TRANSGRID REVENUE RESET APPENDICES

An independent review

Prepared for

AUSTRALIAN ENERGY REGULATOR

PB Quality System:

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APPENDIX A
TERMS OF REFERENCE

APPENDIX A: TERMS OF REFERENCE

Terms of reference

1. Introduction

The Australian Energy Regulator (AER), in accordance with its responsibilities under the National Electricity Rules (NER), is to conduct an assessment into the appropriate revenue determination to be applied to the prescribed transmission services provided by TransGrid from 1 July 2009 to 30 June 2014 (the next regulatory control period). The previous revenue cap for TransGrid (2004–05 to 2008–09) was determined by the Australian Competition and Consumer Commission (ACCC). Relevant documents on this revenue cap, including submissions, consultancies and the final determination, are available at www.aer.gov.au.

As part of the AER's assessment, an appropriately qualified consultant (PB) is required to review TransGrid's past and forecast capital expenditure (capex), operational expenditure (opex), associated policies and procedures, and service standards proposals. These reviews will have regard to the NER, particularly chapter 6A.

Revenue cap determinations made by the AER are subject to merits review by the Australian Competition Tribunal and judicial review in the Federal Court. Without limitation, PB must include in its written report the disclosure of qualitative or quantitative methodologies applied in any calculation or formulae, the input values used or assumed, whether values are derived from the TransGrid revenue proposal or another source, the rationale for any substituted values used or assumptions made and PB's reasons for making a recommendation to the AER in sufficient detail to support the AER in meeting its obligations under clause 6A.14.2 of the NER.

PB's review will assist the AER to assess TransGrid's revenue proposal relative to the requirements of the NER. The following is intended to reflect and summarise information concerning the AER's requirement only and is not necessarily a comprehensive description of it.

2. Services required

2.1 General pre-lodgement work

PB is required to assist the AER with a variety of pre-lodgement tasks. Such tasks may include, for example, reviewing whether TransGrid's revenue proposal includes sufficient information to comply with relevant NER requirements. It would also involve attending preliminary meetings held with TransGrid and the AER during May 2008.

2.2 Review of capex and opex during 2004–05 to 2008–09

PB is required to undertake a high level review of TransGrid's capex and opex over the 2004–05 to 2008–09 regulatory period (current regulatory period) including estimates of expenditure for 2007–08 and 2008–09. PB must examine the drivers and reasons for any significant variances between:

a) capex and opex over the current regulatory period with the forecast expenditures allowed in the 2005 ACCC revenue cap decision for TransGrid.[1] This review will also need to take account of any changes to the capital governance framework in the current regulatory period as set out in section 2.3.1

b) capex and opex over the current regulatory period and TransGrid's proposed capex and opex for the next regulatory control period.

PB is required to indicate whether its review of past expenditure raises any issues for consideration of TransGrid's proposed forecast capex and opex for the next regulatory control period in accordance with clauses 6A.6.6(e)(5) and 6A.6.7(e)(5).

2.3 Forecast capex

PB is required to review TransGrid's proposed forecast capex over the next regulatory control period to assess whether it is in accordance with the requirements established under clause 6A.6.7 of the NER. PB must take into account:

a) the existing network capacity

b) asset utilisation

c) asset lives

d) asset conditions

e) demand growth

f) trade-offs between capex and opex

g) information on historical and forecast capex trends

h) the need to meet specified service, network, environmental and other regulatory requirements under relevant jurisdictional or other laws; and

i) any other internal or external factors that may be relevant.

PB is required to undertake a review of TransGrid's capex governance framework, methodologies and assumptions, detailed review of projects, contingent projects and capex deliverability as outlined below.

2.3.1 Capital governance framework

PB is required to review TransGrid's capital governance framework including its capex strategies, policies and procedures. PB must assess whether TransGrid's capital governance framework:

a) reasonably reflects the capex objectives and criteria under clause 6A.6.7 of the NER

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[1] ACCC, *NSW and ACT Transmission TransGrid Network Revenue Cap, 2004-05 to 2008-09: Final decision*, 27 April 2005.

b) is based on sound principles that are in accordance with its capex strategies, policies and procedures

c) provides a reasonable basis for developing TransGrid's forecast capex

d) is effectively coordinated across the organisation.

PB's review of the capital governance framework will need to take account demand forecasts, methodology and information flow which feed into TransGrid's capex program.

The review should include an assessment of:

a) TransGrid's long-term network development strategies

b) TransGrid's policies and procedures for:

   i. identifying network constraints, replacement of assets (asset management) and non-network needs

   ii. developing investment proposals once a need is established

   iii. analysing alternative investment options and identifying the most cost effective option, including demand management

   iv. ensuring that investment projects take place on a timely basis, with minimum network disruption and at least cost.

c) the integration and consistency of policies and procedures across investment categories.

The assessment of whether the capital governance framework and capex strategies, policies and procedures are applied in practice should be informed by PB's detailed reviews of a sample of forecast investment projects for TransGrid discussed in section 2.3.5 of this document.

It should also be informed by PB's high level review of TransGrid's capex over the current regulatory period, as discussed in section 2.2. PB should comment on the extent to which TransGrid applied its capital governance framework in the current regulatory period, any significant changes to the framework over the current regulatory period and whether TransGrid implemented any changes to the framework as a consequence of the ACCC's findings in the 2005 revenue cap decision.[2]

2.3.2 Methodologies and assumptions

PB is required to undertake a review of the methodologies and assumptions underlying TransGrid's forecast capex requirements for the next regulatory control period. PB must identify and describe relevant methodologies and material assumptions used in

[2] ACCC, *NSW and ACT Transmission TransGrid Network Revenue Cap, 2004-05 to 2008-09: Final decision*, 27 April 2005 and ACCC, *NSW and ACT Transmission TransGrid Network Revenue Cap: Supplementary draft decision 2004-05 to 2008-09, 2 March 2005.*

TransGrid's proposal and provide a view on whether the outcomes of these methodologies are reasonable.

PB is not required to undertake a review of TransGrid's demand forecast methodology. As demand forecasts are a key input into TransGrid's proposed forecast capex, PB must have regard to a report provided to the AER by McLennan Magasanik Associates (MMA) on TransGrid's demand forecast methodology.[3]

2.3.3 *Probabilistic methodology and outcomes*

PB is required to assess whether the methodology and outcomes of TransGrid's probabilistic approach for determining its proposed forecast capex is reasonable. PB must:

a) describe the probabilistic approach in detail

b) determine the reasonableness of the assumptions and inputs used for the theme sets of the model (for example, economic growth expectations, load growth forecasts, generation scenarios and expected customer connections)

c) describe the scenarios and probabilities of the model and assess whether they are reasonable

d) undertake a review of the transmission plans resulting from probabilistic scenarios to determine whether they are reasonable and appropriate.

2.3.4 *Cost accumulation methodologies and outcomes*

PB is required to assess TransGrid's cost accumulation methodologies and outcomes. PB's review should also be informed by the detailed review of projects discussed in section 2.3.5.

PB is required to review whether TransGrid's proposed cost accumulation methodologies and outcomes reasonably reflect the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the capex objectives, in particular:

a) the unit costs used for developing project cost estimates

b) materials, labour, easement/land and other input cost escalators

c) the weightings employed to the capex forecast when broken down into input cost components for the purposes of applying input cost escalators

d) benchmark costs and current available indicators for TNSPs in the NEM and other relevant businesses

e) prices of capital inputs relative to operating inputs in TransGrid's revenue proposal

3 McLennan Magasanik Associates, *Review of TransGrid's demand forecasts for the period 1 July 2009 to 30 June 2014*, 1 May 2008.

f) contingency, location and any other additional costs used to determine the forecast capex proposal.

PB is also required to review TransGrid's proposed expenditure profiles (S-curves) for projects or programs of work. PB must review the methodology and outcomes of TransGrid's proposed S-curves with reference to historical expenditure profiles in the current regulatory period.

As part of reviewing the proposed input cost escalators for materials, easement/land and other input costs, PB must have regard to the methodology used by the AER in its recent determinations for ElectraNet and SP AusNet.[4] The AER will engage a separate consultant (Econtech) to assess TransGrid's proposed labour cost escalators. PB would be expected to have regard to this assessment of labour cost escalators as part of its review of TransGrid's input cost escalators.

PB must also review TransGrid's proposed methodology and outcomes for its cost estimation risk factor. In determining the reasonableness of the risk factor PB must have regard, where appropriate, to actual project costs incurred in the current regulatory period compared to TransGrid's initial cost estimates for these projects.

2.3.5 Detailed review of projects

PB is required to undertake a detailed review of a sample of network and non-network projects (including augmentations, replacements, connections, easements, IT and support the business categories) chosen in consultation with the AER. The detailed review of each project must assess whether:

a) there is a need for the project

b) a reasonable range of alternatives have been investigated by TransGrid including non-network options

c) the proposed scope of the project is reasonable

d) the proposed costs are reasonable

e) the timing of the project is reasonable

f) the project aligns with TransGrid's capital governance framework including strategic plans and capex policies and procedures

g) the information provided by TransGrid is accurate

h) the value and timing at which the project should be included in the forecast capex requirements.

When assessing the need and timing of a sample of TransGrid's augmentation projects, PB must take into account the findings by MMA on TransGrid's demand forecast methodologies. PB must also consider whether the demand forecasts in TransGrid's

[4] Please see the AER's draft and final determinations for ElectraNet and SPAusNet for their 2008–09 to 2012–13 regulatory control periods.

upcoming 2008 *Annual planning report* impacts on the need and timing of these projects.[5]

PB is required to analyse information prepared by TransGrid, such as business cases including decision-making documentation and planning studies. In making its recommendation on the capex program, PB must take into consideration the review of the capital governance framework discussed in section 2.3.1.

In the event that PB is not satisfied that TransGrid's proposed forecast capex reasonably reflects the capex criteria under clause 6A.6.7 of the NER, PB is required to outline why the proposal is not in accordance with the NER, and provide the AER with an alternative proposal that satisfies the relevant criteria in the NER, outlining an alternative cost and timing for relevant projects. PB would also be required to outline why TransGrid's proposed forecast capex does not accord with the NER and provide the AER with the quantified efficient capex level, and justification for this variance.

2.3.6 Replacement or reconfiguration of a connection asset

The consultant must review whether TransGrid has appropriately classified connection assets in accordance with the AER's interpretation of clause 11.6.11 of the NER. The AER considers that the appropriate interpretation of clause 11.6.11 is that any proposed replacement or reconfiguration of an existing connection asset, grandfathered as providing a prescribed transmission service under clause 11.6.11, should be treated as a negotiated transmission service asset.

2.3.7 Contingent projects

PB is required to examine the contingent projects proposed by TransGrid and assess them in accordance with clause 6A.8.1 of the NER. PB is to assess whether each contingent project is reasonably required to be undertaken during the regulatory control period in order to achieve any of the capex objectives as outlined at clause 6A.6.7 of the NER. PB must examine the reasonableness of the proposed cost of the contingent projects and whether they only relate to expenditure for prescribed transmission services.

PB is also required to assess whether:

a) the proposed contingent project involves expenditures already included in TransGrid's proposed forecast capex

b) the proposed contingent project (or expenditure associated with the contingent project) should be included by the AER in TransGrid's forecast capex

c) the proposed trigger events are appropriate and, if not, what the trigger events should be

d) TransGrid's proposed forecast capex includes expenditure relating to projects that should be more appropriately included as contingent projects and if so, recommend appropriate trigger events

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5 TransGrid's 2008 Annual Planning report will be published after TransGrid submits its revenue proposal.

e) there is likely occurrence in the next regulatory control period of the trigger events associated with any proposed contingent projects.

In the event that PB is not satisfied that TransGrid's proposed contingent project is reasonably required in order to meet any of the capex objectives under clause 6A.6.7, PB is required to outline why the proposal does not accord with the NER.

2.3.7 Deliverability

PB is required to comment on the deliverability of TransGrid's proposed capex program. In particular, PB must have regard to capex delivered in the current regulatory period and TransGrid's capex delivery framework and policies for the next regulatory control period.

2.4 Forecast opex

PB is required to review TransGrid's proposed forecast opex for the next regulatory control period to assess whether it is in accordance with clause 6A.6.6 of the NER. PB's review will analyse and comment on the following matters in relation to the contribution of opex forecasts to TransGrid's delivery of prescribed transmission services:

a) the efficiency of TransGrid's forecast opex for each year of the next regulatory control period and whether there exists any scope for efficiencies

b) the reasonableness of TransGrid's allocation of opex costs to specific activities, including the distinctions between regulated and non-regulated activities; routine maintenance and refurbishments/renewals; efficiency of contractor services; application of its capitalisation policy; and the treatment of joint and common costs such as corporate administration expenses and financing charges

c) the effectiveness of TransGrid's operating practices and procedures and asset management system in ensuring only prudent and efficient opex occurs. This will include an examination of the links between capex and opex proposals, asset management plans, approved cost allocation methodology, corporate governance and whether the linkages are reasonable for an efficient TNSP

d) the reasonableness of the key internal and external factors (including the assumptions) underlying the opex forecast that may affect the level of efficient opex required by TransGrid over the next regulatory control period

e) the reasonableness of TransGrid's methodology to forecast its opex requirements

f) the reasonableness of any trade-off between capex and opex.

This review will require an assessment of TransGrid's past opex, including giving consideration to its historical actual opex. The purpose of this is to identify any long-term trends in opex as well as determining an efficient starting opex for the next regulatory control period. As part of the analysis, PB is required to:

a) analyse and explain any variations between forecast and actual opex for the current regulatory period

b) identify any trends (by category and in total) and explanations as to possible drivers of the trends

c) assess whether the opex forecast reasonably reflects the opex criteria under clause 6A.6.6 of the NER and provide its view on an efficient opex level at the start of the next regulatory control period.

When reviewing TransGrid's forecast opex, PB is required to:

a) explain reasons for, and the reasonableness of, any difference between historical opex levels and the forecast level of opex at the start of the next regulatory control period

b) identify and analyse any trends (by category and in total) and explanations as to possible drivers of the trends in the forecast opex proposal

c) compare past opex information to forecast opex proposal

d) recommend an efficient opex allowance (by category and in total), including whether an efficiency target should apply.

PB should assess its recommendation against current available indicators and benchmarks.

PB may be required to review TransGrid's proposed network (grid) support allowance and comment on whether it is reasonable. PB will need to ensure that there is no overlap between this allowance and the forecast capex program.

PB is not required to review benchmark debt/equity raising costs proposed by TransGrid in its opex forecast.

In the event that PB is not satisfied that TransGrid's proposed opex reasonably reflects the opex criteria under clause 6A.6.6 of the NER, PB is required to outline why the proposal is not in accordance with the NER, and provide the AER with an alternative proposal that satisfies the relevant criteria in the NER. PB would also be required to outline why TransGrid's proposed forecast opex does not accord with the NER and provide the AER with the quantified efficient opex level, and justification for this variance.

2.5 Service target performance incentive scheme

The AER's service target performance incentive scheme (version 2) contains the framework which the AER applies service performance and market impact incentives as part of its revenue cap determination.[6] The scheme includes both a service component and a market impact component.

[6] AER, *Electricity transmission network service providers—service target performance incentive scheme (incorporating incentives based on the market impact of transmission congestion): Final decision*, March 2008.

PB must assess the service target performance incentive scheme values proposed by TransGrid under the service component of the scheme. PB is not required to review the values proposed by TransGrid under the market impact component of the scheme.

For the values and weightings proposed under the service component of the scheme, PB must provide an opinion and detailed reasons on whether TransGrid's proposed performance targets, caps, collars and weighting are consistent with the principles in clause 6A.7.4 of the NER and the AER's service target performance incentive scheme.

If PB disagrees with any aspect of the proposed values and weightings it must provide a substitute. PB must provide detailed reasons for why the substitute is consistent with the principles in the NER and service target performance incentive scheme and indicate the methodologies and assumptions used to derive the substitute value.

PB must also review the recording and reporting systems and processes used by TransGrid to record performance against the service target performance incentive scheme. When conducting this review, PB will assess TransGrid's systems and procedures with the aim of identifying:

a) the accuracy and reliability of the performance data

b) the appropriateness of the recording processes in terms of collecting service standards performance data

c) any systemic weakness in these processes or systems.

2.6 Timing and outcomes

TransGrid will submit its revenue proposal on 2 June 2008. Given the timing requirements set out in the NER, the AER must release its draft determination by 30 November 2008. PB will be required to meet the following deadlines:

a) preliminary meetings with the AER and TransGrid during May 2008 and other pre-lodgement work

b) provision of written document outlining PB's findings on initial issues from its preliminary analysis of revenue proposal by 23 June 2008

c) meetings as required with TransGrid following the submission of its revenue proposal, including inspection of the material required to be held by TransGrid at its premises. These meetings are expected to occur during 7 to 11 July. Further meetings with TransGrid may be required for a period before the submission of the PB's draft report for the purposes of addressing outstanding issues

d) provision of draft written report on its findings, accompanied by a presentation to the AER Board, by 31 August 2008. In addition to the draft report, PB must provide supporting spreadsheets and analysis to ensure the AER can meet the requirements of the NER

e) provision of final written report on its findings by 30 September 2008 (a further presentation to the AER Board may be required). In addition to the final report, PB must provide supporting spreadsheets and analysis to ensure the AER can meet the requirements of the NER

f) attendance at the public forums.

PB must be available for follow-up questions from the AER as well as responding to any issues raised in submissions on the draft determination. The extent and scope of the work is unknown and, potentially, it may not be required. Accordingly, should the AER require further advice from PB following the draft determination, the work will form a separate item under the contract, to be charged at the agreed hourly rates and cap.

2.7 Consultation process

During the course of the reviews, PB is expected to liaise extensively with both TransGrid and the AER. These consultations will include:

a) meetings with TransGrid at its Sydney offices

b) meetings with the AER at its Canberra/Sydney offices

c) possible written and oral requests for additional information and documentation

d) presentations on key findings and conclusions to the AER, including attendance at public forums in Sydney on 30 July 2008 and 9 December 2008.

PB will also be required to liaise extensively with AER staff and provide regular updates on:

a) progress towards achieving deliverables

b) any impediments that have arisen to achieving those deliverables

c) significant issues that have been identified.

Attention is drawn to the requirements of clause 6A.14.2 of the NER. PB's report must be sufficiently detailed to enable the AER to satisfy its obligations to meet the disclosure obligations set out in that clause.

2.8 Timeline

The timetable for the AER's review TransGrid's revenue proposal is set out below.

Pre-lodgement

Date	Event
May 2008	The AER and PB attend briefings and meetings with TransGrid prior to lodgement of revenue proposal. PB assists the AER with analysing TransGrid's project packs.

Date	Event
2 June 2008	Revenue proposal, proposed negotiating framework and proposed pricing methodology due from TransGrid.
1–14 June 2008	PB assists the AER with compliance check of the revenue proposal.
16 June 2008	If TransGrid's submitted proposal documents are compliant with the submission guidelines, the AER must publish TransGrid's revenue proposal, proposed negotiating framework and proposed pricing methodology. The AER must also publish its negotiated transmission services criteria and invite written submissions on TransGrid's proposal documents.
23 June 2008	PB to provide initial issues from preliminary analysis to the AER which would be used to arrange meetings with TransGrid.
From 7 July 2008	The AER and PB to meet with TransGrid to discuss initial issues.
25 July 2008	PB to provide interim draft report on issues to the AER, potentially accompanied by a meeting/discussion.
30 July 2008	The AER holds public forum on revenue proposal (seven weeks after lodgement). PB is required to attend.
15 August 2008[7]	Submissions due on revenue proposal, proposed negotiating framework and proposed pricing methodology.
31 August 2008	PB's draft report due to the AER.
30 September 2008	PB's final report due to the AER.
30 November 2008	The AER is required to publish, and request submissions on, its draft determination and consultants' reports. The AER must also publish notice of a pre-determination conference.
A TNSP may submit a revised revenue proposal, negotiating framework and pricing methodology up to 30 business days after the release of the AER draft decision.	
9 December 2008	Pre-determination conference will be held in Sydney.
16 February 2009[8]	Submissions close on the draft determination and the consultant's report.
30 April 2009	The AER is to release its final determination.

[7] This date may vary if the date that the AER publishes the proposals and request for submission changes. Submissions are due not less than 30 business days after the invitation for submissions is published.

[8] This date may also vary, but must not be earlier than 45 business days after the holding of a pre-determination conference.

APPENDIX B
TRANSGRID'S PLANNING DOCUMENTATION

APPENDIX B: TRANSGRID'S PLANNING DOCUMENTATION

Document	When Required	Description	Authorisation
Annual Planning Report (APR)	Annually by 30th June	The NEM Rules require publication of the APR each year. The APR provides advance information to market participants and interested parties on the nature and location of emerging network constraints in NSW. Publication of proposals to construct small transmission network assets meets the Regulatory Consultation requirements for those assets. Other proposals are included in summary form.	TransGrid Board
Outline Plan	Updated periodically	A plan covering possible network developments within an area or major portion of the network over a medium to long term planning horizon.	GM/ND&RA
Planning Report	For each network limitation	Outcomes of planning analysis documenting a future network limitation or an opportunity to undertake an augmentation. May include a description of preferred or other network options. A Planning Report may take one of the following forms: • A numbered report with a register managed by M/NP; • A summary of work in progress on M/SP&A or M/NP file; • A joint planning report with a distributor; • A major report or submission; or • Other documentation such as emails or memoranda.	As appropriate for the type of report.
Request for Proposals for non-network options (RFP)	For some network limitations	An externally published document that seeks input from industry participants for non-network options. A Request for Proposals contains: • A description of a network limitation, as per relevant planning reports; • A summary of a relevant part of the current load forecast; • A summary of the type, size and timing of non-network options that could be effective in alleviating the network limitation; and • A request for external parties to respond with proposals for non-network options	GM/ND&RA
Project Scoping Report (PSR)	For each network constraint or replacement need	An instruction to GM/CPD to carry out investigation of one or more network options. A "Project Scoping Report" should contain: • A brief statement of the driver for network augmentation/replacement and timing; • A detailed description of the options that require investigation; • A detailed description of what information is expected from the investigation, including cost estimates, project timing and practicability issues. • Required timing of any report from the investigation. • Revised PSRs may be issued to consider additional options after consideration of a feasibility report prepared by CPD.	GM/ND&RA
Feasibility Study Report – Network Options	For each network constraint or replacement need	Report produced by GM/CPD in response to a Project Scoping Report.	GM/CPD

Document	When Required	Description	Authorisati on
Feasibility Study Report Non– Network Options	For some network limitations	Report produced by M/NP or M/SP from responses to a Request for Proposals, consultant's report and/or other information.	GM/ND&RA
Project Commencem ent Approval – Sign off to commence Regulatory Consultation process	For new Network Assets	Approval to initiate the Regulatory Consultation process (DG1).	TransGrid Board MD (small network assets)
Application Notice	For New Large Network Assets (>$10m)	Notice to the market of consultation on a proposal for a New Large Network Asset. A short summary is published by NEMMCO An application notice should contain: • Descriptions of network constraints; • Description of all reasonable options; • A preliminary application of the regulatory test; and • Assessment of whether there is a material inter-network impact.	GM/ND&RA
Final Report	For New Network Assets	Notice to the market of the outcomes of consultation on a proposal for a New Network Asset. For new Large Network Assets the final report should contain information as per the application notice plus: • Summary of outcomes of the consultation (submissions on the Application Notice); • Final application of the regulatory test; and • Recommended action. For New Small Network Assets, an item, with similar but less detailed information, should be included in an Annual Planning Report as the application notice and final report, or may be published separately (as a special report).	GM/ND&RA
Project Definition Report (PDR)	For all network changes or augmentation (other than changes under maintenance or asset management strategies)	Clear definition of what is to be constructed and by when for any project that involves the construction or modification of TransGrid's network. The Project Definition Report will contain: • A brief description of the need for the project; • A brief description of how this project may be linked to other projects; • Detailed technical description of the work required, where it is required and by when; and • Other technical information necessary to complete the project.	Managing Director GM/ND&RA for projects <$1m
Project Funding Approval and Approval for Major Contracts	For all network changes or augmentation	Funding to proceed with construction and related activities as detailed in a Project Definition Report. GM/ND&RA will advise GM/CPD when the Regulatory Consultation for a New Large Network Asset consultation process has been completed and the outcome of the process.	As per expenditure procedures
Generation Scenarios Report	Revenue reset ex-ante capex development, and for major main grid network developments	A document setting out likely generation development scenarios given a range of factors such as climate change, economic growth, forecast load trends. The report would normally provide a probabilistic assessment of different generation options and would typically utilise external expertise.	Service Provider

Document	When Required	Description	Authorisation
Project Option Scope and Estimate Reports	For each option where feasibility assessment and costing is needed.	A document which summaries a need to be addressed, an option to meet that need and the feasibility and costing for that option. Prepared under the accelerated forward planning process for a revenue reset.	Group Managers in ND&RA and CPD
Project Evaluation Summary	For each identified need	A document which summarises a need to be addressed, the options available to meet that need and an evaluation of the options, including a preliminary application of the Regulatory Test. The economic evaluation does not require full sensitivity testing, unless such testing is necessary to reasonably determine the most efficient solution. Prepared under the accelerated forward planning process for a revenue reset.	GM/ND&RA
An ex ante capital expenditure program for inclusion in a revenue submission to the AER	As required for development of a revenue submission	A listing with costing, cash flow and commissioning dates of: • capital projects driven by reliability requirements and asset condition; • a probabilistic forecast for augmentations driven by generation development scenarios; and • contingent projects and the relevant triggers.	Approved by GM/ND&RA for submission to Managing Director and TransGrid Board

Source: TransGrid 2008, 'Network Planning Processes and Documentation', Revision No: 0, Issue Date: 28 May 2008, Document No: ND NP G2 002, Attachment 2, page 13.

In addition TransGrid has identified the following planning document that is not identified in the 'Network Planning Processes and Documentation'' policy document ND NP G2 002.

Document	When Required	Description	Authorisation
Strategic Network Development Plan	To provide information to stakeholders on the future of the NSW transmission network	Provides a long term vision of the NSW transmission network and complements the Annual Planning Reports	GM/ND&RA

APPENDIX C
BANNABY-SOUTH CREEK 500 KV LINES & SUBSTATION

APPENDIX C: BANNABY- SOUTH CREEK 500 KV LINES AND SUBSTATION

The Bannaby-South Creek 500 kV lines and substation project (Project ID 5567) is an augmentation project with an anticipated commissioning date in 2014 under 16 of the 36 scenarios forecast by TransGrid[1]. Table C-1 shows the estimated capex for this project that has been included in the overall ex-ante allowance (excluding easements).

By value, this project ranks as the largest ex-ante augmentation expenditure item, and is equivalent to 13.4% of TransGrid's proposed network capex in the 2009/10-2013/14 regulatory period.

Table C-1 – Capex for Bannaby-South Creek 500 kV lines and substation

Expenditure $m (real, 07/08)	2009/10	2010/11	2011/12	2012/13	2013/14	Total
Project 5567 (Median)	1.5	3.9	28.5	179.0	109.5	322.5
Project 5567 (Weighted Average)	1.7	9.8	62.6	110.4	63.1	247.6

Source: TransGrid, CAM V1.8_Future deliverables 12a.xls.

C.1 Project overview

The Newcastle–Sydney–Wollongong load corridor is a major load area accounting for 75% of the NSW peak demand and approximately one third of the total NEM load. While TransGrid expect the load growth in the Newcastle–Sydney–Wollongong area to be met partially by the development of generation within this load corridor, generation development outside this corridor is also anticipated under a range of future generation development scenarios. Consequently, TransGrid is of the view that network reinforcement will be required in order to meet the anticipated load growth, and accommodate the generation development scenarios[2].

During summer, the load in the Newcastle–Sydney–Wollongong load corridor exceeds 10,000 MW, and TransGrid forecast load growth at about 270-300 MW per annum, after demand side measures are considered. About 5650 MW of generation within the corridor is anticipated to be available to partially supply this load by early next decade. However, additional generation will be required outside the load corridor to meet the expected load growth, and this will need to be supplied over the transmission network from sources outside the load corridor[3].

To address the network constraints that arise from the load growth in the Newcastle-Sydney-Wollongong load corridor, TransGrid has a long-term strategy to progressively develop a 500 kV network to supply this area. TransGrid has also committed to the development of reactive support (to the maximum extent practical) in order to defer the development of the 500 kV system for as long as possible. In the Project Evaluation

1 The an anticipated commissioning date is 2013 in 15 of the 36 scenarios, 2015 in 3 of the 36 scenarios and 2016 in 2 of the 36 scenarios.

2 TransGrid 2008, 'Project Evaluation Summary - Reinforcement of Supply to the Newcastle-Sydney-Wollongong Load Corridor', Document Number: PES 5567, Project Number 5567, REVISION 2, Dated 20/05/2008, page 6.

3 TransGrid 2008, 'Project Evaluation Summary - Reinforcement of Supply to the Newcastle-Sydney-Wollongong Load Corridor', Document Number: PES 5567, Project Number 5567, REVISION 2, Dated 20/05/2008, page 16.

Summary, TransGrid has addressed the following supply reinforcement options and developments[4]:

- reactive support within the load corridor
- reactive support at major power stations which are critical to supporting the voltage in the load corridor
- rearrangement of 330 kV circuits to the west of Vales Point
- development of a 500 kV link between Bannaby and Sydney
- development of a 500 kV link between the Hunter Valley and the coast.

That is, TransGrid expect to achieve network reinforcement through a sequence of reactive plant installations followed by the progressive development of the 500 kV network.

Over the 2009/10-2013/14 regulatory period, TransGrid is proposing to develop a double circuit 500 kV transmission line between Bannaby (to the west of Bowral) and South Creek in Sydney's west. This proposal essentially involves the rebuilding of the existing 330 kV line from Bannaby (39 line) as a 500 kV circuit. At South Creek, in the Luddenham area to the west of Sydney, the 39 line crosses the existing Eraring to Kemps Creek line. It is also proposed to establish a new 500/330 kV substation in this location, turn in the Eraring to Kemps Creek line, and connect the new 500 kV Bannaby line[5].

Based on the 2007 load forecast, a 500 kV transmission line will need to be commissioned between Bannaby and Sydney by 2014 under 16 of the 36 scenarios forecast by TransGrid[6]

C.2 Drivers (need or justification)

TransGrid has stated that the primary driver for this project is the load growth in the Newcastle–Sydney–Wollongong load corridor, and the generation developments that are anticipated to occur in order to meet this growth. TransGrid also highlight that generation development is expected to be required in order to meet the overall state load growth.

TransGrid uses a scenario based planning process that is discussed more fully in section 5.2. Under this planning process, 36 scenarios for generation development are considered. The Bannaby-South Creek 500 kV lines and substation project was identified in all scenarios considered, with commissioning dates ranging from 2013 to 2016[7]. The anticipated commissioning date is 2014 under 16 of 36 of these scenarios based on the 2007 demand forecast.

TransGrid has stated that the need arises due to two factors under each of the planning scenarios[8]:

- line loadings exceeding the line thermal ratings; and/or
- voltage control capability of the system being exceeded.

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4 TransGrid 2008, 'Project Evaluation Summary - Reinforcement of Supply to the Newcastle-Sydney-Wollongong Load Corridor', Document Number: PES 5567, Project Number 5567, REVISION 2, Dated 20/05/2008, page 6.

5 TransGrid 2007, "Feasibility Study – Bannaby–Sydney 500 kV Line Development Feasibility", Document No: FS PSR 131, Rev 01, Dated 14/08/07, page 1.

6 The an anticipated commissioning date is 2013 in 15 of the 36 scenarios, 2014 in 16 of the 36 scenarios, 2015 in 3 of the 36 scenarios and 2016 in 2 of the 36 scenarios.

7 The anticipated commissioning date is 2013 in 15 of the 36 scenarios, 2015 in 3 of the 36 scenarios and 2016 in 2 of the 36 scenarios.

8 TransGrid 2008, 'Summary of Need and Timing for the Southern 500 kV Line', Project Number 5567, Supplementary Document, Dated 15/8/2008, page 3-4.

Specifically, in regards to line loading, following a forced outage of the Bannaby–Sydney West 330 kV single circuit line, or the Avon–Macarthur via Leafs Gully 330 kV single circuit line, or the Dapto–Sydney South 330 kV single circuit line the remaining in service lines will be heavily loaded. In the case of scenario 16[9], based on the 2007 50% probability of exceedance forecast, an outage of either the Avon-Macarthur via Leafs Gully line or the Dapto to Sydney South line will result in overload of the other line as shown in Table C-2.

Table C-2 – Forecast Line loading under contingent outage conditions (% of Contingent Rating)

	Summer 2013/14	Summer 2014/15	Summer 2015/16
Bannaby – Sydney West No. 39	95%	98%	99%
Avon – Macarthur (via Leafs Gully) No. 37	104%	112%	124%
Dapto – Sydney South No. 11	103%	112%	125%

Source: TransGrid 2008, 'Summary of Need and Timing for the Southern 500 kV Line', Project Number 5567, Supplementary Document, Dated 15/8/2008, page 4.

TransGrid has timed the project in 2015/16 for this scenario. TransGrid has noted that the anticipated 4% overload in 2013/14 is tolerable as it is anticipated this will be able to be reduced further through the installation of capacitor banks[10].

Voltage control limitations arise in the Sydney area following the forced outage of any one of a number of 330 kV single circuit lines. The line loading compared to contingent rating is shown in Table C-3 for the case of scenario 16[11], based on the 2007 10% probability of exceedance forecast.

9 Scenario 16 is the most probable scenario with a probability of 17.4% and involves medium load growth at 10% probability of exceedance, interregional trading – business as usual, a limited water availability, and a CO_2 tax.

10 TransGrid 2008, 'Summary of Need and Timing for the Southern 500 kV Line', Project Number 5567, Supplementary Document, Dated 15/8/2008, page 4.

11 Scenario 16 involves medium load growth at 10% probability of exceedance, interregional trading – business as usual, a limited water availability, and a CO_2 tax.

Table C-3 – Required Level of Reactive Support - Scenario 16

	Summer 2013/14	Summer 2014/15	Summer 2015/16
Reactive support requirement with Munmorah 3 & 4 available for service[12] (MVAr)	Nil	353	635
Reactive support requirement with Munmorah 3 & 4 de-commissioned[13] (MVAr)	217	683	893

Source: TransGrid 2008, 'Summary of Need and Timing for the Southern 500 kV Line', Project Number 5567, Supplementary Document, Dated 15/8/2008, page 7.

This table shows that under scenario 16, by the summer of 2015/16 an additional 635 to 893 MVAr would be required to be installed on the Sydney system. TransGrid is of the view that while the installation of a further 400 to 600 MVAr of reactive support is manageable, higher levels are not considered feasible due to:

- space limitations in the Sydney substations; and
- the ability to increase the level of shunt compensation and hence the voltage at the point of collapse (on the traditional PV or QE curves).

It is also noted that the Leafs Gully to Macarthur line and the Dapto to Sydney South line operate at a design temperature of 120^{o}C and cannot be uprated.

C.3 Strategic alignment and policy support

Development of the Bannaby-South Creek 500 kV lines and substation project is addressed in the NSW Main System Outline Plan[14], and in the 2007 Annual Planning Report. This project is also identified in the Strategic Network Development Plan. Documentation in accordance with the asset management strategy and the project evaluation procedure has been included in the project documentation provided.

C.4 Alternatives

To address the identified need, TransGrid has considered a range of options including reactive support, line augmentation, line rerating, and various 330 kV and 500 kV network development options. In the Project Evaluation Summary, TransGrid noted the following supply reinforcement options and developments[15]:

- reactive support within the load corridor

12 Note the main system planning criteria which allows for the unavailability of one of the Munmorah units when assessing reactive support requirements. Hence the results in the table assume that one of the Munmorah units is out of service.

13 With both Munmorah units de-commissioned it is assumed that all other Central Coast generating units are in service. Further consideration will be given to this assumption in the future to ensure that this assumption does not introduce unacceptable risks to the Sydney area supply. It is possible that there is a need to consider a further unit out of service, such as a Vales Pt unit or a Sydney area GT, which would lead to increased reactive support requirements.

14 TransGrid 2008, "NSW Main System Outline Plan OLP 01", Outline Plan No.1, Version 2 – June 2008, page 16-25.

15 TransGrid 2008, 'Project Evaluation Summary - Reinforcement of Supply to the Newcastle-Sydney-Wollongong Load Corridor', Document Number: PES 5567, Project Number 5567, REVISION 2, Dated 20/05/2008, page 6.

- reactive support at major power stations which are critical to supporting the voltage in the load corridor
- rearrangement of 330 kV circuits to the west of Vales Point
- development of a 500 kV link between Bannaby and Sydney
- development of a 500 kV link between the Hunter Valley and the coast.

Specifically, TransGrid considered options within the following classes[16]:

- reactive plant and minor works – including capacitor bank installations, line series compensation, and minor line works (specifically the rearrangement of 330 kV circuits west of Vales Point to address local line loading problems) – these options are summarised in Table C-4 below
- southern system 330 kV developments – which includes options for new 330 kV line development to support the load corridor from the south – these options are summarised in Table C-5 below
- southern system 500 kV developments – which includes a set of feasible options for a new 500 kV line development to support the load corridor from the south including termination at Kemps Creek – these options are summarised in Table C-6 and Table C-10 below
- western system developments – that involve the development of a 500 kV line from Mt Piper to different termination points within the Sydney area – these options are summarised in Table C-7 below
- northern system 330 kV developments – that involve the development of a 330 kV line from the Hunter Valley to the coast to support the load corridor from the north – these options are summarised in Table C-8 below
- northern system 500 kV developments – which involve the development of a 500 kV line from the Hunter Valley to the coast to support the load corridor from the north – these options are summarised in Table C-9 below.

[16] TransGrid 2008, 'Project Evaluation Summary - Reinforcement of Supply to the Newcastle-Sydney-Wollongong Load Corridor', Document Number: PES 5567, Project Number 5567, REVISION 2, Dated 20/05/2008, page 40-65.

Table C-4 – Reactive plant and minor works

Option Description	Option cost (+/-25%)[17]
Capacitor banks – Sydney area - Reactive plant installations in the Sydney area (timing dependent on scenario)	$2.5m to $4.6m each
Power station reactive support - Reactive generation at the coal-fired power stations – equivalent to 8 x 330 kV 200 MVAr capacitor banks	Approximately $4.6m per 330 kV capacitor bank
Minor line works - Rearrangement of 330 kV circuits west of Vales Point	$6.3m
Line series compensation - Series compensation of selected lines	$20m per installation - approximate – see text

Source: 'Project Evaluation Summary - Reinforcement of Supply to the Newcastle-Sydney-Wollongong Load Corridor', Document Number: PES 5567, Project Number 5567, REVISION 2, Dated 20/05/2008, page 43.

Table C-5 – Southern system 330 kV developments

Option Description	Option cost (+/-25%)
South A - Bannaby – Sydney No. 39 line uprate conductor temperature to 100oC.	$20.0m
South B - New single circuit 330 kV line from Bannaby to Sydney West on a new route, in addition to the existing 330 kV line	$179.9m
South C - Replace the existing Bannaby – Sydney West 330 kV single circuit line with a double circuit 330 kV line	$136.2m
South D - New single circuit 330 kV line from Marulan to Sydney West on a new route	$196.2m
South E - New double circuit 330 kV line from Marulan to Sydney West on a new route	$170.7m
South F - New single circuit 330 kV line from Bannaby to Dapto on a new route	$113.6m
South G - New double circuit 330 kV line from Bannaby to Dapto, replacing the Marulan – Dapto 330 kV line on part of the route	$112.6m
South H - New single circuit 330 kV line from Marulan to Dapto on a new route	$101.9m
South I - New double circuit 330 kV line from Marulan to Dapto, replacing the Marulan – Dapto 330 kV line	$87.9m

Source: 'Project Evaluation Summary - Reinforcement of Supply to the Newcastle-Sydney-Wollongong Load Corridor', Document Number: PES 5567, Project Number 5567, REVISION 2, Dated 20/05/2008, page 44.

17 Option costs approximately reflect the POSE documents or the Capital Accumulation Model.

Table C-6 – Southern system 500 kV developments

Option Description	Option cost (+/-25%)
South 1A - New Bannaby to Kemps Creek 500 kV double circuit line via South Creek, replacing the existing Bannaby – Sydney West 330 kV line.	$315m +3rd Kemps Creek 500/330 kV transformer $30.1m Total $345.1m
South 1B - New Bannaby to Kemps Creek 500 kV double circuit line via Badgerys Creek, replacing the existing Bannaby – Sydney West 330 kV line.	$280m +3rd Kemps Creek 500/330 kV transformer $30.1m Total $310.1m
South 2 - New Bannaby to South Creek 500 kV double circuit line, replacing the existing Bannaby – Sydney West 330 kV line.	$327.5m (includes cost of South Creek 500 kV Substation)
South 3 - New Bannaby to Cobbitty 500 kV double circuit line, replacing the existing Bannaby – Sydney West 330 kV line.	$343m (includes cost of Cobbitty 500 kV substation)
South 4 - New Bannaby to Sydney West 500 kV double circuit line, replacing the existing Bannaby – Sydney West 330 kV line.	$376m (includes cost of Sydney West 500 kV switchyard)

Source: 'Project Evaluation Summary - Reinforcement of Supply to the Newcastle-Sydney-Wollongong Load Corridor', Document Number: PES 5567, Project Number 5567, REVISION 2, Dated 20/05/2008, page 45.

Table C-7 – Western system developments

Option Description	Option cost (+/-25%)
West 1 - New double circuit 500 kV line from Mt Piper to Cobbity, with re-development of the remainder of No. 39 line to Sydney West as a double circuit 330 kV line	$346.9m
West 2 - New double circuit 500 kV line from Mt Piper to Cobbity, with re-development of part of the remainder of No. 39 line to Kemps Creek as a double circuit 330 kV line	$374.4m
West 3 - New double circuit 500 kV line from Mt Piper to Kemps Creek	$310.5m + 3rd transformer at Kemps Ck $30.1m Total cost $340.6m

Source: 'Project Evaluation Summary - Reinforcement of Supply to the Newcastle-Sydney-Wollongong Load Corridor', Document Number: PES 5567, Project Number 5567, REVISION 2, Dated 20/05/2008, page 46.

