduce costs. For this reason CCP 9 believes that it is important that the AER maintain a stringent test for accepting step changes and the standards for quantifying the net impact of changes.

Recommendations:

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 onto account the impacts on the EBSS.
c) In reviewing TransGrid's proposed opex, AER should include consideration of past trends in real opex and opex/MWh in determining the trends in TransGrid's future efficient costs. This would support 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.

B.5 Rate of Return and Tax

B.5.1 TransGrid's Proposal

TransGrid proposes a weighted average cost of capital of 6.6% (nominal, vanilla WACC), estimated through an approach that, except for the MRP, is consistent with the AER's most recent application of its rate of return guideline.

- Risk-free rate – 2.24%. This is based on the current yield on 10-year Commonwealth Government bonds.
- Beta – 0.7. TransGrid cites evidence increase in estimates of the beta using more recent shorter period estimates of the beta, but has adopted the same value used by the AER.
- MRP – 7.5%. This is based on estimates of the long-term average realised MRP, and estimates based on the Dividend Growth Model (DGM) using current market data and consideration of other information. However, this is higher than the MRP of 6.5% used by the AER in its most recent decisions.
- Return on equity – 7.49%.

- Return on Debt – 6.01%. TransGrid adopted the transition to the long-term trailing average and estimated the cost of debt based on the risk-free rate (see above) and the debt premium based on an average of the RBA and Bloomberg estimates for BBB-rated corporate bonds. The return on debt is to be adjusted annually based on the latest data.

TransGrid estimated tax payments over the regulatory period consistent with the requirements of 6A.6.4 of the National Electricity Rules and methodology for determining the taxable income under the Post-Tax Revenue. This yields an average estimated corporate tax payments of $66m p.a.. TransGrid has then applied a gamma of 0.25, rather than the gamma of 0.4 established in the rate of return guidelines and used by the AER. This results in an average net cost of tax (after allowance for imputation credits of $50m p.a., an increase of $20.3m on the average for the current regulatory period.

B.5.2 Assessment

As TransGrid point out the NEL and NER require that the allowed rate of return:

- Provides investors with the opportunity to earn a fair return on investment and that this is consistent with the long term interest of consumers.
- Is determined with reference to a benchmark efficient entity.
- Is determined having regard to all relevant evidence.

The test for the fair rate of return is the reasonable long term expectations of investors. The challenge for the AER is that these expectations cannot be observed directly – they must be inferred from a range of data and models that are to varying degrees imperfect and incomplete. Furthermore, the relevant expectations are the **long-term** expectation of investors. As the debate around the appropriate maturity of debt has highlighted, the long term expectations extend beyond the length of the regulatory period. CCP 9 does not assume that long-term expectations are fixed. But in considering the implications of short term movements in data and the outcomes of models that attempt to estimate the long-term expectations for the rate of return, the AER has to attempt to discern what is the effect of 'noise' from short term market movements and what is an underlying change in long-term expectations of the rate of return.

The AER's approach to the determination of the return on equity provides a structured framework for the consideration of a wide range of information. Some information is given greater weight – e.g the AER's foundation model with a stable MRP. Other information – such as the estimates of the return on equity and the implied Market Risk Premium – is given less weight. Some information – such as the theoretical implications of the Black CAPM – is considered qualitatively. The weight given to the various 'bits' of information is based on an assessment of the quality of the information. This approach is quite transparent and is set out in detail the AER Rate of Return Guideline. The approach has been further clarified in the worked example in the Rate of Return Guideline and in subsequent decisions. It is clear from the guidelines and subsequent decisions that the AER has given greater weight to the long term historic average for the MRP than the most recent implied estimates from the DGM. In each these decisions the AER has considered the question of the market risk premium and return on equity and whether an adjustment (other than an updating of the risk-free rate) is required in light of the most recent relevant information, including up-dated estimates of the market risk premium using the DGM. Having considered this information the AER has maintained its estimate of the MRP at 6.5%.

Overall CCP 9 supports the AER's approach and the relatively greater weight it has given to the historical realised MRP in framing investor expectations for the future. Rather than restate the arguments already put by the AER and its advisors on this, we propose to review the case made by TransGrid for an increase in the MRP.

B.5.2.1 MRP and the Return on Equity

TransGrid proposes an increase in the MRP from 6.5% to 7.5%. In so doing it draws heavily upon the report by Frontier Economics which concluded that:

> In summary, we have identified the considerations that the AER applied when selecting its Guideline MRP of 6.5%. If we apply those same sorts of considerations to the current evidence that the AER has compiled, the result is an estimate of approximately 7.5%.
>
> An allowed MRP of 7.5% is an outcome that lies between:
>
> − The view that the MRP is constant over all market conditions such that the required return on equity rises and falls one-for-one with changes in the risk-free rate; and
>
> − The view that the required return on equity has remained stable over the period since the Guideline.
>
> In our [Frontier Economics] view, 7.5% is a reasonable estimate of the MRP in light of the weight of evidence set out above – which supports the notion that the required return on equity has not declined materially since the Guideline.[63]

In identifying 'the considerations that the AER applied when selecting its Guideline MRP of 6.5%" Frontier Economics appears to have taken a more mechanical approach to the consideration of the range between the long-term average MRP and the DGM estimates of the MRP than the AER did in its Rate of Return Guideline (including the worked example) and the subsequent decisions of the AER.[64] That said, TransGrid's proposal for an increase in the MRP has to be considered on its merits and in a manner consistent with the Rate of Return Guideline.

CCP-9 has focused on four questions in considering this:

1. Is there evidence that decisions on the RoE using the current approach have not met the NEO and Allowed Rate of Return Objective (ARORO)?
2. Is there evidence supporting a reduction in the required expected RoE since 2013?
3. Do investment fundamentals and market evidence to support a widening risk premium between returns on equity investments and the risk-free rate?
4. Do the DGM estimates appear anomalous or biased?

Is there evidence that decisions under the current approach have not met the NEO and Allowed Rate of Return Objective

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:

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[63] TransGrid, *Revenue Proposal 2018/19-2022/23,* January 2017, p181

[64] See the discussion citing of ranges and mid-points between ranges cited at *Revenue Proposal 2018/19-2022/23,* January 2017, p180.

- Acquisition values do not support the view that the allowed rate of return 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
- Existing investors do not appear to be seeking, on balance, to reduce their exposure to the sector.

Acquisition values

The two most recent electricity network transactions are the long term leases of the TransGrid (2015) and AusGrid (2016) networks where the winning bidders paid 1.6 and 1.4, respectively times the RAB. These multiples are significantly above the RAB multiples commonly seen internationally (see discussion below). The multiples are also above the RAB multiple of 1.15 paid for the Sydney Desalination Plant.