Table C-8 – Northern system 330 kV developments

Option Description	Option cost (+/-25%)
North 330 kV 1 - New single circuit 330 kV line from Liddell to Richmond Vale on a new route	$116.1m
North 330 kV 2 - New double circuit 330 kV line from Liddell to Richmond Vale on a new route	$142.1m
North 330 kV 3 - New single circuit 330 kV line from Liddell to Eraring	$124.6m
North 330 kV 4 - New double circuit 330 kV line from Liddell to Eraring	$162.4m

Source: 'Project Evaluation Summary - Reinforcement of Supply to the Newcastle-Sydney-Wollongong Load Corridor', Document Number: PES 5567, Project Number 5567, REVISION 2, Dated 20/05/2008, page 46.

Table C-9 – Northern system 500 kV developments

Option Description	Option cost (+/-25%)
North 1 - New double circuit 500 kV line from Bayswater to Eraring on a new route (via Richmond Vale area but without the development of Richmond Vale Substation)	$270.5m +3rd transf. at Kemps Ck $30.1m Total cost $300.6m[a]
North 2 - New double circuit 500 kV line from Bayswater to Eraring via Richmond Vale, by replacing No.81 and No. 24 lines	$260.4m + Richmond Vale 500/330 kV Substation $80.4m + 3rd transf. at Kemps Ck $30.1m Total cost $370.9[a]m
North 3 - New double circuit 500 kV line from Bayswater to Richmond Vale (Does not require 3rd transformer at Kemps Ck)	$211.5m + Richmond Vale 500/330 kV Substation $80.4m Total cost $291.9m[a]
North 4 - New double circuit 500 kV line from Bayswater to Richmond Vale, by reconstructing No.81 line (Does not require 3rd transformer at Kemps Ck)	$182.4m + Richmond Vale 500/330 kV Substation $80.4m Total cost $262.8m[a]
Hunter Valley – Sydney - New double circuit 500 kV line from Bayswater to Sydney, by reconstructing the Bayswater – Sydney double circuit 330 kV line	Not considered feasible

NOTE [a] The development of a 500 kV line from Bayswater to Eraring raises the short circuit level at the Hunter Valley power station 330 kV switchyards. The preferred remedial action is the re-connection of the Bayswater units 1 and 2 to the 500 kV switchyard. This involves an additional cost of the order of $50m

Source: 'Project Evaluation Summary - Reinforcement of Supply to the Newcastle-Sydney-Wollongong Load Corridor', Document Number: PES 5567, Project Number 5567, REVISION 2, Dated 20/05/2008, page 47.

Table C-10 – Kemps Creek 3rd 500/330 kV transformer

Option Description	Option cost (+/-25%)
3rd transformer - 3rd 500/330 kV transformer and switchbays	$30.1m

Source: 'Project Evaluation Summary - Reinforcement of Supply to the Newcastle-Sydney-Wollongong Load Corridor', Document Number: PES 5567, Project Number 5567, REVISION 2, Dated 20/05/2008, page 47.

In addition to these basic alternative solutions to addressing the need, TransGrid also considered a number of line route and termination points in the Sydney area for the various line options. In regards to the 500 kV line from Bannaby the termination options are:

- the existing Kemps Creek 500 kV switchyard
- Sydney West, with the development of a new 500 kV switchyard
- Cobbity where the No. 39 line route crosses the Wallerawang – Sydney 330 kV double circuit line
- South Creek where the No. 39 line route intersects with the 500 kV line between Eraring and Kemps Creek.

The main features of the options considered are shown in Table C-11.

Table C-11 – Line route and termination options comparison

Issue	To Kemps Ck via South Ck	To Kemps Ck via Badgerys Ck	To South Ck	To Cobbity	To Sydney West
Total overall capital cost of the option $m	345	310	327.5	343	376
Feasibility within Sydney	Probably more difficult to achieve than Badgerys Ck option on approach to Kemps Creek	Probably easier than South Ck option on approach to Kemps Creek but green-fields line route required.	Higher impact than stopping the 500 kV line at Cobbity	Possibly least impact within Sydney – double circuit 330 kV line required to Sydney West from Cobbity	Proximity to residential areas
Use of existing route	Used apart from the line section to Sydney West	Used apart from the line section to Sydney West	South Creek to Sydney West connection developed as a double circuit 330 kV line	Cobbity to Sydney West as connection developed as a 330 kV double circuit line	Full use is made
Closes 500 kV ring	Yes	Yes	Yes	No – only achievable if progress to South Ck later and establish a 500 kV switchyard there	No – would need a line from Kemps Ck to Sydney West or a South Creek 500 kV switchyard
Needs additional substation site	No	No	Yes	Yes	Yes
Need for additional line corridor in Sydney	No	Yes	No	No	No

Source: 'Project Evaluation Summary - Reinforcement of Supply to the Newcastle-Sydney-Wollongong Load Corridor', Document Number: PES 5567, Project Number 5567, REVISION 2, Dated 20/05/2008, page 51-52.

TransGrid concluded that at the time of developing the Project Evaluation Summary (20/05/2008) that *"… it is not possible to identify the option that would be built as significant environmental assessment and social impact considerations and community consultation processes are required to be undertaken"*[18].

It was also noted by TransGrid that due to the *"… system advantage in closing the 500 kV ring, the Kemps Creek termination or the South Creek 500 kV substation development are preferred"*[19]. TransGrid has also noted that:

18 TransGrid 2008, 'Project Evaluation Summary - Reinforcement of Supply to the Newcastle-Sydney-Wollongong Load Corridor', Document Number: PES 5567, Project Number 5567, REVISION 2, Dated 20/05/2008, page 52.

19 TransGrid 2008, 'Project Evaluation Summary - Reinforcement of Supply to the Newcastle-Sydney-Wollongong Load Corridor', Document Number: PES 5567, Project Number 5567, REVISION 2, Dated 20/05/2008, page 52.

"The South Creek termination provides a viable alternative if there are barriers in developing the 500 kV line to Kemps Creek. It is considered that the double circuit 500 kV line section between South Creek and Kemps Creek would provide adequate power transfer capability between the two sites for many years. Hence it is considered necessary to reserve an appropriate site at South Creek for a 500/330 kV substation at this stage"[20].

In the supplementary document entitled 'Summary of the Selection of the Preferred Option for the Southern 500 kV Development' (Dated 15/8/2008), TransGrid stated that:

"… that a Bannaby – South Creek 500 kV double circuit line, along the route of the existing Bannaby – Sydney West 330 kV line, is the least cost feasible option and meets the long-term strategic requirements of the system"[21].

In regards to this statement and the three possible line routes in the Sydney area, the supplementary document further noted[22]:

- Badgerys Creek to Kemps Creek on a new easement ($310M) – this route has been rejected as not being feasible as the proposed line route:
  - traverses the possible second Sydney airport site
  - would require the demolition of areas of existing housing
  - requires a new easement which would not receive planning approval where the option to re-use an existing easement is available
- South Creek to Kemps Creek, parallel to the existing Eraring – Kemps Creek line ($345M) – is the highest cost option and would not receive planning approval where the option to re-use of an existing easement is available
- reconstruction of the Bannaby–Sydney West line as far as South Creek ($317M) – this option does not require substantial new line easements in the Sydney area and is the least cost feasible 500 kV line development option.

TransGrid has selected the option of developing a double circuit 500 kV transmission line between Bannaby and South Creek which utilises the rebuilding of the existing 330 kV line from Bannaby[23]. TransGrid determined the NPV for the preferred option to be approximately $180m[24].

C.5 Timings

Based on the 2007 load forecast, commissioning of the Bannaby to South Creek 500 kV lines and substation project is anticipated to be in 2014 under 16 of the 36 scenarios forecast by TransGrid[25].

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20 TransGrid 2008, 'Project Evaluation Summary - Reinforcement of Supply to the Newcastle-Sydney-Wollongong Load Corridor', Document Number: PES 5567, Project Number 5567, REVISION 2, Dated 20/05/2008, page 53.

21 TransGrid 2008, 'Summary of the Selection of the Preferred Option for the Southern 500 kV Development', Project Number 5567, Supplementary Document, Dated 15/8/2008, page 2.

22 TransGrid 2008, 'Summary of the Selection of the Preferred Option for the Southern 500 kV Development', Project Number 5567, Supplementary Document, Dated 15/8/2008, page 3-6.

23 TransGrid 2007, "Feasibility Study – Bannaby–Sydney 500 kV Line Development Feasibility", Document No: FS PSR 131, Rev 01, Dated 14/08/07, page 1.

24 TransGrid 2008, 'Project Evaluation Summary - Reinforcement of Supply to the Newcastle-Sydney-Wollongong Load Corridor', Document Number: PES 5567, Project Number 5567, REVISION 2, Dated 20/05/2008, page 79.

25 The anticipated commissioning date is 2013 in 15 of the 36 scenarios, 2014 in 16 of the 36 scenarios, 2015 in 3 of the 36 scenarios and 2016 in 2 of the 36 scenarios.

Explicit justification for this timing was presented in the project documentation provided, in particular the supplementary document entitled ‘Summary of Need and Timing for the Southern 500 kV Line’. Broadly this timing is driven by network constraints that arise under the 2007 load forecast, and the 36 planning scenarios developed that define the anticipated generation development paths over the planning period. This timing is discussed further in section C.2 above.

C.6 Costs and scope

Table C-12 shows the base cost estimate for the Bannaby-South Creek 500 kV lines and substation project.

Table C-12 – Base cost estimates for Bannaby-South Creek 500 kV lines and substation

Work Scope Item	Estimate[1]
Bannaby to South Creek 500 kV TL (107km)	$191M
South Creek Substation Establishment	$70M
Line Rearrangements at South Creek	$2M
Bannaby Substation Augmentation	$12M
Transmission Line and South Creek Substation Property Costs[2]	Not included
Total Estimate	$275.0m

Note 1: This estimate is in real 2006/07 dollars, and does not include real labour and material escalation impacts or any risk allowance

Note 2: These costs were TBA in the Feasibility Study report. TransGrid now estimate these costs at $ 54.0m (Template-AER Schedule (for AER).xls – sheet 4.3).

Source: TransGrid 2007, “Feasibility Study – Bannaby–Sydney 500 kV Line Development Feasibility”, Document No: FS PSR 131, Rev 01, Dated 14/08/07, page 23.

It is noted in the Feasibility Study that and independent review of the transmission line costing has been carried out by quantity surveyor, and this includes a condition assessment of the line access tracks[26].

The scope of the work includes the following:

- rebuilding the existing 330 kV line (39 line) from Bannaby to point where this line crosses the Eraring to Kemps Creek line at South Creek (approx. 107km)
- establishment of a 500/330 kV substation in the vicinity of the South Creek line overcrossing point
- connecting the new 500 kV Bannaby line, turning in the existing Eraring to Kemps Creek line and connecting the tail end of 39 line to the new substation.

26 TransGrid 2007, “Feasibility Study – Bannaby–Sydney 500 kV Line Development Feasibility”, Document No: FS PSR 131, Rev 01, Dated 14/08/07, page 24.

C.7 PB analysis

This section presents PB's view of the project information provided by TransGrid in support of the expenditure for this proposed project. The following sections address each of the key issues when considering the prudence and efficiency of a proposed capital investment.

Drivers (need or justification)

The driver of this project has been stated by TransGrid to be the load growth in the Newcastle–Sydney–Wollongong load corridor, and the generation developments that are anticipated to occur in order to meet this growth. TransGrid's scenario based planning has identified that there are two network constraints that arises under each of the planning scenarios[27]:

- line loadings exceeding the line thermal ratings; and/or
- voltage control capability of the system being exceeded.

While the timing of these constraints are different under the various scenarios, TransGrid has determined that these constraints arise in 2013 in 15 of the 36 scenarios, 2014 in 16 of the 36 scenarios, 2015 in 3 of the 36 scenarios and 2016 in 2 of the 36 scenarios. The details of this are further discussed in section C.5 above and in section 5.2 of the main body of this report.

It is PB's opinion that the information presented supports the view that network constraints will arise under a range of reasonably probable scenarios. Furthermore PB is of the view that these constraints will need to be addressed in order to secure supply to the Newcastle-Sydney-Wollongong load corridor. Consequently, in PB's opinion the need identified by TransGrid has been reasonably demonstrated and we believe it is prudent to address this need.

PB also notes, that in our opinion, a significant project of this magnitude may have some material market benefits in the context of reduced transmission losses (improved MLF's), improved inter-regional transfer capabilities and reduced intra-regional constraints. PB has not indentified any documentation submitted by TransGrid to identify or quantify these benefits to aid in the preferred project selection.

Strategic alignment and policy support

PB is of the view that the Bannaby-South Creek 500 kV lines and substation project aligns with TransGrid's strategies as stated in the NSW Main System Outline Plan[28], and in the 2007 Annual Planning Report.

Alternatives

TransGrid's project documentation presents consideration of a range of options, which can be broadly classified as[29]:

- reactive plant and minor works – including capacitor bank installations, line series compensation, and minor line works (specifically the rearrangement of 330 kV circuits west of Vales Point to address local line loading problems)

27 TransGrid 2008, 'Summary of Need and Timing for the Southern 500 kV Line', Project Number 5567, Supplementary Document, Dated 15/8/2008, page 3-4.

28 TransGrid 2008, "NSW Main System Outline Plan OLP 01", Outline Plan No.1, Version 2 – June 2008, page 16-25.

29 TransGrid 2008, 'Project Evaluation Summary - Reinforcement of Supply to the Newcastle-Sydney-Wollongong Load Corridor', Document Number: PES 5567, Project Number 5567, REVISION 2, Dated 20/05/2008, page 40-65.

- southern system 330 kV developments – which includes options for new 330 kV line development to support the load corridor from the south
- southern system 500 kV developments – which includes a set of feasible options for a new 500 kV line development to support the load corridor from the south including termination at Kemps Creek
- western system developments – that involve the development of a 500 kV line from Mt Piper to different termination points within the Sydney area
- northern system 330 kV developments – that involve the development of a 330 kV line from the Hunter Valley to the coast to support the load corridor from the north
- northern system 500 kV developments – which involve the development of the a 500 kV line from the Hunter Valley to the coast to support the load corridor from the north

Further details of these options are presented in section C.4 above.

PB also notes TransGrid's statement that it has addressed the following supply reinforcement options and developments[30]:

- reactive support within the load corridor;
- reactive support at major power stations which are critical to supporting the voltage in the load corridor;
- rearrangement of 330 kV circuits to the west of Vales Point;
- development of a 500 kV link between Bannaby and Sydney; and
- development of a 500 kV link between the Hunter Valley and the coast.

Hence TransGrid expect to achieve network reinforcement through a sequence of reactive plant installations followed by the progressive development of the 500 kV network.

Having considered the fundamental need identified by TransGrid, PB is satisfied that an appropriate range of practical alternatives has been identified and considered. However, PB has a number of concerns with the options analysis as presented:

- while the analysis considered the costs of the various options, no consideration was presented of the comparison between the NPVs of the various options;
- the options analysis as presented did not include consideration of the sensitivity of the estimates and hence the impact of this sensitivity to the selection of the preferred option. In this case the three primary options were[31]:
  - $310m - Badgerys Creek to Kemps Creek on a new easement
  - $345m - South Creek to Kemps Creek, parallel to the existing Eraring – Kemps Creek line
  - $317m - reconstruction of the Bannaby–Sydney West line as far as South Creek

  Given the uncertainties in the cost estimates, scopes of work, land issues, etc. variation in these key input assumptions may be sufficient to alter the choice of

30 TransGrid 2008, 'Project Evaluation Summary - Reinforcement of Supply to the Newcastle-Sydney-Wollongong Load Corridor', Document Number: PES 5567, Project Number 5567, REVISION 2, Dated 20/05/2008, page 6.

31 TransGrid 2008, 'Summary of the Selection of the Preferred Option for the Southern 500 kV Development', Project Number 5567, Supplementary Document, Dated 15/8/2008, page 3-6.

the preferred option. In PB's opinion, the impact of variation in the key input assumptions should have been demonstrated in the options analysis.

- while project risk is presented and assessed in the Feasibility Study, the baseline risk assessment (i.e. the do nothing option risk) was very limited, and implied in the statement of the need rather than being explicitly documented as a clear statement of the do nothing risk. PB also notes that consideration of the do nothing option was also not explicitly presented.
- the options analysis qualitatively addressed a number of benefits and costs, however in the limited NPV analysis presented these was no apparent qualitative assessment of the benefits or and some cost elements such operating and maintenance costs (savings) were not presented in the NPV analysis.

In PB's opinion, while TransGrid's has identified and considered an appropriate range of practical alternatives, the options analysis presented is lacking. In PB's view, as far as is practical, an options analysis should be based on comparison of the various options NPVs, and should include the value of all know costs and benefits, as well as unbiased estimates of uncertain costs and benefits. Where there are uncertain costs and benefits, a sensitivity analysis should be used to demonstrate the likelihood that the recommended option is the highest value option[32]. Externalities that can't reasonably be estimated can then be used to support the final recommendation. Additionally, consideration of the do nothing option also forms a critical point of reference for the value of the alternatives being considered. Without explicit identification of the value (and risks) of the base case (i.e. do nothing) the benefit of accepting an alternative investment can't be fully defined.

Notwithstanding PB's views on the options analysis presented by TransGrid, we acknowledge that the qualitative assessment of the costs and benefits does demonstrate the relative merits of the preferred option over the alternatives. Specifically, of the three primary options identified in the additional documentation presented by TransGrid, PB notes that the only reasonable option is the selected option. The remaining two options are excluded on the basis of:

- Badgerys Creek to Kemps Creek on a new easement ($310m)
    - Traversing the possible second Sydney airport site at Badgerys Creek;
    - Demolition of areas of existing suburbs;
    - Low probability of receiving planning approval when an existing corridor could be used.
- South Creek to Kemps Creek, parallel to the existing Eraring – Kemps Creek line ($345m)
    - Low probability of receiving planning approval when an existing corridor could be used.

PB is of the view that an alternate route that does not traverse the possible airport site and the demolition and land acquisition required in existing suburbs should have been reasonably costed and reflected in the options analysis. Notwithstanding this, PB acknowledge that, on the basis of the retrospective justification document prepared by TransGrid, the selected 'reconstruction of the Bannaby–Sydney West line as far as South Creek' option at $317m represents the least cost feasible option.

Therefore PB is of the opinion that the most efficient option has been chosen.

32 Or conversely the lowest cost where benefits are excluded.

Timings

TransGrid has proposed to commission the Bannaby to South Creek 500 kV lines and substation project in 2014. This timing is based on the 2007 load forecast and the timing of the identified network constraints under each of the 36 planning scenarios considered by TransGrid (refer also to section C.5 above).

While the timing of these constraints are different under the various scenarios, TransGrid has determined that these constraints arise in 2013 in 15 of the 36 scenarios, 2014 in 16 of the 36 scenarios, 2015 in 3 of the 36 scenarios and 2016 in 2 of the 36 scenarios.

It is PB's opinion that the information presented supports the view that network constraints will arise under a range of reasonably probable scenarios. Consequently, PB is of the opinion that the timing identified by TransGrid has been reasonably demonstrated, and we believe that this timing represents and efficient investment.

Specifically, in the highest weighted and most influential scenario (16), PB notes that TransGrid has timed the project in 2016 even though there is potential for a 12% overload during the preceding summer. In PB's view the project is more appropriately required in the preceding summer.

PB also has some concerns regarding TransGrid's ability to deliver this project should any of the 15 scenarios it is required in 2013 eventuate, and for which costs have been built into the forecast allowance.

Costs and scope

TransGrid's selected option involves the redevelopment of 107km of existing 330 kV line, the establishment of a new 500/330 kV substation, and line works associated with the connection of this substation to the existing network and the new 500 kV Bannaby to South Creek line. More detail of this scope is given in section C.6 above.

TransGrid has provided detailed cost estimates for this work[33] which are summarised in Table C-12. It was noted in the Feasibility Study that and independent review of the transmission line costing has been carried out by a quantity surveyor, and this includes a condition assessment of the line access tracks[34].

PB has conducted a review of the detailed costing as part of our unit cost benchmarking analysis (refer section 3.4 of the main body of this report). This review concluded that in PB's opinion TransGrid's unit costs are in general on the higher side of our expectation for transmission construction. We acknowledge that the construction of 500 kV assets is a relatively infrequent activity, and hence experience with these assets within the industry is specialised and limited. On this basis PB is of the view that the costs as set out in Table C-12 do represent an efficient estimate of the costs for the proposed works.

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33 TransGrid 2007, "Feasibility Study – Bannaby–Sydney 500 kV Line Development Feasibility", Document No: FS PSR 131, Rev 01, Dated 14/08/07, Appendix C.

34 ibid, page 24.

C.8 Conclusion

PB has conducted a detailed review of the proposed Bannaby to South Creek 500 kV lines and substation project, and we are of the opinion that the project is prudent, and that it represents efficient investment.

Table C-13 sets out PB's recommendation on the prudency and efficiency of the submitted expenditure associated with the Bannaby to South Creek 500 kV lines and substation project.

Table C-13 – PB recommendation for Bannaby-South Creek 500 kV lines and substation

Expenditure $m (real, 07/08)	2009/10	2010/11	2011/12	2012/13	2013/14	Total
Submitted	1.7	9.8	62.6	110.4	63.1	247.6
Proposed variation	-	-	-	-	-	-
PB recommendation	1.7	9.8	62.6	110.4	63.1	247.6

Source: TransGrid, CAM V1.8_Future deliverables 12a.xls. and PB analysis.

APPENDIX D
HOLROYD-CHULLORA 330 KV CABLE

APPENDIX D: HOLROYD-CHULLORA 330 KV CABLE

The Holroyd-Chullora 330 kV Cable is an augmentation project (Project ID 6204) with an anticipated commissioning date in 2013. Table D-1 shows the estimated total cost of this project (excluding easements).

TransGrid's submission estimates the value of the project at $244.5m. Easements associated with this cable are estimated at a further $21.5m. The Holroyd-Chullora 330 kV Cable is a component of a larger project – the inner metropolitan 330 kV supply. In TransGrid's revenue proposal the cost of the full project is estimated at $512m in 2008 prices[35].

This project ranks as the second largest overall ex-ante augmentation expenditure item, accounting for 10.1% of TransGrid's network capex in the 2009/10-2013/14 regulatory period.

Table D-1 – Capex for Holroyd-Chullora 330 kV cable

Expenditure $m (real, 07/08)	2009/10	2010/11	2011/12	2012/13	2013/14	Total
Project 6204 (Median and Weighted Average)	-	23.5	187.5	33.5	-	244.5

Source: TransGrid, CAM V1.8_Future deliverables 12a.xls.

D.1 Project overview

TransGrid asserts that the reinforcement of supply to the inner metropolitan area is required by the summer of 2012/2013 due to growth in load and ageing assets becoming unserviceable. The Holroyd-Chullora 330 kV cable is proposed, as part of the wider project, to alleviate the constraints to the network by summer 2012/2013[36]. This project is an augmentation project and does not involve replacement of existing assets.

TransGrid has identified that unless this augmentation project is developed, then Sydney West 330/132 kV substation will become overloaded in the coming years. The project also provides a connection point for 330 kV cables in the Chullora area. TransGrid has identified an ultimate requirement for three 330 kV overhead lines from the west. An additional bulk supply point for EnergyAustralia in the Chullora/Potts Hill area has also been identified.

There are four discrete elements to the overall project:

- Sydney West to Holroyd 330 kV transmission line

  The first element of the project is the construction of three 330 kV circuits from Sydney West substation to the Holroyd area. TransGrid has identified feasible routes for these cables.

- Holroyd 330/132 kV substation

  Following an analysis of alternatives, TransGrid has identified a preferred location in Hyland Road for a new 330/132 kV substation in the Holroyd area.

- Hyland Road, Holroyd to Chullora 330 kV cable

35 TransGrid 2008, 'Revenue Proposal 31 may 2008', page 63, Figure 7.11.

36 TransGrid 2008, 'Project Evaluation Summary: Inner Metropolitan 330 kV Supply: Project Number 5995', page 6.

The next element of the project is the development of a new cable from the Hyland Road substation to Chullora. TransGrid proposes to install a second circuit at the same time. This element of the full project is examined in this review. Apart from acknowledging that it is one of four elements of the full project, no opinion is given here on the validity or efficiency of the other three elements.

- Chullora 330/132 kV substation

  TransGrid is proposing to build a bulk supply point at Chullora to meet EnergyAustralia's needs.

TransGrid states that the main reason for the establishment of the Holroyd substation is to relive loading on the Sydney West substation. In addition, the site would provide a connection point for the proposed 330 kV cables to Chullora – which are required to support an additional substation for EnergyAustralia[37].

TransGrid has stated that before this project gets underway, that it is implementing a number of minor network augmentations in order to defer the need for an additional 330 kV bulk supply point as long as possible[38]. These minor works include:

- increase size of Sydney South transformers to alleviate overloading (to be completed by 2009)
- increase 41 series reactor size to ensure better sharing of load between 41 and 42 cables (to be completed by 2010)
- additional transformer to be installed at Sydney North to alleviate overloading (to be completed by 2010)
- additional transformer to be installed at Beaconsfield West (to be completed by 2009)
- new 132 kV circuits between Kernel and Bunnerong (to be completed by 2010)

TransGrid states that completion of these projects will allow the system to be operated within the required reliability standards until 2012/13, by which time it intends to have the inner metropolitan 330 kV supply augmentation completed.

D.2 Drivers (need or justification)

TransGrid and EnergyAustralia have agreed to adopt a reliability criterion for the Sydney Inner Metropolitan transmission system that is more onerous than the normal n-1 basis used in the rest of NSW.

The agreed criterion stipulates that the system should be capable of meeting the peak load under the following contingencies:

- the simultaneous outage of a single 330 kV cable and any 132 kV feeder or 330/132 kV transformer; or
- an outage of any section of 132 kV busbar.

Based on the 2007 demand forecast, TransGrid modelling of the network has identified constraints under peak load conditions which will develop on the network by 2012/13. The

37 TransGrid 2008, 'Sydney West – Holroyd – Chullora overall feasibility study', page 5.

38 TransGrid 2008, 'Project Evaluation Summary – Document no. 5995 – Inner Metropolitan 330 kV supply', page 9.

identified constraints will have the consequence of breaching the reliability criterion agreed with EnergyAustralia.

TransGrid maintains that without the inner metropolitan 330 kV project, the loading on the current system is likely to lead to failure of either the Sydney South – Beaconsfield West or Sydney South – Haymarket 330 kV cables and any of a number of other critical circuits or transformers which may result in the rating of some remaining network elements being exceeded at or near high load periods.

D.3 Strategic alignment and policy support

The Holroyd-Chullora 330 kV cable aligns with the strategy to augment the 330 kV supply to the inner metropolitan region. The project is referenced in the Outline Plan OLP02 – Supply to the greater Sydney and Sydney metropolitan areas.

D.4 Alternatives

TransGrid has undertaken an option evaluation for the full inner metropolitan 330 kV supply project, which considered three major network augmentation options to avoid the forecast reliability problems:

- supply from Sydney West comprising a 330 kV double circuit overhead transmission line to Holroyd, a new 330/132 kV substation at Holroyd and two 330 kV cables to a new Chullora 330/132 kV substation
- supply from Sydney East comprising a 330 kV cable to Haymarket and establishment of Holroyd 330/132 kV substation, supplied from Sydney West via a 330 kV double circuit overhead transmission line
- supply from Sydney North comprising a 330 kV cable to Haymarket and establishment of Holroyd, supplied from Sydney West via a 330 kV double circuit overhead transmission line

TransGrid has dismissed the Sydney North option as not feasible because it would involve closing down other circuits. The Sydney West option is the preferred option due to lower cost than the Sydney East option (NPV of -$548m in 2008 dollars compared to -$621m)[39].

D.5 Timings

As stated in section D.1, TransGrid intends to implement a number of minor network augmentations in order to defer the need for an additional 330 kV bulk supply point as long as possible. TransGrid expects that the completion of these projects would allow the system to be operated within the required reliability standards until 2012/13, by which time it intends to have the inner metropolitan 330 kV supply augmentation completed.

Therefore it is presently expected that to address the identified limitations, an additional 330 kV line and 330/132 kV substation development supporting the Sydney CBD and inner metropolitan area will be required by summer 2012/13.

Expenditure on the proposed solution would take place over the three year period 2010/11 to 2012/13.

39 TransGrid 2008, 'Project Evaluation Summary – Document No 5995 – Inner Metropolitan 330 kV Supply' page 12.

D.6 Costs and scope

TransGrid has evaluated the costs of the preferred option to be $512m (2008 prices). The component of the Holroyd – Chullora project is estimated at $244.5m.

The scope of the work includes the laying new 330 kV cable(s) from Holroyd, Hyland road to a new Chullora 330/132 kV substation.

TransGrid commissioned J-Power Systems (JPS) to develop a cable route between the proposed substation at Hyland Road, Holroyd and EnergyAustralia's Chullora substation site. Two route options were examined. The main route (approximately 17km includes a 5km section within Sydney Water's pipeline corridor. A slightly longer route (approximately 18km could be achieved through public roads and reserves with minimal impact on the Sydney Water corridor. The JPS investigation was based on a targeted cable rating of 790 MVA with one circuit in operation. This is reduced to 680 MVA with both circuits in operation (if two circuits are installed in the same trench), and the 72 hour cyclic rating has been assumed to be a minimum of 900 MVA peak, with a daily cyclic loading pattern equivalent to that of 42 cable.

Four installation conditions were considered: Trench direct buried, Duct bank embankment, micro tunnel and horizontal directional drilling. A cable size of 1800mm^2 was recommended as the most suitable size of cable to most practically achieve the rating range under installation conditions.

D.7 PB analysis

This section presents PB's view of the project information provided by TransGrid in support of the expenditure for this proposed project. The following sections address each of the key issues when considering the prudence and efficiency of a proposed capital investment.

Drivers (need or justification)

PB is concerned that the exact specifications chosen by TransGrid to alleviate the forecast loading problem may be more than is strictly necessary. In particular the laying of a second circuit between Holroyd and Chullora may not be needed at this time.

PB makes the following observations in relation to the Holroyd to Chullora 330 kV cable.

The JPS review of potential cable routes for the Hyland Road to Chullora 330 kV cable identified two possible routes. TransGrid states that the first route is preferred because it is shorter and reduces the number of parties to consult.

However, more significantly, TransGrid states that only one cable is required to initially satisfy the reliability criteria as set out in section C2 above. TransGrid suggests that a second cable is likely to be needed 5 years after installation of the first cable.

JPS also provided a review of costs and other issues associated with laying two single circuit cables at different timeframes versus laying a double circuit cable initially. PB has not reviewed the JPS report in detail, however, from a review of the key findings it is not clear that a second cable would be needed in this timeframe. PB has seen no sensitivity analysis to demonstrate the impact of uncertainty in this timing.

JPS identifies the benefits of installing two cables simultaneously as a reduced trench width requirement (less environmental impact), reduced EMF and hence reduced separation required to residences, and reduced community impacts associated with a second excavation.

The results of JPS's option cost assessment are given in following Table D-2. Note that PB has not audited these costs but received clarification from TransGrid how it applied a comparative figure of 180% for the cost of installing two cables at the same time relative to the cost of installing one cable.[40]

Table D-2 – Options for circuits on Holroyd-Chullora 330 kV Cable - based on JPS analysis

Option		km	Cost $m per km	Year 1	Year 5	NPV
Option 1 : Install one circuit	First cable	18.0	6.7	120.6		120.6
Option 2: Install one circuit now with second circuit along different route in 5 years	First cable	18.0	6.7	120.6		
	Second cable	21.6	6.7		144.72	224.0
Option 3 : Install one circuit now with extra provisions for second cable along same route in 5 years	First cable	18.0	8.6	154.8		
	Second cable	18.0	8.6		154.80	265.0
Option 4: Install two circuits together	First & second cables	18.0	12.0	216.0		216.0

Source: PB analysis based on figures provided in the Sydney West – Holroyd – Chullora overall feasibility study.

TransGrid's proposal is to install the two cables simultaneously (option 4 in the above table). If a need is established for double cabling then the JSP analysis shows that it is more cost effective to install the two circuits together rather than separately, even if some preparation for the second circuit is done in advance i.e. Option 4 is preferred to option 2 or 3 in table C-2 above.

It is PB's view that this decision not to choose option 1 is very significant, as it adds some $95m to the project above the costs of installing a single cable (Option1 in table C-2). The estimated cost for a double circuit is $216m compared to $121m for a single circuit.[41] However the need for the second cable is not made explicit by TransGrid.

In its feasibility study[42], TransGrid has asserted that these calculations are preliminary and should be reviewed by ND&RA to ensure they are consistent with the assumptions and methodologies used in regulatory justifications, and will withstand the level of scrutiny likely to accompany such significant investment decisions.

PB agrees that it is vital that a proper analysis of the costs takes place before any decision is made to proceed with installing the second cable. This revenue reset review covers the period 2009 to 2014; it is likely that if we were just looking at cost accruing during the period of the review then the option of installing a single cable would be preferred. TransGrid needs to demonstrate that taking a longer-term investment decision could result in significant savings to customers.

Before PB could recommend that a second circuit is laid at the same time as the first circuit, it would need analysis of the need for the cable to be demonstrated. That is, the extra costs for funding the second cable would be the rate of return times the extra $95m for four or five years. The benefits of laying the second cable now would need to outweigh this extra cost.

Assuming that the need for the second cable is justified; then the decision needs to be taken between installing one circuit initially with a second circuit along a different route later or installing two circuits together. The JPS analysis shows that installing the two cables together has a lower NPV, with a saving of $8m. In addition to this cost saving there are a number of non-quantifiable savings associated laying two cables simultaneously. These include:

40 TransGrid 2008, TransGrid response to PB Advice – Number 6 Issue F11.

41 TransGrid 2008, ' Feasibility Study Report – Document No FS PSR 12_18_25' table 11.1.

42 TransGrid 2008, 'Sydney West – Holroyd – Chullora Overall Feasibility Study' page 8.

- a single environmental and planning approval
- single construction disturbance to the community
- maximising the utilisation of scarce rout corridors
- consistency with strategic network development plan
- prudent avoidance of EMF.

On this basis, PB agrees that the most efficient option would be the laying of the two cables at the same time as this is the least cost option.

PB recommends that the budget for this project should be reduced by the amount required to lay the second cable. TransGrid's budget for the project should therefore be reduced by $95m. If the need for the second cable is demonstrated then the laying of the two cables together option is the most efficient.

Strategic alignment and policy support

PB is of the view that the Holroyd-Chullora 330 kV cable aligns with TransGrid's policies and strategies to augment the inner metropolitan 330 kV supply as set out in the Outline plan – Supply to the greater Sydney and Sydney metropolitan areas.

Alternatives

PB is concerned that a convincing argument has not been made for the second circuit. In order for this to be done, TransGrid would need to demonstrate that the capacity needed at the Chullora substation will be not be served by a single 330 kV circuit into the substation. TransGrid also need to demonstrate the likely timing of the demand surplus, thus warranting the upgrade to the double circuit. It could be that demand may not be sufficient until many more years into the future in which case the laying of the second circuit would be surplus to requirement during this revenue reset period. Without further analysis PB cannot make a recommendation that the second circuit is installed. The only information we have regarding the timing of the second cable is contained in the Outline Plan OP2 – Supply to the Greater Sydney and Sydney metropolitan areas which states that 'It is expected that two double circuit 330 kV lines will ultimately be required to supply the load at Holroyd and beyond'.

PB could not recommend that the second circuit be installed until a definite assessment of the need for the second cable takes place. While it is entirely possible that a second cable will eventually be needed given long–term growth forecasts, the case for expenditure in this period has (in our opinion) not been made. In order to reinforce its case, TransGrid needs to show load growth at the proposed Chullora substation, and constraints that arise due to a single 330 kV circuit.

TransGrid has recommended proceeding with option 4 (refer table C-2). Unless it can demonstrate the need within the appropriate timeframe, PB recommends that the appropriate option should be option 1.

Timings

The timing of the proposed Hyland Road to Chullora 330 kV cable project achieves commissioning by summer 2012/13. PB notes that based on TransGrid's network modelling under the 2007 demand forecast, this timing is the latest possible in order to avoid the identified constraints under peak load conditions, which breaches the reliability criterion agreed with EnergyAustralia. Notwithstanding our views on the timing of the second circuit, PB is of the opinion that this is efficient timing for the first circuit.

Costs and scope

PB recommends that unless TransGrid can demonstrate the need for the second circuit, expenditure on this project should be reduced to the cost of the single 330 kV cable option.

TransGrid has provided detailed cost estimates for this project. The JPS study recommended laying a PPLP fluid filled insulated cable of $1800mm^2$. The cost of this cable is estimated for 18 km of 330 kV double circuit cable at $12 m per km, giving a total cost of $216m. Easements associated with the cable are estimated at $18.3m giving a lump sum total for the project estimated at $234.2 m (including easements, unescalated).

Based on PB's benchmarking analysis contained in section 3.5, which revealed that TransGrid's unit costs were at the higher end, but still within our expected range of accuracy, we believe that this is an appropriate cost estimate for this type of cable and installation.

D.8 Subsequent update

The above review was completed on the basis of information provided by TransGrid with their submission, and in response to questions and discussions to clarify the information provided in TransGrid's business documentation. This information was received prior to 20 August 2008. As discussed further in section 5 of the main body of this report, since completing the above review, TransGrid has provided subsequent updates to the project; specifically:

- a revised Project Evaluation Summary entitled 'Supplementary Report – PES – Inner Metropolitan 330 kV Supply, Project Number 5995, 6263', dated 22/08/08;
- a further revision of the Project Evaluation Summary entitled 'Supplementary Report – PES – Inner Metropolitan 330 kV Supply, Project Number 5995, 6263', dated 05/09/08
- an EnergyAustralia document; "Transmission Plan – Sydney Inner Metropolitan", dated May 2008.

This subsequent information is considered in this section, along with its implications on PB views and recommendations. Only those areas impacted by the subsequent information are considered in this section.

Drivers (need or justification)

A significant amount of further information was provided in the revised PES documents. In particular, specific information relating to the nature and extend of the constraints associated with load growth in the inner metropolitan area, and EnergyAustralia's withdrawal from service of specific 132 kV cables that are becoming unserviceable[43]. The constraints identified by TransGrid arising by 2012/13 are shown in Table D-3, and the subsequent constraints that arise prior to summer 2017 are shown in Table D-4.

[43] TransGrid 2008, "Supplementary Report - PES – Project Title: Inner Metropolitan 330 kV Supply", Project Number: 5995, 6263, Dated 22/08/08, page 8.

Table D-3 – Constraints identified for 2012/2013

Constraint (modified n-2 criteria)	Consequence
Outage of cable 42 and 91M/1	Overload on Sydney North Transformer (103.2%)
	Overload of 41 cable (102.3%)
Outage of cable 41 and 91M/1	Overload on Sydney North -Transformer (101.6%)
	Overload of 42 cable (100.5%)
Outage of 42 and one Sydney South transformer	Overload of remaining Sydney South transformers (102.4%)
	Overload of 41 cable (103%)
Outage of 41 and one Sydney South transformer	Overload of remaining Sydney South transformers (103.5%)
	Overload of 42 cable (102.3%)
Outage of 42 and one Sydney North transformer	Overload of 41 cable (100.5%)

Source: TransGrid 2008, "Supplementary Report - PES – Project Title: Inner Metropolitan 330 KV Supply", Project Number: 5995, 6263, Dated 05/09/08, page 9.

Table D-4 – Constraints identified for 2017/18

Constraint (modified n-2 criteria)	Consequence
Outage of 42 cable and one Sydney South transformer	Overload of remaining Sydney South transformers (106.9%)
Outage of 41 cable and one Sydney South transformer	Overload of remaining Sydney South transformers (103.7%)
Outage of 43 cable and one Sydney South transformer	Overload of remaining Sydney South transformers and 42 cable (102.8%)
Outage of 42 cable + any one of the four Chullora to Marrickville/St Peters cables	Overload of the remaining three Chullora to Marrickville/St Peters cables (103.7%)

Source: TransGrid 2008, "Supplementary Report - PES – Project Title: Inner Metropolitan 330 kV Supply", Project Number: 5995, 6263, Dated 05/09/08, page 10.

PB notes that the timing of the withdrawal from service of EnergyAustralia's 132 kV cables is uncertain, and in particular the point that *"… should EnergyAustralia proceed with the retirement of a further two Lane Cove to Daley Street cables, … the constraints may arise as early as November 2015 …"*[44].

The latest revision of the PES (dated 05/09/08) includes a set of load flow result documents that highlight the constraints noted in the revised PES. An EnergyAustralia transmission planning document addressing the Sydney inner metropolitan plans for the period 2007 to 2020 (document dated May 2008) was also supplied.

Alternatives

The revised PES documents, present additional information regarding the analysis of the alternatives. In particular, additional sensitivity analysis information is presented, along with an expanded consideration of the risks of various options which is incorporated into the option analysis and risk assessment in section 3.6 of the revised PES. In particular PB notes:

44 TransGrid 2008, "Supplementary Report - PES – Project Title: Inner Metropolitan 330 kV Supply", Project Number: 5995, 6263, Dated 22/08/2008, page 9.

> *"Since the lodgement of TransGrid's revenue proposal in May 2008, TransGrid has continued to work at refining the timing of each component of works, particularly the timing of specific lines and cables. Hence the Present Value of Cost (PVC) of the results in this report will be marginally different from those contained in PES5595 and PES6276."*

In regards to the critical issue of the timing of the second cable, and the impact of this timing on the selection of the preferred option, the key findings of the addition analysis are presented in Table D-5. This table shows three options:

- option 1 – two cables between Holroyd and Chullora installation together;
- option 2 – one cable between Holroyd and Chullora initially, with a second cable on a new and separate route; and
- option 3 – one cable between Holroyd and Chullora initially with provision for the future installation of a second cable, and the subsequent installation of the second cable[45].