It cannot be assumed that a premium above or below the RAB value indicates that the allowed rate of return is above or below the investors required rate of return. There can be many other factors. In the case of TransGrid, the consortium stated that "the quality of the TransGrid network, the stable regulated operating environment and the consortium's ability to run the network more efficiently made the deal compelling. The consortium is betting TransGrid's two unregulated business units — a telecoms arm and connecting renewable energy to the grid — can provide growth opportunities to warrant the high price." It is also likely that the bidder who makes the most optimistic assessment of these opportunities will be the likely winner and this will be reflected in its bid, adding to the systematic premiums above the RAB.

Credit Suisse took into account the opportunities to improve earnings through efficiency and growth in unregulated income in developing an estimate of the value of TransGrid. It also took into account the tax benefits available. Using rate of return parameters in line with, or below[65], those used by the AER in its decisions Credit Suisse concluded that "Our DCF sum-of-the-parts valuation yields an estimated FY15 value of $9.394bn which is appreciably below the $10,392mn paid by Spark's consortium. … This is based on what we believe are quite generous assumptions including an initial 35% CAGR for un-regulated revenues to FY18"[66]

Acquisition or market values need to be treated with caution. There can be good reasons for a premium that is not inconsistent with the long-term interest of consumers or indicative of an overly generous regulatory regime. But this does not mean that such values do not have some information content. CCP 9 considers that a very conservative interpretation of the RAB multiples in the acquisitions of TransGrid and Ausgrid 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. Indeed, given the magnitude of the multiples in absolute terms and relative to multiples in other regulatory jurisdictions, one could conclude that it provides evidence that the allowances are more likely to have exceeded investors' expectations for the required return on investment.

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[65] Credit Suisse used a MRP of 6.0% rather than 6.5%.

[66] Credit Suisse, ….. p3

The information value of market valuations is recognised by other regulators who consider such information in undertaking a 'sense-check' of recommended rates of return.

> Our focus is not on isolating the individual sources of excess returns. Rather our objective is to assess whether the existing WACC uplift is too generous. As pointed out by Covec, "irrespective of the cause of a high RAB multiple, the existence of such multiples is strong evidence that the WACC is not too low".[67]

The CAA expressed its position as follows:

> The CAA agrees that MARs should be interpreted with caution. By comparing the airport operator MARs to other sectors with higher MARs starts to make inference about whether other sectors have got it 'right' or 'wrong'. This does not take the discussion forward. By comparing the MARs to 1, ignores the idea that a small modest premia might be desirable. The CAA considers that the MARs calculated in respect of HAL disposals (1.09 to 1.14) are within a range that does not give the CAA concern that the current WACC is too high or too low.[68]

The Commerce Commission in New Zealand usefully summarised the way in which market valuations, or RAB multiples have been used in assessing the reasonableness of rates of return. This is reproduced in the box below.[69] Have considered these practice and precedents and, notwithstanding the acknowledged limitations of these ratios, the Commerce Commission considers that RAB multiples provide a cross-check on the reasonableness of the allowed WACC. In its 2016 review of the cost of capital the Commerce Commission stated that:

> As part of our reasonableness checks, we have considered RAB multiples for regulated energy and airports businesses in New Zealand. RAB multiples can provide a useful indicator of whether the allowed rate of return has been set at a sufficient level to adequately compensate investors for putting their capital at risk.[70]

It concluded that the RAB multiples for the electricity networks of 1.13-1.43 supported its view that the allowed rates of return were not unreasonable and cited the RAB multiples in the Vector and Maui gas pipeline sales of 1.14-1.5 supported its decision to remove a beta uplift factor of 0.1 compared to the other regulated energy networks.

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[67] Commerce Commission of NZ, *Amendment to the WACC percentile for price-quality regulation for electricity lines services and gas pipeline services Reasons paper*, 2014, p155

[68] Civil Aviation Authority, *Estimating the cost of capital: a technical appendix to the CAA's Final Proposal for economic regulation of Heathrow and Gatwick after April 2014 CAP 1115*, 2013, p78

[69] Commerce Commission of NZ, *Amendment to the WACC percentile for price-quality regulation for electricity lines services and gas pipeline services Reasons paper*, 2014, pp152-154.

[70] Commerce Commission, *Input methodologies review draft decisions*
Topic paper 4: Cost of capital issues, June 2016, p161.

“C17.1 The Chairman of Ofwat has referred to high RAB multiples for UK water utilities as evidence that the regulator’s allowed WACC is too high noting that “the continuing trend for water companies to be sold for prices around 130% of RAV (regulated asset value) only suggests that the regulator’s adopted cost of capital is too high and the premia reflect excess demand for these assets”.

C17.2 In its February 2014 report on the split cost of capital, the Queensland Competition Authority referred to UK and Australian RAB multiples as evidence of above-normal returns.

C17.3 While the AER decided not to use RAB multiples to assess the reasonableness of its WACC parameters, the AER does monitor RAB multiples as part of a set of indicators to help inform it of potential areas of inquiry and research.

C17.4 In its 2013 advice to the UK Office of Water (Ofwat) on the approach to reviewing the appropriate returns for water companies, PwC noted that “the expectation for out-performance on regulatory assumptions can be gauged by looking at the market-to-asset ratio (MAR) of water industry companies…”. PwC reports an average MAR in the UK water sector of 1.23 and concludes that “the relatively high MARs suggest that there have been consistent expectations of higher returns…”. PwC lists three potential drivers of these expectations:

C17.4.1 outperformance that is attributable to unregulated business units which PwC comments is generally small;

C17.4.2 synergies available to the new entity that are not allowed for by the regulator; and

C17.4.3 allowed revenues being set at levels higher than finance providers require “suggesting operational targets were easy to outperform, and/or the WACC was set too high relative to the actual costs of financing”.

C17.5 In 2014, Grant Samuel prepared an independent expert’s report relating to APA Group’s proposal to acquire the Australian gas distribution company Envestra. In this report, Grant Samuel commented that:

C17.5.1 “A common rule of thumb parameter used in the valuation of energy infrastructure assets is RAB multiples”;

C17.5.2 “Theoretically, listed infrastructure entities should trade at, and assets should be acquired at, 1.0 times RAB. However, that does not occur and, in fact, most assets generally trade at a premium to RAB”; and

C17.5.3 “The precise reasons for this are uncertain but contributing factors probably include: expectations of volume growth above the levels used by regulators…; expectations of savings relative to the operating and capital costs assumed by regulators…; a cost of capital less than that assumed by the regulators…; growth options…; and profit streams from other businesses”.

C17.6 In 2013, PwC published a report on regulated airports in the UK noting that “regulated airports are allowed to earn a return on their regulatory asset base (RAB). RAB is therefore a key valuation metric, and the market places significant emphasis on enterprise value to RAB multiples in assessing the value of regulated airports.”

C17.7 In 2011, Deloitte published a paper in which it explored a number of valuation issues concerning regulated infrastructure assets. When describing factors that had led to Australian utilities trading at a premium to their RAB, Deloitte said: “the effective cost of capital borne by the asset owner may be lower than that assumed by the regulator due to either a cheaper cost of capital and/or greater leverage.”

Third-party Assessments

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 TransGrid, Credit Suisse commented that TransGrid was "governed by a generous regulatory regime which still by design errs on the side of over-incentivising."[71]

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.

Existing Investors responses

If the rate of return 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. From the evidence available to CCP 9 there is no sign of an increase in gearing. For example, 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. [72]

This apparent stability in gearing is occurring at a time when the RAB's continue to increase – as typified the proposed 17% increase in TransGrid's RAB. The generally moderate levels of debt of the regulated utilities and sound credit ratings do not suggest that this increase in equity 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).[73]

Legal Challenges

It should be noted that the current approach has withstood appeal to the ACT. In 2015 Ausgrid and the other NSW Networks appealed the AER's determination of the ROE and MRP. In particular, the networks contended that:

> 793 The Network Applicants asserted that there had been a significant change in market conditions over that period. The AER's DGM estimated range had altered from 6.1 percent - 7.5 percent (as exposed in its Better Regulation: Explanatory Statement – Rate of Return Guideline, December 2013, at p 93) to 7.4 percent to 8.6 percent (JGN Final Decision at p

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[71] Credit Suisse, *Spark Infrastucture Group, Equity Research,* 25 November 2015, p1

[72] 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, p10

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

> 3325 and the other relevant Final Decisions at June 2015 and April 2015 respectively). There had also been a significant fall in the risk free rate: Commonwealth Government Securities from about 4.2 percent to about 2.55 percent over the same period. It is the Network Applicants' contention that as the DGM analysis was that the MRP was not falling in lockstep with the risk free rate, but was increasing over that period, the return on equity should have been higher. [74]

The Networks further contended that "by a different DGM model construction and with different input assumptions, the DGM estimate should have been 8.73 / 8.84 percent rather than the range 7.4 to 8.6 percent."[75] In this case the ACT found that:

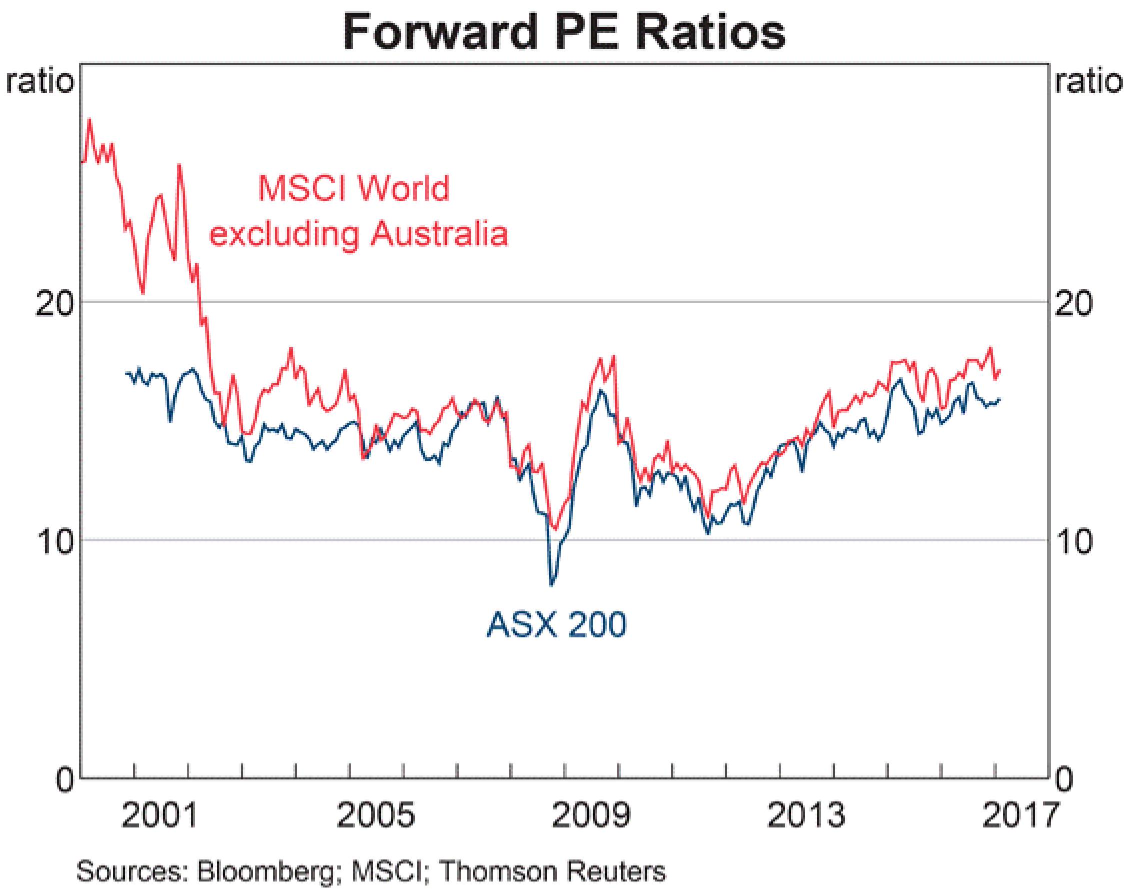
> 803 On this topic of the MRP, the Tribunal does not conclude that the AER's decision was factually erroneous. It selected an available starting point. It addressed the relevant material. It applied its own experience to the qualitative findings to be made, and it sought to crosscheck them with other sources of information. By following the same process, but also in the light of the detailed and thorough submissions on behalf of the Network Applicants and PIAC, the Tribunal has not come to a firm but different conclusion. It does not consider that the AER's selection of the MRP at 6.5 percent was an error of fact. …

The updated ranges for the DGM submitted to, and considered by, the ACT as being relevant to the determination of the MRP were similar to the range for the current estimates of the MRP submitted by Frontier Economics of 7.54-8.86%.[76]

Is there evidence supporting a reduction in the required expected RoE?

The chart below shows the forward price/earnings ratio for Australian stocks since 2000[77]. This is the ratio of stock prices relative to forecast earnings. As expected it fell substantially during the Global Financial Crises, then went through a period of instability. However, since 2012 the forward price earnings ratio has been increasing.