The timing of the works is for completion of the primary works by November 2012, with the subsequent stages timed according to three scenarios:

- scenario 1 – subsequent works completed by November 2015;
- scenario 2 – subsequent works completed by November 2016; and
- scenario 3 – subsequent works completed by November 2017.

PB notes that TransGrid has used a real discount rate of 9% for the base case with sensitivity at 6% and 12% for the discount rate, and approximately 26% and 24% for the capital cost.

45 TransGrid 2008, "Supplementary Report - PES – Project Title: Inner Metropolitan 330 kV Supply", Project Number: 5995, 6263, Dated 22/08/2008, page 21.

Table D-5 – Sensitivity analysis findings[1]

	Option 1 PV of costs ($M)	Rank	Option 2 PV of costs ($M)	Rank	Option 3 PV of costs ($M)	Rank
Timing scenario 1 (base)	603	1	628	2	654	3
12% discount rate	473	1	503	2	525	3
6% discount rate	769	1	767	1	798	3
26% increase capital cost	759	1	791	2	825	3
24% decrease capital cost	458	1	482	2	502	3
Timing scenario 2 (base)	603	1	604	1	632	2
12% discount rate	473	1	469	1	492	2
6% discount rate	769	1	778	2	811	3
26% increase capital cost	759	1	761	1	795	2
24% decrease capital cost	458	1	459	1	479	2
Timing scenario 3 (base)	603	2	583	1	608	2
12% discount rate	473	2	461	1	483	3
6% discount rate	769	3	721	1	751	2
26% increase capital cost	759	3	735	1	767	2
24% decrease capital cost	458	2	449	1	468	2

Note 1: Where the present value of costs of options are within $5M of each other then they are equally ranked.

Source: TransGrid 2008, "Supplementary Report - PES – Project Title: Inner Metropolitan 330 kV Supply", Project Number: 5995, 6263, Dated 22/08/2008, page 20-21.

TransGrid also included an elaboration of some of the key issues raised in other previously supplied documents. This information was supplied in the form of Table D-6.

Table D-6 – Key issues comparison

Criteria	Description	Option 1	Option 2	Option 3
1	Meeting Community Expectations including repeated construction disturbance	Disturbs community once	No Produces unacceptable repeated disturbance	Higher than option 1 but may be manageable if disclosed early
2	Environmental and Planning Approvals	Minimises impact on community. Co-locates with Sydney Water infrastructure	Multiple impacts due to requirement for 2 cable routes.	Impact is higher than option 1 but may be manageable if disclosed early
3	Maximise utilisation of scarce route corridors	Yes	No. Sterilises part of corridor	Yes
4	Consistency with Strategic Network Development Plan	Yes	No. Reduces number of cables from Sydney West	Yes
5	EMF and prudent avoidance	Yes	More community impact as two separate routes are used	Acceptable, although EMF is higher than option 1 due to wider separation

Source: TransGrid 2008, "Supplementary Report - PES – Project Title: Inner Metropolitan 330 kV Supply", Project Number: 5995, 6263, Dated 22/08/2008, page 22.

TransGrid concluded that option 2 (i.e. initially lay one cable, with a second cable on a new and separate route) was not prudent, and recommends option 1 (i.e. initially lay two cables)[46].

PB analysis

PB's concern has been the justification for the second cable, and specifically the timing of the need that drives the installation of the second cable. Based on TransGrid's original documentation, and PB's detailed review, we concluded that in our opinion the drivers, strategic alignment and timing of the project are demonstrated to be both prudent and efficient, and that a reasonable range of alternative options has been identified. However, we could not conclude that the scope and cost efficiency of the selected option had been adequately demonstrated, due to the lack of specific support for the need and timing of the second cable. On this basis PB's recommendation was the least cost option of the single circuit option with installation of a second cable at a later date. The adoption of this recommendation would result in a reduction of $95.0 in the proposed ex-ante capex allowance.

In PB's opinion, the revised PES documentation, along with the information contained in the load flow documents, and the Energy Australia transmission plan, support the position that the second cable is likely to be required prior to 2017 due to the impacts of the retirements and alterations to EnergyAustralia's 132 kV cable network. That is, the revised information shows that need for the second cable arises within 5 years of the installation of the first cable. On the basis of this cash flow timing, PB is now of the opinion that the option to lay both cables together is efficient. PB's revised conclusions are given in the following section.

46 TransGrid 2008, "Supplementary Report - PES – Project Title: Inner Metropolitan 330 kV Supply", Project Number: 5995, 6263, Dated 05/09/08, page 25.

D.9 Conclusion

PB has conducted a detailed review of the Holroyd-Chullora 330 kV Cable augmentation project, and considers that the drivers, strategic alignment and timing of the project are demonstrated to be both prudent and efficient. We are also of the view that a reasonable range of alternative options has been identified, and based on the revised information provided by TransGrid (see previous section); we also are of the view that the scope and cost efficiency of the selected option has been demonstrated.

Table D-7 sets out PB's recommendation based on our assessment of the prudency and efficiency of the submitted expenditure associated with the Holroyd-Chullora 330 kV Cable augmentation project.

Table D-7 – PB recommendation for Holroyd-Chullora 330 kV cable

Expenditure $m (real, 07/08)	2009/10	2010/11	2011/12	2012/13	2013/14	Total
Submitted	-	23.5	187.5	33.5	-	244.5
Proposed variation	-	-	-	-	-	-
PB recommendation	-	23.5	187.5	33.5	-	244.5

Source: TransGrid, CAM V1.8_Future deliverables 12a.xls .and PB analysis.

APPENDIX E
DUMARESQ-LISMORE 330 KV LINE - AUGMENTATION

APPENDIX E: DUMARESQ-LISMORE 330 KV LINE

The Dumaresq-Lismore 330 kV Line is a committed[47] augmentation project (Project ID 9094) with a proposed commissioning date set invariably in 2012. Table E-1 shows the estimated total cost of this project (excluding easements).

Table E-1 – Capex for Dumaresq-Lismore 330 kV Line

Expenditure $m (real, 07/08)	2009/10	2010/11	2011/12	2012/13	2013/14	Total
Project 9094 (Median and Weighted Average)	5.5	80.0	80.0	-	-	165.5

Source: TransGrid, CAM V1.8_Future deliverables 12a.xls.

This project ranks as the third largest overall ex-ante expenditure item and accounts for 6.7% of TransGrid's network capex in the 2009/10-2013/14 regulatory period. There is also just over $1.1m of historical capex associated with this project in the current regulatory period.

E.1 Project overview

The far north coast of NSW, which includes major supply points at Coffs Harbour, Koolkhan, Lismore and Nambucca, is presently supplied by one major 330 kV line, an underlying 132 kV network and the DirectLink interconnection with south east Queensland. At times of high demand, outage of the 330 kV line can cause thermal overloads of the remaining network and poor voltages. The existing demand in the area is approximately 370 MW in 2007/08, growing by 100 MW to 470 MW in the 5-year period to 2012/13[48]. As the demand grows these technical issues become more severe, eventually resulting in the need for investment.

TransGrid is proposing to construct a new single circuit 215km, 330 kV transmission line between Dumaresq switching station and Lismore substation, and provide the appropriate switchgear, protection and monitoring devices at these sites to allow the new circuit to be operated.

TransGrid and Country Energy published an Application Notice for the new large transmission network asset in accordance with the NER in April 2008, and is anticipating the publication of the final report in October 2008 after the appropriate industry consultation.

The joint Application Notice also justifies two other projects in the revenue submission:

- uprating the Armidale-Coffs Harbour 132 kV line to allow a maximum conductor operating temperature of 100ºC in 2009/10 at a cost of $8m. This has the effect of deferring the major augmentation (Project ID 599049)
- the second Coffs Harbour 330/132 kV transformer at a cost of $13.4m in 2013/14 (Project ID 599950).

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47 A project that has been formally approved in accordance with TransGrid's governance process. TransGrid has approved this project through to DG1.

48 Page 12, Application Notice, Development of Electricity Supply to the NSW Far North Coast (TransGrid, April 2008).

49 PB notes that project 5990 has a cost of $13.1m in the templates and is timed for 2011 (i.e. 2010/11).

50 PB notes that project 5999 has a cost of $10.8m in the templates and is timed for 2012 (i.e. 2011/12), and that TransGrid advised that the advanced timing was a result of deliverability smoothing.

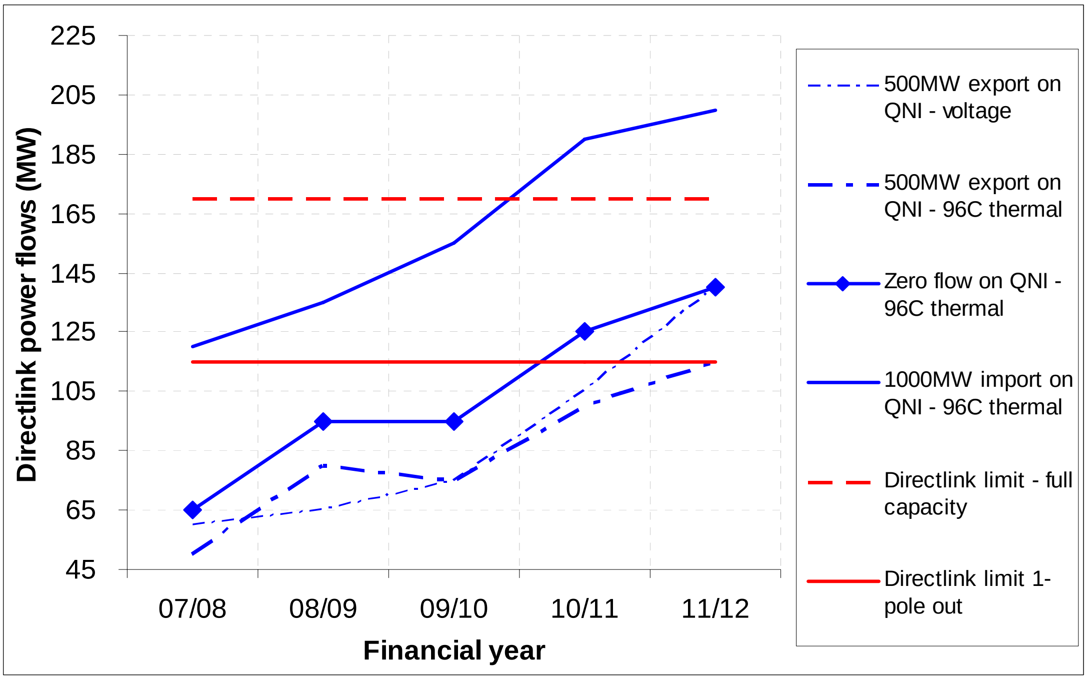
E.2 Drivers (need or justification)

The fundamental and most critical need for this investment, as outlined in the Application Notice[51], is a combination of thermal and voltage limits arising as a result of the N-1 outage of the 137km long Lismore-Coffs Harbour 330 kV line. The underlying Armidale-Coffs Harbour 132 kV line becomes overloaded and unacceptably low voltages occur at the heavily loaded and remote Lismore substation busbars.

The degree of overloaded or suppressed voltages is critically dependant on the support provided by DirectLink, and the inter-regional transfer between NSW and Queensland.

The constraint is depicted in Figure E-1, which shows the limits of DirectLink (as horizontal constraints) under full rated capacity (170 MW) and with one pole unavailable (115MW). Superimposed on these capabilities are the flows that DirectLink is required to carry under (Medium growth, 50% PoE) peak summer demand conditions coincident with the critical N-1 outage condition, and under a range of inter-regional flows on QNI.

Figure E-1 – Flows required on DirectLink to eliminate constraints



The key observations from Figure E-1 are that:

- even in 2007/08, 1000 MW import from QNI is not possible without the full capacity of DirectLink available
- and it will be constrained below 1000 MW in 2010/11 even with all three poles available
- without any investment prior to summer 2010/11, QNI import to NSW will be constrained below 1000 MW even with the full capacity of DirectLink available
- without any investment prior to summer 2010/11, and even with 500 MW QNI export to Queensland, unacceptable constraints will occur even with DirectLink at its restricted (1-pole out) capacity.

51 Application Notice, Development of Electricity Supply to the NSW Far North Coast (TransGrid, April 2008), page 28.

As part of the conversion of DirectLink to a regulated inter-connector, the AER assumed that if the capacity of DirectLink was taken to be that of two of the three links, then appropriate levels of availability could be achieved.

Secondary voltage limit constraints also exist for outage of the Coffs Harbour-Lismore 330 kV line (causing low voltages at Lismore) and for outages of the Coffs Harbour 330/132 kV transformer (causing low voltages locally), however neither of these influence the timing of the Dumaresq-Lismore 330 kV line development.

E.3 Strategic alignment and policy support

Development of the Dumaresq-Lismore 330 kV line is addressed in the Supply to the North Coast of NSW outline plan[52], and in the 2007 Annual Planning Report. Documentation includes the Application Notice and the relevant Project Scoping Reports, Project Feasibility Study Report and Project Definition Report, where direct references are made to the transmission planning criteria.

E.4 Alternatives

As part of the Application Notice, TransGrid considered and evaluated two options:

- the development of a 215km Dumaresq-Lismore 330 kV line
- the development of a 300km Armidale-Lismore 330 kV line

Across a range of sensitivity studies (discount rates, annual O&M costs, asst lifetimes and capital costs), the present value economic assessments identified the Dumaresq-Lismore 330 kV line was always the lowest cost alternative. In the base case study the difference in PV's was $49m ($111m compared with $160m).

TransGrid's concluded the Dumaresq-Lismore 330 kV line was the preferred option.

In addition to the two options that were evaluated, TransGrid also documented and considered four other network development possibilities. These included:

- a 139km Armidale-Kempsey 330 kV line and an associated 330/132 kV substation at Kempsey – dismissed, amongst other reasons, on the basis it would take an extra two years to develop; it would not defer further augmentation as well as other options; and the logistical issues associated with the reconstruction of the existing Armidale-Kempsey 132 kV line
- a 200km Ebenezer(QLD)-Lismore 330 kV line – dismissed on the basis of the difficulties in obtaining a suitable line route; and the likely impacts on advancing development needs in south east Queensland
- a 300km Armidale-Coffs Harbour-Lismore 330 kV line – dismissed on the basis of the difficulties in obtaining suitable line routes and the considerable cost of development over the long distance
- 132 kV line developments – dismissed on technical grounds due to limited transfer capability and the adverse environmental and community impacts associated with the need for multiple lines within a short space of time from one another.

52 TransGrid 2007, "Outline Plan OLP 08 Supply to the North Coast of NSW", Outline Plan No.8, Version 2 – Nov 2008, page 8-11.

E.5 Timings

The application highlights the year of onset of the network limitations is around 2010 with reasonable levels of support from DirectLink. However each of the two options evaluated could only be practically completed in late 2011[53]. TransGrid's revenue proposal includes this project in 2012 (i.e. 2011/12).

E.6 Costs and scope

As outlined in TransGrid's Project Definition Report[54] and Project Feasibility Study Report[55], the scope of work for this project is summarised in Table E-2, and the total cost is $151m ±25% in 2005/06 dollars.

Table E-2 – Capex for Dumaresq-Lismore 330 kV Line

Item	Rate	Total ($k, real 2005/06)
Environmental approval		1,500
Survey and easement acquisition		22,400
Line construction contract – 215km		80,881
Scoping cost for line	15%	12,132
COD design and project management cost	12%	9,706
TO Filed supervision	12%	9,706
330 kV works at Dumaresq (four new 330 kV circuit breakers)		8,588
330 kV works at Lismore (three new 330 kV circuit breakers)		6,440
TOTAL		151,353

Source: Appendix A of PFS.

The line length is based on the longest probable feasible line route[56] of 215km, average span lengths of 400m, and the database default ratio of suspension to tension towers of 16:5.

The cost for the substation works includes a 10% market factor, DCF and NCF factors of 10% and an SCF factor of 15%. The cost for the line construction includes a 10% allowance for inflation to reflect TransGrid's use of a $06/07 basis for the estimate figures included in their Revenue Proposal as the original estimate has been made on a $05/06 basis.

E.7 PB analysis

This section presents PB's view of the project information provided by TransGrid in support of the expenditure for this proposed project. The following sections address each of the key issues when considering the prudence and efficiency of a proposed capital investment.

53 Section 3.1 and 3.2 of the Application Notice.

54 Dumaresq to Lismore 330 kV line construction – project Number T.2164, 18 April 2008.

55 Project Feasibility Study Report - Dumaresq to Lismore 330 kV transmission line FS PSR 96, 12 Sept 2006.

56 Ibid, Page 17.

Drivers (need or justification)

PB accepts that outage of the 137km Lismore-Coffs Harbour 330 kV line is a critical N-1 contingency that has the impact of heavily loading the underlying 132 kV network on the far north coast of NSW. On this basis, and given that the dependence on DirectLink is 125MW in 2010/11 (based on zero QNI flows) compared to its 115MW capacity[57] PB acknowledges there is a clear need for augmentation.

Strategic alignment and policy support

PB considers the outage conditions assessed are in accordance with the TransGrid's documented planning criteria and that this project has been foreshadowed for some time as part of the Annual Planning Review processes. In PB's view, more prescriptive documentation within the planning criteria regarding the treatment of DirectLink would facilitate technical assessments – however to offset this TransGrid has appropriately tested the sensitively of this investment decision against various levels of DirectLink capacity.

Alternatives

In PB's view, and while recognising that TransGrid has identified a number of alternatives as part of its Regulatory Test assessment, the technical and economical assessment of the feasible options appeared quite limited. TransGrid has proposed a major line development project that will have considerable long term benefits and is very strategic on the context that additional investment in the area will not be required for a considerable period. However, a number of options were dismissed on the grounds of costs, environmental issues, technical issues, etc without sufficient rigour and transparency. From a high level perspective, and without any power systems analysis to support its assertions, PB has identified a number of less expensive options that warrant further investigation. In PB's view these included:

- a number of 132 kV developments, such as Dumaresq-Tenterfield[58], or Armidale-Coffs Harbour-Kolkahn-Lismore[59]
- a new Armidale - Coffs Harbour line 330 kV line[60]
- real time temperature and wind monitoring across the Armidale-Coffs Harbour cut set of lines

In discussions on these matters, TransGrid re-iterated the technical limitations of (long) 132 kV options and the community issues associated with developing multiple small capacity lines into an area that already has many 132 kV lines[61]. Importantly, except as what appeared to

57 In accordance with the AER's assumption as part of the conversion of DirectLink to a regulated status, PB considers it is prudent to accept the (1-pole out) capacity of DirectLink is 115MW, and that this will provide an appropriate level of reliability for the purposes of planning under peak summer demand conditions. PB also notes TransGrid's reservations regarding the reliability of DirectLink to provide this level of transfer capacity consistently.

58 Most likely built at 330 kV, but operated as a medium term measure at 132 kV to aid deferring significant capex, without precluding the ultimate arrangement proposed by TransGrid.

59 In PB's view a number of sub option exist with regards to the 132 kV connection from Armidale to Lismore – in particular the option of building from Armidale to Coffs Harbour only - appears feasible given this section of the network gets overloaded for the N-1 event.

60 TransGrid did identify this option as part of it Application Notice but dismissed it on the basis of cost (it proposed the full 300km to Lismore as opposed to just the shorter 137km more critical first stage section to Coffs Harbour) and the environmental sensitivity associated with accessing a new easement between Armidale and Coffs Harbour.

61 In PB's view the number of 132 kV lines already in operation in the area goes someway to support the principle that the 132 kV lines are technically feasible over the distances considered.

be retrospective technical and economical analysis[62], TransGrid could not support its position with a detailed internal report on the matter. PB highlights that as part of the retrospective economical analysis, the NPV of the preferred option reduced from $111m to $76m without any explanation[63], and that one of the new options (while more expensive than the preferred option) had an NPV lower then the alternative included as part of the Application Notice. In PB's view, this example highlights the risk that TransGrid adopts but not undertaking a robust and systematic economical analysis of multiple options (and sub-options) – there maybe a chance that TransGrid misses a more efficient project by dismissing options at too early a stage within its assessments.

Additional observations made regarding TransGrid's alternatives economic assessment include:

- lack of sensitivity analysis on key input assumptions such as individual cost components/factors and deferral periods, etc[64]
- PB has not indentified any documentation submitted by TransGrid to identify or quantify market benefits to aid in the preferred project selection. A project of this significance and magnitude is likely to have some material market benefits in the context of reduced transmission losses (improved MLF's), improved inter-regional transfer capabilities (it forms a parallel link with the QNI interconnector circuits) and reduced intra-regional constraints.

Notwithstanding matters regarding TransGrid's planning process, based on the technical and economic assessment presented by TransGrid PB generally concludes that of the options presented, the selected option for the Lismore-Dumaresq transmission line project represents efficient investment.

Timings

The timing for the Dumaresq-Lismore line has been included in the CAM as 2011/12, whereas in PB's view the need is actually earlier in 2010/11. The reason for this delay is associated with the long lead times required for planning approvals and project construction.

PB also notes that technically feasible options were dismissed from the economic evaluation on the basis they would take too long to develop. In PB's view this is a potential weakness of the planning process as those options may have actually been more efficient. As TransGrid has not developed cost estimates for these options, PB is unable to determine whether these options would actually represent more efficient investment, or the additional cost associated with failing to pursue this option if it were found to be more efficient when timing considerations are removed.

From a planning process perspective, PB would have expected some degree of discussion within the Application Notice regarding the sensitivity of the constraint and the project timing to the range of demand forecasts.

Assessment of market benefits would have also assisted given that under the 2007/08 demand conditions, import can be constrained from QLD.

[62] Supplementary Report, Document number 3979, 15/08/08.

[63] PB presumes this may be associated with using a different reference year.

[64] The Application Notice does present a sensitivity analysis of various typical input assumptions, however these are applied evenly across each project. PB would expect that there are also some key assumptions that are more relevant to individual options that require testing (easements is one such example).

Costs and scope

PB has identified that the project cost estimate for the Dumaresq-Lismore line appears to include the cost for the survey and easement acquisition[65] in error. The easement cost is included in the allowance separately (project ID 9095). PB recommends this amount ($22.4m) be removed from the allowance and TransGrid provide assurances this matter has not occurred elsewhere.

In addition to the cost of the easement PB has identified addition maters regarding the scope and cost estimate provided:

- the substation works at Dumaresq require five new circuit breakers to be installed in a 'breaker-and-a-half-arrangement. In PB's view two of these circuit breakers only provide limited benefits under normal situations (but they do marginally improve operation flexibility and increase the extent of redundancy). Given that TransGrid has not outlined the basis for it decision to include this extent of circuit breakers, PB recommends a nominal adjustment of 30%[66] be made to the substation works at Dumaresq resulting in a reduction of $2.6m

- in addition to other factors, a generic 'Scoping Cost Factor on Line Works' of 15% has been applied to the line construction costs. This factor does not appear to be defined in any documentation. On the basis that this development has captured the "longest probable feasible line route", and given that the majority of the line route is based on an existing 132 kV, PB recommends that the scoping factor should be reduced to 10% to reflect the relatively well known aspects and this results in a reduction of $4.0m

- it appears the original cost estimate of $151.4m has been established in 2005/06 dollars and the CAM entry is 10.1% higher than this at $166.6m. In PB's view this represents the 2-year CPI escalation, which appears high – so PB recommends using ABS actual CPI (1.062) to escalate the original cost- resulting in a further reduction of $7.4m

The net impact on the cost of the project as a result of PB's recommendations is a reduction of $36.4m.

E.8 Conclusion

Table E-3 sets out PB's recommendation on the prudency and efficiency of the submitted expenditure associated with the Dumaresq-Lismore 330 kV Line augmentation project.

Table E-3 – PB recommendation for Dumaresq-Lismore 330 kV Line - Augmentation

Expenditure $m (real, 07/08)	2009/10	2010/11	2011/12	2012/13	2013/14	Total
Submitted	5.5	80.0	80.0	-	-	165.5
Proposed variation	(1.2)	(17.6)	(17.6)	-	-	(36.4)
PB recommendation	4.3	62.4	62.4	-	-	129.1

Source: TransGrid, CAM V1.8_Future deliverables 12a.xls.and PB analysis.

65 Appendix A, page 25 of PFS Report FS PSR 96.

66 Informed by the ratio of 3/5 circuit breakers remaining, and increased by 10% to account for loss of economies of scale.

APPENDIX F
COMMUNICATION - SW NSW MICROWAVE & SATELLITE

APPENDIX F: COMMUNICATION - SW NSW MICROWAVE & SATELLITE

The SW NSW Microwave & Satellite augmentation project (Project ID 5607) has an anticipated commissioning date in 2011 across all 36 scenarios forecast by TransGrid. Table F-1 shows the estimated capex for this project that has been included in the overall ex-ante allowance (excluding easements).

By value, this is project represents only a relatively small ex-ante augmentation expenditure, accounting for 0.2% of TransGrid's proposed network capex in the 2009/10-2013/14 regulatory period. It is however being reviewed in order to inform AER of TransGrid's management of secondary systems, and in particular the communications networks that are essential to effective and efficient management of a large geographically distributed transmission network.

Table F-1 – Capex for Communication - SW NSW Microwave & Satellite

Expenditure $m (real, 07/08)	2009/10	2010/11	2011/12	2012/13	2013/14	Total
Project 5607 (Median and Weighted Average)	0.2	4.6	-	-	-	4.8

Source: TransGrid, CAM V1.8_Future deliverables 12a.xls.

F.1 Project overview

This project involves expenditure on new telecommunications assets at substations in South West NSW. The project will provide SCADA facilities to substations on the substations on the Wagga – Darlington Point system.

An issues paper recommending the provision of SCADA facilities to all TransGrid substations was adopted by the TransGrid reliability steering committee in 2006. In addition, TransGrid states that NEMMCO has requested provision of SCADA data from TransGrid's 132 kV substations in the Wagga – Darlington Point system and has sought TransGrid's to provide a program to install SCADA facilities at other non-SCADA facilitated substations[67].

The project involves establishing or modifying the communication links with the Yanco, Griffith, Coleambally, Finley and Deniliquin 132 kV substations. It is proposed to install microwave radio communications for Coleambally, Griffith and Yanco and to provide satellite communications for Finley and Deniliquin.

F.2 Drivers (need or justification)

The driver for the project is the need to comply with the National Electricity rules requirement that new transmission substations have SCADA facilities. TransGrid states that a limiting factor in its ability to comply with the rules has been the fact that these five substations have no SCADA facilities at all.

TransGrid states that it is required by the National Electricity Rules to augment the telecommunications network to fully comply with the required performance standards. Without augmentation, the Griffith SCADA data could not be maintained after maintenance replacement of either the PLC communications channel or the Toshiba substation control system.

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67 TransGrid 2008, 'PES – Provision of communication services to 132 kV substations in south-western N.S.W.' paragraph 1.2.1.

TransGrid also states that good industry practice requires the provision of detailed system data from all substations in the transmission network. The provision of full-function SCADA systems to Yanco, Finley, Coleambally and Deniliquin to be able to remotely monitor and control all TransGrid substations, and the telecommunications network bearers required to carry the data generated by these sites, is part of this requirement.

F.3 Strategic alignment and policy support

This project is in accordance with the policy adopted by TransGrid's reliability steering committee and is required under the direction from NEMMCO.

F.4 Alternatives

Yanco, Finley Griffith and Coleambally are currently not provided with any substation automation system (SAS) whatever. Griffith is provided with a Toshiba SCADA outstation which is scheduled for maintenance replacement.

For each communications link the options of utilising power line carrier (PLC), OPGW, microwave radio and satellite communications were considered. The following analysis shows that having considered the options there was only one feasible solution for Coleambally, Griffith and Yanco; while out of the two feasible options for Deniliquin and Finley, TransGrid chose the least cost option:

- the use of PLC for SCADA facilities at Coleambally, Yanco and Griffith was not pursued due to the need to preserve PLC spectrum for protection services. PLC is not a feasibility option for Finley and Deniliquin due to the distances involved

- the use of OPGW for any of the sites was not pursued due to the requirement for extended line outages to restring the earth conductor, however future HV network augmentations may provide OPGW to Finley and Coleambally

- the use of microwave radio for Coleambally, Griffith and Yanco is the preferred option due to the availability of existing radio repeater sites and the resultant simple installation

- the use of microwave radio for Deniliquin and Finley was not pursued due to the distances involved and the resultant costs and complexity of the microwave radio network

- the use of satellite based services for Deniliquin and Finley is the preferred option due to the lack of suitable alternatives.

TransGrid concluded that the microwave radio option is the only feasible option for Coleambally, Griffith and Yanco able to address the requirements of the Power Systems data Communications Standard (PSDCS). While microwave could be used for the other two substations, Finley and Deniliquin, this would involve additional 'hops' to be installed and consequently satellite based SCADA is the preferred option for these two sites. This is the cheaper option for these two sites[68].

The option selected by TransGrid is to develop microwave radio to those sites where practicable, and 9600bps satellite-based bearers to the remaining sites.

68 TransGrid 2008, 'PES – Provision of communication services to 132 kV substations in south-western N.S.W.' section 2.

Development of telecommunications networks is not defined under the NER as an augmentation, and consequently is not subject to AER's regulatory test.

F.5 Timings

This work is anticipated to require an implementation timeframe of 24 months. TransGrid suggest that the SCADA facilities at these sites can be commissioned progressively over the course of the 2009-14 regulatory period but augmentation of the Griffith facilities must be coordinated with the asset management replacement of the Toshiba equipment at Griffith, currently expected in 2001. Aside from Griffith, explicit justification for the timing at the other substations was not presented in the project documentation provided.

F.6 Costs and scope

Table F-2 shows the base cost estimate for the Communication - SW NSW Microwave & Satellite augmentation project.

Table F-2 – Base cost estimates for Communication - SW NSW Microwave & Satellite

Work Scope Item	Estimate[1]
Microwave equipment and installation costs	$3.7m
Satellite cost	$500k
Project management, design, and commissioning cost	$65k
Total Estimate	$4.3m

Note 1: This estimate is in real 2006/07 dollars, and does not include real labour and material escalation impacts or any risk allowance

Source: TransGrid 2008 Provision of Communications Services to 132 kV substations in south-western NSW Appendix B.

The overall project is expected to cost $4.3m in 2007 prices.

F.7 PB analysis

This section presents PB's view of the project information provided by TransGrid in support of the expenditure for this proposed project. The following sections address each of the key issues when considering the prudence and efficiency of a proposed capital investment.

Drivers (need or justification)

The need for this project has been established through TransGrid's obligation to comply with the appropriate industry standards.

TransGrid states that good industry practice dictates that SCADA facilities should be provided at transmission substations and the NER rules require *new* transmission substations to have SCADA. PB notes that while it may be laudable to aim for industry best practice and for the TransGrid steering committee to adopt policies based on these aspirations; this in itself does not demonstrate the need for the investment. However, PB notes NEMMCO's request that SCADA facilities be provided at the substations addressed by this project and on this basis considers that TransGrid's internal policy objectives are appropriate.

Therefore PB is of the view that on the basis of the compliance requirements outlined by TransGrid, NEMMCO's request to provide SCADA data from TransGrid's 132 kV substations covered in this project and the alignment with TransGrid's internal asset management strategies, the need for the project has been reasonably justified.

Strategic alignment and policy support

This project is in accordance with the policy adopted by TransGrid's reliability steering committee and is required under the direction from NEMMCO.

Alternatives

Technical requirements have dictated the choice of technology at each of the substations.

On this basis PB concurs that it is appropriate that this expenditure takes place and the communications with the substations is undertaken in the manner set out by TransGrid in its Project Evaluation Summary.

Timings

While PB is of the view that the need to establish SCADA communications at one of the substations has been reasonably demonstrated, we can not conclude that the timing represents efficient investment since apart from the Griffith timing being aligned to replacement of assets, no indication of the timing for the other substations is developed.

Notwithstanding the above, PB notes the compliance nature of the project and the request from NEMMCO to provide SCADA facilities at the sites covered by this project. Therefore PB considers that undertaking the project in the 2009/10-2013/14 regulatory period appears appropriate.

Costs and scope

TransGrid has examined alternative options for communications at the substations but in most instances has been restricted to a single technology. Where an alternative is available TransGrid has chosen satellite to reduce expenditure on additional 'hops'. On this basis, PB is satisfied that this represents efficient expenditure.

F.8 Conclusion

PB has conducted a detailed review of the proposed Communication - SW NSW Microwave & Satellite augmentation project, and we are of the opinion that the project is prudent given industry standards and NEMMCO requirements, and is efficient investment given that where there has been a choice of technology options available, TransGrid has chosen the least cost option.

Table F-3 sets out PB's recommendation on the prudency and efficiency of the submitted expenditure associated with the SW NSW Microwave & Satellite augmentation project.

Table F-3 – PB recommendation for Communication - SW NSW Microwave & Satellite

Expenditure $m (real, 07/08)	2009/10	2010/11	2011/12	2012/13	2013/14	Total
Submitted	0.2	4.6	0.0	0.0	0.0	4.8
Proposed variation	-	-	-	-	-	-
PB recommendation	0.2	4.6	0.0	0.0	0.0	4.8

Source: TransGrid, CAM V1.8_Future deliverables 12a.xls.and PB analysis.

APPENDIX G
WALLERAWANG NO. 1 & 2 TRANSFORMERS

APPENDIX G: WALLERAWANG NO. 1& 2 TRANSFORMERS

The Wallerawang No. 1 & 2 transformers project (Project ID 5625) is anticipated for commissioning in 2010 across all 36 scenarios forecast by TransGrid. Table G-1 shows the estimated total cost of this project (excluding easements).

This project ranks is the sixth largest overall ex-ante replacement expenditure item and accounts for 0.8% of TransGrid's network capex in the 2009/10-2013/14 regulatory period.

Table G-1 – Capex for Wallerawang No.1 & 2 Transformers

Expenditure $m (real, 07/08)	2009/10	2010/11	2011/12	2012/13	2013/14	Total
Project 5625 (Median and Weighted Average)	19.0	-	-	-	-	19.0

Source: TransGrid, CAM V1.8_Future deliverables 12a.xls.

G.1 Project overview

In 2007 the No.1 330/132 kV transformer at Wallerawang failed due to a severe fault[69]. At the time of the fault, the No.1 and No.2 215 MVA transformers were of the same age, and both were subjected to the same fault conditions that caused the No.1 transformer to fail.

In order to maintain supply to Delta Electricity, the failed unit has been temporarily replaced with a 200 MVA transformer sourced from ElectraNet. This replacement transformer not fully compatible with the existing supply arrangements as it is 30 degrees out of phase with the No. 2 transformer tertiary and the supplies from the unit auxiliary transformers[70]. In addition the temporary arrangement does not permit maintenance access to No. 2 Transformer.

TransGrid has undertaken limited testing of the No. 2 transformer as it is not possible to remove the unit from service for more extensive testing. While these limited tests have not shown any specific detrimental impact of the through fault on the transformer, it now provides the main supply to the power station, and TransGrid is of the view that unit is at risk of failure. As this transformer is of identical construction to the failed unit and has been subjected to severe stress during the fault that caused the No.1 Transformer failure, the ability of the transformer to withstand a similar fault is now in doubt. A condition review of the No. 2 transformer concluded that[71]:

> *"Condition of this unit is considered to be average, with furan levels outside policy limits at 690ppb indicating advanced age. Additionally, there is some evidence of paper overheating with elevated levels of CO. Oil quality is poor, with high moisture content, very high DF and very low resistivity of the oil circuit. The condition of the 132 kV bushings requires investigation with DF slightly greater than policy and a capacitance measurement on White Phase approximately 10% greater than the other two phases. This may indicate a*

69 TransGrid has identified the fault as a close-up through fault resulting in the fault current running through the transformer. This fault caused irreparable damage to the No.1 transformer leading to its replacement.

70 TransGrid 2008, 'Project Evaluation Summary – Replacement of Wallerawang 330/132 kV Transformers', Project Number: 5625, Revision No. 1, 11/06/2008, page 4, 5.

71 TransGrid 2008, 'Network Asset Replacement Project Evaluation – Wallerawang No. 1 and No. 2 Transformers', Document Number: 5625 ARPE, Revision Number: 2, Dated 29/5/08, page 15.

> *short circuit foil section in the bushing and will require additional testing to confirm possible suspect condition as a matter of priority."*

The No. 2 transformer is the only one of its type in the TransGrid system, and its failure would result in the loss of supply to the Wallerawang power station, and the failure of the transformer may cause tripping of the power station.

TransGrid is proposing to replace both the No 1 and 2 transformers with new 375 MVA units by summer 2009/10. Once the replacement transformers at Wallerawang have been commissioned the temporary transformer is to be relocated[72].

G.2 Drivers (need or justification)

A consequence of a close up through fault in 2007 the No.1 330/132 kV transformer at Wallerawang failed. In order to maintain supply to Delta Electricity, the failed unit has been temporarily replaced with a transformer that is not fully compatible with the current supply arrangements due to a 30 degree phase shift with the No. 2 transformer tertiary and the supplies from the unit auxiliary transformers[73]. This temporary arrangement also does not permit maintenance access to No. 2 Transformer.

At the time of the fault, the No.1 and No.2 215 MVA transformers were of the same age, and both were subjected to the same fault conditions that caused the No.1 transformer to fail. TransGrid has concerns regarding the possible condition of the No. 2 transformer, as damage may have occurred to the transformer windings. Based on condition assessment of the failed transformer, TransGrid is of the view that the remaining strength of the paper in No. 2 transformer is low. Furthermore there is a risk that outage limitations will lead to ineffective or incomplete maintenance of the No. 2 transformer.

While an interim arrangement is in place to restore duplicate auxiliary supply to Wallerawang Power Station, the arrangement does not permit maintenance access to No. 2 Transformer and TransGrid has concluded that this is not acceptable.

The failure of the No. 2 transformer would have significant impact on Wallerawang Power Station, with supply restricted to a contingency arrangement put in place following the No. 1 transformer failure. TransGrid has noted that such an arrangement is not tolerable over an extended period[74].

G.3 Strategic alignment and policy support

Replacement of the Wallerawang No. 1 and 2 transformers is noted in the businesses substations asset management strategy[75]. Documentation in accordance with the asset management strategy and the project evaluation procedure has been included in the project documentation provided.

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72 TransGrid 2008, 'Project Evaluation Summary – Replacement of Wallerawang 330/132 kV Transformers', Project Number: 5625, Revision No. 1, 11/06/2008, page 9.

73 ibid, page 4, 5.

74 TransGrid 2008, 'Network Asset Replacement Project Evaluation – Wallerawang No. 1 and No. 2 Transformers', Document Number: 5625 ARPE, Revision Number: 2, Dated 29/5/08, page 10.

75 TransGrid 2008, 'Asset Management Strategy – Substations', Document No. GM AS S5 001, Revision No: 11, Issue Date: 3rd June 2008, page 37.

G.4 Alternatives

To address the stated need, TransGrid considered four options[76,77] and assessed the do nothing risk. Specifically, the documentation addresses the following options:

- do nothing – TransGrid assessed the pre-investment risk of this option at an overall risk score of 257[78]
- replace transformers and re-arrange supplies – this option involves the replacement of the No. 1 and No. 2 transformers with 330/132/11 kV, 375 MVA transformers that would supply Wallerawang power station at 132 kV and with associated auxiliary transformers to supply TransGrid's 330 kV substation. The current No. 1 transformer would become a system spare and the No. 2 transformer would be tested to determine if it is serviceable and suitable for use as a system spare. TransGrid identified the following key advantages and disadvantages of this option[79]

  Advantages

  - removes outage access constraints
  - addresses reliability issues at Wallerawang and restores normal duplicated supply to Wallerawang Power Station as well as enabling faster supply restoration due spares availability
  - outage requirements for construction and commissioning are manageable
  - minimises environmental exposure through upgrade of oil containment system
  - allows full separation of functions from the power station site – i.e. transformers no longer located on the power station runway, control and protection systems separated

  Disadvantages

  - significant capital cost

  This option was estimated to have an NPV of -$11,966k and the post investment risk was estimated to reduce by 172 points to an overall risk score of 85.
- replace transformers – existing supply arrangement – this option involves the replacement of the No. 1 and No. 2 transformers with specially constructed 375 MVA transformers to maintain the existing supply arrangements and remove present maintenance outage limitations. The existing No. 2 transformer would be tested to determine its serviceability and suitable for use as a system spare. TransGrid identified the following key advantages and disadvantages of this option[80]:

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76 TransGrid 2008, 'Network Asset Replacement Project Evaluation, Wallerawang No. 1 and No. 2 Transformers', Project Number: 5625 ARPE, Revision No 2, Dated 29/05/08, page 11-13.

77 TransGrid 2008, 'Project Evaluation Summary – Replacement of Wallerawang 330/132 kV Transformers', Project Number: 5625, Revision No 1, Dated 11/06/2008, page 6-8.

78 Determined in accordance with GM AS G2 025 – Network Asset Replacement Project Evaluation

79 TransGrid 2008, 'Network Asset Replacement Project Evaluation – Wallerawang No. 1 and No. 2 Transformers', Document Number: 5625 ARPE, Revision Number: 2, Dated 29/5/08, page 11-12, 14.

80 TransGrid 2008, 'Network Asset Replacement Project Evaluation – Wallerawang No. 1 and No. 2 Transformers', Document Number: 5625 ARPE, Revision Number: 2, Dated 29/5/08, page 11-12, 14.

Advantages

- removes outage access constraints
- addresses reliability issues at Wallerawang
- restores normal duplicated supply to Wallerawang Power Station

Disadvantages

- significant capital cost
- required outages will be difficult to achieve
- oil containment system would not be upgraded
- would require renegotiation of certain arrangements
- if No. 2 transformer is found to be unserviceable the project cost will increase in order to replace it to provide a viable spare
- requires TransGrid transformers be located on the power station property
- requires the protection systems be interconnected with those of the power station
- a future failure event could result in loss of supply at a critical location in TransGrid's network

This option was estimated to have an NPV of -$7,421k and the post investment risk was estimated to reduce by 102 points to an overall risk score of 155.

TransGrid identified two potential options that were not considered for evaluation and no costing was provided. Specifically these options are[81]:

- replace No. 2 transformer only – this option involves the construction of a new transformer bay in the 330 kV switchyard to accommodate a new 330/132 kV transformer to enable the existing transformer to be removed and to create space for a 132/33 kV transformer. TransGrid identified this option as being impractical for the following reasons:
    - design of the interim arrangement on No. 1 is unsatisfactory for a final installation
    - maintenance access for No. 2 transformer is not resolved due to the location of the 132/33 kV transformer
    - 200 MVA rating on the present No. 1 transformer is inadequate for maintenance access
    - incompatible with Delta Electricity's asset management plans
- establish a 330/132 kV transformer bay in the 330 kV switchyard – this option involves a contingency plan for failure of No. 2 transformer which requires the construction of a transformer bay in the 330 kV switchyard in order to accommodate the installation of a spare 330/132 kV transformer and provide space for the installation of a spare 132/33 kV transformer near the power station. TransGrid identified this option as being impractical for the following reasons:
    - does not resolve the present outage constraint problem
    - does not address the concerns regarding the condition of No. 2 transformer

81 TransGrid 2008, 'Network Asset Replacement Project Evaluation – Wallerawang No. 1 and No. 2 Transformers', Document Number: 5625 ARPE, Revision Number: 2, Dated 29/5/08, page 13-14.

- does not resolve the present reliability issue for the power station 33 kV supply
- design of the interim arrangement is unsatisfactory for a final installation
- incompatible with the design requirements for the site

TransGrid concluded that on a risk and financial basis that the option to replace transformers and re-arrange supplies was the preferred option[82]. Specifically this option was selected for the following reasons:

- it removes the operating restriction from No. 2 transformer
- reduces the risk of a loss of supply to an acceptable level
- allows a future transformer failure to be managed effectively using the standard system spare transformer
- provides a full separation of control and protection functions from the power station
- Delta Electricity are committed to taking supply from TransGrid at 132 kV and as TransGrid has given preliminary agreement to this course of action a change in these plans will cause additional cost to TransGrid

G.5 Timings

The timing of this work is proposed commissioning in 2010 across all 36 scenarios forecast by TransGrid, and the anticipated implementation timeframe is 36 months[83]. Explicit justification for this timing was not presented in the project documentation provided.

G.6 Costs and scope

Table H-2 shows the base cost estimate for the Wallerawang No.1 and 2 transformers replacement project.

Table G-2 – Base cost estimates for Wallerawang No.1 and 2 transformers

Work Scope Item	Estimate[1]
Contractor Site Establishment	$0.4m
Civil works	$1.9m
Plant procurement	$12.5m
Electrical Works	$0.3m
Panels	$0.2m
Cabling and other items	$2.7m
Total Estimate	$18.0m

Note 1: This estimate is in real 2006/07 dollars, and does not include real labour and material escalation impacts or any risk allowance

Source: TransGrid 2007, 'Feasibility Study – Replacement of Wallerawang 330/132 kV Transformers', Document No. FS PRS 202, Revision 1.0, Appendix B.

82 TransGrid 2008, 'Network Asset Replacement Project Evaluation – Wallerawang No. 1 and No. 2 Transformers', Document Number: 5625 ARPE, Revision Number: 2, Dated 29/5/08, page 13-14.

83 TransGrid 2008, 'Project Evaluation Summary – Replacement of Wallerawang 330/132 kV Transformers', Project Number: 5625, Revision No. 1, 11/06/2008, page 9.

The scope of the work includes the following:

- 330 kV switchyard works including the installation of a new 375 MVA transformer with associated controls, protection civil works including blast wall and oil containment system, as well as realignment of the switchyard boundary fence
- 132 kV switchyard works including the installation of new switchbays with associated controls and protection, as well as the installation of VTs in the two switchbays (VTs to be supplied by Delta Electricity)
- removal and dispose of existing TransGrid transformers
- cable works to install 132 kV cables between the 330 kV and the 132 kV switchyards

Delta Electricity are to supply and install a new 132/33 kV transformer and provide all the associated protection and control equipment[84].

G.7 PB analysis

This section presents PB's view of the project information provided by TransGrid in support of the expenditure for this proposed project. The following sections address each of the key issues when considering the prudence and efficiency of a proposed capital investment.

Drivers (need or justification)

The driver of this project has been stated by TransGrid to be the suspected condition of the No. 2 transformer following the failure of the No. 1 transformer as a consequence of a close up through fault in 2007. The No. 2 transformer is of the same age and type, and was subject to the same fault conditions. Additionally, the replacement of the failed transformer with a non-standard transformer has resulted in supply arrangements to the Wallerawang power station that are of concern to Delta Electricity and TransGrid. TransGrid state that the current supply arrangement has resulted in a 30 degree phase shift between the alternative supplies to the power station, and the arrangement does not allow maintenance access to the No. 2 transformer[85]. As a consequence, TransGrid has concluded that this supply arrangement is not acceptable as the arrangement is not tolerable over an extended period[86].

It is PB's opinion that the information presented supports TransGrid's concerns regarding the supply arrangement. We note in particular the importance of the supply to the operations of the Wallerawang power station, and the conclusions of TransGrid's condition review of the No. 2 transformer, specifically[87]:

"Condition of this unit is considered to be average, with furan levels outside policy limits at 690ppb indicating advanced age. Additionally, there is some evidence of paper overheating with elevated levels of CO. Oil quality is poor, with high moisture content, very high DF and very low resistivity of the oil circuit. The condition of the 132 kV bushings requires investigation with DF slightly greater than policy and a capacitance measurement on White Phase approximately 10% greater than the other two phases. This may indicate a short circuit foil section in the bushing and will require additional testing to confirm possible suspect condition as a matter of priority."

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84 TransGrid 2007, 'Feasibility Study – Replacement of Wallerawang 330/132 kV Transformers', Document No. FS PRS 202, Revision 1.0, page 16, 17.

85 TransGrid 2008, 'Project Evaluation Summary – Replacement of Wallerawang 330/132 kV Transformers', Project Number: 5625, Revision No. 1, 11/06/2008, page 4, 5.

86 TransGrid 2008, 'Network Asset Replacement Project Evaluation – Wallerawang No. 1 and No. 2 Transformers', Document Number: 5625 ARPE, Revision Number: 2, Dated 29/5/08, page 10.

87 ibid, page 15.

In PB's view, that the need to address the supply arrangement at Wallerawang has been reasonably demonstrated by TransGrid. Furthermore, in PB's opinion addressing this need is prudent.

Strategic alignment and policy support

PB is of the view that the replacement of the Wallerawang 330/132 kV transformers aligns with TransGrid's policies and strategies as stated in the substations asset management strategy[88].

Alternatives

TransGrid's project documentation presents consideration of various replacement alternatives' specifically[89]:

- installation of two new 375 MVA units
- installation of a new 375 MVA transformer with a non-standard tertiary winding
- retaining the No. 1 transformer and replacing the No. 2 transformer
- installing a new transformer at the 330 kV switchyard to provide a contingency supply

In accordance with TransGrid's network asset replacement project evaluation procedure, both pre and post implementation risk evaluation has been undertaken and included for the options subject to detailed analysis. The NPV of each of the assessed options has also been determined with the exception of the do-nothing option. Table H-3 presents a summary of the options analysis conducted by TransGrid based on the use of a post-tax nominal WACC of 7.17%.

Table G-3 – Summary of options considered

Option	NPV	Risk score	$ per risk score reduction
Do nothing	-	257	-
Replace (both) transformers and re-arrange supplies	-$11.97m	85	-$0.14m
Replace (both) transformers – existing supply arrangement	-$7.42m	155	-$0.05m

Source: PB summary.

TransGrid did not conduct a detailed assessment of the option to replace the No. 2 transformer only, or the option to install a new transformer in the 330 kV switchyard. The reasons for this are discussed in section G.4 above.

On the basis of this analysis TransGrid selected the in-situ replacement option, even though it had the greatest cost, on the basis that it[90]:

- removes the operating restriction from No. 2 transformer

88 TransGrid 2008, 'Asset Management Strategy – Substations', Document No. GM AS S5 001, Revision No: 11, Issue Date: 3rd June 2008, page 37.

89 TransGrid 2008, 'Project Evaluation Summary – Replacement of Wallerawang 330/132 kV Transformers', Project Number: 5625, Revision No. 1, 11/06/2008, page 6.

90 TransGrid 2008, 'Network Asset Replacement Project Evaluation – Wallerawang No. 1 and No. 2 Transformers', Document Number: 5625 ARPE, Revision Number: 2, Dated 29/5/08, page 13-14.

- reduces the risk of a loss of supply to Delta Electricity to an acceptable level
- allows a future transformer failure to be managed effectively using the standard system spare transformer
- provides a full separation of control and protection functions from the power station
- Delta Electricity are committed to taking supply from TransGrid at 132 kV and as TransGrid has given preliminary agreement to this course of action a change in these plans will cause additional cost to TransGrid

Having considered the fundamental need, and in particular the circumstance associated with the plant failure and the replacement of the failed unit with non-standard equipment, PB is satisfied that the alternatives identified are appropriate. However, after examining the options analysis, PB is of the view that the analysis is incomplete as it fails to account for maintenance costs, operational costs, and the proposed and subsequent works at the Wallerawang site (i.e. PES 6208 Wallerawang 132/66 kV substation rebuild). In particular, PB is concerned that consideration of the need associated with the Wallerawang 330/132 kV transformers did not adequately address the overarching needs of the Wallerawang substation itself. PB notes that this concern was also reflected in TransGrid's feasibility study for the replacement of the Wallerawang 330/132 kV transformers; specifically in relation to the proposed fencing to accommodate the transformer replacements it notes:

> *"This work should be delayed until the final design for this project is completed as it will be necessary to realign the switchyard boundary to accommodate the new transformers. It is assumed that the security fence will be installed before this project is commences and hence no allowance has been made in the budget estimates for this project to cover the cost of realigning the switchyard fence."*[91]

With regards to the future of the 132 kV switchyard the feasibility study states:

> *"Consideration is now being given to rebuilding the Wallerawang 132 kV switchyard … Any decisions made regarding the rebuild of the station will be taken into account during the design phase of this project to minimise the amount of new work done for this project which may become redundant when the station is rebuilt."*[92]

In the risk assessment section of the feasibility study it further notes:

> *"There is also a risk that the scope of this project could increase because of the need to make provision for the planned rebuilding of the Wallerawang 132 kV switching station."*[93]

After considering the documentation provided by TransGrid, with regards to the Wallerawang 330/132 kV transformer replacement, we are of the view that while TransGrid has identified and assessed appropriate options for this specific need, TransGrid has not, in its strategic planning, considered the overarching needs of the site as a whole in a cohesive manner. PB is also of the view that TransGrid was attempting to minimise the impacts of this apparent lack of strategic planning for the Wallerawang site by resolving these issues at the detailed design stage, or in the field through works scheduling. It is PB's opinion that this is not an effective and efficient practice.

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91 TransGrid 2007, 'Feasibility Study – Replacement of Wallerawang 330/132 kV Transformers', Document Number: FS PSR 202, Report Rev 1, Dated 04/12/07, page 16.

92 TransGrid 2007, 'Feasibility Study – Replacement of Wallerawang 330/132 kV Transformers', Document Number: FS PSR 202, Report Rev 1, Dated 04/12/07, page 16.

93 TransGrid 2007, 'Feasibility Study – Replacement of Wallerawang 330/132 kV Transformers', Document Number: FS PSR 202, Report Rev 1, Dated 04/12/07, page 18.

In PB's opinion, TransGrid's options analysis as presented in its option comparison document is incomplete and consequently the conclusions are potentially affected by shortcomings in the analysis. Furthermore, in our view, the analysis fails to reasonably demonstrate the efficiency and value of the chosen option over the alternatives considered. Consequently, on the basis of the options analysis presented we can not conclude that the most efficient option has been chosen.

However, PB notes the questionable condition of the No.2 transformer and criticality of the equipment in serving the Wallerawang power station. Should TransGrid has assessed the risk and cost of failure with consideration of penalty payments and the increased costs associated with emergency replacement, the value of the chosen option would, in PB's opinion, be more clearly demonstrated. TransGrid has not undertaken this analysis, or included these specific costs in its submission documentation but has identified the risk and criticality of the equipment as factors affecting their decision[94].

Therefore PB recognises that with the inclusion of all appropriate costs and benefits, along with consideration of the other proposed works at the Wallerawang site, in our opinion it is highly likely that the most efficient option to address the indentified need would be to replace both transformers.

Timings

TransGrid has proposed that the Wallerawang 330/132 kV transformers will be replaced with a commissioning date of 2010 across all 36 scenarios forecast by TransGrid. The anticipated implementation timeframe has been estimated as 36 months[95]. Explicit justification for this timing was not presented in the project documentation provided.

PB accepts the fundamental need to address the suspected condition of No. 2 transformer, and the constraints associated with the supply arrangement to the Wallerawang power station. Given the issues with the supply arrangement, the critical nature of the supply, and in particular the findings of the condition review of No. 2 transformer, PB is of the view that replacement should be undertaken as a priority. Therefore commissioning in 2010 is considered to be prudent. However, given the other proposed works at the Wallerawang substation (see discussion on Alternatives above); we are concerned that the timing may not be efficient. PB is of the opinion that the transformer replacement works should be integrated at a planning level with other works at the substation to ensure that the timing of all these related works is efficient, and that rework or redundant works are avoided. That is to say, we believe that the efficient timing of these works can only be achieved through the strategic planning for the site as a whole, and not through appears to be a piecemeal approach. Consequently, based on the documentation provided by TransGrid we cannot conclude that the timing of the proposed replacements is efficient.

Costs and scope

TransGrid's recommend option requires replacement of both No. 1 and No. 2 330/132 kV transformers at Wallerawang. A detailed estimate of the scope and cost of this work is set out in the project feasibility study[96] and is summarised in section G.6 above. It is proposed that this work will require a timeframe of 36 months to complete.

PB is of the view that the estimated replacement timeframe is reasonable given the complexity of replacing such equipment in an operational substation.

94 TransGrid 2008, 'Asset Replacement Project Evaluation – Wallerawang No.1 and No.2 Transformers' 5625 APRE, Revision 2, 29/05/08, page 14.

95 TransGrid 2008, 'Project Evaluation Summary – Replacement of Wallerawang 330/132 kV Transformers', Project Number: 5625, Revision No. 1, 11/06/2008, page 9.

96 TransGrid 2007, 'Feasibility Study – Replacement of Wallerawang 330/132 kV Transformers', Document No. FS PRS 202, Revision 1.0, Appendix B.

Broadly, the scope of the work includes:

- the installation of new 375 MVA 330 kV transformers
- the installation of new 132 kV switchbays
- removal and disposal of existing transformers
- 132 kV cable works

However, PB is concerned that the project management and mobilisation/demobilisation costs for these works are inefficient due to the apparent lack of strategic planning as discussed under Alternatives above. That is, we are of the view that savings in field supervision and mobilisation costs (at least) could be made though strategically managing the Wallerawang 132 kV substation switchyard rebuild project (project No. 6208) in conjunction with the transformer replacement project. Consequently, it is PB's opinion that the costs as set out in Table G-1 are not efficient costs for a project of this nature when considered in the context of other proposed works at the site. PB's recommendation is for a reduction in the project management costs of the project by $300k[97] to account for the duplicated mobilisation/demobilisation and project management inefficiencies.

G.8 Conclusion

PB has conducted a detailed review of the proposed Wallerawang No. 1 & 2 transformers project, and while we are of the opinion that the project is prudent, we are not able to conclude that it represents efficient investment due to the lack of planning integration with other works proposed at the Wallerawang substation.

Table G-4 sets out PB's recommendation on the prudency and efficiency of the submitted expenditure associated with the Wallerawang No.1 and 2 transformer replacement project.

Table G-4 – PB recommendation for Wallerawang No.1 and 2 transformer project

Expenditure $m (real, 07/08)	2009/10	2010/11	2011/12	2012/13	2013/14	Total
Submitted	19.0	-	-	-	-	19.0
Proposed variation	(0.3)	-	-	-	-	(0.3)
PB recommendation	18.7	-	-	-	-	18.7

Source: TransGrid, CAM V1.8_Future deliverables 12a.xls. and PB analysis.

97 TransGrid Project Feasibility Study Report, Replacement of Wallerawang Transformers, FS_PSR_202, page 27 –Contractor facilities and mobilisation line item.

APPENDIX H
COOMA 132 KV SUBSTATION REPLACEMENT

APPENDIX H: COOMA 132 KV SUB REPLACEMENT

The Cooma 132 kV substation replacement (Project ID 6194) is anticipated for commissioning in 2014 across all 36 scenarios forecast by TransGrid. Table H-1 shows the estimated total cost of this project (excluding easements) that has been included in the overall ex-ante allowance.

By value, this project ranks as the second largest ex-ante replacement expenditure item, and accounts for 1.8% of TransGrid's proposed network capex in the 2009/10-2013/14 regulatory period.

Table H-1 – Capex for Cooma 132 kV substation replacement

Expenditure $m (real, 07/08)	2009/10	2010/11	2011/12	2012/13	2013/14	Total
Project 6194 (Median and Weighted Average)	-	-	1.1	11.5	30.2	42.8

Source: TransGrid, CAM V1.8_Future deliverables 12a.xls.

H.1 Project overview

Cooma substation was built in 1960 as a 132/66/11kV substation and provides a hub for the transmission system in the Snowy Mountains, providing supply for the Cooma city and regional Cooma area[98].

The Cooma substation is currently supplied via two 132 kV lines from Canberra substation and is connected at 132 kV to Munyang, Snowy Adit, and Bega. There are three 132/66/11kV transformers which supply three Country Energy 66 kV lines and the Country Energy 11kV busbar. The 11kV busbar is supplied from voltage regulators from the transformer tertiary winding[99].

TransGrid has undertaken an asset condition review which found that replacement of a number of major assets was required. This review considered reconstruction of the substation in-situ, as well as the development of a new site, and concluded that reconstruction on a new site was the preferred option[100].

The Cooma 132 kV substation replacement project involves the development of a 132/66 kV substation on a suitable site away from the existing substation to avoid line congestion in the area and accommodate connection of the second Bega 132 kV line. The proposed initial arrangement would include five (5) 132 kV line switchbays attached to two (2) 132 kV bus sections, and two (2) 60 MVA 132/66 kV transformers.

The proposed project also involves the establishment of new 66 kV switchgear at Cooma Substation with the initial arrangement involving five (5) 66 kV line switchbays, two (2) 66 kV bus sections, and two (2) 8 MVAr 66 kV capacitor banks. A section of line 978 would be reconstructed as a 132 kV double circuit line to connect the existing Cooma – Munyang tee to

98 TransGrid 7 July 2008, 'Condition Review – Cooma Substation, page 1.

99 TransGrid 30 April 2008, 'Network Asset Replacement Project Evaluation – Cooma Substation', Document No. 6194 ARPE, Revision No. 2, page 13-14.

100 TransGrid 12 June 2008, 'Project Evaluation Summary – Cooma Substation 132/66 kV Substation Rebuild', Revision No. 0, page 4.

Snowy Adit line. Additional line works are required to marshal both the Cooma - Canberra/Williamsdale 132 kV lines at the new substation[101].

H.2 Drivers (need or justification)

TransGrid has undertaken an asset condition review of the assets at Comma substation[102]. This review found that a range of issues at the site associated with equipment condition and design compromises. The key issues identified were[103]:

- 80% of secondary equipment requires replacement under asset management strategies
- SCADA control is required and is not currently available
- the operating arrangement of the three transformers coupled with three 11 kV regulators introduces complexities that are difficult to manage, interfere with access to plant, and lower the reliability of supply from the site
- the condition of two transformers, the three regulators, one of the capacitor banks and the 132 kV and 66 kV disconnectors is poor
- the spill oil containment system for the transformers and regulators is unacceptable

The condition review document noted the following specific points in relation to the major equipment items:

- transformer No. 1 – does not show any clear risks of failure, however due to its age and consequences of failure it is considered prudent to plan for replacement. The transformer bund and control cabling were also noted as being in good condition[104]
- transformer No. 2 – does not show any clear risks of failure, however due to its age and consequences of failure it is considered prudent to plan for replacement. The transformer bund and control cabling were also noted as being in good condition[105]
- transformer N0. 3 – was noted as having a *"… good operational history with some minor defects appearing since 2000, concerning oil leaks, AVR problems and tapchanger faults."* [106]
- support for the transformers was identified as being unavailable from the manufacturer, but that normal internal maintenance support was available. Transformer spares were noted as being unavailable except for some limited spares stocks[107]
- regulator No. 1 – does not show any clear risks of failure, however due to its age and possible consequences of failure it is considered prudent to plan for

101 TransGrid 16 April 2008, 'Project Option Scope and Estimate - Cooma North 132/66 kV Substation', Document No. 6194b, Revision No. 2, page 1.

102 TransGrid 7 July 2008, 'Condition Review – Cooma Substation'.

103 TransGrid 30 April 2008, 'Network Asset Replacement Project Evaluation – Cooma Substation', Document No. 6194 ARPE, Revision No. 2, page 4.

104 TransGrid 2008, 'Transformer Condition Review – Cooma 132 kV Substation No. 1 Transformer', page 3.

105 Ibid.

106 TransGrid 7 July 2008, 'Condition Review – Cooma Substation', page 2.

107 TransGrid 2008, 'Attachment – Comma Transformers No. 1 & 2 Supplementary Information', – not numbered.

replacement. The condition assessment further recommended that consideration be given to replacement in the 2010 to 2014 period[108]

- regulator No. 2 – same state and recommendations were made in relation to this unit as were made in relation to regulator No. 1
- regulator No. 3 – is generally out of service and only used when regulators 1 or 2 are unavailable. There is a steady degradation in the insulating oil and due to the possible consequences of failure it is considered prudent to plan for replacement. The condition assessment further recommended that consideration be given to replacement in the 2010 to 2014 period[109]. No. 3 regulator also has a different tapping range than the other regulators which creates operational complexities[110]
- support for the regulators was identified as being unavailable from the manufacturer, but that normal internal maintenance support was available. While spares were noted as being unavailable except for some limited spares stocks. No replacement regulator is available[111]
- capacitors are noted as having some leakage problems, manufactures support, internal support and spares are available (although limited)
- the condition of the 132 kV switchgear was not specifically addressed, other than to note that *"The 132 kV switchgear are a mixture of modern SF6, modern oil-filled and original oil-filled designs. With the exception of the busbar and disconnectors, most of the original 1960s era equipment has been replaced*." This switchgear was noted as being of various manufacturing dates, specifically, one (1) unit in 1976, one (1) unit in 1985, one (1) unit in 1986, three (3) units in 2007, and one (1) with an unstated date[112]
- the 66 kV switchgear was noted as being a risk due to the condition of the units and the individual components. Most of the installed 66 kV switchgear is not supported by the original equipment manufacturer and continued retention in service may lead to additional risk[113]
- disconnectors were noted as having operational and maintenance issues and cannot be repaired as no spares are available. In addition the steelwork was identified as not meeting design requirements with a possibility of failure under particular loading conditions
- safety concerns regarding bus VTs
- concerns regarding the condition of the site earthing
- the operating arrangement at the site was noted as being complicated and restrictive.

The Cooma substation condition report concluded that based on the assessment, the reconstruction of Cooma 132 kV substation should be considered.

108 TransGrid 2008, 'Transformer Condition Review – Cooma 132 kV Substation No. 1 Regulator', page 2-3.

109 Ibid.

110 TransGrid 2008, 'Attachment – Cooma – Regulators Supplemental Information', – no page numbers.

111 Ibid.

112 TransGrid 7 July 2008, 'Condition Review – Cooma Substation', page 3.

113 Ibid.

H.3 Strategic alignment and policy support

TransGrid has identified the following strategic relationships[114]

- GM AS S5 001 Asset Management Strategy – Substations - Section 5.12
- Network 30 Year Asset Management Plan 2009 – 2039 Section 4.2.1 Substations and Switching Stations
- Network Management Plan 2007-2011 Section 4.2.2 A

H.4 Alternatives

To address the stated need, TransGrid has considered reconstruction of the substation both in-situ and on a new site[115]. Specifically, the documentation addresses the following options:

- Pre-Investment Risk (Do Nothing Option) – TransGrid assessed the pre-investment risk of this option at an overall risk score of 287.6. While TransGrid's Network Asset Replacement Option Comparison document provided some commentary on the do nothing option, no explicit examination was noted in the project documentation provided
- Reconstruction – this option involves the construction of a new 132/66 kV substation at a location north of the Cooma Township along the existing Canberra transmission line easement. The existing easement would then be used to supply a new 66/11 kV substation on the existing site which would be owned by Country Energy.

  This option was estimated to have an NPV of -$16,571k and the post investment risk was estimated to reduce by 247.4 points to an overall risk score of 40.2.

  This option was costed and two variations (sub-options) were considered in the Project Evaluation Summary[116]; specifically:

  - remote reconstruction of a 132/66 kV substation at Cooma North at an estimated cost of $37.0m (including non-TransGrid cost elements)
  - local reconstruction of the Cooma 132/66 kV substation at an estimated cost of $30.4 m

  Due to congestion in the vicinity of the existing Cooma substation, part of the existing Williamsdale – Cooma 132 kV lines would need to be rebuilt as a double circuit line in the future to accommodate the proposed additional Country Energy 132 kV Bega line. TransGrid also note that the remote reconstruction cost includes $4.9m for the provision for an ultimate 330 kV substation layout. The remote reconstruction sub-option was selected as the technically preferable solution as TransGrid noted that it fully provides for future expansion and relieves line congestion around Cooma.

- In-situ project package including busbar replacement – this option involves the following works:
  - replacement of transformers 1 and 2 due to poor condition
  - replacement of the regulators due to poor condition

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114 TransGrid 30 April 2008, 'Network Asset Replacement Project Evaluation – Cooma Substation', Document No. 6194 ARPE, Revision No. 2, page 11.

115 TransGrid 2008, 'Network Asset Replacement Project Evaluation - Cooma Substation', Project Number: 6194, Revision 2, 30/4/2008, page 11-13.

116 TransGrid 2008, 'Project Evaluation Summary - Cooma 132/66 kV Substation' Rebuild, Project Number: 6194, Revision 0, 12/6/2008, page 7-12.

- construction of a new 132 kV bus section to enable the connection of a new Country Energy Bega line
- replacement of all protection and metering equipment in accordance with applicable asset management strategies due to obsolescence and reliability issue
- replacement of the 66 kV and 132 kV busbars and disconnectors due to condition
- replacement of the 66 kV VTs as they are considered to be a safety hazard
- replacement of No 4 capacitor cans which are leaking
- reconstruction of the spill oil system as they are considered inadequate
- installation of SCADA and associated replacement of the control panels - SCADA control is required under TSP2006-027.

This option was estimated to have an NPV of -$13,045k and the post investment risk was estimated to reduce by 170.8 points to an overall risk score of 116.8.

- In-situ project package excluding busbar replacement – essentially the same as the in-situ project package including busbar replacement option above, but without the replacement of the 66 kV and 132 kV busbars and disconnectors.

  This option was estimated to have an NPV of -$10,235k and the post investment risk was estimated to reduce by 138.8 points to an overall risk score of 148.8.

Based on TransGrid's options analysis, the remote reconstruction of a 132/66 kV substation at Cooma North option is identified as the preferred option[117]. TransGrid notes that this option was selected as the preferred option as it[118]:

- provides the best improvement in risk score
- fully provides for future site expansion
- fully overcomes the issues of the existing site and legacies of past design compromises
- has greatest confidence in feasibility
- avoids future issues associated with the present busbars and disconnectors.

H.5 Timings

The timing of this work is proposed for the period 2010/11 to 2013/14, and is anticipated to require an implementation timeframe of 38 months. Explicit justification for this timing was not presented in the project documentation provided, however TransGrid states that *"the timing of this project is indicative and may be subject to further refinement"*[119].

H.6 Costs and scope

Table H-2 shows the base cost estimate for the Cooma 132 kV substation replacement project (ID 6194).

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117 TransGrid 2008, 'Project Evaluation Summary - Cooma 132/66 kV Substation' Rebuild, Project Number: 6194, Revision 0, 12/6/2008, page 14.

118 TransGrid 2008, 'Network Asset Replacement Project Evaluation - Cooma Substation', Project Number: 6194, Revision 2, 30/4/2008, page 13.

119 TransGrid 2008, 'Project Option Scope and Estimate - Cooma Area – Cooma North 132/66 kV Substation', Project Number: 6194, Document No. 6194B, Revision 2, 16/04/2008, page 2, 13.

Table H-2 – Base cost estimates for Cooma 132 kV substation replacement

Work Scope Item	Estimate[1]
Cooma North 132 kV Substation	$19.88m
Category ‘B’ Substation Services	$0.30m
Provision for 330 kV Ultimate Substation Layout	$4.94m
978 Line Demolition	$0.10m
Line Rearrangements	$1.98m
Cooma North Telecommunications	$1.85m
Protection Signalling to Williamsdale	$0.26m
Cooma Substation 66 kV High Voltage Plant	$4.68m
Cooma Substation Switchgear Removal	$2.34m
Protection Signalling to Bega (Cost provided for Country Energy)	$0.33m
Total Estimate	$36.69m

Note 1: This estimate is in real 2007/08 dollars, and does not include real labour and material escalation impacts or any risk allowance.

Source: TransGrid 2008, ‘Project Option Scope and Estimate - Cooma Area – Cooma North 132/66 kV Substation’, Project Number: 6194, Document No. 6194B, Revision 2, 16/04/2008, page 12.

The scope of the work includes the following:

- a new two (2) 60 MVA transformer 132/66 kV substation at Cooma North
- five (5) 132 kV line switchbays with two (2) 132 kV bus sections to accommodate the additional Country Energy 132 kV Bega line
- reconstruction of a section of 132 kV line as a double circuit to connect the existing Cooma – Munyang Tee Snowy Adit 132 kV Line
- line works to marshal both 97D and 978 (Cooma - Canberra/Williamsdale) 132 kV lines at the new Comma North substation
- provision of low capacity microwave radio and extension of the fibre optic installation between the proposed Cooma North site and the existing Cooma site
- establishing protection signalling to Williamsdale and Bega.

Also included are modifications to the existing Comma site to remove redundant equipment, and provide 66 kV switchgear to restore the site to an operational substation configuration. TransGrid notes that the estimate does not include any assessment for impacts or costs at associated sites.

H.7 PB analysis

This section presents PB’s view of the project information provided by TransGrid in support of the expenditure for this proposed project. The following sections address each of the key issues when considering the prudence and efficiency of a proposed capital investment.

Drivers (need or justification)

The driver of this project has been stated by TransGrid to be the condition of the Cooma substation equipment, and issues with the arrangement of the substation. Specifically, the key issues identified are that[120]:

- 80% of secondary equipment requires replacement under asset management strategies
- SCADA control is required and is not currently available
- the operating arrangement of the three transformers coupled with three 11 kV regulators introduces complexities that are difficult to manage, interfere with access to plant, and lower the reliability of supply from the site
- the condition of two transformers, the three regulators, one of the capacitor banks and the 132 kV and 66 kV disconnectors is poor
- the spill oil containment system for the transformers and regulators is unacceptable

The stated need is supported by a number of condition reviews, the key findings of which are summarised in section H.2.

Based on the condition review reports, it is PB's opinion that the information presented supports the view that the Cooma 132 kV substation has a range of condition and design related issues. PB acknowledges that these design issues, the arrangement of the transformers and regulators, the condition of the No. 4 capacitor bank, the disconnectors and busbar structures, as well as the condition of the secondary systems are problematic in terms of operations, reliability, and safety. However, PB is of the view that the transformers and regulators, while in an aged condition, are not unserviceable[121]. PB notes that TransGrid's condition review concluded that the transformers and regulators do not show any clear risks of failure. We also note that the condition review recommended that due to the age and consequences of failure of this equipment that planning for replacement is considered prudent[122, 123]. Notwithstanding this, given the range of issues at the site, and the condition of some of the equipment and structures, PB is of the view that it is prudent to address these issues, and that this need has been reasonably demonstrated by TransGrid.

Strategic alignment and policy support

As noted in section H.3, TransGrid's documentation addressed a number of strategic relationships. PB also notes that these relationships were also identified in the condition review documentation. PB is of the opinion that the application of policy and strategic documentation at the condition review documentation level demonstrates a strong integration of policies and strategies within TransGrid. In PB's view, that Cooma 132 kV substation project aligns with TransGrid's policies and strategies.

Alternatives

TransGrid's project documentation presents consideration of reconstruction of the Cooma substation both in-situ and on a new site. In accordance with TransGrid's network asset replacement project evaluation procedure, both pre and post implementation risk evaluation

120 TransGrid 30 April 2008, 'Network Asset Replacement Project Evaluation – Cooma Substation', Document No. 6194 ARPE, Revision No. 2, page 4.

121 PB is of the view that it is reasonably likely that the transformers and regulators could be refurbished and their life extended.

122 TransGrid 2008, 'Transformer Condition Review – Cooma 132 kV Substation No. 1 Transformer', page 3.

123 TransGrid 2008, 'Transformer Condition Review – Cooma 132 kV Substation No. 1 Regulator', page 2-3.

has been undertaken and included for all options. The NPV of each option has also been determined, with the exception of the do-nothing option and the local reconstruction option. Table H-3 presents a summary of the options analysis conducted by TransGrid based on the use of a post-tax nominal WACC of 7.17%.

Table H-3 – Summary of options considered

Option	NPV	Risk score	$ per risk score reduction
Do nothing	-	287.6	-
Reconstruction (remote reconstruction option)	-$16.57m	40.2	-$0.07m
In-situ project package including busbars	-$13.05m	116.8	-$0.08m
In-situ project package excluding busbars	-$10.24m	148.8	-$0.07m

Source: PB summary.

TransGrid also noted a range of advantages and disadvantages for these options that principally considered the capital cost, equipment condition and operational issues, project risk, safety and environmental issues, maintenance cost, land requirements, and the feasibility of implementation given the required outages[124].

TransGrid selected the remote reconstruction option even though it has the greatest cost on the basis that:

> *"This solution has the best improvement in risk score, fully provides for future site expansion, fully overcomes the issues of the existing site and legacies of past design compromises, provides full life for site infrastructure; has the lowest risks associated with implementation and greatest confidence in feasibility; avoids future issues associated with the present busbars and disconnectors."* [125]

Having considered the identified need, PB is of the view that reconstruction, or refurbishment[126] of the substation, are the practical alternatives (other than the do-nothing option). While TransGrid considered both these options, the documentation did not demonstrate consideration of refurbishment of the transformers and regulators (refer to the discussion on Drivers (need or justification) above). Consequently, PB is of the view that not all practical alternatives have been identified and considered.

The project evaluation summary provides a review of the options and notes that:

> *"Rebuilding the Cooma Substation on the existing site would involve extensive work within a live substation. It would also perpetuate a three voltage substation and the associated congestion of 132 kV, 66 kV and 11 kV lines with additional lines expected to be required to be connected to Cooma in the future.*
>
> *The evaluation found that replacement was required and recommended that reconstruction on a new site be undertaken as this option fully provides for future site expansion, overcomes the issues of the existing site, and has*

124 TransGrid 30 April 2008, 'Network Asset Replacement Project Evaluation – Cooma Substation', Document No. 6194 ARPE, Revision No. 2, page 11-13.

125 TransGrid 30 April 2008, 'Network Asset Replacement Project Evaluation – Cooma Substation', Document No. 6194 ARPE, Revision No. 2, page 13.

126 Refurbishment is essentially the in-situ reconstruction of the major elements of the substation and is generally equivalent to TransGrid's in-situ reconstruction options.

> *the lowest risks associated with implementation and the greatest confidence in feasibility. Therefore, options involving rebuilding on the existing site were not considered further."*[127]

While PB acknowledges that that redevelopment of an existing operational substation is a complex and risky project, the analysis undertaken by TransGrid and summarised in Table H-3, shows that there is a significant difference in the NVP for these options. PB notes that the remote reconstruction option includes costs associated with the provision of *"…an ultimate 330 kV substation layout"*[128]. However, even with this cost removed, the in-situ options still have a lower NPV. PB is also concerned that the options analysis did not specifically address the inclusion of the ultimate 330 kV arrangement costs, and the need for this was not addressed in the documentation. Furthermore, PB is also of the view that the costing of the in-situ project package options are inflated, as the costing for this option includes an allowance of $9,430 k for *"new control and protection"*[129]. PB is of the view that this figure should be in the vicinity of $1.0 m, and consequently the in-situ redevelopment options are more economically favourable than represented in TransGrid's options analysis.

In order for TransGrid's options analysis to be meaningful in the context of making this investment decision (i.e. the NPV costs complete and comparable), the estimates must include the costs associated with the in-situ redevelopment of the operational Cooma substation. Amongst other matters this costing must include the additional costs of outages, standby arrangements, extended working hours, working under access permits, etc. Hence, while there are clearly technical limitations and operational limitations that must also be considered in making the final options selection, the NPV analysis should have a significant role in informing such a decision.

In PB's opinion, TransGrid's selection of the most expensive option is not fully justified and fails to reasonably demonstrate the efficiency and value of this option over the alternatives considered. Consequently, we are of the view that the most efficient option has not been chosen. Based on TransGrid's costing and supporting documentation of the advantages and disadvantages, we are of the view that the in-situ refurbishment of the substation is the most efficient option and we recommend this option. PB notes that adoption of this recommendation would remove the need for the associated Cooma easement project which has been included in the capex forecast at $0.6 m.

Timings

TransGrid has proposed that the Cooma 132 kV substation should be rebuilt on a new site during the period 2010/11 to 2013/14, and is anticipated to require an implementation timeframe of 38 months. PB notes that explicit justification for this timing was not presented in the project documentation provided, however TransGrid states that *"the timing of this project is indicative and may be subject to further refinement"*[130].

PB also notes that the condition assessment reports recommended that consideration be given to replacement of the regulators in the 2010-2014 period[131]. Planning for replacement of the transformers was also recommended as prudent by thee reports. As the condition assessment reports gave no indication any remaining life estimates for this equipment, and

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127 TransGrid 2008, 'Project Evaluation Summary - Cooma 132/66 kV Substation' Rebuild, Project Number: 6194, Revision 0, 12/6/2008, page 12.

128 TransGrid 2008, 'Project Evaluation Summary - Cooma 132/66 kV Substation' Rebuild, Project Number: 6194, Revision 0, 12/6/2008, page 13.

129 TransGrid 2008, 'Network Asset Replacement Option Comparison', Document No. AROC, Revision 0, page 7.

130 TransGrid 2008, 'Project Option Scope and Estimate - Cooma Area – Cooma North 132/66 kV Substation', Project Number: 6194, Document No. 6194B, Revision 2, 16/04/2008, page 2, 13.

131 E.g. TransGrid 2008, 'Transformer Condition Review – Cooma 132 kV Substation No. 3 Regulator', page 3.

as the date of these assessments was not given in the reports, it is not possible to infer the necessary timing of the project from this documentation. Hence PB can only conclude that that the timing of the Cooma 132 kV substation replacement is to some degree discretionary.

PB is of the view that replacement of equipment due to poor condition should ideally be timed just prior to failure. Naturally however, PB acknowledges that predicting the time of failure of equipment is difficult. However, estimates of remaining life can generally be conservatively made, particularly where failure modes are understood from experience with similar equipment. While PB accepts the need created by the range of issues at the site and the condition of some of the equipment and structures we are nonetheless of the view that TransGrid should have explicitly stated its estimate of the expected remaining life of the major equipment at the site. In any event, we are of the view that TransGrid should have documented the date of the condition review, provided a clear statement of the estimated remaining life and the reasoning for this estimate, and provided an explicit explanation (justification) of the proposed replacement timing. Consequently, while PB is of the view that the identified need has been reasonably demonstrated, we can not conclude that the timing represents efficient investment.

Costs and scope

TransGrid's recommend option requires the development of a new Cooma North 132 kV substation and associated line connections. The project scope of work is set out in the 'Project Option Scope and Estimate' document[132], and is summarised in section H.6. It is proposed that this work will require a timeframe of 38 months, with an allowance of 20 months for the construction works.

PB is of the view that the estimated replacement timeframe is reasonable given the stated scope of the works.

Table H-2 sets out the estimated cost of the project works. The proposed works essentially involves the development of:

- a new two (2) 60 MVA transformer 132/66 kV substation at Cooma North
- five (5) 132 kV line switchbays with two (2) 132 kV bus sections to accommodate the additional Country Energy 132 kV Bega line
- reconstruction of a section of 132 kV line as a double circuit to connect the existing Cooma – Munyang Tee Snowy Adit 132 kV Line
- line works to marshal both 97D and 978 (Cooma - Canberra/Williamsdale) 132 kV lines at the new Comma North substation
- provision of low capacity microwave radio and extension of the fibre optic installation between the proposed Cooma North site and the existing Cooma site
- establishing protection signalling to Williamsdale and Bega.

Also included are modifications to the existing Comma site to remove redundant equipment, and provide 66 kV switchgear to restore the site to an operational substation configuration.

PB notes TransGrid's advice that the DCF, NCF, AWF factors are included in the Cooma cost estimate but are not explicitly shown as a line item in the cost estimate summary. We also note that the estimate includes $4.94m for the provision of the 330 kV ultimate substation layout. While PB is of the view that suitable design and space allowances (e.g. land) should be made to meet foreseeable future expansion needs, we are concerned that this cost should be justified where it is significant. PB is of the view that the inclusion of a $4.94m allowance for an unjustified future conversion to 330 kV is not efficient and we recommend it is not included in the allowance (where a decision is made to allow TransGrid's preferred option.

132 TransGrid 2008, 'Project Option Scope and Estimate – Cooma Area – Cooma North 132/66 kV Substation', Document No. 6194B.

Notwithstanding our views on the efficiency of the chosen option, PB is of the opinion (for the reasons give above) that the costs as set out in Table H-2 are not efficient costs.

H.8 Conclusion

PB has conducted a detailed review of the proposed Cooma 132 kV substation replacement project, and while we are of the opinion that it is prudent to address the identified need, we are not of the view that the selected option, its timing, or the proposed costs represent an efficient investment.