[74] Applications by Public Interest Advocacy Centre Ltd and Ausgrid [2016] ACompT 1.
[75] Applications by Public Interest Advocacy Centre Ltd and Ausgrid [2016] ACompT 1
[76] TransGrid, *Revenue Proposal 2018/19-2022/23,* January 2017, Appendix S: Frontier Economics, The Market Risk Premium, p73.
[77] Reserve Bank of Australia, *Chart Pack*, accessed at rba.gov.au on 30 April 2017.



Like the DGM, the forward P/E ratio is a measure of the relationship of the asset's price and the expected earnings[78]. In principle the P/E ratio would rise (other things being equal) with a fall in the required return on equity, which is the sum of the RFR and the MRP.

Through changes in other assumptions – such as expected long term growth rates – a higher P/E ratio can be reconciled with a higher required rate of return under the DGM. However, the rise in the P/E ratio is more likely to reflect a decline in the return on equity. Hence, it is important to examine the fundamentals drivers of risk and return in considering the evidence put forward of a higher MRP.

In their advice to TransGrid for the Power Sydney's Future RIT-T Houston Kemp commented that:

> Grid Australia's RIT-T Handbook (July 2011) recommends that a commercial discount rate of 10 per cent (real pre-tax) be adopted in any RIT-T assessment unless there is compelling evidence to adopt a different rate. In this section we identify that financial conditions have changed since Grid Australia recommended a 10 per cent commercial discount rate, with rates on both risk free and risky assets falling since July 2011.[79]

In estimating the indicative mid-point commercial discount rate Houston Kemp assumed a return on equity (with a beta of one) of 8.4% "within the AER's Capital Asset Pricing Model"(p.8). While Houston Kemp were obliged to use regulated returns to establish the low range for the discount rate

[78] Indeed with stable returns the DGM model can be expressed in terms of the P/E and the growth rate.
[79] Appendix C of TransGrid, Powering Sydney's Future, PADR, May 2017, Houston Kemp, The Commercial Discount Rate to be used in the RIT-T Test, Sep 2016, p5

they were not obliged to do so in estimating the mid-point indicative return – as shown by the use of a market average gearing of 28%. Houston Kemp also used a gamma of 0.4.

Do investment fundamentals and market evidence to support an increase in the MRP

Firstly, it should be noted that a component of the reduction in the yield on 10-year CGS (the RFR) has been due to a decline in inflation expectations. Between Dec 2013 and March 2017 nominal bond yields fell by 1.4% and inflation expectations fell by 0.6%.

Table B.5.1 – Government Bond Yields and Inflation Expectations

	10-year Govt Bond Yields	Implied Inflation expectations[1]
December, 2013	4.24	2.6
December, 2014	2.96	2.3
December, 2015	2.85	2.2
December, 2016	2.79	2.0
March 2017	2.81	2.0

1. Average annual inflation rate implied by the difference between 10-year nominal bond yield and 10-year inflation indexed bond yield; End-quarter observation

Source: RBA Statistics, Tables on Inflation expectations and monthly Government interest rates

The question then is whether with a decline in inflation expectations one would in principle expect that the expected return on equity would similarly fall or the MRP increase. Under "the Wright approach" it is the real return on equity that is assumed constant over the long term.

> Mason, Miles & Wright (2003, hereafter MMR) proposed a methodology in which the real market cost of equity (that is, the expected real return on investments in the equities of a firm with a CAPM β of precisely one), should be assumed constant, and set in the light of realised historic real returns over long samples.[80]

While TransGrid has not adopted the Wright approach, it has not argued that a decline in the RFR due to lower inflation expectations would not normally be expected to be reflected in the return on equity. There is some support for the proposition that inflation outturns that are different to expectations can signal greater uncertainty and hence support a higher risk premium. But there does not appear to evidence to suggest that a decline in long-term inflation expectations, reinforced by consistent inflation outturns, would lead to perception of increased long-term risk for equities, relative to risk-free investments.

Hence, the relevant change in question is the 0.8% real reduction in the RFR. This requires consideration of whether investment fundamentals and other information support the the DGM estimates and an increase in the MRP relative to the previous decisions of the AER.

Professor Damodaran similarly adopts a fundamentals approach when examining the market risk premium and the latest evidence from the DGM models and other information.[81] The MRP is the

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[80] S Wright and A Smithers, *The Cost of Equity Capital for Regulated Companies: A Review for Ofgem*, p3

[81] A Damodaran, *Equity Risk Premiums (ERP): Determinants, Estimation and Implications – The 2016 Edition Updated: March 2016* , pp10-21.

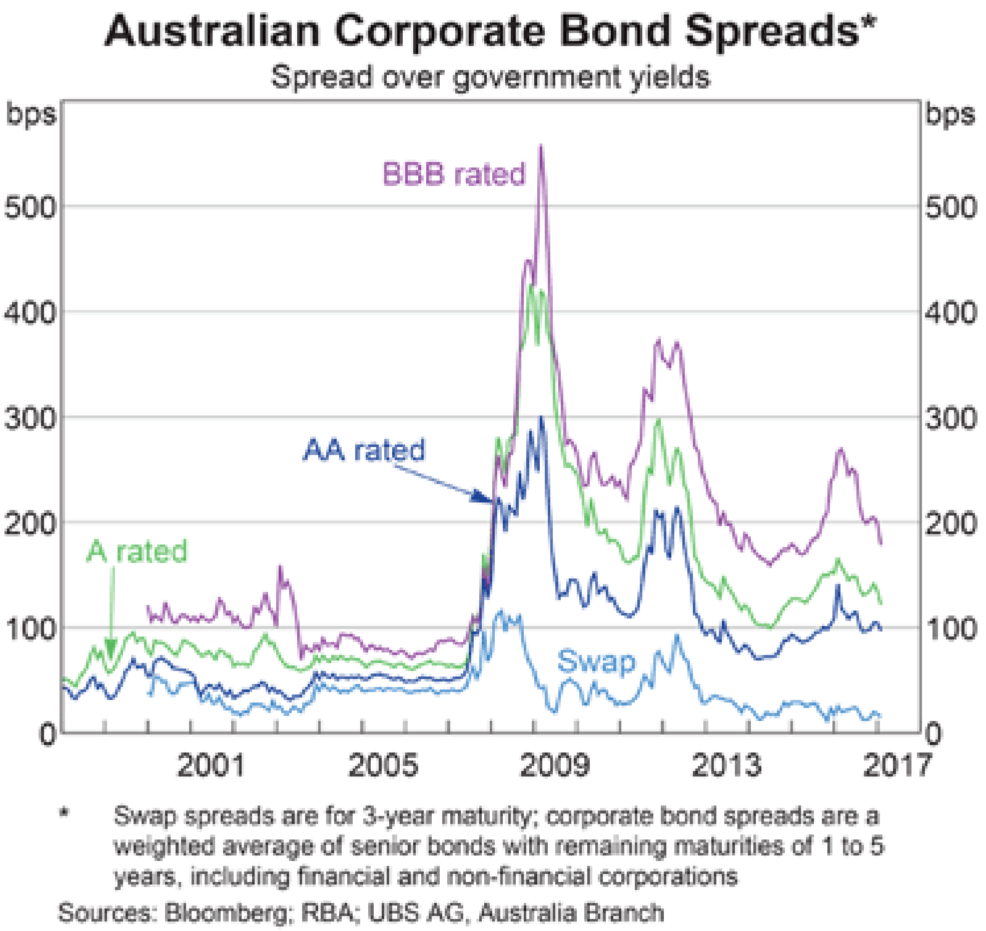
additional return for holding an asset with the average market risk rather than a MRP and should reflect should reflect level of market uncertainty and risks. Damodaran lists the following factors that should determine the market risk premium:

1. Risk aversion and consumption preferences
2. Economic risk
3. Information and volatility of returns
4. Liquidity and funds management
5. Catastrophic factors
6. Government policy changes
7. Monetary policy
8. The behavioural/irrational component

The most relevant factors in the period since 2013 are (2), (3), and (4) – the broadly defined economic conditions. Except for the last factor, the others have been broadly stable. The last – the behavioural/irrational component – is important as it acts as a caution against putting too much weight on short term movements.

CCP 9 suggests that a careful consideration of these investment fundamentals would not support the proposed increase in the MRP. The period since 2013 has been a been a period of sluggish but relatively stable growth. Typical measures of market and economic uncertainty – or conditioning variables – are interest spreads and the VIX index have seen some degree of volatility but not to the degree of the preceding period. Furthermore, overall market conditions do not appear markedly different to conditions in 2013. This is supported by evidence on the conditioning variables presented by Frontier Economics in their report for TransGrid. For example:

- Dividend yields shown Figure 14 of the Frontier Economics Report have not been significantly more variable in the period since 2012-13 than in periods prior to the GFC, nor are the recent yields shown substantially higher than in 2012-13.
- Figure 15 shows that while there have been some periods of increased volatilities in stock options in the period since 2012-12, these have been limited and the overall picture is one of lower volatility over the period. Volatility at the end of the period covered by the Figure was similar to that in 2012-13. The VIX index published by Standard and Poor's shows further reductions since then to levels of volatility at or near 10-year lows.
- Bond spreads (figure 16 in the Frontier Economics report) spiked in 2016, but more recent data shows a return to levels comparable to 2012-13 – see below – a point that again highlights the risk of placing too much weight on short term movements in data.



Source: RBA Chart Pack, April 2017.

Do the DGM estimates appear anomalous or biased

The above has suggested that the apparent increase in the estimated expectations the MRP from the application of the DGM is not supported by other data such as the data on market conditions and P/E ratios. This the raises questions of the stability and robustness of the estimates. Partington and Satchell[82] have set out in detail their concerns with the robustness of the DGM model and the dangers of placing too much reliance on the results of the model without considering a broader set of information. Partington and Satchell also note that the case can be made that the MRP has declined, rather than increased, and that the current MRP may be lower rather than higher than the long term average.

CCP 9 supports the analysis and conclusions of Partington and Satchell. The DGM models are widely used but are highly dependent on the assumptions particularly in regard to, for example, investors expectations for long term growth in dividends.

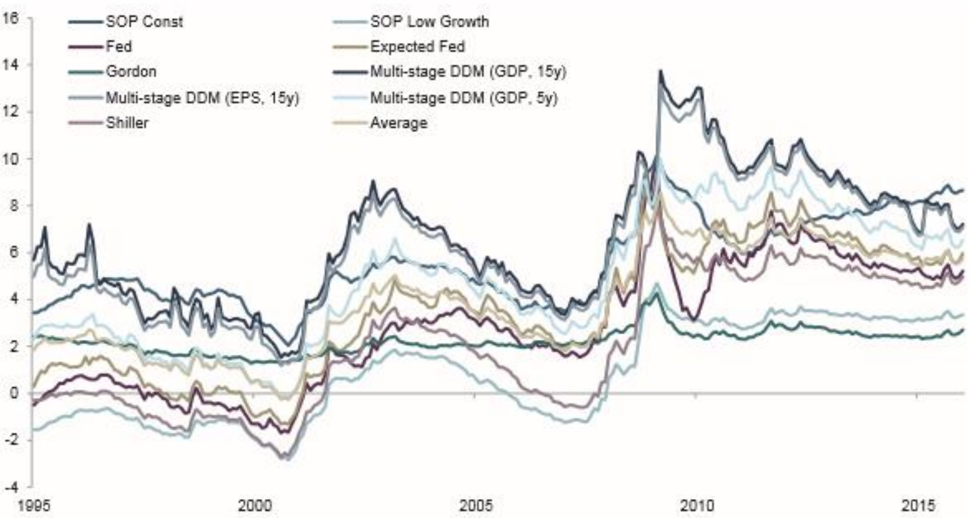
In the section below we present additional information that:

- Provides demonstrates the range of feasible estimates of the return on equity and MRP using different versions of the DGM

[82] Add reference

- Compares the trends in the estimates of DGM generated for Australia with those on other markets
- Provides further examples of how advisers have responded to changing estimates of the MRP.

Norges Bank has used a variety of different DGM models to calulate the implied world MRP for the period since 1995.



Source: Factset, IMF, OECD, Bloomberg, USDA Macroeconomic data; Norges Bank Investment Management

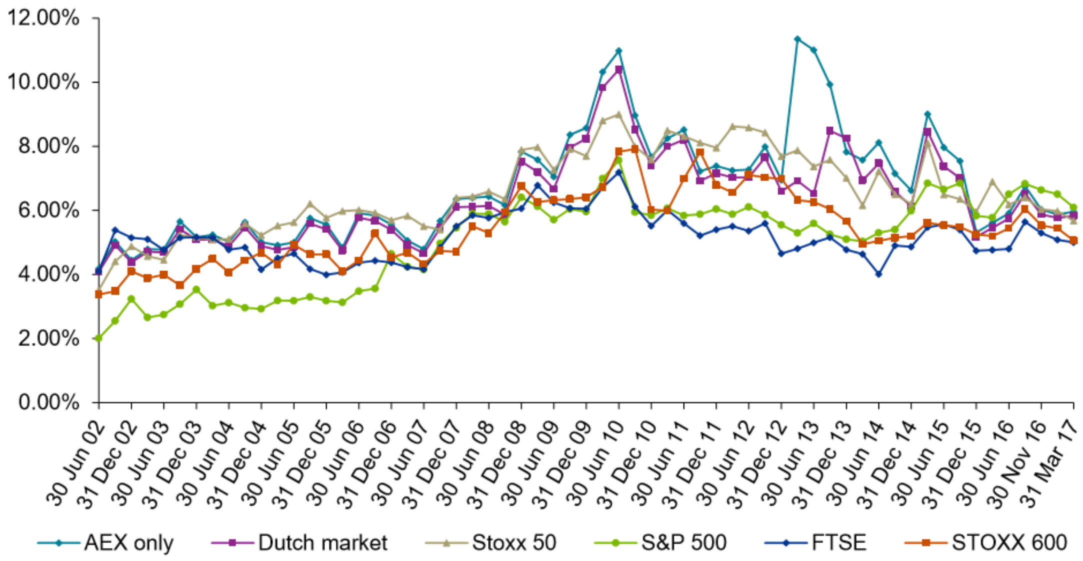
Source: Norges Bank, *The Equity Risk Premium Discussion Note,* 2016, p32.

The results highlighted the range of the estimates of the MRP under different versions of the models. Not surprisingly the key factor in the differences in the results is the assumption on long-term dividend growth rates. Simple versions of the Gordon dividend discount model that assume dividends grow at the risk-free interest rate use shows the MRP since 2008 and are more stable over time. Models that assume dividends grow at the average of past long-term GDP growth rates provide the highest estimates. The sensitivity of the results to the assumed long-term growth rates focuses attention on whether investors assumptions of the long-term growth rate are constant through time. Or in the current circumstances of an extended period of slower than expected recovery would investors have reduced their expectations of the long-term growth in dividends?

If so, maintaining a constant assumption for the long-term growth in dividends may understate the reduction in the MRP in recent years. Importantly the discussion paper observed that “Overall, the current World ERP forecast from DDMs is on a par with the unconditional mean forecasts (Table 5)…”

In contrast to the estimates of the DDM using the AER’s model and other estimates for Australia cited by Frontier Economics, the estimates compiled for the world MRP by Norges Bank using a range of models show a stable or slightly falling MRP sin the last 5 years. KPMG have also estimated the MRP in the US, UK, Pan-European, and the Netherlands (see below). Across the four markets there has been a narrowing in the range for the estimates. In the US the MRP has increased to a some extent, but in the other markets it has tended to fall or be relatively stable. During the period from 2012-13 the estimated return on equity has fallen in the Pan-European, Netherlands and the UK markets as the RFR has also fallen. The exception to this is the US where the return on equity has been more stable.

Figure B.5.X – Estimates of the MRP for Selected Major Economies



Source: KPMG, *Equity Market Risk Premium: Research Summary,* April 2017.

Taken together this information suggests that while DGM models of forward-looking estimates of MRP have value, the AER should be cautious in adjusting the MRP in response to this information. It is important that any change by made with regard to, and be supported by, a wide range of information and can be demonstrated to be consistent with commercial practice.

The next question to be considered is whether, given the variation from international estimates and the data on market and economic conditions, there are reasons to believe that the estimates using the DGM may be biased in the current circumstances.

The Norges Investment Bank Research paper considered this and concluded that:

> The average World ERP estimate from various dividend discount models is 5.9 percent. These estimates may be affected by recent data bias. Cash flow growth has been exceptionally large since the end of the Global Financial Crisis in 2009, which in turn may bias upward expectations of future cash flow growth when extrapolated from historical data. In a below-average cash flow growth scenario, the estimated World ERP is 3.7 percent. Estimates of the expected ERP are also affected by the choice of proxy for the future risk-free rate. The current near-zero short-term interest rates may be a poor proxy for future short-term rates if the market expects rate increases in the future. The expected World ERP from the discount models may be closer to 4 percent if expectations of interest rate normalisation are taken into account.[83]

[83] Norges Bank, *The Equity Risk Premium Discussion Note,* 2016, p3.

In summary, it cannot be presumed that the MRP is likely to increase if there is a reduction in the RFR. Indeed, where the fall in the RFR is due to a reduction in inflation expectations on investment fundamentals it is more likely that this would be accompanied by a reduction in the return on equity. A reduction in long-term expectations for inflation is unlikely to be associated with a change in the fundamental relative risks of risk of equities and the risk-free asset.[84]

Furthermore, the estimates of the return on equity and the MRP using the DGM are quite sensitive to the form of the model and the assumptions. In particular, it requires strong assumptions to be made about the investor's expectations for the long term growth in dividends and the stability of these expectations over time. The results can also be affected by the 'behavioural/irrational component', to use Damodaran's term. Market volatility and extended period of positive or negative market sentiment will affect the measured MRP using the DGM while expectations may remain more stable.

Given these factors, the AER should exercise caution in adjusting the MRP in response to variations in the forward looking estimates of the MRP derived from the DGM. It is important that any change in the assumed MRP can be shown to be consistent with investment fundamentals and the impacts of market conditions on the relative risks and demand for different asset classes. In the absence of strong supporting market information, CCP 9 considers that this case has not been made and that the AER should continue to give weight to the long term realised MRPs as an anchor for long term expectations.

B.5.2.2 Tax Expense and Gamma

Under section 6A.6.4, the estimation of the tax expense is a function:

- An estimate of taxable income
- The statutory tax rate
- The value of imputation credits (gamma)

Under the PTRM taxable income is taxable revenue less tax costs. Tax-deductible costs include interest or debt servicing, depreciation allowances, opex and tax expense revenue adjustments. Interest expense is based on the notional gearing and benchmark interest costs rather than actual gearing and interest cost – consistent with the regulated cost building blocks. The main difference between the cost building blocks for calculating regulated income and tax costs is depreciation. Tax depreciation is based on the tax asset base and depreciation rates rather the regulatory asset base and depreciation rates.

The value of gamma has been extensively debated and analysed over many years in regulation in Australia. In its Better Regulation review in 2013 the AER reviewed the previous studies.Since then the issue of the value of gamma has been appealed to the Australian Competition Tribunal (ACT). In *Applications by Public Interest Advocacy Centre Ltd and Ausgrid [2016] ACompT 1* (determined on 26 February 2016) the ACT upheld the appeal by the NSW DNSPs and ActewAGL against the AER's use of a gamma of 0.4. In this case the ACT found that:

[84] See A Damodaran, *Equity Risk Premiums (ERP): Determinants, Estimation and Implications – The 2016 Edition Updated: March 2016* , p13

> “1110 The Tribunal considers that the AER decision on this topic should be set aside. Further reasons for the conclusion, having regard to s 71P(2a) and (2b) of the NEL are in the concluding section of these reasons.
>
> 1111 As explained, the AER’s decision sets a value for gamma which is too high, where the relevant upper bounds for theta should be no more than the ATO statistical data of 0.43 (or 0.45 in the case of JGN).”