Table H-4 sets out PB's recommendation on the prudency and efficiency of the submitted expenditure associated with the Cooma 132 kV substation replacement project. PB's recommended adjustment is probabilistically weighted and includes risk and escalation calculated using TransGrid's Capital Accumulation Model.

Table H-4 – PB recommendation for Cooma 132 kV substation replacement

Expenditure $m (real, 07/08)	2009/10	2010/11	2011/12	2012/13	2013/14	Total
Submitted	-	0.0	1.1	11.5	30.2	42.8
Plus easements	-	0.1	0.5	-	-	0.6
Proposed variation	4.8	4.8	3.8	(6.5)	(25.2)	(18.2)
PB recommendation	4.8	4.9	4.9	5.0	5.0	24.6

Source: TransGrid, CAM V1.8_Future deliverables 12a.xls. and PB analysis.

APPENDIX I
BEACONSFIELD WEST 132 KV GIS REPLACEMENT

APPENDIX I: BEACONSFIELD WEST 132 KV GIS REPLACEMENT

The Beaconsfield West 132 kV GIS Replacement project (Project ID 6378) is anticipated for commissioning in 2013 across all 36 scenarios forecast by TransGrid. Table I-1 shows the estimated capex for this project that has been included in the overall ex-ante allowance.

By value, this project ranks as the largest ex-ante replacement expenditure item, and accounts for 2.0% of TransGrid's proposed network capex in the 2009/10-2013/14 regulatory period.

Table I-1 – Capex for Beaconsfield West 132 kV GIS Replacement

Expenditure $m (real, 07/08)	2009/10	2010/11	2011/12	2012/13	2013/14	Total
Project 6378 (Median and Weighted Average)	2.4	7.2	10.5	28.1	-	48.1

Source: TransGrid, CAM V1.8_Future deliverables 12a.xls.

I.1 Project overview

Beaconsfield West 330/132 kV substation was commissioned in 1979 to meet the demand growth of the inner metropolitan areas. The substation is located adjacent to the Alexandra Canal, and is a major supply point for the inner city, Sydney CBD, as well as the southern metropolitan areas of Sydney including the Port of Botany and Sydney Airport. Due to the constrained nature of the site, a compact substation design was adopted to suit the site conditions[133].

The substation comprises two 330/132 kV transformers, supplied from standard outdoor 330 kV switchgear via a single 330 kV underground cable from Sydney South substation. The 132 kV switchgear is indoor SF6 Gas Insulated Switchgear (GIS) which was employed at this site due to its compact design that suits the constrained site conditions. The 132 kV switchgear consists of 18 switchbays of ABB ELK type switchgear fitted with ECK type circuit breakers (CBs). At the time of installation ECK CBs were specified and installed as the ELK type CB's were untested in service[134]. TransGrid has advised that this installation is one of the only three of its type around the world.

Whilst the 132 kV switchgear was installed and commissioned in 1979, and although the switchgear is 29 years old, TransGrid has identified a number of condition based issues. Specifically, slow circuit breaker operation due to seal deterioration, a number of SF6 gas leaks, a history of compressor failures (see section I.2 below for further details) Furthermore, TransGrid has stated that there are limited spare parts available, as well as limited internal expertise and supplier support for this specialist and relatively rare plant. Additionally, TransGrid has raised concerns regarding the busbar arrangement, which TransGrid states is suboptimal and inhibits the future substation expansion[135]. Concerns have also been noted regarding the physical condition of the switchgear building.

While minor replacement work has been undertaken at Beaconsfield West in the 1990's and 2000's, the majority of the substation is in its original state. TransGrid reports that in 1996,

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133 TransGrid 2008, 'Condition Review - Beaconsfield West Substation GIS', page 1.

134 TransGrid 2008, 'Project Option Scope and Estimate - 6378 – Beaconsfield West 132 kV GIS Replacement', Document No. 6378, page 4-5.

135 TransGrid 2008, 'Network Asset Replacement Project Evaluation, Beaconsfield West 132 kV Gas Insulated Switchgear Replacement', Document No. 6378 ARPE, Rev. 1, page 4.

ABB as the manufacturer of the plant was contracted to provide advice on the condition of the 132 kV switchgear. ABB is reported to have advised that its support for the circuit breakers would cease in April 1998[136].

I.2 Drivers (need or justification)

TransGrid has stated that the primary driver for this project is the condition of the 132 kV switchgear[137]. In support of this, TransGrid has undertaken a condition review of the switchgear which included an overview of the defect and failure history as well as gas usage data[138]. The condition assessment report notes that total gas usage between July 04 and June 07 was 782.27 kg or almost 22 kg per month of gas leakage. This review also states that the GIS has exhibited a total of 272 defects over its life with each unit exhibiting an average number of defects of 9.4. As the GIS is approximately 29 years old, this also equates to 9.4 defects per year. Table I-2 shows the top ten (10) worst performing units.

Table I-2 – Top ten worst performing GIS units

Equipment Reference	Equipment Description	Equipment	No of recorded defects
CMSBFW2F2	9S2 HAYMARKET / 2 REACTOR 132 kV CB BAY	6642	30
CMSBFW2BB	B BUSBAR 132 kV	6660	23
CMSBFW2B3	NO2 BUS COUPLER 132 kV B BUS CB BAY	6665	19
CMSBFW2R	91A CHULLORA T ST.PETERS 132 kV FDR BAY	6656	14
CMSBFW2E	91Y CHULLORA T MARRICKVILLE 132 kV FDR BY	6639	14
CMSBFW2C	264 MAROUBRA 132 kV FEEDER BAY	6635	14
CMSBFW2G	9SB DOUBLE BAY T SURRY HILLS 132 kV FDR B	6643	13
CMSBFW2D2	91M/3 BUNNERONG 132 kV FEEDER CB BAY	6638	13
CMSBFW2N2	NO1 REACTOR 132 kV CB BAY 4912A	6670	12
CMSBFW2K	261 CLOVELLY T ZETLAND 132 kV FEEDER BAY	6646	12

Source: TransGrid 2008, 'Condition Review - Beaconsfield West Substation GIS', Attachment A, page 6.

After conducting a condition assessment of the Beaconsfield West 132 kV switchgear, TransGrid concluded that the switchgear is nearing the end of its life[139] and should be replaced over the 2009/10 to 2012/13 period.

I.3 Strategic alignment and policy support

Replacement of the Beaconsfield West 132 kV GIS is noted in TransGrid's substations asset management strategy[140]. Documentation in accordance with the asset management strategy and the project evaluation procedure has been included in the project documentation provided.

136 TransGrid 2008, 'Condition Review - Beaconsfield West Substation GIS', page 1.

137 TransGrid 2008, 'Project Evaluation Summary, Project Number: 6378, Beaconsfield West GIS Replacement', page 5.

138 TransGrid 2008, 'Condition Review - Beaconsfield West Substation GIS', Appendix A and B.

139 TransGrid 2008, 'Condition Review - Beaconsfield West Substation GIS', page 2.

140 TransGrid 2008, 'Asset Management Strategy – Substations', Document No. GM AS S5 001, Revision No: 11, Issue Date: 3rd June 2008, page various.

I.4 Alternatives

To address the stated need, TransGrid has considered both refurbishment and replacement options[141], which has included consideration of the costs and benefits of replacement in-situ as well on a new site[142]. Specifically, the documentation addresses the following options:

- do nothing – TransGrid assessed the pre-investment risk of this option at an overall risk score of 217.4[143]. While TransGrid's Network Asset Replacement Option Comparison document provided some commentary on the do nothing option, no explicit examination was noted in the project documentation provided
- in-situ replacement – involving the replacement of the 132 kV switchgear in its present location and the redevelopment of the switchgear building. Extension of the existing 132 kV feeder cables is not required under this option as bus trunking would be used to extend to the site of the existing cable terminations. TransGrid identified the following key advantages and disadvantages of this option:

  Advantages

  - no need to rejoin the EnergyAustralia 132 kV cables
  - does not require purchase of additional land in a built up urban area
  - resolves the condition-based issues associated with the 132 kV switchgear and restores reliability standard
  - full manufacturer's support would be available
  - resolves existing busbar arrangement problems

  Disadvantages

  - switchgear construction and building restoration would need to be undertaken in a working substation with inherent security and safety implications
  - the adverse impact of staging coordination supply security maintenance and associated protection issues during transition stages.

  This option was estimated to have an NPV of -$21,667k and the post investment risk was estimated to reduce by 130.4 points to an overall risk score of 87.

- replace on new site – this option involves replacement the 132 kV substation on a nearby site and the cut over circuits from the existing substation. In particular, this option includes the development of a new switchgear building on a greenfield site, and installation of new 132 kV GIS, and the extension of the existing 132 kV feeders to the new site.
- TransGrid identified the following key advantages and disadvantages of this option:

  Advantages

  - resolves the condition-based issues associated with the 132 kV switchgear and restores reliability standard
  - full manufacturer's support would be available

141 TransGrid 2008, 'Project Evaluation Summary, Project Number: 6378, Beaconsfield West GIS Replacement', page 6-7.

142 TransGrid 2008, 'Network Asset Replacement Project Evaluation, Beaconsfield West 132 kV Gas Insulated Switchgear Replacement', Document No. 6378 ARPE, Rev. 1, page 11.

143 Determined in accordance with GM AS G2 025 – Network Asset Replacement Project Evaluation.

- avoids issues of construction in a working substation
- resolves existing busbar arrangement problems

Disadvantages

- requires the purchase of additional land in a built up urban area
- a means to cut-over to the new substation would be required
- EnergyAustralia cables would need to be jointed and connected to the new substation over an extended period

This option was estimated to have an NPV of -$21,424k and the post investment risk was estimated to reduce by 130.4 points to an overall risk score of 87

- replace 2 circuit breakers (to release spares) and refurbish remaining units – this option involves replacing two units with ELK circuit breakers, followed by the staged refurbishment of the reaming 132 kV switchgear units. TransGrid anticipates that this would extend the remaining life of the refurbished circuit breakers by approximately 10 years. At that time the refurbished units would then be replaced as there would be no technical support available from the manufacturer and spare parts are not likely to be viable (or would have been consumed). TransGrid identified the following key advantages and disadvantages of this option:

  Advantages

  - lowest cost option – see below

  Disadvantages

  - does not resolve the majority of SF6 gas leakage due to the design of circuit breaker relief valves
  - SF6 gas leakage (which contributes to a significant greenhouse gas impact) may have a large financial impact and adverse community reaction following the introduction of carbon trading
  - technology to repair the disconnector seals within the outage time windows is not available
  - the life of flange seals is unknown and a replacement programme for these seals is not feasible
  - remaining manufacture support for ELK circuit breakers is unknown
  - limited availability of expertise
  - spares shelf life is unknown – in particular, seals and other perishable components
  - three additional feeder bays will need to be installed by 2012 to meet EnergyAustralia's requirements

  This option was estimated to have an NPV of -$12,440k and the post investment risk was estimated to reduce by 25.8 points to an overall risk score of 192.

Based on TransGrid's options analysis, the in-situ replacement option is identified as the preferred option and TransGrid propose to replace the Beaconsfield West Gas Insulated Switchgear (GIS) with a new GIS over the period 2009/10 to 2012/13. This option was selected for the following reasons:

- provides full resolution of the switchgear condition issues
- provides the lowest overall risk score (along with replace at a new site)
- relocation of numerous EnergyAustralia cables is not required

- provision of the additional EnergyAustralia feeder bays is possible in the required timeframe (required by 2012)
- the difficulty of obtaining additional land in a constrained environment is avoided

It should also be noted that in selecting this option TransGrid has stated that the residual risk of the refurbishment option is unacceptable[144].

I.5 Timings

The timing of this work is proposed for the period 2009/10 to 2012/13, and is anticipated to require an implementation timeframe of 42 months. Explicit justification for this timing was not presented in the project documentation provided.

I.6 Costs and scope

Table I-3 shows the base cost estimate for the Beaconsfield West 132 kV GIS replacement project.

Table I-3 – Base cost estimates for Beaconsfield West 132 kV GIS replacement

Work Scope Item	Estimate[1]
Contractor Site Establishment	$0.8m
132 kV GIS Supply and Install (24 bays x $735k per bay)	$17.7m
Building Extension (scaled from Holroyd estimate)	$4.5m
Additional Foundation Support	$0.5m
Control, Protection and Metering Replacement	$1.8m
Technical Services and Communications	$0.3m
DCF (20%)	$5.5m
NCF (30%)	$8.2m
Ancillary Costs (15%)	$1.6m
Total Estimate	$40.9m

Note 1: This estimate is in real 2006/07 dollars, and does not include real labour and material escalation impacts or any risk allowance

Source: TransGrid 2008, 'Project Evaluation Summary, Project Number: 6378, Beaconsfield West GIS Replacement', page 9.

The scope of the work includes the following:

- building extension and civil works – this includes the development of a 14m by 12m extension to the existing building. TransGrid expects that piled foundations will be required in order to adequately support the building extension due to poor soil conditions. Site levels also require the use of column supports to maintain existing floor levels within the building extension. An allowance has been included for the additional foundation support costs and restricted work practices involved when working at a live site
- installation of new 132 kV switchgear – this involves 24 GIS bays consisting of four (4) bus coupler bays, 12 line bays, six (6) transformer bays, and two (2) reactor bays

144 TransGrid 2008, 'Network Asset Replacement Project Evaluation, Beaconsfield West 132 kV Gas Insulated Switchgear Replacement', Document No. 6378 ARPE, Rev. 1, page 13.

- secondary systems – including a new control room to allow for the new GIS to be fully tested and commissioned prior to commencing the cut over. New control, protection and feeder metering. Communications facilities will also be replaced as the building extension will require the existing communications room to be relocated while minimising communications outages. Additionally full SCADA functionality has been included to facilitate works staging
- progressive connection of the existing cables to the new GIS via lengths of bus ducting is also included

I.7 PB analysis

This section presents PB's view of the project information provided by TransGrid in support of the expenditure for this proposed project. The following sections address each of the key issues when considering the prudence and efficiency of a proposed capital investment.

Drivers (need or justification)

The driver of this project has been stated by TransGrid to be the condition of the 132 kV switchgear. Specifically, the key issues identified are SF6 gas leaks, slow operation due to seal deterioration, compressor failures, and limited spares combined with a lack of manufacture's support. This assessment is supported by a condition review of the switchgear, which includes an overview of the defect and failure history as well as gas usage data[145].

It is PB's opinion that the information presented supports the view that the 132 kV GIS at Beaconsfield West does have significant condition problems. Furthermore PB is of the view that the defect history and gas usage presented, reflects operational and sealing problems unexpected in equipment that is not yet 30 years old. Given TransGrid's maintenance policies and practices, as well as the previous inspection by ABB[146], PB is of the view that the condition of the 132 kV GIS is not associated with maintenance practices. Rather, PB considers that the switchgear potentially has a number of design and/or manufacturing deficiencies that are equipment type related. TransGrid has stated that the reason for the selection of the 132 kV switchgear was driven by the constrained nature of the site, and a deliberate procurement decision was taken to avoid the purchase of ELK type CB's that were (at that time) untested in service[147]. It is our view that such an approach, and the subsequent selection of the service tested ELK switchgear, is not inconsistent with sound industry practice. Consequently, PB is of the view that the need to address the condition of the 132 kV GIS at Beaconsfield West substation has been reasonably demonstrated by TransGrid.

Strategic alignment and policy support

PB is of the view that the replacement of the Beaconsfield West 132 kV GIS aligns with TransGrid's policies and strategies as stated in the substations asset management strategy[148].

145 TransGrid July 2008, 'Condition Review - Beaconsfield West Substation GIS', Appendix A and B.

146 TransGrid July 2008, 'Condition Review - Beaconsfield West Substation GIS', page 1.

147 TransGrid 2008, 'Project Option Scope and Estimate - 6378 – Beaconsfield West 132 kV GIS Replacement', Document No. 6378, page 4-5.

148 TransGrid 2008, 'Asset Management Strategy – Substations', Document No. GM AS S5 001, Revision No: 11, Issue Date: 3rd June 2008, page various.

Alternatives

TransGrid's project documentation presents consideration of refurbishment and replacement alternatives both in-situ and at a new location. In accordance with TransGrid's network asset replacement project evaluation procedure, both pre and post implementation risk evaluation has been undertaken and included for all options. The NPV of each option has also been determined with the exception of the do-nothing option. Table H-3 presents a summary of the options analysis conducted by TransGrid based on the use of a post-tax nominal WACC of 7.17%[149].

Table I-4 – Summary of options considered

Option	NPV[1]	Risk score	$ per risk score reduction
Do nothing	-	217	-
Replace in-situ	-$21.67m	87	-$0.17m
Replace on a new site	-$21.42m	87	-$0.16m
Replace two (2) circuit breakers and refurbish	-$12.44m	192	-$0.50m

Note 1: This estimate is in real 2006/07 dollars, and does not include real labour and material escalation impacts or any risk allowance

Source: PB summary.

TransGrid also noted a range of advantages and disadvantages for these options that principally considered the need for jointing of the EnergyAustralia 132 kV feeder cables, the need for additional land, whether or not the option fully or partially resolved the issues with the 132 kV GIS, the issue with the busbar arrangement, and the complexity of the implementation.

TransGrid selected the in-situ replacement option even though it had the greatest cost on the basis that it:

- provides full resolution of the switchgear condition issues
- provides the lowest final risk score (along with replace at a new site)
- relocation of the EnergyAustralia cables is not required
- enables provision of the EnergyAustralia feeder bays when required (i.e. 2012)
- avoids the difficulty of obtaining additional land in a constrained environment

It is also noted that TransGrid views the residual risk of the refurbishment option as unacceptable[150].

Having considered the fundamental need, PB is satisfied that an appropriate range of practical alternatives has been identified and considered. However, PB notes that it is apparent that not all costs have been included in the analysis of the options. For example, with the refurbishment option, the cost to extend the GIS to accommodate the EnergyAustralia 132 kV feeders in 2012 is explicitly stated as not being included in the NPV calculation[151]. For the replacement option at a new site, the NPV analysis did not include the

149 TransGrid 2008, 'Network Asset Replacement Project Evaluation', Document No. GM AS G2 025, Revision No: 1, Issue Date: 2nd July 2008, page 18.

150 TransGrid 2008, 'Network Asset Replacement Project Evaluation, Beaconsfield West 132 kV Gas Insulated Switchgear Replacement', Document No. 6378 ARPE, Rev. 1, page 13.

151 TransGrid, 'Network Asset Replacement Option Comparison', Document No.: 6378 AROC, Revision No.: 1, Revision Date: 9/05/2008, page 9.

acquisition cost of the additional land required. Inclusion of these omissions would result in potentially significant changes to the NPVs of the options being considered. For example a potentially significant increase in the present value of the cost of this option to replace on a new site due to the additional land acquisition costs, and a smaller increase in the present value of the cost of the replacement in-situ option associated with accommodating the Energy Australia 132 kV feeders.

PB is of the view that these errors and omission could materially influence the preferred option selection by changing the NPV associated with each option such that the order of the options is altered, or the order of the options is made more certain. Based on the changes described above, the result of the analysis would be expected to favour the refurbishment option more strongly. The order of the replacement options could change depending on the difference between the cost of land acquisition and the cost of accommodating the Energy Australia feeders. Whilst PB notes that we have not undertaken a detailed costing of these omitted items, we also highlight the uncertainty regarding the cost and availability of land for a replacement site resulting in an increased cost and timing risk associated with this acquisition. Therefore, on the balance of the documentation presented, PB would expect that the replacement in-situ option would become the most favourable option after the replace two circuit breakers and refurbish option.

Furthermore, the benefits from operating and maintenance savings associated with each option have not been presented in the NPV analysis. Indeed, it is apparent that no benefits have been identified and included in the NPV analysis of the options. PB has noted that some analysis of the sensitivity to key input assumptions was undertaken[152], and that this did not alter the rankings of the options and therefore influences the project selection. In all sensitivity studies, the preferred option remained the most expensive option. In PB's opinion, the sensitivity analysis presented did not reflect the true intent of sensitivity analysis, that is, it failed to demonstrate the impacts on the option selection of the variance in the uncertain costs and benefit estimates.

In PB's view, as far as is practical, an NPV analysis comparing various options should include the value of all known costs and benefits, and unbiased estimates of uncertain costs and benefits. Where there are uncertain costs and benefits, a sensitivity analysis should be used to demonstrate the likelihood that the recommended option is the highest value option[153]. Externalities that can't reasonably be estimated can then be used to support the final recommendation. Additionally, consideration of the do nothing option also forms a critical point of reference for the value of the alternatives being considered. Without the value of the base case (i.e. do nothing) the benefit of accepting an alternative investment can't be fully defined.

In PB's opinion, TransGrid's options analysis as presented in its option comparison document is incomplete and in our view fails to reasonably demonstrate the efficiency and value of the chosen option over the alternatives considered. Apparent material errors in the options analysis, key omissions, and in our opinion a less than complete sensitivity analysis, combine to undermine the value of such an analysis. Consequently, on the basis of the options analysis presented, we are unable to conclude that the most efficient option has been chosen. We do however note that while the highest cost option has been selected by TransGrid, that this may not have been the highest cost option had the all missing costs and benefits been included in the analysis.

PB also has concerns regarding the relationship of this project to other works at Beaconsfield West. Specifically, TransGrid propose to carry out related works as shown in Table I-5. In addition to these works, and as previously noted, EnergyAustralia is also proposing to connect additional 132 kV cables at Beaconsfield West in 2011/12. TransGrid has not presented any documentation demonstrating the efficient timing and efficient sequencing of

152 TransGrid, 'Network Asset Replacement Option Comparison', Document No.: 6378 AROC, Revision No.: 1, Revision Date: 9/05/2008, page 13.

153 Or conversely the lowest cost where benefits are excluded.

this set of proposed works. PB is concerned that the options analysis presented for the project under review, does not consider (or reference consideration) of the broader options in terms of this set of works. Furthermore, PB is concerned that the installation of the 3rd transformer in 2011, with subsequent rearrangement of the 330 kV supply arrangement in 2017 may represent an inefficient investment.

Table I-5 – Related Beaconsfield projects

Project ID	Project name	Commissioning date	Total[1]	Reason for project
6378	132 kV GIS Replacement	2013	48.1m	Poor asset condition
6096	132 kV Capacitor Bank	2011	6.8m	Network approaching limit of capacity
5818	330 kV 3rd Transformer	2011	13.1m	Network approaching limit of capacity
6263	330 kV Substation Busbar – Augmentation	2017	0.1m	
6263	330 kV Substation Busbar – Easements	2017	36.2m	Asset approaching limit of capacity

Note 1: Expenditure $m (real, 07/08)
Source: Template-AER Schedule (for AER).xls – sheet 4.3.

Given the above concerns, it is PB's view that the options analysis presented by TransGrid does not demonstrate that the most efficient option has been chosen. However, PB does accept that condition of the equipment is such that action is required, and that refurbishment of such a specialist item of equipment in a live substation environment would be a very complex operation. Furthermore, we also accept the concerns regarding the support of the manufacturer in undertaking such a refurbishment. Given these issues, PB is of the view that replacement of the switchgear is prudent and may be the only practical alternative.

It should be noted that subsequent to issuing this review as a preliminary draft, TransGrid revised its options analysis and related documentation in response to PB's concerns, and addressed many of the issues raised regarding the completeness and quality of the analysis originally presented. However, while TransGrid has been able to undertake further analysis in response to our concerns, PB maintains that TransGrid's analysis as originally presented does not demonstrate that the most efficient option has been chosen, and does not demonstrate consideration of the broader investment issues at the Beaconsfield site. In our opinion this issue suggests that TransGrid's options analysis process may, in a broader sense, be failing to reasonably demonstrate the relative efficiency of the alternatives being considered as well as identify the most efficient investment package when a suite of interrelated works are being proposed.

Timings

TransGrid has proposed that the 132 kV GIS will be replaced during the period 2009/10 to 2012/13. PB notes that explicit justification for this timing was not presented in the project documentation provided. In the condition review[154] undertaken by TransGrid it states that:

> *"The difficulty and long timeframes involved in obtaining expertise to address issues of concern … is a major contributing factor for the short foreseeable life-span of the substation GIS equipment. Furthermore the manufacturer no longer supports the ECK CB's and it has reached the end of life."*

154 TransGrid 2008, 'Condition Review - Beaconsfield West Substation GIS'.

As this statement indicates that the switchgear has either a 'short remaining life' or 'has reached the end of life', it is not clear to PB what expected remaining life that TransGrid has placed on this equipment. Furthermore, PB notes that, notwithstanding the review date noted on the condition review document[155] and the references to the 1996 ABB inspection, the date that the condition review was undertaken was not provided on the condition review document. Hence PB can only conclude that that the timing of this equipment replacement is to some degree discretionary.

PB is of the view that replacement of equipment due to poor condition should ideally be timed just prior to failure. Naturally however, PB acknowledges that predicting the time of failure of complex and specialist equipment is difficult and in some instances impractical. However, estimates of remaining life can generally be conservatively made, particularly where failure modes are understood from experience with similar equipment, or from laboratory testing. While PB accepts that the 132 kV GIS at Beaconsfield West has significant condition problems, and that globally there are only three other installations of this particular equipment, we are nonetheless of the view that TransGrid should have explicitly stated its estimate of the expected remaining life of the 132 kV switchgear. In any event, we are of the view that TransGrid should have documented the date of the condition review, provided a clear statement of the estimated remaining life and the reasoning for this estimate, and provided an explicit explanation (justification) of the proposed replacement timing.

While PB is of the view that the need to address the condition of the 132 kV GIS at Beaconsfield West substation has been reasonably demonstrated, we can not conclude that the timing represents efficient investment as TransGrid has not provided specific justification for the project timing.

However, PB notes that the criticality of the equipment to the Sydney Metropolitan Area supply and the documented condition is such that PB does not consider deferral of the project to be prudent.

Costs and scope

TransGrid's selected option requires replacement of the 132 kV GIS in-situ, that is, within the constraints of the operational Beaconsfield West site. The project scope of work is set out in the 'Project Option Scope and Estimate' document[156], and is summarised in section I.6. It is proposed that this work will require a timeframe of 42 months, with an allowance of 24 months for the construction works. Table I-3 sets out the estimated cost of the project works.

Notwithstanding PB's opinion of the selected option, PB is of the view that the estimated replacement timeframe for TransGrid's selected option is reasonable given the complexity of replacing such equipment in an operational substation.

As part of the project cost estimating process, PB has concerns regarding the application of generalised DCF[157] and NCF[158] factors, as well as the 'Ancillary Costs[159,160]. It is noted that

155 TransGrid 2008, 'Condition Review - Beaconsfield West Substation GIS', page 1.

156 TransGrid 2008, 'Project Option Scope and Estimate - 6378 – Beaconsfield West 132 kV GIS Replacement', Document No. 6378, page 4-5.

157 DCF - the Design Cost Factor which includes costs associated with the design, specification preparation, tendering process, the environmental assessment and project management. TransGrid, 'CAPEX Estimation Database Manual', page 5.

158 NCF - the Network Cost Factor which includes costs associated with field supervision, site management and commissioning of the project. TransGrid, 'CAPEX Estimation Database Manual', page 5.

159 AWF - the Ancillary Works Factor which includes costs to account for the minor project costs that are not captured by the high level scoping. It includes the costs of integrating the new project into the existing network, changes to control and protection systems, and ancillary/incidental works that occur during the construction period. TransGrid, 'CAPEX Estimation Database Manual', page 5.

the DCF and NCF factors have been doubled due to the difficulties of working at an operational site, and due to the one-off nature of the work. While PB accepts these basic reasons, the basis of doubling these costs is not clear and appears arbitrary. The cost of these three general %-based factors account for some $15.3m (or 37.4%) of the total project estimated cost (refer Table I-3). Furthermore, this cost has been escalated for real labour and material cost increases, and adjusted for inclusion of a risk based allowance. Moreover, on examination of the dollar value of these factors, it is unclear from the figures given by TransGrid (refer Table I-3) how these factors are applied to arrive at the dollar values stated. As the basis of these factors, their allocation, and their apparent arbitrary scaling is unclear, and given their significant dollar value within the project cost estimate, PB is of the view that the DCF, NCF, and AWF factors should be fully justified and transparently applied. Additionally, we believe that the values of these factors should be supported by evidence to demonstrate their reasonableness. Consequently, PB can not conclude that the application of these factors represents an estimate of efficient costs, and consequently PB recommends a 50% reduction in the DCF and NCF values.

Given our concerns as set out above, PB is of the view that the costs as set out in Table I-3 do not represent an efficient estimate of the costs for the proposed works.

I.8 Subsequent Update

The above review was completed on the basis of information provided by TransGrid with their submission, and in response to questions and discussions to clarify the information provided in TransGrid business documentation. This information was received prior to 20 August 2008. As discussed further in section 5 of the main body of this report, since completing the above review, TransGrid has provided subsequent updates to the project information. This subsequent information includes:

- a document entitled 'Response to PB Advice #7 Question F4' detailing the TransGrid response to PB questions;
- a revised cost estimate for 'Option 3 – Replace 2 Circuit Breakers and Refurbish';
- ABB 'Inspection Report on 132 kV GIS Type ECKSI at Beaconsfield' July 1996;
- ABB – TransGrid email 'Re: FW: BEACONSFIELD WEST SUBSTATION 132 kV GIS' 17/10/2007
- ABB – TransGrid letter 'ECK Switchgear at Beaconsfield' 01/05/1996

This subsequent information is considered in this section, along with its implications on PB views and recommendations.

The Asset Replacement Project Evaluation (ARPE) document[161] that was originally supplied by TransGrid presented the refurbishment option as a feasible option representing the highest NPV option; however the more expensive replacement option was selected[162]. Following PB questioning with regard to the selection of the replacement option, the following revised business case documents were provided on 11 August 2008:

- a revised Asset Replacement Project Evaluation document entitled 'Beaconsfield West 132 kV Gas Insulated Switchgear Replacement' Revision 2, 07/08/08;

[160] TransGrid 2008, 'Project Option Scope and Estimate - 6378 – Beaconsfield West 132 kV GIS Replacement', Document No. 6378, page 7.

[161] TransGrid, Asset Replacement Project Evaluation 6378ARPE Beaconsfield West 132 kV Gas Insulated Switchgear Replacement' Revision 1, 09/05/08.

[162] TransGrid, Asset Replacement Project Evaluation 6378ARPE Beaconsfield West 132 kV Gas Insulated Switchgear Replacement' Revision 1, 09/05/08 page 13.

- a revised Network Asset Replacement Options Comparison document entitled 'Beaconsfield West Gas Insulated Switchgear (GIS)'Revision 2;

The refurbishment option was withdrawn in the revised ARPE document where TransGrid states:

> *A third option to replace 2 circuit breakers and complete refurbishment work on the remainder of the equipment was considered unsuitable as it did not address the project objectives.*[163]

Upon further questioning relating to the reasons for the withdrawal of the option, TransGrid has provided the subsequent information identified above on 21 August 2008.

This information comprises supplier condition inspection reports dated July 1996 that support the stated condition of the equipment and limited results expected from a refurbishment program. Written confirmation from the supplier, dated October 2007 outlining the limited support that can be offered for the equipment has also been provided in the form of the email was quoted by TransGrid in their original business case document:.

> *This type of GIS is now so old that even ABB has gaps in specific repair/overhaul expertise required for this particular equipment - and the same situation applies to several sub-supplier / parts availability.*[164]

Whilst PB acknowledges the suppliers' limited support capabilities for the existing ECK equipment, we note that the supplier also states in the same email:

> *There may still be a possibility to replace an entire breaker with a new type and adapt it to fit – thereby creating some spares…A rough estimate for that could be around Swiss Francs [budget price] per breaker excluding labour.*
>
> *…We could come and take a look with your staff and try to define and photograph specific areas of work (eg gas leaks) that make sense to do to extend the life of this GIS…*[165]

On this basis we are of the view that the level of supplier support available to TransGrid has not been fully identified in the ARPE documentation.

The circuit breaker replacement proposed by the supplier appears similar to the refurbishment option originally proposed by TransGrid. However PB note that the investigation of further options to reduce gas leaks, as proposed by ABB, is not addressed in the option presented in the TransGrid documentation.

Given that the primary justification for dismissing the refurbishment option relates to the failure to address the well documented gas leakage issues and the limited supplier support for the equipment, PB is of the view that the omission of the supplier's offer to undertake an investigation to address the leakage issues and provide life extension recommendations for the equipment represents a material omission from the options assessment process.

This view is supported by conclusion iii of TransGrid's Condition Assessment report that states:

> *With the ELK type switchgear, TransGrid needs to engage ABB or industry experts to determine if inherent leakage and other defects can be fixed. The*

163 TransGrid, Asset Replacement Project Evaluation 6378ARPE Beaconsfield West 132 kV Gas Insulated Switchgear Replacement' Revision 2, 07/08/08, page 4.

164 ABB, email to TransGrid , 'Re: FW: BEACONSFIELD WEST SUBSTATION 132 kV GIS' 17/10/2007.

165 ibid.

> *limited spares available also need to be assessed to check if they are suitable for use. Given this is ABB equipment, it is anticipated that only ABB may be able to provide input into this process*[166]

No evidence was provided in the project documentation to indicate that TransGrid has engaged ABB to undertake this investigation.

Furthermore, PB notes that the budget price for a new circuit breaker quoted by the supplier in October 2007[167] is approximately 43%[168] of the price adopted by TransGrid in developing their cost estimate for the refurbishment option. In contrast, the price used by TransGrid has been derived from a 1996 quote and escalated at 3% p.a. PB does not consider the use of the 1996 quoted price in place of the 2007 budget price to be reasonable and further notes that neither the source of the 1996 price or the basis for escalation has been substantiated by TransGrid.

On the basis of the supplementary information provided, PB is of the view that:

- material omissions have been made in the assessment of the refurbishment option that may not reasonably justify the withdrawal of the option; and,
- the omission of the most recent cost information available to TransGrid at the time of preparing the original ARPE document significantly influences the cost associated with the GIS refurbishment option.

Therefore the documentation provided by TransGrid to the Regulator has either incorrectly presented unfeasible alternative options as feasible, or has contained significant omissions to the pricing and scope of the refurbishment option that may have materially influenced the result of the analysis.

In the absence of the specific recommendations from the supplier, PB is unable to determine the efficient cost or scope of a feasible refurbishment project. However based on the supplier's statement that:

> *We have found in our recently undertaken practical work in Oerlikon that we were unable to reassemble the impulse and isolating chambers of the ECK breakers in a gastight condition. The reason is that special sealing materials and special seals as were originally fitted are not obtainable anywhere today*[169]*.*

PB is of the view that the scope to adequately address the circuit breaker gas leakage problems is likely to require a large number of ECK circuit breaker replacements. Depending on the specific issues identified, the cost of this work may approach the cost of the replacement option.

Following from our review of the subsequent information provided by TransGrid, PB reiterate our conclusion that the options analysis presented by TransGrid does not demonstrate that the most efficient option has been chosen. However, PB does accept that the condition of the equipment is such that action is required, and that refurbishment of such a specialist item of equipment in a live substation environment would be a very complex operation. Furthermore, we also accept the concerns regarding the support of the manufacturer in undertaking such a refurbishment, most notably the supplier's uncertainty of obtaining a gastight seal in the

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166 TransGrid, Condition Review Beaconsfield West Substation GIS, undated (file 6378 Beaconsfield West GIS Replacement ARCA.doc saved 7 July 2008), page 5.

167 ABB, email to TransGrid , 'Re: FW: BEACONSFIELD WEST SUBSTATION 132 kV GIS' 17/10/2007.

168 October 2007 Average Interbank currency conversion rate of 0.94842 CHF = 1.00000 AUD used, http://www.oanda.com/convert/fxhistory, Accessed 4 September 2008.

169 ABB, TransGrid Quotation Q17/96, June 1996, page 2.

refurbishment process. Given these issues, PB is of the view that replacement of the switchgear may be the only practical alternative and on this basis is considered prudent. Therefore no changes to our previous recommendations are proposed.

I.9 Conclusion

PB has conducted a detailed review of the proposed Beaconsfield West 132 kV GIS replacement project, and while we are of the opinion that the project is prudent, we are not able to conclude that it represents efficient investment.

Table I-6 sets out PB's recommendation on the prudency and efficiency of the submitted expenditure associated with the Beaconsfield West 132 kV GIS Replacement project. PB's recommended adjustment is probabilistically weighted and includes risk and escalation calculated using TransGrid's Capital Accumulation Model.

Table I-6 – PB recommendation for Beaconsfield West 132 kV GIS Replacement

Expenditure $m (real, 07/08)	2009/10	2010/11	2011/12	2012/13	2013/14	Total
Submitted	2.4	7.2	10.5	28.1	-	48.1
Proposed variation	(0.5)	(1.6)	(2.3)	(6.2)	-	(10.6)
PB recommendation	1.9	5.6	8.2	21.9	-	37.5

Source: TransGrid, CAM V1.8_Future deliverables 12a.xls., and PB analysis.

APPENDIX J
NEWCASTLE 330 KV SUBSTATION TRANSFORMER REPLACEMENT

APPENDIX J: NEWCASTLE 330 KV SUBSTATION TRANSFORMER REPLACEMENT

The Newcastle Transformers Replacement project (Project ID 5622) is anticipated for commissioning in 2013 across all 36 scenarios forecast by TransGrid. Table J-1 shows the estimated capex profile for this project that has been included in the overall ex-ante allowance.

By value, this project ranks as the fourth largest ex-ante replacement expenditure item, and accounts for 0.8% of TransGrid's proposed network capex in the 2009/10-2013/14 regulatory period.

Table J-1 – Capex for Newcastle 330/132 kV transformers replacement

Expenditure $m (real, 07/08)	2009/10	2010/11	2011/12	2012/13	2013/14	Total
Project 5622 (Median and Weighted Average)	-	-	1.3	17.6	-	18.9

Source: TransGrid, CAM V1.8_Future deliverables 12a.xls.

J.1 Project overview

Newcastle Substation was commissioned in 1969 and comprises four 330/132 kV transformer sets. The three single phase units comprising the original No.1 transformer set was replaced in 2005 with a three phase 375 MVA unit[170].

The project scope proposed for the 2009/10-2013/14 regulatory period covers the replacement of six of the single phase transformer units with new two new three phase units. The three most serviceable single phase units would be used to extend the life and reliability of the remaining single phase transformer set. Secondary systems replacement and oil containment upgrade work has also been included in the project scope[171].

Eight of the single phase transformer units are the original Mitsubishi units installed between 1969 and 1972 and are of the same type associated with three recent failures at Sydney West and Newcastle relating to tapchanger failures[172].

The remaining unit is an ASEA unit manufactured in 1970 and installed at Newcastle following the failure of the Blue phase unit of No.2 transformer in 2000. TransGrid state that the replacement transformer is not well matched to the other phases, resulting in the need to restrict the tapping range due to rating restrictions of the neutral earthing reactor. Furthermore, TransGrid has identified that extensive re-gasketting work is required to maintain this transformer in service.

TransGrid state that the transformers, at 42-44 years old at the time of replacement would be at the end of their expected life of 42 years[173]. TransGrid has provided internal condition assessment reports supporting the deteriorating condition of the transformers[174] consistent

170 TransGrid Project Option Scope and Estimate 5622, June 2008, page 4.

171 Ibid, page 5.

172 TransGrid Network Asset Replacement Project Evaluation 5622 ARPE, June 2008, page 6.

173 Ibid.

174 TransGrid, Transformer Condition Reviews, Newcastle No. 2, 3 & 4 Transformers, July 2008.

with their age and have highlighted the increasing risk associated with their inability to respond to multiple single phase transformer failures[175].

J.2 Drivers (need or justification)

TransGrid has stated that the primary driver for this project is the condition of the 330/132 kV single phase transformers leading to an increased risk of multiple single phase unit failures at the Newcastle substation. TransGrid has undertaken a condition review of the three remaining single phase transformer sets, which included an overview of the defect and failure history as well as insulation, oil and dissolved gas analysis[176] results and a discussion on the risk factors associated with the transformers.

The condition assessment reports note that the condition of the transformer units is consistent with the advanced age of the units. However, with the exception of the No.2 transformer blue phase unit, the condition assessment reports do not specifically recommend replacement[177]. Notwithstanding, indicators above policy limits are noted for the majority of the units and the susceptibility of the Mitsubishi units to tapchanger faults due to the high number of operations is also highlighted in a number of cases.

TransGrid acknowledge that the condition monitoring results do not, in themselves justify the full replacement of the transformers but highlight the need to manage the replacement of the single phase units at Newcastle[178] due to the increasing risk of TransGrid being unable to respond multiple failures of single phase units on the basis of:

- the deteriorating condition of the units;
- the limited number of similar units and spare single phase transformers available to TransGrid[179]; and,
- the degree of civil and electrical works required to make use of standard three phase replacement units[180].

After conducting a condition assessment of the Newcastle single phase transformer sets, TransGrid concluded that, whilst serviceable, the units are nearing the end of their life and two of the transformer sets should be replaced over the 2009/10 to 2012/13 period to mitigate the risk associated with the limited stock of spare transformers and parts.

J.3 Strategic alignment and policy support

Replacement of the Newcastle 330/132 kV Transformers is noted in the businesses substations asset management strategy[181]. The strategy for the replacement of these transformers [182] and the timing for the dependent projects at Tomago and Waratah West[183]

175 TransGrid Network Asset Replacement Project Evaluation 5622 ARPE, June 2008, page 8

176 TransGrid, Transformer Condition Reviews, Newcastle No. 2, 3 & 4 Transformers, July 2008

177 TransGrid, Transformer Condition Review, Newcastle No. 2 Transformer, July 2008, page 9

178 TransGrid Network Asset Replacement Project Evaluation 5622 ARPE, June 2008, page 4

179 ibid, page 5

180 TransGrid, Transformer Condition Review, Newcastle No. 2 Transformer, July 2008, page 1.

181 TransGrid 2008, ‘Asset Management Strategy – Substations’, Document No. GM AS S5 001, Revision No: 11, Issue Date: 3rd June 2008, page 37.