However, the ACT went on to note that:

> “1118 The Tribunal notes that the SFG 2013 Study represents one point of view. As in a number of instances in these matters, there are conflicting expert views. Without the benefit of learning further from the experts, the Tribunal (like the AER) is faced with the selection between competing views.
>
> 1119 There are finely balanced decisions to be made in that light. …”

The AER appealed this decision of the ACT to the Federal Court and the decision on this appeal is pending.

The SA Power Networks also appealed the AER’s use of a gamma of 0.4 to the ACT in 2015. In *Application by SA Power Networks [2016] ACompT 11* (determined on 28 October 2016) the ACT found that:

> “196 In the face of significant uncertainty, the approach by the AER of considering a range of approaches to estimating gamma and applying different weights to those approaches is, the Tribunal believes, appropriate. It is clear that some experts would apply different weights to the alternative types of evidence, and that some support the AER’s relative ranking while others disagree. In particular, some would accord much higher weight to results of dividend drop-off studies. The Tribunal has noted the arguments about the problems of deriving reliable tax-related parameters such as investor valuation of imputation credits from drop-off parameters, and is of the view that the AER did not err in forming the judgement it did regarding weight to give to different forms of evidence.”

The CCP anticipates that the decision on the appeal to the Federal Court will be available prior to the finalisation of the decision on TransGrid’s revenue re-set and that decision be binding on the value of gamma to be used. In these circumstances, it is not necessary for the CCP to comment on the relative merits of the arguments for different gamma values. However, we believe that, given the conflicting decisions of the ACT, the value of 0.4 should continue to be used, pending the decision of the Federal Court.

The estimation of the corporate tax expense (prior to allowance of imputation credits) has not been subject to the same level of disputation as the other elements in the cost building blocks. The objectives and difficulties are the same as other costs: the AER must come to a judgement on the reasonable costs for the Benchmark Efficient Entity (BEE), but these cannot be observed directly.

However:

It is open to question whether the current approach may overestimate the tax expense of the BEE; and

1. The CCP believes it would be appropriate for the AER to review, as part of its scheduled review of the Rate of Return Guideline, whether the current approach generates a reasonable estimate of the tax expense of the BEE

As the Commonwealth Treasury has highlighted the effective corporate tax rate, before the allowance for imputation credits, is around 20% (well below the statutory tax rates of 30%), although it must be noted that the effective tax rate is based on a broad measure of income drawn from the National Accounts. Furthermore the low effective tax rates on owners for some infrastructure investments has been noted in broker reports. For example Credit Suisse commented that:

- **Tax efficient structure approved by ATO:** Spark's management indicated that the consortiums purchase had been structured in a tax optimised manner. We forecast zero cash tax to be paid in the medium term. Importantly, management stated that the structure had been approved both by the State and by the Australian Taxation Office[85]

We would stress that Credit Suisse is commenting on the tax position of Spark Infrastructure in regard to the effective tax on its equity in TransGrid, rather than on the tax position of TransGrid. But equally, by allowing for imputation credits, the formula for allowance for tax is a calculation of the effective tax rate on the equity owner in regard to the income generated by the business rather the company tax paid by the business itself.

Similar concerns have been raised in other jurisdictions. For example, the National Audit Office in the UK raised concerns that tax paid by the water companies was significantly below the tax allowed by OfWat:

> The NAO considered the tax allowed at PR09 in respect of AMP5 covering the period from 2010/11 to 2014/15 and compared this to the current tax charge reported in the financial statements of the regulated companies. The NAO report noted that the aggregate current tax charge of the companies over this period was £710 million lower than the tax allowed at PR09. The main reasons identified in the NAO report for this were as follows:
>
> ● Reduction in tax paid due to group relief claimed by regulated companies but not paid for;
> ● A significant reduction in the headline corporation tax rate in AMP5 from 28% to 21%; and,
> ● One-off accounting adjustments affecting the regulated companies. [86]

Ofwat commissioned a targeted review by Alvarez and Marsal that provided a higher degree of reconciliation between the tax allowances and tax payments than the NAO. Notwithstanding this, it recommended that Ofwat consider an ex-post true-up for allowed tax payments similar to that adopted by OfGem, under which there is an adjustment for differences due to high levels of gearing.

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[85] Credit Suisse*, Spark Infrastrucure Group*, Equity Research Note, 15 November, 2015.
[86]Quoted in Alvarez and Marsal, *Ofwat: Targeted Review of Corporation Tax,* May 2016, p6. Extract form the NAO report are included as an appendix to the report by Alvarez and Marsal.

The CCP is not suggesting that the approach should be changed for this determination – or even that there is definitive evidence that it should be changed. We are saying, however, that it would be desirable to review how tax payments align to the tax allowances and explore the reasons for these differences. This is similar to the targeted review commissioned by OfWat. Such a review may allay any concerns. If not, it can provide a basis for the consideration of a measured and proportionate change. Any change in this area is a potentially significant change that should be considered carefully with a view to application across all reviews. Furthermore, the current approach is embedded within the PTRM. The next review of the rate of return guideline will provide an appropriate opportunity to review this approach.

Recommendation:

a) AER should not accept TransGrid's proposal for a MRP of 7.5%
b) As part of the next review of the Rate of Return Guideline, the AER should review its approach to the estimation of tax expense.

B.6 Incentive Schemes

The incentive schemes that will apply to TransGrid are:

- Efficiency Benefit Sharing Scheme (EBSS)
- Capital Efficiency Sharing Scheme (CESS)
- Service Target Performance Incentive Scheme (STPIS)

TransGrid's Tables15.6 and 15.7 outline the contributions to revenue from the EBSS and CESS. To give a sense of scale, an EBSS carryover of $65.3m = 6.4% of proposed Opex or 1.5% of total revenue. CESS revenues of $26.1m = 1.2% of Return on Capital or 0.6% of total revenue. The STPIS puts 5% of revenue at risk.

15.1.8 Efficiency Benefit Sharing Scheme

The efficiency benefit sharing scheme (EBSS) is discussed in Chapter 13. A summary of the EBSS carryover amounts is set out in Table 15.6.

Table 15.6: Efficiency carryover ($m nominal)

	2018/19	2019/20	2020/21	2021/22	2022/23	Total
EBSS carryover	26.0	26.6	3.6	9.1	-	**65.3**

Source: TransGrid. Totals may not add due to rounding

15.1.9 Capital Expenditure Sharing Scheme

The capital expenditure sharing scheme (CESS) is discussed in chapter 14. A summary of the CESS amounts is set out in Table 15.7.