182 TransGrid, Outline Plan to the Newcastle Area, 2004, page 6.

183 TransGrid & Energy Australia, Final Report – Development of Electricity Supply to the Newcastle Area, Dec 2007 page various.

to avoid the need for the construction of the No.5 transformer 330 kV switchbay are also identified in documents provided in the project package.

J.4 Alternatives

To address the stated need TransGrid has considered refurbishment, replacement and project scoping options[184] which has included consideration of the costs and benefits of replacement in-situ as well on a new site[185]. Specifically, the documentation addresses the following options:

- *Option 1 - Replace One Transformer.* Replace one transformer and use the most serviceable single phase unit to replace a unit on the remaining original banks to improve their overall reliability. Including the upgrade of the oil containment system for the new transformer and replacement of the tertiary bus system and switchgear with a cable based connection for the original units. TransGrid identified the following key advantages and disadvantages of this option[186]

  Advantages

  - Lower risk of failure at Newcastle
  - Some improvement in environmental performance from the upgrade for the new transformer
  - Removal of the tertiary bus system and possible risks associated
  - Lowest outright cost
  - Some reduction in maintenance cost from the installation of one three phase transformer bank

  Disadvantages

  - Two transformers with lower reliability and increasing risk of failure remain in service – creating some uncertainty regarding achievement of project objectives
  - Relocation of units and replacement of tertiary ducting relatively expensive for the outcome.

  This option was estimated to have an NPV of -$6,179k and the post investment risk was estimated to reduce by 30.2 points to an overall risk score of 145.2.

- *Option 2 – Replace Two Transformers.* Replace two transformers and use the most serviceable single phase units to replace units on the remaining original bank to improve its overall reliability. Including the upgrade of the oil containment system for the new transformers and replacement of the tertiary bus system and switchgear with a cable based connection for the original transformer set. TransGrid identified the following key advantages and disadvantages of this option

  Advantages

  - Risk of failure at Newcastle lower compared with Option 1
  - Increased improvement in environmental performance from the upgrade for the new transformer

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184 TransGrid Network Asset Replacement Project Evaluation 5622 ARPE, June 2008, page 8.

185 TransGrid 2008, ‘Network Asset Replacement Project Evaluation, Beaconsfield West 132 kV Gas Insulated Switchgear Replacement’, Document No. 6378 ARPE, Rev. 1, page 11.

186 TransGrid Network Asset Replacement Project Evaluation 5622 ARPE, June 2008, page 9.

- Removal of the tertiary bus system and possible risks associated
- Additional spares phases would become available
- Moderate outright cost
- Increased reduction in maintenance cost from the installation of two three phase transformer banks

Disadvantages

- One transformer with lower reliability and increasing risk of failure remains in service - creating some uncertainty regarding achievement of project objectives (better than Option 1)
- Relocation of units and replacement of tertiary ducting relatively expensive for the outcome

This option was estimated to have an NPV of -$8,210 and the post investment risk was estimated to reduce by 60.4 points to an overall risk score of 115

- *Option 3 – Replace Three Transformers*. Replace two transformers in the 2013/14 regulatory period and allow for replacement of the last transformer in the following period if required. Including the upgrade of the oil containment system for the new transformers. TransGrid identified the following key advantages and disadvantages of this option[187]

  Advantages

  - Lowest risk of failure at Newcastle
  - Best improvement in environmental performance from the upgrade for the new transformers.
  - Removal of the tertiary bus system and possible risks associated.
  - Best reduction in maintenance cost from the installation of one three phase transformer bank.
  - Lowest risk in obtaining required outcomes

  Disadvantages

  - Highest cost

  This option was estimated to have an NPV of -$10,278k and the post investment risk was estimated to reduce by 96.4 points to an overall risk score of 79.

- *Option 4 – Refurbishment.* Refurbishment program covering the following activities

  - Replacement of high operation tapchangers
  - Oil treatment to improve oil breakdown strength
  - Installation of on-line condition monitoring to track possible gas generation for an early warning of gas generation escalation
  - Replacement of the tertiary bus ducting system and switchgear
  - Repair of leaks

  TransGrid identified the following key advantages and disadvantages of this option

  Advantages

  - Lower cost
  - Eliminates some risk factors.

187 TransGrid Network Asset Replacement Project Evaluation 5622 ARPE, June 2008, page 10.

Disadvantages

- Serious concerns regarding the condition of particular phase units (note that any single unit failure would result in loss of the bank) and the consequences of failure create an unacceptable risk. The risks are not eliminated by this option
- There is evidence of oil quality and insulation conditions reverting to pre 1997 refurbishment levels and there is no certainty that the dissolved gas generation issues found in No. 3 and No. 4 banks (in particular) will be resolved by refurbishment
- Costs are relatively high (although lower than replacement) due to the need to treat three separate phases in each bank. Contract costings for this type of work have increased markedly in recent projects undertaken
- The likely effectiveness of this option in obtaining the required project outcomes is considered poor
- The tap-range limitation associated with No. 2 Transformer remains

This option was estimated to have an NPV of -$4,153 and the post investment risk was estimated to reduce by 16.8 points to an overall risk score of 158.2.

Option Selection

Based on TransGrid's options analysis, Option 2 – Replace Two Transformers, was identified as the preferred option and TransGrid propose to replace six of the single phase transformer units with two three phase transformers over the period 2011/12 to 2012/13. This option was selected for the following reasons: [188]

- TransGrid state that this option is recommended by an independent report prepared by Wasinger Transformers[189] to re-establish the transformer reliability at the site
- the reduction in the risk of transformer failure

TransGrid has established risk score criteria for transformers to identify both the acceptable risk for existing transformers and the risk score required to be achieved by replacement or refurbishment projects[190].

It should also be noted that in selecting this option, the risk score of 158.2 provided by the refurbishment option is only marginally within the maximum risk score criterion of 160 established for undertaking a condition review to trigger further risk reduction work. Similarly, as the refurbishment option does not meet TransGrid's risk score criterion of <120 for pursuing the option, the refurbishment option is considered to be unacceptable.

J.5 Timings

The timing of this work is proposed for the period 2011/12 to 2012/13, and is anticipated to require an implementation timeframe of 31 months. TransGrid has stated that the transformer replacements are required to occur over two consecutive shoulder periods[191] resulting in a nine month construction period to accommodate the outages required to undertake the work.

188 TransGrid Network Asset Replacement Project Evaluation 5622 ARPE, June 2008, page 11.

189 This report has not been provided to or reviewed by PB.

190 TransGrid Presentation M5_Replacement Capital Expenditure for AER July08v2 page 36.

191 TransGrid Project Evaluation Summary PES5622, June 2008, page 9.

The timing of the commissioning date for the project has been established later into the 2009/10 to 2013/14 regulatory period due to TransGrid's prioritisation of six transformer replacement projects to occur prior to the Newcastle project[192].

J.6 Costs and scope

Table J-2 shows the base cost estimate for the Newcastle 330/132 kV Transformer Replacement project. A more detailed breakdown of the costs has not been provided in the project documentation.

Table J-2 – Base cost estimates for Newcastle 330/132 kV transformer replacement

Work Scope Item	Estimate[1]
Replacement of No. 2 Transformer	$7.42m
Replacement of No. 3 Transformer	$7.52m
No. 5 Transformer Switchbay	$1.03m
Total Estimate	$15.97m

Note 1: This estimate is in real 2006/07 dollars, and does not include real labour and material escalation impacts or any risk allowance

Source: TransGrid 2008, 'Project Option Scope and Estimate', Project Number: 5622, Newcastle 330/132 kV Transformer Replacements', page 5.

The scope of the work includes the following:

- Replacement of the existing No.2 & No. 3 330/132 kV 400 MVA transformer sets with new 330/132 kV 375 MVA three phase units[193] including the replacement of the existing 132 kV CTs, control, protection and voltage regulation panels[194]
- Demolish existing single phase transformer bays and construct new compound suitable for new 375 MVA 3 phase 330/132 kV transformers
- Replacement of the existing control, protection and voltage regulation panels associated with the No.1 and No.5 transformer bays[195]
- Replacement of tertiary bus system and switchgear with a cable base connection for the remaining 3 x 1ph transformer set
- Replacement of associated secondary systems and switchgear that does not meet the required ratings.
- Upgrade of oil containment systems serving the new transformers to current standards
- New HV connections from the transformer secondary side bushings to the existing strung bus arrangements
- New rigid bus bar to connect the primary side of the transformers.

192 TransGrid Transformer Risk Scoring and Timing of Replacement 7 August 2008, page 5.

193 TransGrid Project Evaluation Summary PES5622, June 2008, page 7.

194 TransGrid Network Asset Replacement Project Evaluation 5622 ARPE, June 2008, page 9.

195 TransGrid Project Option Scope and Estimate 5622, June 2008 page 3.

J.7 PB analysis

This section presents PB's view of the project information provided by TransGrid in support of the expenditure for this proposed project. The following sections address each of the key issues when considering the prudence and efficiency of a proposed capital investment.

Drivers (need or justification)

The driver of this project has been stated by TransGrid to be the condition of the single phase 330/132 kV transformers. Specifically, the key issues identified are oil leaks, tapchanger fault vulnerability, dissolved gas indicators above policy limits on the majority of units and the deterioration of oil quality. This assessment is supported by an internal condition review of each transformer set, which includes an overview of the defect and failure history as well as insulation, bushing and oil test results[196]. An external condition report has been referenced in the ARPE document but not provided in the project documentation.

It is PB's opinion that the information presented supports the view that the 330/132 kV transformers at Newcastle do have significant age related condition problems which pose an increased risk of failure. Furthermore PB is of the view that the defect history, asset population and limited spares holding support the planned replacement of the single phase units to mitigate the risk associated with multiple unit failure at the Newcastle substation.

Given TransGrid's maintenance policies and practices, as well as the condition assessment history, PB is of the view that the condition of the 330/132 kV single phase transformer sets is age related and not associated with maintenance practices. TransGrid has stated that the primary concern over the continuing use of this equipment is the limited availability of suitable system spares in the event of a failure. TransGrid note that by not replacing all of the single phase transformer sets, the most serviceable units would be reconfigured into the remaining single phase set(s) to ensure that the maximum remaining life of the single phase units is obtained[197].

Consequently, PB is of the view that the need to mitigate the risks presented by the 330/132 kV transformer at Newcastle substation has been reasonably demonstrated by TransGrid.

Strategic alignment and policy support

PB is of the view that the replacement of the Newcastle 330/132 kV transformer replacements align with TransGrid's policies and strategies as stated in the substations asset management strategy[198] and Newcastle area supply strategies[199].

Alternatives

TransGrid's project documentation presents consideration of refurbishment and replacement alternatives at the Newcastle substation.

In accordance with TransGrid's network asset replacement project evaluation procedure, both pre and post implementation risk evaluation has been undertaken and included for all options. The NPV of each option has also been determined with the exception of the do-

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196 TransGrid, Transformer Condition Reviews, Newcastle No. 2, 3 & 4 Transformers, July 2008.

197 TransGrid Network Asset Replacement Project Evaluation 5622 ARPE, June 2008, page 11.

198 TransGrid 2008, 'Asset Management Strategy – Substations', Document No. GM AS S5 001, Revision No: 11, Issue Date: 3rd June 2008, page 37.

199 TransGrid & Energy Australia, Final Report – Development of Electricity Supply to the Newcastle Area, Dec 2007 page various & TransGrid, Outline Plan to the Newcastle Area, 2004, page 6.

nothing option. Table J-3 presents a summary of the options analysis conducted by TransGrid based on the use of a post-tax nominal WACC of 7.17%[200].

Table J-3 – Summary of options considered

Option	NPV[1]	Risk score	$ per risk score reduction
Do nothing	-	175.4	-
Replace one transformer	-$6,179m	145.2	-$204.6m
Replace two transformers	-$8,210m	115	-$135.9m
Replace three transformers	-$10,278m	79	-$106.6m
Refurbish existing transformers	-$4,153m	158.2	-$241.5m

Note 1: This estimate is in real 2006/07 dollars, and does not include real labour and material escalation impacts or any risk allowance

Source: PB summary.

TransGrid also noted that the Refurbishment option was excluded on the basis of providing an unacceptably low risk reduction[201]. This is reflected in the higher cost per risk score shown in Table J-3. The selection of the option to replace two transformers over a single transformer is based on the recommendations provided in a report prepared by Wasinger Transformers to mitigate the failure risk associated with the aging Newcastle transformer fleet[202]. PB note that this report was not provided as part of the project documentation.

TransGrid selected the replacement of two transformers option even though it was not the highest NPV option on the basis that it:

- reduces the transformer failure risk to an acceptable level
- represents the lowest cost option of reducing the risk to the acceptable level
- generates additional spares to extend the service life of the remaining single phase units.

TransGrid states that the decision to replace two transformer sets instead of replacing a single transformer set has been made on the basis that the replacement of a single transformer set, although less expensive, does not meet TransGrid's acceptable risk score outcome for replacement or refurbishment projects.

TransGrid notes that the decision to replace two transformers instead of replacing all three transformers has been made on the basis that the two transformer replacement option meets TransGrid's acceptable risk criterion and therefore no further expenditure is justified. The option of replacing all three single phase transformer sets is excluded on this basis, despite its lower cost per risk score reduction.

200 TransGrid 2008, 'Network Asset Replacement Project Evaluation', Document No. GM AS G2 025, Revision No: 1, Issue Date: 2nd July 2008, page 18.

201 TransGrid Presentation M5_Replacement Capital Expenditure for AER July08v2 page 36.

202 TransGrid Network Asset Replacement Project Evaluation 5622 ARPE, June 2008, page 11.

Therefore the basis for option selection for this project is entirely dependent on the definition of 'acceptable risk' used by TransGrid. TransGrid has defined their risk score criteria for transformer replacement projects as follows:

- transformer reviewed for refurbishment/replacement when the risk score exceeds 160
- transformer option considered appropriate where the risk score after the project is implemented is less than 120.

PB notes that TransGrid's specific acceptable risk criteria and their derivation are not explicitly stated in TransGrid's policy documentation, risk assessment guidelines, or the project documentation itself. Furthermore, no acceptable risk scores have been identified to PB for other project types. On this basis, the derivation of the criteria for transformer replacement is considered arbitrary.

PB does acknowledges that, in general, the use of an acceptable risk criterion is a reasonable basis for evaluating the value of the risk reduction to a project for the purpose of option selection on the basis it is pre-defined, documented and authorised.

Having considered the fundamental need, PB is satisfied that an appropriate range of practical alternatives has been identified and considered by TransGrid. However, PB also notes that the selection of the two transformers replacement option is largely based on the achieving TransGrid's arbitrary 'acceptable risk score', which we do not consider to be reasonable. PB is of the view that acceptable and required risk thresholds should be defined on an auditable basis that is appropriate to the equipment under consideration and reflective of specific, reasonable risk mitigation targets in each of the risk categories analysed. In setting the required risk score, specific attention should be paid to ensure that this criterion does not implicitly favour the replacement of older equipment that could more efficiently be refurbished to the meet the 'acceptable' criteria that are applied to existing installations.

Given the above concerns, it is PB's view that the options analysis presented by TransGrid does not demonstrate that the most efficient option has been chosen. Given this view, and based on the documentation presented, PB considers that the single transformer replacement option is a more efficient option than replacement of two transformers. Hence PB recommends the single transformer replacement option is selected on the basis that it returns the highest NPV for the options presented that address the stated project needs of mitigating the risk associated with the deteriorating condition and limited spares availability to serve the transformer population at Newcastle substation.

Timings

TransGrid has proposed that the 330/132 kV transformers will be replaced during the period 2010/11 to 2012/13. PB notes that justification for this timing was presented in the project documentation provided on the basis of performing the replacement work during shoulder periods[203] and prioritisation of other transformer replacement projects[204].

In the condition review[205] undertaken by TransGrid, only the No.2 transformer Blue Phase is specifically recommended for replacement[206] with monitoring of developing issues typically recommended for the remaining units.

These recommendations indicate that, whilst not explicitly identified, TransGrid expects that most of the transformers have some remaining life. The cashflow indicated in the Asset

203 TransGrid Project Evaluation Summary PES5622, June 2008, page 9.

204 TransGrid Transformer Risk Scoring and Timing of Replacement 7 August 2008, page 5.

205 TransGrid, Transformer Condition Reviews, Newcastle No. 2, 3 & 4 Transformers, July 2008.

206 TransGrid, Transformer Condition Reviews, Newcastle No. 2 Transformer, July 2008 page 9.

Replacement Options Comparison document used to calculate the NPV and risk score for each option shows the replacement of the remaining single phase transformer sets occurring between 2022 and 2025[207]. Hence PB can only conclude that that the timing of the second and third transformer replacement is largely discretionary.

PB is of the view that replacement of equipment due to poor condition should ideally be timed just prior to failure. Naturally however, PB acknowledges that predicting the time of failure of complex and specialist equipment is difficult and in some instances impractical. However, estimates of remaining life can generally be conservatively made, particularly where failure modes are understood from experience with similar equipment, or on the basis of the laboratory tests performed for the condition assessment report. In any event, we are of the view that TransGrid should have provided a clear statement of the estimated remaining life and the reasoning for this estimate.

While PB is of the view that the need to replace the first 330/132 kV single phase transformer set at Newcastle substation has been reasonably demonstrated, we can not conclude that the timing the additional transformer replacement represents efficient investment.

Costs and scope

TransGrid's selected option requires the construction of the 330 kV No.5 transformer bay to overcome the load sharing issues between the single phase sets and three phase transformers at Newcastle[208]. The system spare fifth transformer usually held at Newcastle would be used to manage load issues during the replacement project.

The project scope of work is set out in the 'Project Option Scope and Estimate' document[209], and is summarised in section J.6. It is proposed that this work will require a timeframe of 31 months, with an allowance of 9 months for the construction works. Table J-2 sets out the estimated cost of the project works.

Notwithstanding PB's opinion of the selected option, PB is of the view that the estimated replacement timeframe for TransGrid's selected option is reasonable given the need to confine replacement work for major equipment to shoulder periods.

TransGrid has not provided a detailed cost estimate in the project assessment documentation. However, the approximate cost of $7.5m per transformer replacement including equipment, oil containment, civil works, protection and secondary systems appears consistent with the output from the TransGrid cost estimating database and in PB's opinion, is considered to be reasonable.

PB is of the view that the costs as set out in Table J-2 represent an efficient estimate of the costs for the proposed works.

J.8 Conclusion

PB has conducted a detailed review of the proposed Newcastle 330/132 kV Transformer Replacement project, and while we are of the opinion that the project is prudent, we are also of the view that the selected option has not been demonstrated to be the most efficient option.

Therefore PB recommends that the scope of the project is reduced to reflect the single transformer replacement option, representing the most efficient option demonstrated in

207 TransGrid Asset Replacement Options Comparison 5622 AROC, June 2008 page 13.

208 TransGrid Project Evaluation Summary PES5622, June 2008, page 8.

209 TransGrid 2008, 'Project Option Scope and Estimate - 6378 – Beaconsfield West 132 kV GIS Replacement', Document No. 6378, page 4-5.

TransGrid's analysis. PB's recommended adjustment is probabilistically weighted and includes risk and escalation calculated using TransGrid's Capital Accumulation Model.

Table J-4 sets out PB's recommendation on the prudency and efficiency of the submitted expenditure associated with the Newcastle 330/132 kV Transformer Replacement project.

Table J-4 – PB recommendation Newcastle 330/132 kV transformer replacement

Expenditure $m (real, 07/08)	2009/10	2010/11	2011/12	2012/13	2013/14	Total
Submitted	-	-	1.3	17.6	-	18.9
Proposed variation	-	-	-	(10.5)	-	(10.5)
PB recommendation	-	-	1.3	7.2	-	8.4

Source: TransGrid, CAM V1.8_Future deliverables 12a.xls., and PB analysis.

APPENDIX K
HUNTER VALLEY - CENTRAL COAST 500 KV LINES

APPENDIX K: HUNTER VALLEY - CENTRAL COAST 500 KV LINE EASEMENTS

The Hunter Valley - Central Coast 500 kV Lines is an easement project (Project ID 5568) associated with the Hunter Valley - Central Coast 500 kV Lines contingent project which has an anticipated commissioning of 2017. Table K-1 shows the estimated total easement costs.

The proposed transmission line project is scheduled for commissioning in 2016-2017 under five of the ROAM scenarios[210]. Therefore the majority of the construction work will take place outside the 2009/10-20013/14 regulatory period. This review covers the easement acquisition expenditure associated with the early stage works that are scheduled to occur in prior to the end of the regulatory period.

Table K-1 – Capex for Hunter Valley - Central Coast 500 kV Lines

Expenditure $m (real, 07/08)	2009/10	2010/11	2011/12	2012/13	2013/14	Total
Project 5568 P (Median)	-	-	-	3.8	38.7	42.6
Project 5568 P (Weighted Average)	-	-	0.2	2.1	1.9	4.2

Source: TransGrid, CAM V1.8_Future deliverables 12a.xls.

This project ranks as the third largest overall ex-ante easement expenditure item and is equivalent to 1.8% of TransGrid's network capex in the 2009/10-2013/14 regulatory period.

K.1 Project overview

The Hunter Valley to Central Coast 500 kV lines project forms part of the TransGrid strategy to implement a 500 kV ring to enable future development of generation serving the expected load growth in the Newcastle-Sydney-Wollongong load corridor[211].The project provides a network solution to line loading issues arising from a potential power station development in the Hunter Valley or Bayswater area and further generation or import from the north of the load corridor[212].

The concept of developing a 500 kV transmission ring around the Newcastle-Sydney-Wollongong load corridor was developed in the 1970's to minimise the transmission corridors into the Sydney basin and manage the technical constraints on switchgear that restrict the ability to connect further generation[213]. TransGrid states that the further development of the 500 kV ring will address emerging transmission network limitations by:

- reducing the loading on the existing 330 kV lines between the Hunter Valley power stations and the Newcastle area;
- supporting voltage control in the Newcastle-Sydney-Wollongong load corridor; and,
- facilitating new generation connection at a range of suitable locations.

Due to the inclusion of the Bannaby to Sydney 500 kV transmission line project (Project ID 5567) in the ex-ante capital expenditure forecast, TransGrid acknowledge that the Hunter

210 TransGrid Capital Accumulation Model CAM V1.8_Future Deliverables 12a.

211 TransGrid Project Feasibility Study Report FS PSR 119, Rev 0, February 2008, page 1.

212 TransGrid Project Evaluation Summary 5567, Rev 2, May 2008, page 77.

213 ibid

Valley to Central Coast transmission line project is unlikely to be required in the majority of the ROAM scenarios. In the scenarios where the project is required, the commissioning date for the project is 2016-2017.

TransGrid engaged Connell Wagner to conduct a preliminary desktop feasibility assessment for the route selection of the Hunter Valley to Central Coast 500 kV transmission line to support the Revenue Proposal and identify the timing and costs associated with the early stage work for the project. Due to the early stage of planning and the level of stakeholder consultation required to determine the final route selection, the preliminary route selection process has been conducted on a desktop basis and has not involved input from government departments, landholders, heritage groups and other relevant parties[214].

The route option included in the forward capital expenditure calculation presented[215] by TransGrid is the Bayswater to Eraring via Kurri Kurri option presented in TransGrid's POSE document 5568A[216].

K.2 Drivers (need or justification)

TransGrid has stated that the core 330 kV and 500 kV electricity transmission network is predicted to reach its capacity to reliably supply power to the Newcastle-Sydney-Wollongong load corridor under high load conditions for a range of future scenarios[217]. The Hunter Valley to Central Coast transmission line project forms part of TransGrid's strategy to construct a 500 kV ring to serve this load corridor. This project is required under a total of five of the thirty six ROAM scenarios presented by TransGrid with a median commissioning date of 2017 and a 6.8% overall probability of being required during the 2009/10-20113/14 timeframe covered by the ROAM scenarios.

TransGrid state that the Hunter Valley to Central Coast line is necessary to overcome line rating constraints under the following circumstances:

- development of further generation in the Hunter Valley;
- development of large scale northern NSW generation; and,
- increased import from Queensland.[218]

TransGrid also note that the line rating issues would be exacerbated by any reduction in generation at the Central Coast power stations. Furthermore, TransGrid state that the project is also required to overcome voltage control limitations on the 330 kV lines that are expected to emerge between the Hunter Valley and Sydney and Wallerawang and Sydney.[218]

K.3 Strategic alignment and policy support

TransGrid has identified that the 500 kV ring to supply the Newcastle-Sydney-Wollongong load corridor is a longstanding main system development strategy. This is supported by a number of documents including:

- TransGrid Annual Planning Report 2007 Section 6.3.22
- TransGrid Annual Planning Report 2006 Section 7.3.10.
- TransGrid Strategic Network Development Plan 2008

214 TransGrid Project Feasibility Study Report FS PSR 119, Rev 0, February 2008, page 3.

215 TransGrid Capital Accumulation Model CAM V1.8_Future Deliverables 12a.

216 TransGrid Project Option Scope and Estimate 5568A, April 2008.

217 TransGrid Project Evaluation Summary 5567, Rev 2, May 2008, page 6.

218 TransGrid Presentation TU6_Session 500 kV, 2 July 2008, page 27.

K.4 Alternatives

To address the stated need, TransGrid has considered both 500 kV and 330 kV options on new and existing corridors. TransGrid has also considered the need for reactive support and the impact of other significant projects on the priority of undertaking the northern 500 kV augmentation project. TransGrid has acknowledged that the project is unlikely to be required within the 2009/10-2013/14 regulatory period due to the prioritisation of the southern 500 kV line project. TransGrid has provided an option analysis document supporting this prioritisation[219].

The documentation provided addresses the 330 kV options identified in Table K-2 and 500 kV options identified in Table K-3.

Table K-2 – Summary of 330 kV options considered

Option	Total Project Cost $m	Easement Cost $m
Liddell to Richmond Vale S/C 330 kV line (POSE 5568F)	$116.1	$28.1
Liddell to Richmond Vale D/C 330 kV line (POSE 5568G)	$142.1	$28.5
Liddell to Eraring S/C 330 kV line (POSE 5568H)	$124.6	$34.7
Liddell to Eraring D/C 330 kV line (POSE 5568I)	$162.4	$35.2

Source: TransGrid, Project Evaluation Summary 5567, May 2008 page 46.

TransGrid has rejected the 330 kV options on the basis that they do not provide adequate relief of voltage control constraints and are considered to make unacceptable utilisation of scarce line routes and result in increased environmental constraints associated with the need for additional line construction on new corridors in the longer term.[220]

Table K-3 – Summary of 500 kV options considered

Option	Option Cost $m	Option Cost inc. related works $m	Easement Cost $m
Bayswater to Eraring 500 kV line via Richmond Vale (POSE 5568B);	$270.5	$300.6[ac]	$47.2
Bayswater to Eraring 500 kV line via Richmond Vale By replacing No. 81 and No. 24 Lines (POSE 5568C);	$260.4	$370.9 [abc]	$47.2
Bayswater to Richmond Vale 500 kV line (POSE 5568D)	$211.5	$291.9 [ab]	$37.7
Bayswater to Richmond Vale 500 kV line - Rebuild 81 Line (POSE 5568E);	$182.4	$262.8 [ab]	$16.0
Bayswater to Sydney 500 kV line – Replace existing 330 kV lines 31/32 (POSE 5568J)	Considered not feasible		

[a] Requires re-connection of the Bayswater units 1 and 2 to the 500 kV switchyard due to increased short circuit level at an additional cost of the order of $50M. This amount has not been included in the option cost.

[b] Requires Richmond Vale substation establishment (6005 POSE) at additional cost of $80.4m

[c] Requires 3rd Kemps Creek Transformer Project (6003 POSE) at additional cost of $30.1m

Source: TransGrid, Project Evaluation Summary 5567, May 2008 page 47.

219 TransGrid, NSW Main System Option Analysis Introduction 2007/08, Rev 0, June 2008, section 9.

220 TransGrid Project Evaluation Summary 5567, Rev 2, May 2008, page 70.

The 5568C option is excluded form the options analysis on the basis of cost and complications associated with extended outage requirements[221].

The 5568D and 5568E options are excluded on the basis that they do not adequately address the voltage control issues identified as a project need[222].

TransGrid has identified the 5568B option as the preferred option in determining the timing of the scenario based transmission planning.

PB note that the costs included in the Capital Accumulation Model reflect the marginally more expensive option 5568A[223] that has not been included in the options analysis presented in the PES document.

K.5 Timings

TransGrid states that the timing of this work is dependent on the location of new generation developments and has therefore based their planning on the probabilistic approach presented in the ROAM report[224]. The project appears under five scenarios and as noted in section K.2, carries a 6.8% probability of requiring any expenditure during the regulatory period under consideration.

The median commissioning year for the project under the five scenarios where expenditure is required prior to the end of the 2009/14 regulatory period is 2017.

TransGrid has advised that the program to construct the 500 kV line between Bayswater and Eraring would take approximately 72 months from project commencement largely due to the consultation, planning and environmental approvals processes. TransGrid's board approval of the corridor selection report is scheduled to occur in month 19, whilst contract award in month 42[225]. This implies that the easement acquisition would occur in the 23 months prior to contract award.

The timing of the project is heavily dependent on load growth and generation development over the next regulatory period and therefore the actual timing of the project is subject to the constraints that develop. TransGrid has not presented a definitive commissioning date for the Hunter Valley to Central Coast 500 kV line but has considered its timing to be contingent on generation development in the Hunter Valley, northern NSW or increased import from Qld[226].

K.6 Costs and scope

Table K-4 shows the base cost estimate for the Hunter Valley to Central Coast 500 kV transmission line easements project (ID 5568B). Costs have been also been provided for the other options considered by TransGrid.

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221 TransGrid Project Evaluation Summary 5567, Rev 2, May 2008, page 69.

222 TransGrid Project Evaluation Summary 5567, Rev 2, May 2008, page 70.

223 TransGrid, Capital Accumulation Model CAM V1.8_Future Deliverables 12a.

224 ROAM Consulting, Scenarios for Revenue Reset Application 2009-10 to 2013-14, 20 February 2008.

225 TransGrid, Project Feasibility Study Report, FS PSR 119, February 2008, page 32.

226 TransGrid Project Evaluation Summary 5567, Rev 2, May 2008, page 77.

Table K-4 – Base cost estimates for Hunter Valley to Central Coast 500 kV line

Work Scope Item	Estimate[1]
New D/C Transmission Line from Eraring 500 kV switchyard to the Bayswater 500 kV substation via Richmond Vale	$208.2m
Augmentations of Eraring 500 kV Switchyard	$7.6m
Augmentation of Bayswater 500 kV substation	$7.5m
Property Estimate	$47.2m
Total Estimate	$270.5m

Note 1: This estimate is in real 2007/08 dollars, and does not include real labour and material escalation impacts or any risk allowance.

Source: TransGrid 2008, 'Project Option Scope and Estimate – Hunter Valley to Central Coast 500 kV Development – Bayswater to Eraring 500 kV line via Richmond Vale', Project Number: 5568, Document No. 5568B, Revision 2, 03/04/2008, page 7.

The scope of the work for the preferred option includes the following:

- development of a 500 kV line from Bayswater to Eraring mainly using a greenfield route nearby Richmond Vale;
- acquisition of approximately 120km of 70m wide easement
- augmentation of the Bayswater and Eraring 500 kV switchyards; and,
- connection of switchbays at Eraring

K.7 PB analysis

This section presents PB's view of the project information provided by TransGrid in support of the expenditure for this proposed project. The following sections address each of the key issues when considering the prudence and efficiency of a proposed capital investment.

Drivers (need or justification)

The driver of this project has been stated by TransGrid to be the need to reinforce the transmission infrastructure supplying the Newcastle-Sydney-Wollongong load corridor due to line rating and voltage control constraints on the 330 kV lines supplying Sydney from the north and west.

TransGrid state that the Hunter Valley to Central Coast line is necessary to overcome line rating and voltage control constraints under the following circumstances:

- development of further generation in the Hunter Valley
- development of large scale northern NSW generation
- increased import from Queensland.[227]

The stated need is supported by the findings of the Owen Inquiry that states that an additional 10,500GWh of generation will be required by 2013-14[228]. No identification of the location for the new generation has been identified by external sources. Therefore due to the uncertainty associated with the drivers of the project eventuating over the 2009/10-20013/14 regulatory period, TransGrid has adopted a scenario based approach to identifying whether the project would be required.

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227 TransGrid Presentation TU6_Session 500 kV, 2 July 2008, page 27.

228 Anthony D Owen, Report of the Owen Enquiry into Electricity Supply in NSW, Sept 2007 page 2-1.

Based on the information provided in the Project Evaluation Summary[229], it is PB's opinion that the information presented supports the view that augmentation of the existing 330 kV network will be required to support future generation serving the Newcastle-Sydney-Wollongong load corridor and that environmental impacts may be a significant consideration in securing new line routes.

However PB notes that at 6.8%, the low probability that the project would require any expenditure over the 2009/14 regulatory period indicates that the need for significant easement acquisition and to progress early work on the project is not well supported. PB acknowledges that the probability weighting of the expenditure is intended to address the uncertainty of whether the project is required.

PB recognises TransGrid's view that the documentation provided supports the future augmentation of the transmission system between the Hunter Valley and Central Coast and that easement acquisition would be required to support this work. However, no specific compelling support has been provided to justify the need for early acquisition of easements to enable the augmentation to occur. Therefore, in our opinion TransGrid has not demonstrated the proposed expenditure is prudent.

Strategic alignment and policy support

As noted in section K.3, TransGrid's documentation addressed a number of strategic relationships, most notably to the TransGrid annual planning reports for 2006 and 2007. PB recognises that this project forms part of TransGrid's long term strategy to establish a 500 kV transmission line ring to reinforce supply to the Newcastle-Sydney-Wollongong load corridor. PB is of the opinion that the level of consideration given to alternative options to address the voltage control and line rating constraints, including the prioritisation of the southern 500 kV line project, demonstrates a clear alignment with TransGrid's long term network development strategies.

Alternatives

TransGrid's project documentation presents consideration of options at two levels applicable to this project.

Firstly, the alternatives to reinforcement of supply in the Newcastle-Sydney-Wollongong load corridor is discussed in detail with an optimal set of projects determined to efficiently address the line rating and voltage control constraints identified to the south and north of Sydney[230]. This analysis has considered the timing, effectiveness and cost of projects that would address the identified issues and prioritises them to defer the 500 kV southern line project beyond the reactive support projects that would relieve constraints in the shorter term.

PB has conducted a high level review of this analysis and accepts that the conclusion presented by TransGrid to defer the most expensive 500 kV developments as long as practicable[231] represents prudent and efficient expenditure. This option is outlined in the PES document[232] and prioritises reactive plant installation projects before the development of new 500 kV lines.

Secondly, a range of alternative route options have been assessed for the specific Hunter Valley to Central Coast 500 kV line project. These are identified in section K.4 and represent the various options considered for the project alignment itself.

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229 TransGrid, Project Evaluation Summary 5567 – Reinforcement of supply to the Newcastle-Sydney-Wollongong load corridor, May 2008.

230 TransGrid, NSW Main System Option Analysis Introduction 2007/08, Rev 0, June 2008, section 9.

231 TransGrid, Project Evaluation Summary 5567 – Reinforcement of supply to the Newcastle-Sydney-Wollongong load corridor, May 2008, page 78.

232 ibid, page 81.

TransGrid has identified but excluded a range of 330 kV options unacceptable due to the inadequately addressing the voltage control constraints and the requirement to acquire further easements in heavily constrained or environmentally sensitive areas to enable future augmentation once the new 330 kV lines reach their capacity[233]. PB acknowledges that this is consistent with TransGrid's long term strategy to establish a 500 kV ring to serve the Newcastle-Sydney-Wollongong load corridor however, no assessment of the timing and quantity of additional future transmission line corridors that may be required was provided in the supporting document. Similarly, limited consideration of further reactive support augmentation to specifically overcome the voltage control constraints was investigated despite the magnitude of the apparent cost benefit associated with the 330 kV options.

Furthermore, TransGrid states that the operation of a 330 kV line would require additional 500/330 kV transformation at each end, which would become redundant within a short period[234]. However no attempt has been made to assess the cost or timing impact of these additional works to enable the comparison of the NPV of these options against the 500 kV options.

As TransGrid has not provided the requisite analysis to support the exclusion of the 330 kV options, PB is unable to assess whether the exclusion of the 330 kV options is prudent or represents efficient expenditure.

Should the project require expenditure within the 2009/14 regulatory period, the easement acquisition costs would represent the vast majority of project expenditure in the period. Therefore the total project costs and easement costs for the options presented by TransGrid are summarised Table K-5 and Table K-6

Table K-5 – Summary of 330 kV options considered

Option	Total Project Cost $m	Easement Cost $m
Liddell to Richmond Vale S/C 330 kV line (POSE 5568F)	$116.1	$28.1
Liddell to Richmond Vale D/C 330 kV line (POSE 5568G)	$142.1	$28.5
Liddell to Eraring S/C 330 kV line (POSE 5568H)	$124.6	$34.7
Liddell to Eraring D/C 330 kV line (POSE 5568I)	$162.4	$35.2

Source: TransGrid, Project Evaluation Summary 5567, May 2008 page 46.

233 ibid

234 ibid, page 40

Table K-6 – Summary of 500 kV options considered

Option	Option Cost $m	Option Cost inc. related works $m	Easement Cost $m
Bayswater to Eraring 500 kV line via Richmond Vale (POSE 5568B);	$270.5	$300.6[ac]	$47.2
Bayswater to Eraring 500 kV line via Richmond Vale By replacing No. 81 and No. 24 Lines (POSE 5568C);	$260.4	$370.9 [abc]	$47.2
Bayswater to Richmond Vale 500 kV line (POSE 5568D)	$211.5	$291.9 [ab]	$37.7
Bayswater to Richmond Vale 500 kV line - Rebuild 81 Line (POSE 5568E);	$182.4	$262.8 [ab]	$16.0
Bayswater to Sydney 500 kV line – Replace existing 330 kV lines 31/32 (POSE 5568J)	Considered not feasible		

[a] Requires re-connection of the Bayswater units 1 and 2 to the 500 kV switchyard due to increased short circuit level at an additional cost of the order of $50M.

[b] Requires Richmond Vale substation establishment (6005 POSE) at additional cost of $80.4m

[c] Requires 3rd Kemps Creek Transformer Project (6003 POSE) at additional cost of $30.1m

Source: TransGrid, Project Evaluation Summary 5567, May 2008 page 47.

PB note that the preferred 5668B 500 kV option between Bayswater and Eraring represents the second most expensive option for the construction of a transmission line between the Hunter Valley and the Central Coast. The scope difference between the selected option and the two less expensive options is the extension of the 500 kV line from Richmond Vale to Eraring which is required to alleviate the expected voltage control constraints on the northern lines supplying the Newcastle-Sydney-Wollongong load corridor.

Therefore PB accept that the selected option is the only 500 kV option that adequately addresses all of the needs identified for this project however, PB note that the basis for excluding the 330 kV options has not been adequately demonstrated in TransGrid's project documentation.

The specific option selected has little material impact on the expenditure during the 2009/10-2013/14 regulatory period as the expenditure relates to easement acquisition and preliminary works components which are then adjusted in the capital accumulation model by the probability of the project proceeding. On this basis PB consider that the materiality adjustment associated with the options assessment process is reflected in our recommendations regarding the project cost efficiency.

Therefore PB recommends no specific adjustments be made with regards to the deficiencies identified in TransGrid's options assessment.

Timings

TransGrid has proposed that the Hunter Valley to Central Coast 500 kV line project be assigned a median commissioning year of 2017 for five of the thirty six scenarios presented. TransGrid has presented an implementation timeline of 72 months[235] to account for the route selection, statutory approvals and construction of the transmission line. The corridor selection report would be approved by the TransGrid Board in month 19, with contract award occurring in month 42. This implies that the majority of the easement acquisition would need to occur in the 23 months prior to contract award following the selection of the preferred corridor.

235 TransGrid, Project Feasibility Study Report, FS PSR 119, February 2008, page 32.

PB is of the view that the rate of easement acquisition is consistent with TransGrid's stated expectation that approximately 10% of easement acquisitions for transmission line projects would occur 15 months prior to contract award[236] Therefore PB is of the view that the timing of the easement expenditure against a 2017 commissioning year is prudent.

However, PB notes that justification for the commissioning year is dependent on the increase in electricity import from Queensland or the development of uncommitted potential generation projects in the Hunter Valley or Northern NSW. Therefore the justification for the timing of the project within the scenarios remains poorly supported.

Notwithstanding, PB is of the view that the uncertainty of the project timing is adequately addressed by the low probabilistic weighting applied to the project expenditure.

Costs and scope

As previously mentioned in our discussion on the options analysis, PB is of the view that the selected option represents the most efficient 500 kV option that meets the stated project needs. PB considers the scope of the easements portion of this option to be reasonable.

However a comparison of the easement costs between the similar 330 kV and 500 kV line routes between Eraring and the Hunter Valley reveals a large disparity in cost which PB does considers does not appear reasonable. Specifically, the $47.6m easement cost presented for the preferred 500 kV option 5568B for a 70m wide 120km easement far exceeds the $41.1m easement cost associated with the 330 kV D/C option 5568I[237] line that follows essentially the same route, when corrected for the difference in easement width. TransGrid has subsequently identified this additional cost primarily as the increased compensation associated with the difference in visual impact of a 500 kV line over a 330 kV line.

PB also notes that the property costs detailed in the Project Feasibility report for a greenfield 500 kV line between the Hunter Valley and Central Coast are significantly lower again at $36.3m[238]

PB notes that the property estimates included in the TransGrid options are considered to be indicative[239] only and no identification of specific easements or breakdown for how the estimates have been derived has been provided in the project information. On this basis, PB recommends that the externally provided easement cost estimate of $36.3m contained in the feasibility study report is applied.

On this basis, PB is of the view that the project expenditure associated with the Hunter Valley to Central Coast 500 kV line easements is not sufficiently supported and does not represent efficient expenditure.

PB recommends that the easement expenditure for the project is reduced by a factor of 23.1% to reflect the cost of contained in TransGrid's feasibility study presented in the project package.

K.8 Conclusion

Table K-7 sets out PB's recommendation on the prudency and efficiency of the submitted expenditure associated with the Hunter Valley - Central Coast 500 kV Lines easement project. PB notes that all values have been adjusted to reflect the 6.8% probability of this

236 TransGrid, Capex Estimating Database – "S" Curves, D2008/06031 page 6.

237 TransGrid Project Option Scope and Estimate 5568I, April 2008, page 7 $35.2m corrected by a factor of 70m/60m to account for the difference in easement width.

238 TransGrid Project Feasibility Study Report FS PSR 119, February 2008, page 28.

239 Property estimates in the Project Option Scope Estimate documents are noted in the Property Estimate as "(TBA)".

project being required under the 36 scenarios represented in the CAM. PB's recommended adjustment is probabilistically weighted and includes risk and escalation calculated using TransGrid's Capital Accumulation Model.

Table K-7 – PB recommendation for Hunter Valley - Central Coast 500 kV Lines

Expenditure $m (real, 07/08)	2009/10	2010/11	2011/12	2012/13	2013/14	Total
Submitted	-	-	0.2	2.1	1.9	4.2
Proposed variation	-	-	-	(0.1)	(0.9)	(1.0)
PB recommendation	-	-	0.2	2.0	1.0	3.2

Source: TransGrid, CAM V1.8_Future deliverables 12a.xls. and PB analysis.

APPENDIX L
REPLACEMENT PROGRAMS

APPENDIX L: REPLACEMENT PROGRAMS

A high level review was undertaken for the capital expenditure associated with the asset replacement programs. These programs comprise $161.2m, or 6.1% of the total forward capital expenditure estimate.

Table L-1 – Asset replacement program expenditure ($m real 07/08, escalated)

Program Category	2009/10	2010/11	2011/12	2012/13	2013/14	Total
Communication & control replacement	2.4	1.9	2.0	1.7	2.2	10.1
Protection & metering	5.1	5.9	5.0	6.0	5.2	27.2
Substation - circuit breakers[1]	3.3	3.3	4.4	5.8	5.0	21.8
Substation - instrument transformers	5.2	4.7	3.9	3.8	4.2	21.8
Substation - plant & equipment	3.0	1.4	0.8	1.0	0.1	6.4
Substation - security	0.1	-	-	-	-	0.1
Substation - civil work	3.5	3.9	3.0	2.7	0.8	14.0
Transformer replacement & addition	12.2	5.5	5.1	5.0	5.6	33.4
Transmission lines - minor upgrades	0.1	0.2	-	0.6	1.6	2.5
Transmission lines - wood poles	6.2	6.1	3.9	3.9	3.8	23.9
Total	41.2	32.9	28.2	30.5	28.4	161.2

[1]Incorrectly labelled as 'Capacitor Bank' in the AER Template spreadsheet

Source: Template-AER Schedule (for AER).xls – sheet 4.4.

L.1 Overview

Due to the large number of programs associated with asset replacement works, PB has reviewed a typical component program from each category to assess the prudency and efficiency of the capital expenditure. The total value of the reviewed programs is $74M, and accounts for 46% of the total replacement program expenditure.

The program expenditure relates to a number of similar, typically smaller projects that will be undertaken over an extended period of time. The nature of programs and asset replacement work means that the timing of each component work package is typically discretionary. Significant scope typically exists in program delivery for the deferral of part of the proposed expenditure where the timing of the program is not dependent on a time specific driver.

The purpose of this review is to identify any systemic issues that may affect PB's view on the prudency and efficiency of TransGrid's proposed replacement capital program expenditure. This review has been conducted at a high level and is not intended to cover every replacement program in detail. The replacement programs reviewed are identified in Table L-2.

Table L-2 – Reviewed replacement programs ($m real 07/08, unescalated)

Program	09/10	10/11	11/12	12/13	13/14	Total Value ($M)
Communication & control MITS MD1000 replacement (4978)	0.8	0.8	0.8	0.8	0.8	4.2
Protection & metering Replacement of DB protection relays (5922)	-	0.6	-	0.7	1.4	2.7
Substations						
Civil work	1.9	3.2	2.4	2.0	0.7	10.2
upgrade oil containment (5201)						
Plant & equipment						
Sprecher 330 kV circuit breakers (5519)	1.8	0.9	1.6	1.1	0.2	5.7
Instrument transformer replacements (4910, 5085, 5086, 5087)	2.5	3.2	3.4	3.3	3.3	15.7
Transformers Transformer failures (4884)	11.0	4.4	4.4	4.4	4.4	28.4
Transmission lines Wood Pole replacement program TL 99F (4939 TL 99F)	-	-	2.6	2.6	2.4	7.5
Total	18.0	13.1	15.2	14.9	13.2	74.4

Source: PB analysis.

L.2 Communication and control replacement

A total of six communications programs are included in the proposed forward capital works portfolio with a combined value of $10.1m over the 2009/14 regulatory period. PB has conducted a high level prudency review of the MITS MD1000 Replacement program (4978) which comprises 45% of the total value of the Communications and Control Replacement programs.

Drivers

TransGrid state that that the project is required based on the following factors threatening the reliability of the equipment over the 2009/14 regulatory period

- withdrawal of vendor support;
- limited internal repair capability;
- declining spares availability; and,
- compliance with NEMMCO Standard for Power System Data Communications requirements[240].

[240] TransGrid, PB7 F1 Response, 19 August 2008.

Due to the age of the equipment approaching 20 years[241] against the standard life of 10[242] - 15 [243] years for microprocessor based communications equipment, PB is of the view that a review of the condition and potential replacement of these assets would be prudent. Further compliance and support factors confirm the need to replace these units over the 2009-14 regulatory period.

Therefore, the need for the program has been adequately identified.

Scope

The scope of the program covers the replacement of 275 Logica MITS MD1000 frames across 50 sites. As the withdrawn vendor support and non-compliance issues affect the entire asset population, the scope of the program must cover all of this asset type and is therefore considered to be reasonable.

Costs

TransGrid states that cost estimates for the revenue proposal are based on their cost estimating procedures which have been reviewed in section 5.3 of the PB report. The documentation notes that the cost estimate for the project is based on current labour rates, period order prices and supplier advised costs sourced from 2007 competitive tender processes[244]. This is consistent with the inputs to the cost estimation database.

PB has not requested or reviewed the detailed cost breakdown for this program. However, at a high level, the average implied cost of approximately $84K per site or $15K per unit installed is considered reasonable.

Timing

The timing of the program has been justified based on TransGrid's forecast of the withdrawal of vendor support, declining internal repair capability and declining spares availability[245]. TransGrid has stated that the current spares holding is sufficient to maintain the equipment until 2012. On undertaking the replacement project, support is predicted to extend to 2014[246] due to the declining asset population and increased availability of parts from retired units.

Whist PB is satisfied that the timing of the program has been considered by TransGrid, we note that the two year extension in spare parts availability arising from the retirement of 275 units with high historical reliability appears conservative. However, due to the need to comply with NEMMCO requirements, this extension makes reasonable use of the recently commissioned units installed between 1999 and 2007[247]. Therefore PB is of the view that the proposed timing is reasonable.

Alternatives

The options assessment undertaken by TransGrid identifies four alternative options and rejects them based on reasonable technical inadequacies or the need to maintain unsupported equipment[248]. The selection is made based on the risk reduction presented by

241 TransGrid 4978 ARPE Rev 1.0, March 2008, page 4.

242 NSW Treasury, Valuation of Electricity Network Assets, May 2003 (Draft).

243 TransGrid, Network 30 Year Asset Management Plan 2009-2039, page 24.

244 TransGrid 4978 ARPE Rev 1.0, March 2008, page 10.

245 ibid, page 8.

246 ibid, page 9.

247 TransGrid, PB7 F1 Response, 19 August 2008.

248 TransGrid 4978 ARPE Rev 1.0, March 2008, page 9.

the preferred option over the Do Nothing option as no other feasible alternative have been assessed.

PB is of the view that a reasonable range of options have been identified and the selected option is the only identified option that addresses the stated project needs.

Conclusion

PB is of the opinion that the need, timing, scope and cost for this program is adequately supported. Based on our review of this program, no specific adjustments are recommended.

L.3 Protection and metering

A total of 29 protection and metering programs are included in the proposed forward capital works portfolio with a combined value of $27.2m over the 2009/14 regulatory period. PB has conducted a high level prudency review of the DB protection relays replacement program (5922) which comprises 11% of the total value of the protection and metering replacement programs.

Need

TransGrid state that that the project is required due to the following factors threatening the reliability of the equipment over the 2009/14 regulatory period[249]:

- withdrawn vendor support and spares availability;
- declining internal support capability;
- moderate historical failure rate consistent with end-of life indicators; and,
- risk of damage to HV plant due to increased probability of relay failure.

TransGrid state that the age of the equipment is between 16 and 52 years[250]. Due to the advanced age of some of the equipment against the standard life of 40 years[251] for electromechanical protection equipment, PB is of the view that the review of the condition and potential replacement of some of these assets is prudent. Therefore, the need for the program has been adequately identified.

Scope

The scope of the program covers the replacement of 48 DB transformer protection relays which comprise approximately 30% of the total population of this type on the TransGrid network. The scope of the program has been based on replacing the assets over an extended period due to the declining internal support for the equipment[252].

TransGrid state that due to the declining support affecting the total population of DB relays on the TransGrid network, replacements of all of the DB relays should occur progressively as condition dictates. The scope of this program ultimately covers the replacement of all of this asset type over an undefined future period. Given that the average age of the assets is approaching the useful life of the asset, the 30% scheduled for replacement in the 2009/14 period appears reasonable.

249 TransGrid 5922 ARPE Rev 1.0, May 2008, page 8.

250 ibid, page 5.

251 TransGrid, Network 30 Year Asset Management Plan 2009-2039, page 24.

252 TransGrid 5988 ARPE Rev 1.0, May 2008, page 6.

PB considers that the magnitude of replacement is generally consistent with the age profile of the equipment[253]. Therefore the proposed scope of the replacement program is considered to be appropriate.

Cost

TransGrid states that cost estimates for the revenue proposal are based on their cost estimating procedures which have been reviewed in section 5.3 of the PB report.

PB has not requested or reviewed the detailed cost breakdown for this program. However, at a high level, the average implied cost of approximately $62K per scheme, installed is considered reasonable.

Timing

The timing of the project is based on the expectation that the reliability of the equipment will continue to deteriorate over time. Due to the combination of a moderate failure rate, extended life of the oldest of the DB relays and the relatively large population within the TransGrid network, the timing for commencing the replacement program is considered appropriate.

Alternatives

The options assessment undertaken by TransGrid identifies five alternative options and rejects four based on reasonable technical inadequacies, compliance issues or the inability to source the requisite parts. The remaining alternative option of using blanking plates and adaptor boxes was assessed as part of the options analysis[254].

The selection of the preferred option is made based on the comparative cost of the two options. As the risk reduction for both options was considered equal, and both options offered a substantial improvement over the Do Nothing option, the least cost option of replacement has been selected.

PB is of the view that a reasonable range of options have been identified with the selected option demonstrated to be the least cost option.

Conclusion

On the basis of our high level review of the DB relays replacement program, PB is of the opinion there is a demonstrated need to undertake the replacement of all assets of this type. The scope of the initial program proposed for the 2009/14 regulatory period is considered to be prudent based on the extended age and moderate reported failure rate.

PB note that the timing of the remainder of the program scheduled for later regulatory periods remains discretionary. The volume of replacements should be reassessed based on the performance history and condition of the relays at the time of the revenue review.

Based on our review of this program, no specific adjustments are recommended.

253 TransGrid 5988 ARPE Rev 1.0, May 2008,, page 5.

254 ibid, page 10.

L.4 Substations

A total of 37 substation programs are included in the proposed forward capital works portfolio with a combined value of $91.2m over the 2009/14 regulatory period. PB has conducted a high level prudency review of the following three typical programs which together comprise 43% of the total value of the substation replacement programs.

- Upgrade Oil Containment (5201)
- Sprecher 330 kV HPF Circuit Breaker Replacement (5519)
- Instrument Transformer Replacement with High Dissolved Gas Analysis Results (4910, 5085, 5086 & 5087)

Need

TransGrid states that the need for the programs is based on environmental compliance, safety, condition assessment and maintainability of the proposed asset replacements.

PB is of the view that for the Oil Containment and Instrument Transformer substation equipment replacement programs, the need is sufficiently supported by the age, condition and compliance factors presented in the ARPE documentation[255].

For the 5519 Sprecher circuit breaker replacement program, PB is of the view that the need is adequately supported by the asset condition and declining spares availability[256].

Scope Efficiency

The scope of the programs is summarised below:

- Oil Containment – upgrade twenty five substation sites with non-draining transformer bunds of a design that was proven to be insufficient in a recent transformer failure[257]. Where transformer replacement projects have been scheduled for affected substations, the oil containment bund will be upgraded as part of the project and have therefore been excluded from the program;
- Sprecher 330 kV CB – replacement of a class of 26 circuit breakers due to type faults associated with leaking grading capacitors and limited spares availability[258]. PB note that the age of the circuit breakers is lower than expected for end of life replacement; and,
- Instrument Transformers – allowance for the replacement of instrument transformers based on condition monitoring results. The scope has been determined based on the asset population, test results and the historical replacement rate[259].

The scope of the programs is consistent with addressing the identified program needs in a prudent manner.

PB notes that the scope efficiency is affected by the options analysis which in our view does not adequately address all reasonable options for the three substation programs considered.

255 TransGrid 5201 ARPE Rev 0, April 2008, page 6 & TransGrid 4910 ARPE Rev 1, April 2008, page 6.

256 TransGrid 5519 ARPE Rev 0, February 2008, page 7.

257 TransGrid 5201 ARPE Rev 0, April 2008, page 5.

258 TransGrid 5519 ARPE Rev 0, February 2008, page 6.

259 TransGrid 4910 ARPE Rev 1, April 2008, page 6.

Cost Efficiency

TransGrid states that cost estimates for the revenue proposal are based on their cost estimating procedures which have been reviewed in section 5.3 of the PB report. PB has generally not reviewed the detailed cost breakdown of each program for the purpose of this program prudency review.

With regard to the specific programs a high level review of the unit costs was undertaken. The following comments are made regarding cost efficiency.

- Oil Containment – the implied cost per site of $400K for the upgrade of the oil containment systems appears high. TransGrid has provided a breakdown of the costs[260] which indicate program cost is influenced by large civil works components required for some sites. On this basis, PB consider that the costs appear reasonable;

- Sprecher 330 kV CB – the implied average installed cost of $230K per 330 kV circuit breaker is considered reasonable; and

- Instrument Transformers – the implied average installed cost of $134K per three phase instrument transformer set is approximately 19% higher than the weighted average instrument transformer benchmark cost s determined for section 5.3 of the PB report. However, on the balance PB considers that this cost is reasonable when complications associated with replacement program work on operating substation sites is considered.

Therefore PB is of the view that the cost efficiency of the three programs generally appears reasonable.

Timing

The timing of the programs has been determined based on an assessment of the age, condition, asset population and risk associated with the assets. The following comments are made regarding the justification of timing for specific programs:

- Oil Containment – a recent containment incident following a transformer failure has indicated that the bund replacement program is necessary[261]. The specific sites included in the program will be prioritised based on bund condition and environmental sensitivity of the site

- Sprecher 330 kV CB – replacement of the circuit breaker type is due to the high defect rate and slow operating times. The timing has been justified on the basis of the declining reliability and spares availability issues associated with the circuit breaker type[262]

- Instrument Transformers – replacement of each instrument transformer is determined by condition monitoring and therefore forms an ongoing program of work with an indefinite completion date[263]. Therefore the timing of the program is considered appropriate.

PB is of the view that the timing of the programs proposed for the 2009/14 regulatory period is justified.

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260 TransGrid 5201 AROC Rev 0, April 2008.

261 TransGrid 5201 ARPE Rev 0, April 2008, page 5.

262 TransGrid 5519 ARPE Rev 0, February 2008, page 9.

263 TransGrid 4910 ARPE Rev 1, April 2008, page 6.

Options Assessment

An options analysis has been undertaken for each of the programs evaluated. In two cases, PB has identified shortcomings in the options assessment process which are discussed below:

- Oil Containment – PB is of the view that the upgrade work is the only feasible option to meet the stated project needs

- Sprecher 330 kV CB – the option development section of the ARPE documentation specifically identifies circuit breaker refurbishment as a lower cost option[264]. However, this option is excluded from the cost and risk assessment on the basis of limited parts availability. As limited availability would increase the cost of the refurbishment, PB is of the view that the omission of the refurbishment option from the options comparison is not reasonable

- Instrument Transformers – the option comparison presented in the ARPE documentation[265] identifies Option 2 (Replace three phases and re-use spare units) as a higher NPV and higher risk option than the preferred Option 3 (Replace three phases and re-use spare units for emergency replacements only). Whilst PB recognises that the decision has been made on the basis of the risk reduction per dollar NPV, we note that there is no cost saving or risk increase associated with TransGrid's preferred reuse option over Option 1 (Replace three phases with no re-use).

  This discrepancy infers that there is no significant risk associated with the reuse of retained instrument transformers, subject to the specific condition criteria noted in the ARPE document[266]. On this basis, PB is of the view that the wider use of retained instrument transformers, as proposed in Option 2, subject to the re-use criteria proposed for Option 3, would also represent minimal risk.

  Therefore the selection of the preferred option over the highest NPV option is dependent on an inconsistent risk assessment process. On this basis, PB is of the view that the highest NPV option (Option 2) represents prudent and efficient investment.

PB is of the view that the options analysis presented by TransGrid does not adequately assess the reasonable options that have been identified for asset replacement. The selection of the preferred option is based on factors other than those detailed in the options comparison documentation, typically resulting in additional cost or scope that has not been included in the options costing. Therefore the selection has not been made on the basis of least cost or highest NPV. Where risk mitigation is used as the basis for the investment decision, the evaluation of the risk reduction is inconsistent and generally does not consider lower cost mitigation measures that may be applied to the 'Do Nothing' option in the comparison.

Notwithstanding, PB is satisfied that the reviewed programs are necessary to meet performance, compliance and environmental requirements and therefore cannot be entirely deferred.

[264] TransGrid Network Asset Replacement Project Evaluation, 5519 ARPE rev 0, February 2008, page 8.

[265] TransGrid Network Asset Replacement Project Evaluation, 4910 ARPE rev 1, April 2008, page 10.

[266] TransGrid Network Asset Replacement Project Evaluation, 4910 ARPE rev 1, April 2008, page 10.

Conclusion

On the basis of our high level review of the substations replacement program, PB is of the opinion that there is a demonstrated need to undertake the replacement programs. However, PB considers that inconsistencies in the options assessment process do not enable the assessment of the efficiency of the expenditure.

Therefore, whilst the prudency of undertaking the work has been justified, the efficiency of the investment has not been demonstrated. Therefore we recommend the following adjustment:

- The instrument transformer replacement program should be adjusted to reflect the highest NPV Option 2 (Replace three phases and re-use spare units) in place of the more costly Option 1 (Replace three phases and retain spare units).

  PB recommends that the expenditure profile is adjusted based on the 72% ratio of the NPV's[267] presented in the ARPE documentation[268].

Table L-3 – PB adjustment to substations programs

Component	09/10	10/11	11/12	12/13	13/14	Total Value ($k)
TransGrid Proposed Inst Transformers	2,460	3,198	3,394	3,282	3,319	15,653
Total Adjustment	(689)	(895)	(950)	(919)	(929)	(4,382)
PB Recommended Inst Transformers	1,771	2,303	2,444	2,363	2,390	11,271

Source: PB analysis.

L.5 Transformers

A total of 3 transformer programs are included in the proposed forward capital works portfolio with a combined value of $33.4m over the 2009/14 regulatory period. PB has conducted a high level prudency review of the Transformer Failures program (4884) which comprises 93% of the total value of the transformer replacement programs.

Need

The program allows for the replenishment of the spares inventory following the transformer failures that are expected to occur over the 2009/14 regulatory period. The need for the replacement is justified based on the failed condition of the transformers. Given that the replacement is based on irreparable transformer failure, no condition assessment is required.

Therefore PB considers that the need for the program is adequately justified.

Scope

The scope of the program covers the replenishment of spare transformers following their use of the existing spare transformer in emergency replacement projects.

The replacement rate has been determined based on the historical failure rate. As transformer replacements over the past regulatory period have not significantly reduced the

267 As the two options cover failures occurring at identical times, the change in NPV between options is assumed to be proportional to the change in costs in each year.

268 TransGrid 4910 ARPE Rev 0, February 2008, page 10.

average transformer age, the continued use of historical failure rates is considered to be reasonable.

The magnitude of replacement is generally consistent with the historical performance of the TransGrid transformer fleet. Therefore the proposed scope of the replacement program is considered to be appropriate.

Cost

TransGrid states that cost estimates for the revenue proposal are based on their cost estimating procedures which have been reviewed in section 5.3 of the PB report.

PB has reviewed the calculation of the capital estimate for this program. The methodology used by TransGrid is considered reasonable and is derived from the weighting of TransGrid's historical failure rates by transformer size and the current replacement cost. PB note that TransGrid has adopted a conservative approach of discounting the current 5 year average failure rate by a factor of 17% to account for specific projects that replace older units[269].

The unit costs used by TransGrid cover the purchase of equipment only. PB has reviewed these costs and considers them to be reasonable. Installation and clean up costs are typically covered by TransGrid's insurance arrangements.

Therefore, PB considers that the cost of the program is reasonable.

Timing

The timing of individual transformer purchases is based on the actual occurrence of transformer failure. TransGrid's policy is to order a replacement at the time the existing spare transformer is used[270]. An adjustment to the annual allowance has been made to account for the recent failure of two 330 kV transformers that have already been replaced.

PB considers that the timing of the replacement program expenditure proposed by TransGrid is reasonable.

Options Assessment

PB notes that no alternative options have been considered due to the inventory replenishment nature of the program. In this case, PB is satisfied that the selected option is the only feasible option.

Conclusion

On the basis of our high level review of the transformer replacement program, PB is of the opinion there is a demonstrated need to replenish the spares holding of replacement transformers following unplanned failures. The scope, timing and selection of the preferred timing have been adequately supported.

Based on our review of this program, no specific adjustments are recommended.

L.6 Transmission lines

A total of 9 transmission lines programs are included in the proposed forward capital works portfolio with a combined value of $26.4m over the 2009/14 regulatory period. PB has conducted a high level prudency review of the wood poles replacement program (4939 TL 99F) which comprises 29% of the total value of the transmission line replacement programs.

269 TransGrid Spreadsheet, CalculationOfReplacementTxCosts.xls.

270 TransGrid 4884 ARPE Rev 0, June 2008, page 7.

Need

TransGrid states that the replacement program for the 99F line wood pole is required due to the high historical defect rate and condition of the wood structures. The defect rate pertains primarily to the susceptibility of wood poles in the area to termite attack. This is supported by TransGrid's statements that:

- the maintenance history of the line indicates that 20% of the wood poles have already been replaced, primarily due to termite attack[271];
- 25% of the structures are currently being treated for termite problems; and,
- a condition assessment of the poles has been conducted that indicates that the defect rate is expected to increase in the future due to ongoing termite problems.

Therefore PB considers that the need for a replacement program to address the condition of the wood poles on the line is adequately justified.

Scope Efficiency

The scope of the program covers the replacement of the 602 wooden structures that comprise the line with concrete poles that are not susceptible to termite attack. A total of 420 structures have been scheduled for replacement over the 2009/14 regulatory period, with the remainder occurring in the subsequent period.

However, PB notes that every second structure was replaced in 1985[272] to increase the temperature rating of the line. Therefore, at approximately 23 years, the age of approximately half of the wooden structures on the line is significantly lower than would typically be considered for replacement.

The condition assessment report[273] does not specifically identify the upgrade and therefore does not differentiate between the two distinct ages of poles.

Based on TransGrid's statement that the current age of the original poles on the line is approximately 36 years, PB is of the view that the poles replaced in 1985 could reasonably be expected to have a residual life in the order of 15 years under the existing maintenance regime.

Therefore due to the wide disparity in the age and condition of the wood structures, PB is of the view that the proposed program scope covering the replacement of all structures on the line appears excessive. Significantly, we note that the option of replacing the original wood structures that were not replaced in 1985 with concrete structures has not been proposed or assessed.

PB considers that the scope of the program is not adequately justified and therefore does not represent prudent and efficient investment.

Cost

TransGrid states that cost estimates for the revenue proposal are based on their cost estimating procedures which have been reviewed in section 5.3 of the PB report.

271 TransGrid Network Asset Replacement Project Evaluation, 4939 TL 99F- ARPE Rev 2, April 2008, page 5.

272 ibid, page 4.

273 TransGrid 4939 TL 99F ARCA Wagga – Yanco, May 2008.

PB has not requested or reviewed the detailed cost breakdown for this program. However, at a high level, the average implied cost of approximately $18K per structure replacement is considered reasonable.

Timing

The timing of the program has been determined from the condition assessment of the wood structures that comprise the transmission line. PB acknowledges that the age, condition and failure history of the line[274] supports the commencement of a pole replacement program. However PB believes that the replacement of the line could reasonably be expected to occur in two stages, with the second stage commencing in approximately 10-15 years. We note that this timing is broadly consistent with the timing presented in option 3 (defect replacement of wood poles with concrete poles).

Therefore PB considers that the timing of the commencement of a replacement program is reasonable. However, in PB's opinion, a significant proportion of the program could reasonably be deferred into subsequent regulatory periods.

Options Assessment

Whilst PB accepts that TransGrid's objective is to replace wood poles that are subject to an accelerated defect rate, we note that the disparity in the age of the structures is such that partial replacement is considered to be a reasonable option.

Furthermore, the defect replacement of wood poles with concrete poles has been identified by TransGrid as current standard practice[275] but is excluded in the options analysis on the basis of providing no reduction in risk over like-for-like defect replacement. PB also note that the estimated 1241 future pole replacements used to estimate the cost of this option implies that each of structures comprising the line would be replaced with concrete poles approximately twice over a 20 year period. This is inconsistent with the two-for–one replacement of wood poles described by TransGrid[276] and the 0.1% defect rate quoted by TransGrid[277] for concrete poles.

PB is of the view that the defect replacement of wood poles with concrete poles, in accordance with TransGrid's stated standard practice, represents a significant reduction in risk over the like-for-like replacement option. Given the significantly higher NPV of this option, a modest reduction in the risk score would demonstrate that this option is the most efficient from a combined risk and NPV perspective.

For this program, PB is not satisfied that all reasonable options have been considered or that the risk assessment process used by TransGrid has been applied consistently.

Conclusion

PB is of the view that the condition of the wood structures on the line demonstrates that a replacement program is required, however the scope of the replacement program appears excessive. Therefore PB is of the view that this program does not represent prudent and efficient investment

Based on the options presented by TransGrid, the defect replacement of wood poles with concrete poles option is considered to be the most efficient option. However, PB acknowledge that the increasing defect rate on the line is likely to be concentrated in the older PI wood structures and a therefore a targeted program of reduced scope is supported.

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274 TransGrid Network Asset Replacement Project Evaluation, 4939 TL 99F- ARPE, April 2008, page 5-6.

275 TransGrid 30 Year Network Asset Management Plan 2009-39 page 80.

276 TransGrid Network Asset Replacement Project Evaluation, 4939 TL 99F- ARPE, April 2008, page 11.

277 ibid, page 7.

PB recommends that the program scope is revised to cover the planned replacement of 50% of the structures.

A review of the remaining wood poles replacement programs has identified similar issues relating to the 94T and 967 line replacements where large disparities in age between structures and/or similar inconsistencies in the options assessment process also exist:

- in the case of the 94T line wood pole replacement, TransGrid has identified that only 42 composite structures need to be replaced in the next 7 years with the remaining 48 non composite structures to be replaced within 20 years[278]. Given the significant residual life associated with the majority of the structures, PB recommend that the scope of the program be reduced to cover the 42 composite structures

- in the case of the 967 line, the 1.15% defect rate[279] for the remaining non-composite wood poles exceeds TransGrid's nominal condition review trigger of 0.8% - 1.0%[280]. On this basis no adjustment is recommended for the 967 line program.

Table L-4 – PB adjustment to program 4939 TL 99F & 94T (wood poles)

Component	09/10	10/11	11/12	12/13	13/14	Total Value ($M)
TransGrid Proposed 99F	-	-	2,603	2,550	2,388	7,541
Adjustments 99F	-	-	-	-	(2,335)	(2,335)
PB Recommended 99F	-	-	2,603	2,550	53	5,497
TransGrid Proposed 94T	1,186	1,136	-	-	-	2,322
Adjustments 94T	(102)	(1,136)	-	-	-	(1,238)
PB Recommended 94T	1,084	-	-	-	-	1,084
Total Adjustments	(102	(1,136	-	-	(2,335)	(3,573)

Source: PB analysis.

As shown in Table L-4, PB recommend a total reduction in the forward capital expenditure for the 4939a wood poles replacement program of $3.57M over the 2009/14 regulatory period.

L.7 High level age benchmark

PB has conducted a high level review of the change in age profile of the assets arising from the proposed replacement programs and projects for the purpose of determining whether the volume of the asset replacement is consistent with expectations based on the age profile of selected asset types.

Circuit Breakers

TransGrid has included a total of 8 circuit breaker replacement programs in the calculation of their forward capex requirements with a total value of $21.8M[281]. These programs typically involve the replacement of circuit breakers by type across a range of sites.

Due to the number of sites, a review of the program scope was conducted by TransGrid to identify any scope overlap with other replacement or augmentation projects proposed for the

278 TransGrid Network Asset Replacement Project Evaluation, 4939 TL 99T- ARPE, April 2008, page 7.

279 PB analysis based on quantities and failure rates quoted in TransGrid 4939 TL 967 ARPE, April 2008.

280 TransGrid 30 Year Network Asset Management Plan 2009-39 page 80.

281 AER Template Revenue Proposal Pro Forma Schedule 4.4.

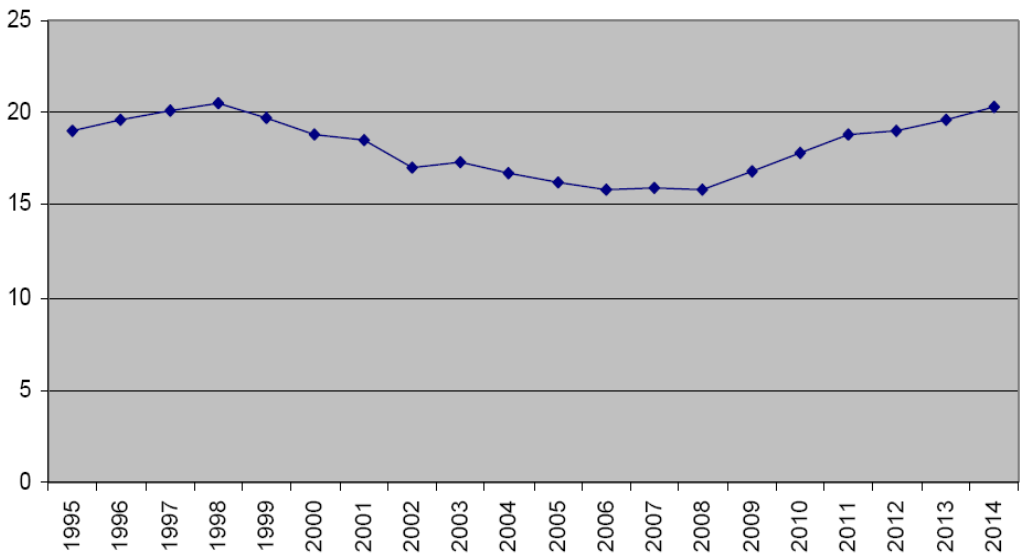
2009/14 regulatory period. A total of 14 Delle 66 kV circuit breakers included in program 4905 were identified that will be replaced under the Orange Substation replacement and Tamworth 132 kV transformer replacement projects. The total value of the adjustment is $1.039M and has been identified in section 5.4 of the PB report.

A total of 129 circuit breakers accounting for approximately 9.5% of TransGrid's circuit breaker population of 1351[282] are scheduled for replacement over the 2009/14 regulatory period. At a high level, this degree of replacement is slightly above the level of replacement that would be expected from the age profile of the circuit breaker fleet and expected asset life of 40 years[283].

PB note that 23 circuit breaker replacements result from SF6 leakage faults associated with the Merlin Gerin FA1 and FA2 type circuit breakers which will be replaced prematurely.

The effect on the age profile of the circuit breaker replacement programs on the average age of the TransGrid population is shown in Figure E-1. We note that the increase in average age over the period is due to the aging of the large population of circuit breakers installed between 1975 and 1984.

Figure L-1 – TransGrid average circuit breaker age



Source: TransGrid.

From our high level review, PB is of the opinion that the level of circuit breaker replacement proposed over the 2009/14 period is reasonable.

Instrument Transformers

TransGrid has included a total of 7 instrument transformer replacement programs in the calculation of their forward capex requirements with a total value of $21.8M. These programs typically involve the replacement of instrument transformers based on condition assessment results.

282 TransGrid Network Management Plan 2009-14 page 24.

283 TransGrid 30 Year Network Asset Management Plan 2009-39.

A total of 193 three phase instrument transformer sets accounting for approximately 9.5% of TransGrid's instrument transformer population of 6067[284] individual units are scheduled for replacement over the 2009/14 regulatory period. At a high level, this degree of replacement is below the level of replacement that would be expected from the age profile of the instrument transformer fleet and expected asset life of 40 years.

PB note that the adjustment has been made on the basis of the condition based replacement triggers used by TransGrid. This has resulted in the deferral of approximately 500 instrument transformer replacements to future years[285].

From our high level review, PB is of the opinion that the level of instrument transformer replacement proposed over the 2009/14 period appears reasonable.

Notwithstanding, a more detailed assessment of the instrument transformer programs proposed by TransGrid indicates that significant scope exists for deferral of a significant proportion of the proposed instrument transformer replacement expenditure to subsequent regulatory periods.

Transformers

TransGrid has included 3 transformer replacement programs in the calculation of their forward capex requirements with a total value of $33.4M. These programs cover the replenishment of the spare transformers inventory on the deployment of the existing spare in the event of an unscheduled transformer failure.

A total of 6 transformers are expected to be replaced over the 2009/14 regulatory period under unscheduled transformer replacement program, accounting for approximately 3.6% of TransGrid's total transformer population of 168[286].

PB note that the majority of TransGrid's transformer replacements are undertaken on a project basis with the need determined by condition monitoring or load growth. A total of 16 additional transformers[287], or 9.5% of the TransGrid transformer population, are required for planned condition based replacement projects over the 2009/14 regulatory period. The effect of the proposed replacements on the average age of the TransGrid transformer population is shown in Figure L-2.

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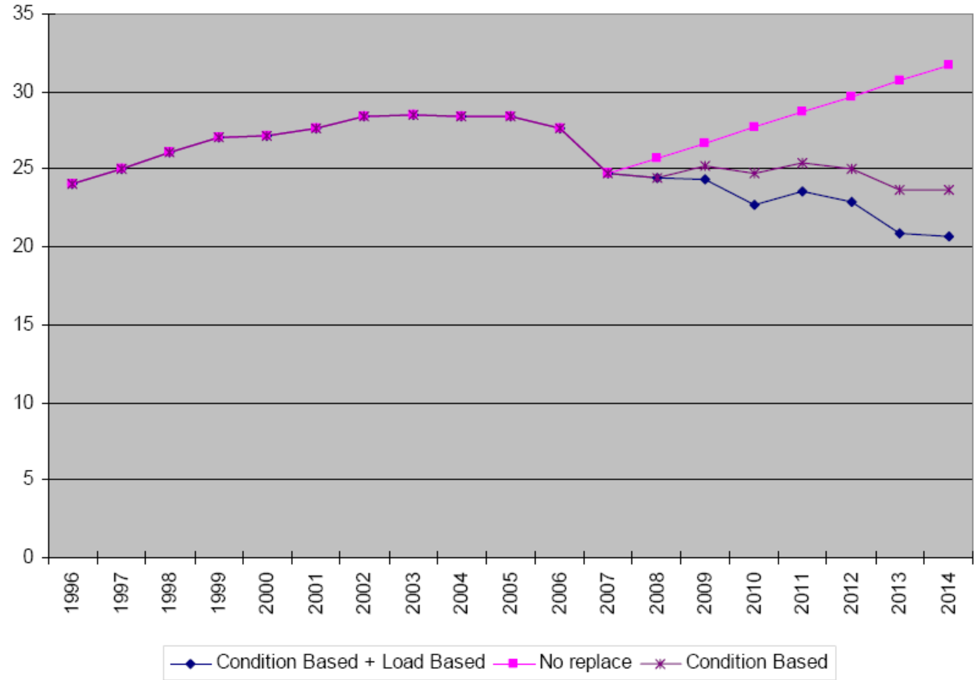
284 TransGrid Network Management Plan 2009-14 page 46.

285 TransGrid 30 Year Network Asset Management Plan 2009-39 page 64.

286 TransGrid Network Management Plan 2009-14 page 45.

287 TransGrid Transformer Risk Scoring and Timing of Replacement document 7 August 2008.

Figure L-2 – TransGrid average transformer age



Source: TransGrid.

At a high level, this degree of replacement is slightly below the level of replacement that would be expected from the age profile of the transformer fleet and expected asset life of 45 years.

PB note that the discrepancy is largely due to the reuse of five transformers in the replacement projects that have been subject to early withdrawal from service during augmentation projects.

From our high level review, PB is of the opinion that the level of transformer replacement proposed over the 2009/14 period is reasonable.

Transmission Lines

TransGrid has included a total of 6 transmission line structure replacement programs in the calculation of their forward capex requirements with a total value of $33.4M[288]. These programs typically involve the replacement of wood poles for six lines.

PB has conducted a review of the proposed wood pole replacement projects against the augmentation projects nominated by TransGrid. No scope overlap in structure replacement was identified in our review.

A total of 1,055 wood structures (or 2110 poles) accounting for approximately 6.4% of TransGrid's wood pole population of approximately 33,000[289] are scheduled for replacement over the 2009/14 regulatory period. At a high level, this degree of replacement is above the level of replacement that would be expected from the age profile of the wood pole population and TransGrid's expected wood pole asset life of 65 years[290]. PB notes that TransGrid has

288 AER Template Revenue Proposal Pro Forma Schedule 4.4.

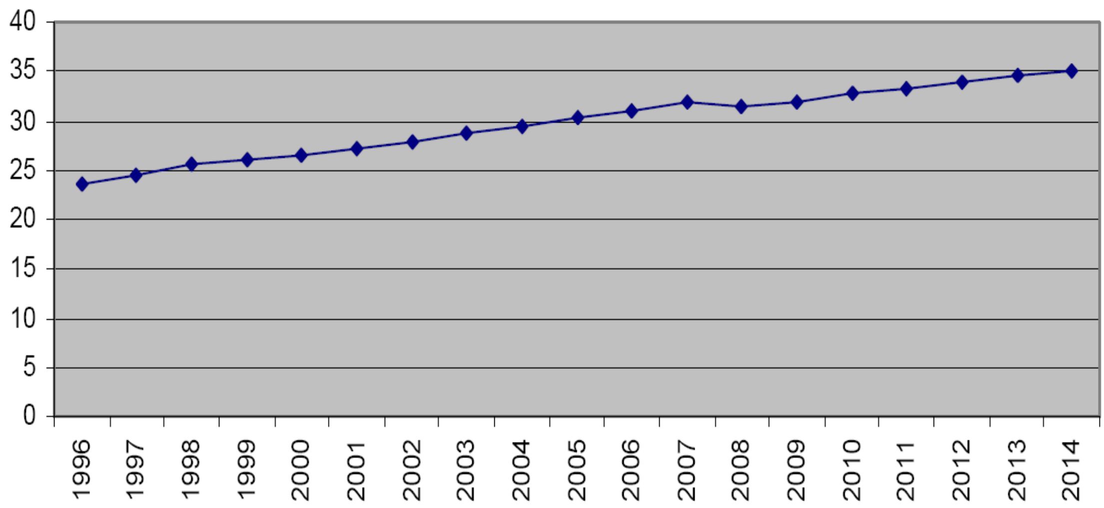
289 TransGrid Network Management Plan 2009-14 page 24.

290 TransGrid 30 Year Network Asset Management Plan 2009-39.

identified significantly reduced asset lives achieved in practice for composite and PI type wood poles. This is consistent with the increased level of replacement when compared to the 65 year standard life.

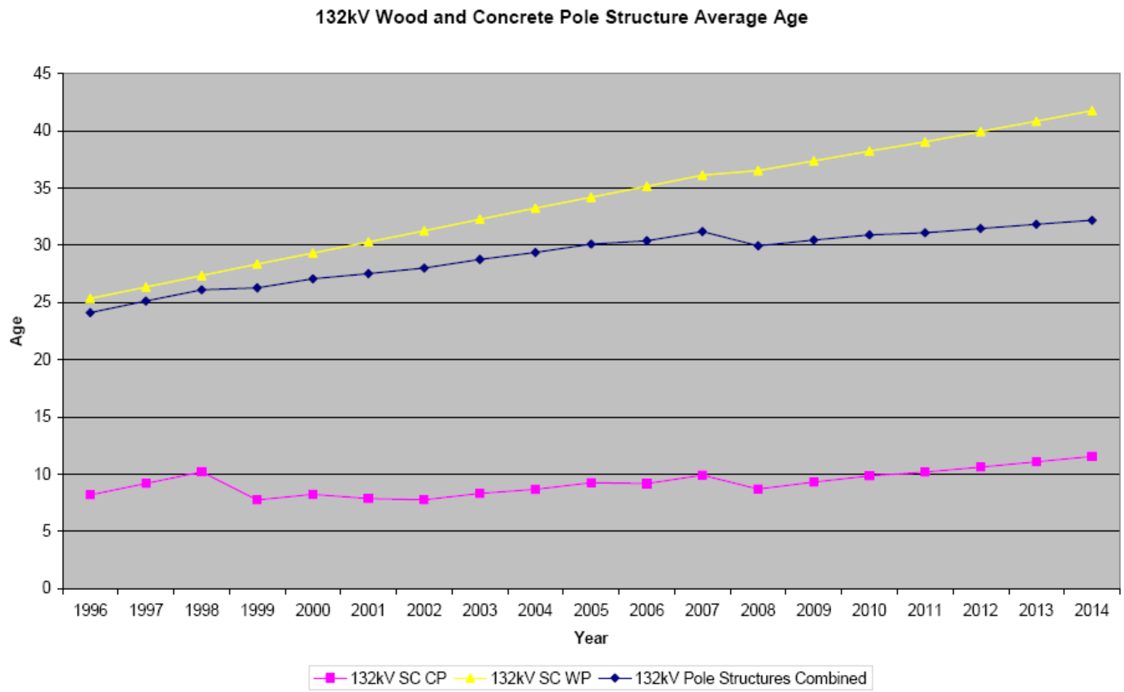
The effect of the proposed replacements on the average age of the TransGrid transmission line structure population is shown in Figure L-3 and Figure L-4.