Table 15.7: Capital Expenditure Sharing Scheme ($m nominal)

	2018/19	2019/20	2020/21	2021/22	2022/23	Total
CESS	5.0	5.1	5.2	5.3	5.5	**26.1**

Source: TransGrid. Total may not add due to rounding

B.6.1 EBSS

The estimation of Opex for the final year of the current RP (2017/18) has been discussed earlier in this submission. As discussed there CCP 9 is concerned that the interaction between TransGrid's proposed approach to base-year Opex and the EBSS is not fully explained in the proposal. The operation of each of the incentive schemes is generally not well understood by consumers and, in our view, worthy of more 'plain language' explanation to consumers. As noted above there does not appear to be a strong logical reason for using two different forecasts of the final year opex in the EBSS and for the forecasting of opex in the next regulatory period.

We note TransGrid's claim of the benefits that have accrued to consumers and encourage the AER to provide confirmation of the scale achieved:

TransGrid estimates it will have achieved a combined $151 million of operating efficiencies by 2017/18, since operating efficiency incentive schemes were introduced in 2004/5. According to the approximate 30:70 sharing ratio in favour of consumers, with a correctly functioning sharing scheme this will lock in more than $100 million in benefits to consumers by the end of this regulatory period.[RP p202]

We also note that TransGrid has identified "potentially inappropriate rewards and penalties" and is seeking a five year carryover period instead of the four years articulated in the Framework and Approach [RP p202]. CCP 9 supports the clarification of this by the AER in the upcoming draft determination.

B.6.2 CESS

The CESS is presented at Chapter 14 of the TransGrid proposal. On the basis of the AER Guideline, 70% of the efficiency savings benefit consumers and 30% is allocated to TransGrid. TransGrid has calculated the CESS building block allowance for 2018/19 to 2022/23 (which arises from performance in 2015/16 to 2017/18) to be $22.47 million ($m June 18) [RP p209] based on claimed underspend of 71.5+51.9+32.6 = $156m (nom).

CCP 9 notes the commentary provided in the Final Framework and Approach regarding the intended symmetry of the EBSS and CESS. We encourage the AER to review the operation of the incentive schemes over the current regulatory control period and into the 2018-23 period and provide a plain-language description in the preliminary determination.

B.6.3 STPIS

It is our understanding that Service Target Performance Incentive Scheme (STPIS) version 5 will apply during the RP and can result in a maximum revenue increment or decrement between 1% and 5% of the annual Maximum Allowed Revenue (MAR)[87].

The STPIS consists of three components: service, market impact and network capability. In terms of the *market impact* component, TransGrid is seeking to defer the introduction of a penalty.

"TransGrid requests the AER to further consider the recent operation of the scheme, and defer the introduction of a penalty for the market impact component pending further consideration of perverse

[87] AER TransGrid Final Framework and Approach 2018-23 available from https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/TransGrid-determination-2018-23/aer-position

incentives this appears to create. TransGrid proposes the continuation of the 0% to 2% weighting applied in version 4 of the STPIS until this can be considered and resolved." [p222]

CCP 9 is of the view that a symmetrical financial incentive is appropriate and does not support the deferral of this component.

B.6.4 Recommendations:

a) AER to clarify the EBSS carryover period (4 years or 5) for the 2018-23 period

b) AER to review the operation of the incentive schemes over the current regulatory control period and into the 2018-23 period and provide a plain-language description in the preliminary determination.

B.7 Tariffs

The TransGrid Proposal refers to consumer engagement on pricing at section 3.3.1 (p46-). TransGrid state that substantial changes were introduced to the pricing methodology in the current regulatory period and that recent views from stakeholders confirmed satisfaction with the form and approach of the Pricing Methodology (p46).

TransGrid's proposed pricing methodology for the 2018/19 period is unchanged from the current period. TransGrid published an issues paper in September 2016 but has not published a summary of results other than that provided in Table 3.4 of the Regulatory Proposal. This provides only a high-level summary rather than a summary for each of the six questions posed by the Issues Paper.

As discussed in relation to Consumer Engagement (See Section A.X), we have observed a general view that TransGrid's tariff review process was effective and that TransGrid responded appropriately to the views of most stakeholders given the limitations under the Rules. However, for the purposes of the Regulatory Proposal, CCP 9 would prefer to see further evidence presented of continued customer support for the existing pricing methodology.

B.7.1 Recommendation(s):

a) AER should seek further evidence of continued support for TransGrid's Pricing Methodology.

CONCLUSION

CCP 9 has concluded that TransGrid has generally reflected on the feedback from stakeholders on their previous CE processes and made further and substantial enhancements to its CE program. All stakeholders that CCP 9 has spoken to noted these improvements and expressed a growing level of trust in TransGrid's communications. Positive features of TransGrid's revised CE program were the early establishment of the CE framework on an ongoing basis with strong support from the Board, CEO, and senior managers, and the provision of clear and continuous information.

However, CCP 9 has also highlighted a number of areas that TransGrid should further consider to increase engagement in the more strategic areas with a more proactive approach to engaging with stakeholders on the changing energy market and to the risks and opportunities that face the network businesses over the next few years. CCP 9 would like to see a more structured approach adopted to the process of evaluation and review of the CE program. CCP 9 and TransGrid's stakeholders would like to see TransGrid respond to consumers' concerns around operational and capital investment efficiency and productivity in order to drive and sustain lower prices. Finally, CCP 9 sees significant scope for enhancement of the CE program around the RIT-T process, in particular the Powering Sydney Future project.

In addition to the enhanced customer engagement discussed above, there are a number of positive elements in TransGrid's proposals. In particular, TransGrid has largely accepted and worked within the regulatory framework set out by the AER. Following the substantial price reductions in the past period, the real increase in proposed prices is relatively small and the underlying real change in the average revenue requirement has of 1.9% reflects past efficiency gains.

However, there are various matters on which we have questions or where we believe that there are alternative assumptions or conclusions that would better serve the long-term interests of the consumer while also respecting the reasonable commercial interests of TransGrid:

- The capex program will see the RAB increase by 17% in nominal terms while technology is changing rapidly and customers bear the risk of asset stranding. The customers also bear the risk of future rises in interest rates. *Together these two risks faced by customers highlight the importance of pursuing opportunities to defer or reduce capex and the potential role of non-network options*
- More use is being made of contingent projects and it is important the potential price impacts and that the review and analysis of the contingent projects is no less rigorous.
- TransGrid has achieved significant reductions in real opex and continuation of past trends can provide a realistic cross-check against TransGrid's assumed productivity gains.
- The proposed WACC may be higher than required by the NEO and rate of return objective. In particular, the higher MRP proposed is not supported.

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

Signed

	B. Hughson		
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Eric Groom	Bev Hughson	Andrew Nance	Click here to enter Name of sub-panel Member.
Sub-panel Chairperson			