Figure L-3 – TransGrid average transmission structure age



Source: TransGrid.

Figure L-4 – TransGrid average 132 kV transmission structure age by type



Source: TransGrid.

PB note that the wood pole replacement programs proposed for the 2009/14 period are generally driven by condition assessment that has revealed accelerated deterioration in composite poles and some PI pole types that comprise a significant proportion of the TransGrid wood pole population.

Therefore at a high level, PB consider that the volume of replacements under the proposed wood pole replacement programs is reasonable. Notwithstanding, a more detailed assessment of the specific wood poles programs proposed by TransGrid indicates that scope exists for the deferral of a proportion of the wood poles expenditure in to subsequent regulatory periods.

L.8 PB comments and recommendations

In PB's view, the TransGrid options assessment process provides a weak justification for the selection of the preferred option. Where decisions are based on a combination of NPV and risk reduction, TransGrid has advised that selection is typically made informed by the risk reduction achieved per dollar NPV and engineering judgement[291].

PB note the following systemic inconsistencies and implicit bias in the TransGrid replacement capex assessment process:

- the use of risk reduction against the 'Do Nothing' benchmark will always exclude the 'Do Nothing' option as it, by definition, provides zero risk reduction
- the risk score evaluation process is considered arbitrary as it does not capture differences in the risk associated with significantly different options such as the use of replacement concrete poles over wood poles
- the baselines established for the 'Do Nothing' options are in some cases inconsistent with TransGrid standard practice, resulting in an overstatement of the risk reduction provided by other options
- the calculation of the NPV of the project does not appear to include all future costs associated with each option. This results in incompatible, and therefore, arbitrary NPV comparisons
- the options development does not identify all reasonable options. For example, on up-rated lines with two distinct installation dates, no assessment has been made of replacing the older structures and newer structures under separate programs.

Notwithstanding the above comments, at a high level, the volume and total value of the proposed replacement capital works does not appear to be unreasonable based on the network asset age and condition factors presented by TransGrid.

L.9 Subsequent Update

The above review was completed on the basis of information provided by TransGrid with their submission, and in response to questions and discussions to clarify the information provided in TransGrid business documentation. This information was received prior to 20 August 2008. As discussed further in section 5 of the main body of this report, since completing the above review, TransGrid has provided subsequent updates to the project information. This subsequent information includes:

- a response to PB Advice #7 Question F5, advising that the following statement contained in the ARPE document originally submitted to the Regulator was incorrect:

291 TransGrid Action 4 5 Cost Risk Reduction Response, 11 August 2008, page 3.

Transmission line 99F was built in 1971 with Pressure Impregnated (PI) wood poles and up-rated to 85°C by replacing every second structure with a taller PI pole in 1985.[292]

In their response, TransGrid advise:

The statement in the document 4939 TL99F ARPE (section 2 Situational Assessment – Population) relating to uprating of the line to 85°C in 1985 is incorrect. This had been inadvertently copied from another document unrelated to this line. The 99F transmission line was originally constructed for 85°C operation.[293]

- condition assessment reports entitled 'Wood Pole TL Condition Review' undertaken by TransGrid for wood poles on Transmission Lines 99J, 94T, 996, 967, 94B and 99F.[294]

This subsequent information is considered in this section, along with its implications on PB views and recommendations.

The original statement regarding the uprating of the line in 1985 was made in the specific context of the 99F line with the correct commissioning year for the line noted. PB observes that the ARPE report is identified by TransGrid as the third verified and approved issue of the document[295]. Considering the materiality of the statement to PB's original assessment of the project and the level of review documented by TransGrid, we are of the view that the inclusion of a factual error of this magnitude in the submitted documentation demonstrates a shortcoming in TransGrid's document review and verification procedure for documents informing investment decisions.

Notwithstanding, PB accepts that TransGrid's advice is a factual correction and has considered the implications with regard to the 99F transmission line wood pole replacement program.

Based on TransGrid's documentation, and PB's detailed review, we concluded that in our opinion the drivers, unit cost and strategic alignment of the selected option are demonstrated to be prudent However, we could not conclude that the scope efficiency of the selected option had been adequately demonstrated or that a reasonable range of alternative options had been considered. On this basis PB recommended that half of the pole replacements for the 99F transmission line were deferred in accordance with the age profile resulting from the incorrectly stated 1985 uprating work. A corresponding reduction of $2.3m in the proposed ex-ante capex allowance was recommended.

Having considered the revised project evaluation information, PB accepts that there is no significant age disparity in the wood pole population on the 99F transmission line. Therefore, we revise our recommendation for project deferral and conclude that the scope efficiency of the selected option has been adequately demonstrated and that a reasonable range of options has been assessed.

However, PB remain of the opinion that TransGrid's justification for excluding the defect replacement of wood poles with concrete poles on the basis of limited risk reduction is both weak and inconsistent with the standard practice stated in TransGrid's 30 Year Asset Management Plan[296]. Notwithstanding the above, PB has considered the strategic alignment and TransGrid's forecast need for resource levelling for wood pole replacements identified in

292 TransGrid Network Asset Replacement Project Evaluation, 4939 TL 99F – ARPE, Revision 2, 22/04/08.

293 TransGrid Response to PB Advice #7 Question 5, undated, received 21 August 2008.

294 TransGrid, 4939 TL Asset Replacement Condition Assessment reports, undated, saved April-May 2008.

295 TransGrid Network Asset Replacement Project Evaluation, 4939 TL 99F – ARPE, Revision 2, 22/04/08, page 2.

296 TransGrid 30 Year Network Asset Management Plan 2009-39 page 80.

the long term asset management documentation and, on the balance of the information presented, PB are of the view that the replacement of the wood poles on this line is prudent.

Therefore we recommend the following adjustment is to the wood poles replacement program. We note that the recommended adjustments to the 94T line replacement remain unchanged.

Table L-5 – PB adjustment to program 4939 TL 99F & 94T (wood poles)

Component	09/10	10/11	11/12	12/13	13/14	Total Value ($M)
TransGrid Proposed 99F	-	-	2,603	2,550	2,388	7,541
Adjustments 99F	-	-	-	-	-	-
PB Recommended 99F	-	-	2,603	2,550	2,388	7,541
TransGrid Proposed 94T	1,186	1,136	-	-	-	2,322
Adjustments 94T	(102)	(1,136)	-	-	-	(1,238)
PB Recommended 94T	1,084	-	-	-	-	1,084
Total Adjustments	(102)	(1,136)	-	-	-	(1,238)

Source: PB analysis.

As shown in Table L-5, PB recommends a total reduction in the forward capital expenditure for the 4939a wood poles replacement program of $1.24M over the 2009/14 regulatory period.

L.10 Conclusion

Based on our assessment, PB recommends the following adjustments to the TransGrid forward replacement capex:

- for the instrument transformers replacement programs 4910, 5085, 5086 and 5087, a reduction of $4.38M is recommended to make allowance for the replaced instrument transformers to be reused
- the capital expenditure for the transmission lines replacement program for the 94T line be reduced by $1.24M to cover the reduction in scope associated with the deferral of approximately half of the structure replacements to future regulatory periods.

Table L-6 provides the annual breakdown of PB's recommended adjustments.

Table L-6 – Summary of PB adjustments to replacement programs

Component	09/10	10/11	11/12	12/13	13/14	Total Value ($M)
Substation adjustments	(689)	(895)	(950)	(919)	(929)	(4,382)
Transmission line adjustments	(102)	(1,136)	-	-	-	(1,238)
Total adjustments	(791)	(2,031)	(950)	(919)	(929)	(5,620)

Source: PB analysis.

APPENDIX M
CONTINGENT PROJECTS REVIEW

APPENDIX M: CONTINGENT PROJECTS REVIEW

This section reviews a suite of 18 network projects that have been proposed by TransGrid as contingent projects. PB's review of the contingent projects will consider the appropriateness of including the projects as part of TransGrid's Revenue Proposal.

M.1 Review against the NER requirements

As discussed in section 5.6 of the main report, section 6A.8.1 of the NER defines a set criterion to determine if a project is a contingent project and can be accepted as part of the revenue determination. In PB's view, there are six key criteria that a project must meet to be classed as a contingent project and these are discussed in the following section.

A project can be included as a contingent project where the proposed contingent capital expenditure:

1. is not otherwise provided for (either in part or in whole) in the total of the forecast capital expenditure allowance
2. reasonably reflects
   a. efficient costs in achieving the objectives
   b. costs that a prudent operator would require to achieve the objectives
   c. the realistic expectation of the demand forecast and cost inputs required to achieve the objectives

   taking into account the capital expenditure factors, in the context of the proposed contingent project as described in the Revenue Proposal
3. exceeds either $10m or 5% ($33.4m[297]) of the value of the maximum allowed revenue for the first year of the relevant regulatory control period, whichever is the larger amount

and where the trigger event:

4. is reasonably specific and capable of objective verification
5. generates increased costs or categories of costs that relate to a specific location rather than a condition or event that affects the transmission network as a whole
6. is probable during the next regulatory period but is not sufficiently certain that the event will occur in the next regulatory period.

In reviewing the contingent projects, PB has presented the six criteria into a tabular format. The format is shown in Table M-1.

Table M-1: Format of the contingent project summary table

expenditure			trigger event		
no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain

297 In the case of TransGrid – this figure of $33.4m is based on 5% of the 2009/10 smoothed revenue of $670.2m, refer page 121 of submission.

The six sections of the summary table are intended to align with the six main criterion identified when reviewing the NER requirements. The alignment is defined in accordance with the following descriptions:

no provision – is not otherwise provided for (either in part or in whole) in the total of the forecast capital expenditure allowance

reflective – reasonably reflects

a. efficient costs in achieving the objectives

b. costs that a prudent operator would require to achieve the objectives

c. the realistic expectation of the demand forecast and cost inputs required to achieve the objectives

taking into account the capital expenditure factors, in the context of the proposed contingent project as described in the Revenue Proposal

exceeds limit – exceeds either $10m or 5% ($33.4m[298]) of the value of the maximum allowed revenue for the first year of the relevant regulatory control period, whichever is the larger amount

specific and verifiable – is reasonably specific and capable of objective verification

generates costs – generates increased costs or categories of costs that relate to a specific location rather than a condition or event that affects the transmission network as a whole

probable but uncertain – probable during the next regulatory period but is not sufficiently certain that the event will occur in the next regulatory period.

Where the information provided on the project meets the NER requirements, the corresponding entry in the table will be marked with a tick, as shown in Table M-2. Should PB consider that the submitted information presented by TransGrid for each project does not meet the NER requirements, then a cross will be entered.

Table M-2: identifying criterion for project reviews

meets criterion	does not meet criterion
✓	×

Importantly, in order for a project to be accepted as a contingent project as part of the revenue proposal, all six criteria must be met.

M.2 Project review

This section is a detailed review of the 18 proposed contingent projects against the NER requirements.

298 In the case of TransGrid – this figure of $33.4m is based on the 2009/10 smoothed revenue of $670.2m, refer page 121 of submission.

Kemps Creek – Liverpool 330 kV line – Undergrounding of all or part of the proposed connection (POSE 3978N)

TransGrid's proposed forecast capex allowance includes the construction of an overhead line at 330 kV from Kemps Creek to Liverpool. This contingent project is an allowance to underground a section of the 330 kV line.

PB has identified the complementary project in the forecast capex allowance pertaining to the construction of the Kemps Creek – Liverpool 330 kV transmission line (ID 3978) and this project is for the construction of the whole line as overhead. This contingent project is the undergrounding of either a section, or all of the transmission line. TransGrid has estimated that differential cost of undergrounding a section of the route is $77m.

In reviewing the scope and cost, based on the information provided by TransGrid, PB is of the view that the scope and cost is reflective of the necessary expenditure and the assets scoped appear to relate to providing prescribed services.

The project is estimated to cost $77.4m, which exceeds the threshold of $33.4m.

The trigger is stated as the inability to get the environmental consents to construct the required overhead transmission line. Should approvals be withheld, the additional cost will be incurred for the construction of an underground section. In PB's view this meets the NER requirements for being a specific and verifiable trigger and one that will generate the required costs.

This project is expected to commence in the next regulatory period, but there is uncertainty associated with the environmental consents described within the trigger.

In PB's view, this contingent project meets the conditions of the NER to be classified as a contingent project, and is consistent with the approach adopted for undergrounding as part of other AER revenue determinations.

Table -M-3: Kemps Creek – Liverpool 330 kV line, summary of review

expenditure			trigger event		
no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
✓	✓	✓($77 m)	✓	✓	✓

Darlington – Balranald – Buronga system upgrade 275 kV (PSR 178)

This project is listed as upgrading the existing Darlington – Balranald – Buronga 220 kV transmission line to operate at 275 kV. The upgrade will help in reducing the transmission losses on the long line, and therefore assist in improving system power flow and transfer capacity.

PB has not identified any allowance in the proposal relating to this project and the capital expenditure for this project is estimated at $51m and this exceeds the threshold limit of $33.4m. In reviewing the scope and cost, based on the information provided by TransGrid, PB is of the view that the scope and cost is reflective of the necessary expenditure and the assets scoped appear to relate to providing prescribed services.

The trigger has been listed as satisfying the regulatory test under the market benefits criteria. In PB's view the general description of this trigger does not meet the requirements of the NER in that it is not reasonably specific or capable of objective verification. Additionally, the trigger does not specifically generate increased cost as no specific event has been listed that will increase the costs. PB considers the trigger for this project would need to be presented in more detailed terms of the specific inputs to the Regulatory Test application.

Given the lack of specific information, PB has not been able to establish if the trigger is a probable event within the next regulatory period.

Table M-4: Darlington – Balranald – Buronga system upgrade, summary of review

expenditure			trigger event		
no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
✓	✓	✓ ($51 m)	×	×	×

Development of a second 500 kV link (PSR 131, POSE 5568B; POSE 6002)

This project has an 'either/or' optional element and is dependent on which 500 kV project in the capex allowance is built first. The current revenue proposal has two major 500 kV projects included on a probabilistic basis. The two projects are:

- Bannaby – South Creek 500 kV transmission line - Project ID 5567
- Hunter Valley – central Coast 500 kV transmission line - Project ID 5567

This contingent project capex amount is intended to cover the incremental cost of constructing the second 500 kV transmission line project on the basis that construction of 'either/or' the 500 kV transmission lines has been committed to. Under the NER requirements, contingent project capital expenditure can only be accepted where it is not otherwise provided for (either in part or in whole) in the total of the forecast capital expenditure allowance. Given that TransGrid's forecast capital expenditure has an allowance for both projects (for example the Southern 500 kV link has been included in all 36 scenarios and in five scenarios both projects have been included), then in PB's view, this project does not meet the definition of a contingent project[299].

The estimated incremental cost of the constructing the second 500 kV line project is $331m and this exceeds the capital cost limit specified in the NER. In reviewing the scope and cost, based on the information provided by TransGrid, PB is of the view that the scope and cost is reflective of the necessary expenditure and the assets scoped appear to relate to providing prescribed services.

The trigger for the construction of the second line has been identified as a significant power station, interconnection or load development which requires both 500 kV links. In PB's view, this does not meet the NER requirements as the trigger is not sufficiently specific or descriptive beyond the bounds of the scenario analysis undertaken by TransGrid. As the load or generation has not been presented by TransGrid in a discrete manner, it is not possible to establish if the construction of either additional load or generation will increase the costs faced by TransGrid. Specifically, PB is of the view that the either/or statement is superfluous because the Southern 500 kV link has been included in all of the scenarios assessed – and therefore as a minimum, the contingent trigger should only refer to the Northern link being required. In PB's view, this project does not meet the NER requirements for a contingent project in a number of areas.

PB reviewed this project against the final NER trigger requirement that the project is probable, but uncertain and accept that it is possible for a generation scenario to be realised that may result in both lines being required.

299 PB acknowledges that it could be interpreted that since the contingent project value is the incremental cost of the second project only, then it has not been provided for in either part or in whole, within the capex allowance.

Table M-5: Development of a second 500 kV link, summary of review

expenditure			trigger event		
no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
×	✓	✓ ($331 m)	×	×	✓

Richmond Vale 500/330 kV substation (POSE 6005)

This project is the construction of a new substation to supply the Newcastle area. TransGrid has included an allowance in the proposal forecast capex for a 500 kV transmission line from the Hunter Valley to the Central Coast. This proposed transmission line does not include the construction of a new substation to supply the Newcastle area. PB did not identify any provision in the current forecast capex allowance relating to this project.

The proposed capital cost is for the construction of a new 500/330 kV substation including the provision of two 500/330 kV, 500 MVA transformers, 4 x 500 kV circuit breakers and 8 x 330 kV circuit breakers. The project is estimated to cost $80m and exceeds the required threshold of $33.4m. Based on this information provided by TransGrid, PB is of the view that the scope and cost is reflective of the necessary expenditure and the assets scoped appear to relate to providing prescribed services.

TransGrid has advised that the chosen route for the new 500 kV line may have to be altered due to environmental regulations. The chosen route is new and TransGrid may be required to utilise an existing 330 kV transmission easement. Should TransGrid be required to use the existing 330 kV easement a new 500/330 kV substation would be required at Richmond Vale. The need to utilise the route of the existing 330 kV line has been identified as the trigger, in combination with the project evaluation satisfying the regulatory test. In accordance with TransGrid's existing plans, should the proposed easement be used then an existing substation that supplies the Newcastle area will remain in service and this contingent project will not be required. In PB's view this meets the NER trigger requirements of a specific and verifiable trigger that will generate the stated cost.

The final requirement of the NER is to establish if the project is probable but uncertain in the next regulatory period. Notwithstanding the proposed 500 kV line from the Hunter Valley to the Central Coast is listed as a forecast capex project, PB considers there is some probability that this project will commence and activate the contingent project. Therefore in PB's view this meets the requirement that the trigger is probable but uncertain.

In PB's view, this project meets the requirements of a contingent project.

Table M-6: New 500/330 kV substation at Richmond Vale, summary of review

expenditure			trigger event		
no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
✓	✓	✓ ($80 m)	✓	✓	✓

Yass to Wagga 500 kV double circuit transmission line (POSE 6009G)

TransGrid has included the construction of a double circuit transmission line from Yass to Wagga. PB has not identified any existing project within the forecast capex allowance relating to this project. TransGrid has estimated the cost of construction of this transmission line at $329m. PB did not identify any provision in the existing forecast capex allowance relating to this project.

In reviewing the scope and cost, based on the information provided by TransGrid, PB is of the view that the scope and cost is reflective of the necessary expenditure and the assets scoped appear to relate to providing prescribed services.

The trigger has been stated as being either a generator south of the NSW border (i.e. Victoria) or increased Victorian to NSW transfer. PB has not been able to clearly establish the location or the size of the new generator or the increase in transfer that would trigger this project. Therefore in PB's view the trigger for this project does not meet the NER condition of being specific and verifiable. Subsequently, PB has not been able to establish if the trigger would generate the increased cost – this is particularly important given the materiality of the proposed contingent project costs.

As the trigger is a general comment, it is not possible to establish if the trigger will occur or may occur in the next regulatory period, therefore in PB's view this trigger may not be probable but uncertain in the next regulatory period.

In PB's view, this project trigger does not meet the NER requirements as it is not sufficiently specific with regards to quantity or location, nor is it appropriately descriptive beyond the bounds of the scenario analysis undertaken by TransGrid.

Table M-7: Yass to Wagga 500 kV transmission line, summary of review

expenditure			trigger event		
no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
✓	✓	✓ ($329 m)	×	×	×

Liddell – Tamworth 330 kV transmission line (POSE6003D)

The project included in the contingent list is the construction of a 330 kV transmission line from Liddell to Tamworth. PB has not identified any provision for this project within the forecast capex allowance. The proposed cost of this project is $163m which exceeds the threshold of $33.4m. In reviewing the scope and cost, based on the information provided by TransGrid, PB is of the view that the scope and cost is reflective of the necessary expenditure and the assets scoped appear to relate to providing prescribed services.

TransGrid has proposed the trigger as either a significant upgrade to the interconnector between Queensland and New South Wales (known as QNI) or significant generation (electrically) north of Armidale. PB has not been able to confirm the specific location of the new generation or the expected volume of either the new generation or the expected QNI transfer that would act as a discrete and objectively defined trigger, therefore PB is of the opinion that this project does not meet the requirements of a contingent project as set out in the NER as the trigger is not specific and verifiable. Consequently, we were not able to establish if the trigger would generate the increased cost – this is particularly important given the materiality of the proposed contingent project costs.

Additionally, as the trigger is not well defined, we were not able to establish a probable likelihood of the trigger occurring in the next regulatory period but being an uncertain trigger. Therefore in PB's view it does not meet the NER requirements.

In PB's view, this project trigger does not meet the NER requirements as it is not sufficiently specific with regards to quantity or location, nor is it appropriately descriptive beyond the bounds of the scenario analysis undertaken by TransGrid.

Table M-8: Liddell – Tamworth 330 kV transmission line, summary of review

expenditure			trigger event		
no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
✓	✓	✓ ($163 m)	×	×	×

Tamworth – Armidale 330 kV transmission line (POSE 6290D)

The project included in the contingent list is the construction of a 330 kV transmission line from Tamworth to Armidale. This contingent project appears to be an extension of the Liddell Tamworth 330 kV transmission line, which is also a contingent project. PB has not identified any provision for this project within the forecast capital allowance.

The proposed cost of this project is $130m and exceeds the threshold of $33.4m. In reviewing this scope and cost, based on the information provided by TransGrid, PB is of the view that the scope and cost is reflective of the expenditure and the assets scoped appear to relate to providing prescribed services.

TransGrid has established the trigger as either a significant upgrade to the interconnector between Queensland and New South Wales (known as the QNI) or significant generation (electrically) north of Armidale. PB has not been able to confirm the specific location of the new generation or the expected volume of either the new generation or the expected QNI transfer that would act as a discrete and objectively defined trigger, therefore PB is of the opinion that this project does not meet the requirements of a contingent project as set out in the NER. Consequently, we were not able to establish if the trigger would generate the increased cost – this is particularly important given the materiality of the proposed contingent project costs.

Additionally, as the trigger is not well defined, we were not able to establish a probable likelihood of the trigger occurring in the next regulatory period but being an uncertain trigger. Therefore in PB's view it does not meet the NER requirements.

In PB's view, this project trigger does not meet the NER requirements as it is not sufficiently specific with regards to quantity or location, nor is it appropriately descriptive beyond the bounds of the scenario analysis undertaken by TransGrid.

Table M-9: Tamworth – Armidale 330 kV transmission line, summary of review

expenditure			trigger event		
no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
✓	✓	✓ ($130 m)	×	×	×

QNI upgrade – series compensator (POSE 4342A)

This project is an alternative to augment QNI without the need for constructing new transmission lines. PB has not identified any projects in the proposed future capital expenditure that would constitute partial or full provision of this project - however we note the proposed Dumaresq-Lismore 330 kV line will have some influence on QNI transfer levels.

The expected cost of the solution varies between $60m to $120m dependent on the exact lines to be compensated. The NER requires that the project reasonably reflects the cost, but as the cost can vary by 100% and it is not possible to identify what the preferred solution will be, in PB's view this does not meet the reflective criteria of a contingent project.

In reviewing the potential scope, PB found that scope appears to relate to providing prescribed services only and has no association with any negotiated services.

The trigger has been listed by TransGrid as the successful completion of the Regulatory Test. In PB's view, this project trigger does not meet the NER requirements as it is not sufficiently specific with regards to the inputs to the Regulatory test application, nor is it appropriately descriptive beyond the bounds of the scenario analysis undertaken by TransGrid.

The identified trigger does not relate to a defined location and therefore does not meet the requirements of the NER insofar that the trigger generates the increased cost. The final requirement of the NER is that the project is probable but uncertain, but as the trigger is generic it is not possible to establish the probable nature of the work, therefore in PB's view this does not meet the terms of the NER.

Table M-10: QNI upgrade – series compensator, summary of review

expenditure			trigger event		
no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
✓	×	✓ ($60 - $120 m)	×	×	×

Interconnection development from Victoria (POSE 4338)

This project is the augmentation of the interconnector from Victoria to NSW to allow an increase in the imports and exports between the two states. PB has not identified any projects in the proposed future capital expenditure that would constitute partial or full provision for this expenditure.

The expected total cost of this project is $59.5m where $33m would be picked up by TransGrid and $26.5m being picked up by a Victorian transmission business. Based on the information provided by TransGrid, PB is of the view that the scope and cost is reflective of the necessary expenditure and the assets scoped appear to relate to providing prescribed services.

The NER requires the cost of the project to be material to the business and greater than 5% of the MAR in the first year of the regulatory period, but this project is marginally below this criteria, with a degree of ambiguity as to how the overall project costs are allocated across TNSP businesses.

The trigger has been listed by TransGrid as the successful completion of the Regulatory Test. In PB's view, this project trigger does not meet the NER requirements as it is not sufficiently specific with regards to the inputs to the Regulatory test application, nor is it appropriately descriptive beyond the bounds of the scenario analysis undertaken by TransGrid.

The identified trigger does not relate to a defined location and therefore does not meet the requirements of the NER insofar that the trigger generates the increased cost.

In assessing if the project was probable, but uncertain, PB was not able to establish a probable trigger. That is to say a trigger that would require the interconnector to be upgraded. Therefore, in PB's view this does not meet the terms of the NER.

Table M-11: Interconnection development from Victoria, summary of review

expenditure			trigger event		
no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
✓	✓	× ($33 m)	×	×	×

Bannaby – Yass reinforcement (POSE 4342A)

TransGrid has included the uprating of an existing 330 kV double circuit transmission line from Bannaby to Yass as a contingent project. PB has not identified any existing project within the forecast capex allowance relating to this project.

TransGrid has estimated the cost of this development as $45m and this exceeds the required threshold of $33.4m. Based on this scope and cost information provided by TransGrid, PB is of the view that the scope and cost is reflective of the necessary expenditure and the assets scoped appear to relate to providing prescribed services.

TransGrid has established the trigger as either a significant upgrade to the interconnector between Victoria and New South Wales or significant generation (electrically) south of Bannaby. PB has not been able to confirm the specific location of the new generation or the expected volume of either the new generation or the expected Victoria to NSW transfer that would act as a discrete and objectively defined trigger, therefore PB is of the opinion that this project does not meet the requirements of a contingent project as set out in the NER. Consequently, we were not able to establish if the trigger would generate the increased cost.

The identified trigger does not relate to a location and in PB's opinion does not meet the requirements of the NER insofar that the trigger generates the increased cost. Nor were we able to establish that the project is probable but uncertain as the trigger is not well defined.

Table M-12: Yass reinforcement, summary of review

expenditure			trigger event		
no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
✓	✓	✓ ($45 m)	×	×	×

CBD supply – 330 kV cable into the CBD

This project is associated with joint planning with the local distribution company EnergyAustralia. EnergyAustralia owns and controls 132 kV cables that supply the city of Sydney and as part of its businesses asset management plans these cables are identified as items that may be retired in the medium term future. The retirement of the cables means that the ability to supply the CBD in a secure and reliable manner in accordance with planning criteria will be exceeded unless augmentation takes place. This proposed contingent project is the installation of an additional 330 kV cable into the CBD area from Potts Hill to Surry Hills.

PB has not identified any allowance in the forecast capital expenditure relating to this project – however highlights the strategic co-ordination required between this project and the Holroyd-Chullora 330 kV cable project included in the allowance. As part of PB's review, TransGrid has stated that several of the examined options require a 330 kV cable to be installed and the scope of this contingent project is limited to the 330 kV cable. Therefore PB is satisfied that the most likely expenditure is reflected in the proposal.

The estimated cost of this project is $650m and this exceeds the threshold of $33.4m for a contingent project. In PB's view, based on the scope and cost provided by TransGrid the cost is high, but not unfeasible and the assets scoped appear to relate to providing prescribed services.

The trigger for this project is listed as the retirement of EnergyAustralia's 132 kV cables. However, in PB's view the trigger is not specific as to which cables are being retired and how this would impact on the need for this additional cable. For example, it is not clear if the trigger relates to one specific cable or a certain combination of cables that drives the need for the $650m investment. In PB's opinion the trigger is not sufficiently defined to meet the requirements of the NER, nor does the trigger as expressed clearly generate the entire cost of this project – this is particularly important given the materiality of the proposed contingent project costs

PB notes that the retirement of EnergyAustralia's cables is a risk, and as mentioned above, though not well defined as a specific trigger, the event may occur. Therefore, PB is of the opinion that this will meet the NER requirement of a probable but uncertain trigger within the next regulatory period.

Table M-13: CBD supply – cable into CBD, summary of review

expenditure			trigger event		
no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
✓	✓	✓($650 m)	×	×	✓

Visy Gadara Mill local area support (PES 6218)

The work required as part of this project is to increase the capacity of the network that supplies the Visy Gadara Mill. The project would be the development of a 132 kV transmission line from Wagga to either Tumut or Gadara substations.

PB has not identified any provision in the forecast capital expenditure that relates to this project. The project scope is estimated at $54m and appears to reflect the necessary cost of the project and the assets scoped appear to relate to providing prescribed services. The cost of the project exceeds the threshold of a contingent project which is $33.4m.

The trigger has been identified as the expansion of the Gadara Mill or an increase in local demand. TransGrid has been advised that the expansion is expected to double the energy requirements at that site. PB's is of the view that the expansion of the Gadara Mill and the expected doubling of the energy requirements (for example the existing load is 100 MW and the application will increase the load to 200 MW) is a sufficiently specific trigger to meet the NER requirements for a contingent project in that it can be objectively verified based on the existing load levels.

However, the specified increase in local demand also appears to be a function of local demand growth and therefore is not a specific trigger outside the bounds of the demand scenarios used by TransGrid to determine its forecast capex allowance. Therefore PB recommends that the Gadara Mill expansion and the doubling of the energy requirements for this point load is the only trigger event that meets the NER requirements.

The scope of works appears to be the reinforcement of the local area around the Gadara Mill area rather than transmission equipment supplying the site and it appears the physical connection to the Gadara Mill does not require augmentation. Therefore, PB's interpretation is that an increase in local demand may trigger the augmentation rather than specific growth at the Gadara Mill. Given the requirements of the NER requires that the trigger must increase the cost rather than a condition or event that affects the transmission network as a whole, In PB's view this does not pass the NER requirements.

Should the trigger be described as expansion of the Gadara Mill only, then this would meet the terms of a probable, but uncertain trigger event in the next regulatory period.

Table M-14: Visy Gadara Mill local area support, summary of review

expenditure			trigger event		
no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
✓	✓	✓($54 m)	✓	×	✓

Williamsdale – Cooma 3rd circuit (PES 6261)

This project is the construction of a third circuit from Williamsdale to Cooma. PB has not identified any allowance in the forecast capital expenditure relating to this project. The estimate for this project is $40m and this exceeds the required threshold of $33.4m. In reviewing the scope and cost, based on the information provided by TransGrid, PB is of the view that the scope and cost is reflective of the necessary expenditure and the assets scoped appear to relate to providing prescribed services.

The trigger is identified as a confirmed generator in the Cooma or Bega area, however the connection point and critical capacity of the generator is not specified. On this basis, in PB's view this does not meet the NER requirements of a specific and objectively defined trigger. Consequently, as the trigger event is not specific, it is not possible to establish if the trigger will generate the increased cost.

As the generator is confirmed in a specific area, it is PB's view that the trigger is probable but it is uncertain when the generator will generate, therefore this project meets the final requirement of the NER is so far as it is probable, but uncertain.

Table M-15: Williamsdale – Cooma 3rd circuit, summary of review

expenditure			trigger event		
no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
✓	✓	✓($40 m)	×	×	✓

Orange 330 / 132 kV substation (PES 6262)

The project is the construction of a new 330 / 132 kV substation in the Orange area. PB has not identified any allowance in the forecast capital expenditure relating to this project.

The project has been identified as required due to the confirmed expansion of the Cadia gold mine. Additional to this, TransGrid has stated that an industrial load in the same area would also be a trigger. The cost of $63m includes the procurement of 2 x 330 / 132 kV; 375 MVA transformers plus associated switchgear and busbars. This project cost exceeds the required threshold of $33.4m to be considered a contingent project.

The low voltage side of the transformers (132 kV) would be constructed with switchgear bays that would allow six additional circuits that feed the Panorama and Mt Icely area. This augmentation is on the shared network and the assets scoped appear to relate to providing prescribed services, that is, PB has not identify any assets that could relate to a negotiated service.

The costs associated with this project allow for a substation that would support the local area in the future, however the NER states that the project must be reflective of the scope. As the scope has been identified as the expansion of the Cadia gold mine, in PB's view the current scope exceeds this requirement and does not meet the NER requirement.

The trigger has been identified as the confirmed expansion of the Cadia gold mine or an industrial load in the same area, where the increase in additional load cannot be supported by the current transmission assets. In PB's view, the confirmed expansion of the gold mine meets the terms of the NER as it is an event that may occur, but an unconfirmed and non-specific increase in industrial load in a generic location does not.

In PB's view, the proposed trigger as currently defined, does not meet the terms of the NER as an unconfirmed increase in industrial load does not meet the criteria.

As the expansion of the Cadia mine is confirmed, but not fixed, this meets the NER requirement for probable but uncertain trigger that may occur in the next regulatory period.

Table M-16: Orange 330 kV substation, summary of review

expenditure			trigger event		
no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
✓	×	✓($63 m)	×	×	✓

Williamsdale 330 / 132 kV substation (PES 5564)

A new substation at Williamsdale would supply the ACT. The ACT government is in the process of examining the regulatory and planning approvals required in order to increase the security requirements for electricity supply to the ACT. The assets scoped appear to relate to providing prescribed services.

This contingent project is stage 2 of a multistage project estimated at $35m. Stage 1 is the establishment of Williamsdale 330 / 132 kV substation. This contingent project is the establishment of a switching station at Wallaroo and the installation of a second transformer at Williamsdale.

PB has identified a project (project ID 9276 a) included in the forecast capital expenditure relating to the construction of Williamsdale 330 / 132 kV substation. PB notes that stage 2 includes the installation of a second transformer at Williamsdale. As the substation at Williamsdale is new, PB has assumed that civil works will be undertaken during stage 1. For a project to be classified as a contingent project, no allowance (part or whole) is allowed in the forecast capex allowance. However it appears that preliminary works will be undertaken in stage 1 to allow the installation of the second transformer, which is part of this proposed contingent project.

PB recommends restricting stage 2 to the installation of a switching station at Walleroo and that the proposed second transformer at Williamsdale 330 / 132 kV is included in the stage 1 works. As the current contingent project includes the transformer at Williamsdale, in PB's view this does not meet the terms of the NER.

The total project cost has been established at $35m, where $10.1m is the cost of the additional transformer at Williamsdale. As the project stands, this NER threshold is met, but should the transformer be transferred to stage 1, then this project will no longer meet the threshold requirement of exceeding $33.4m.

The trigger is identified as a change in the regulatory and planning approvals required for the ACT and its surrounding area. In PB's view, this trigger meets the requirements of a discrete and verifiable trigger outside the control of TransGrid. The trigger will also generate the necessary costs as identified by TransGrid.

It is not clear when the regulatory planning approvals will be changed requiring TransGrid to increase the security requirements. On this basis the project trigger is suitably probable, but uncertain in the next regulatory period.

Table M-17: 330 kV substation at Williamsdale, summary of review

expenditure			trigger event		
no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
×	×	✓($35 m)	✓	✓	✓

Voltage compensation (POSE 6098)

This project is the installation of voltage compensation equipment within the TransGrid network. The equipment is defined as either a 'statcom[300]' or a static VAr compensator (SVC)[301]. The request is for compensation dependent on an unconfirmed load. As the load is unconfirmed the site is not firm. The assets scoped appear to relate to providing prescribed services.

The NER requires that no allowance has been provided for in the forecast capital expenditure however PB has identified the current forecast capital expenditure has an allowance for SVC upgrades and refurbishment at Tamworth / Armidale (POSE 6098). In PB's view, there is some degree of allowance for voltage compensation equipment in the forecast capital expenditure, and therefore the NER requirement is not clearly met.

The estimated cost of the project is $40m and is reflective of the cost of installing a 330 kV SVC with a range of +280 MVAr to -100 MVAr and all the associated switchgear at an established substation. In reviewing the scope and cost, based on the information provided by TransGrid, PB is of the view that the scope and cost is reflective of the necessary expenditure.

The trigger has been identified as an increase in load, but no specific quantity or site has been chosen. In PB's view, this does not meet the NER requirements, and a more prescriptive trigger is required that is beyond the bounds of the scenario analysis undertaken by TransGrid.

As the trigger is not clearly defined, it is not possible to establish if the trigger will generate the increase in cost. In PB's view, the project does not meet the requirements of a contingent project as defined in the NER.

The final requirement of the NER is that the trigger is probable, but uncertain. PB is in agreement that it is probable that additional reactive control equipment will be required somewhere on the network and that it is uncertain when it will be required. This is supported with the inclusion of SVC upgrades and voltage compensation in the probabilistic scenarios. Therefore, this project does meet this term of the NER.

300 A statcom is a power electronics voltage-source converter based device that can act as either a source or sink of reactive AC power to an electricity network and if connected to a source of power can also provide active AC power.

301 A Static VAR Compensator (or SVC) is an electrical device for providing fast-acting reactive power compensation on high-voltage electricity transmission networks. SVCs are part of the Flexible AC transmission system (FACTS) family of devices.

SVCs are used both on bulk power transmission circuits to regulate voltage and contribute to steady-state stability; they also are useful when placed near high and rapidly varying loads, such as arc furnaces, where they can smooth flicker voltage.

Table M-18: Voltage compensation, summary of review

expenditure			trigger event		
no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
×	✓	✓($40 m)	×	×	✓

Reactive support at six sites

This project is the installation of reactive support at either of the six separate switchyards, listed below.

- Bayswater
- Liddell
- Eraring
- Vales Point
- Munmorah
- Mt Piper
- Wallerawang

The additional reactive equipment would be required should the current arrangements for reactive power procurement become uneconomic. TransGrid currently acquires reactive support from generators via network support arrangements.

PB has not identified any allowance in the current forecast capital expenditure for reactive support at the six identified sites. The project is expected to cost $36m but PB has not been able to establish the nature of the specific scope of works, and subsequently we are not able to determine if any element of the scope relates to negotiated services, so we were not able to determine that the cost is reflective of the contingent project triggers need. PB highlights that the contingent project cost is the aggregate cost of the individual capacitor banks which could be assessed from an efficiency and prudency perspective on a separate basis. The grouping of several smaller discrete projects in this manner is not directly consistent with the materiality requirements of a contingent project.

PB has not been able to establish the demand or generation scenarios beyond the 36 considered by TransGrid that would trigger the need for the installation of additional reactive support equipment.

Table M-19: Reactive support at Bayswater, summary of review

expenditure			trigger event		
no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
✓	×	✓($36 m)	×	×	×

System protection scheme

TransGrid has proposed a system protection scheme to increase power flow from the Snowy region into NSW. The proposal is for either a network support contract or for inter-tripping services.

PB has not identified any allowance in the current forecast capital expenditure for this purpose. PB has not been able to establish the exact value of this project, nor are we able to establish if any element of the scope of works pertains to negotiated services, therefore we are not able to determine if the project reflects the expenditure required

TransGrid has identified that a majority of the cost will be in contracted inter-tripping services, but the NER only allows the cost of capital to be included as a contingent project and not contractual allowance. Therefore in PB's view, this project does not exceed the required limit of a contingent project.

The trigger has been listed as satisfying the regulatory test. In PB's view this does not meet the requirements of the NER in being a specific trigger. Additionally, the trigger does not specifically generate increased cost as no specific event has been listed that will increase the costs.

We were not able to establish any probability that this scheme would be required in the next regulatory period.

Table M-20: System protection scheme, summary of review

expenditure			trigger event		
no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
✓	×	×	×	×	×

M.3 Subsequent update on 26 August 2008 (superceded)

TransGrid provided additional information on 26 August 2008 based on PB's initial assessment of contingent projects proposed. The subsequent update affected 14 projects, and these are listed in Table M-21. This section will review the additional information provided by TransGrid in relation to these 14 projects.

Table M-21: Projects with subsequent information supplied on 26 August 2008

Project	Capital cost ($m)
Darlington – Balranald system upgrade 275 kV	$51
Development of a second 500 kV link	$330
Yass to Wagga 500 kV double circuit transmission line	$329
Liddell – Tamworth 330 kV	$163
Tamworth – Armidale 330 kV line	$130
QNI upgrade – series compensator	$120
Interconnection development from Victoria	$33
Bannaby – Yass reinforcement	$45

Project	Capital cost ($m)
CBD supply – cable into the CBD	$650
Visy Gadara Mill local area support	$54
Williamsdale – Cooma 3rd circuit	$40
Orange 330 kV substation	$63
330 kV substation at Williamsdale	$35
Reactive support at Bayswater	$36

Darlington – Balranald – Buronga system upgrade 275 kV (PSR 178)

The subsequent information submitted re-evaluates the trigger as being one of three possibilities:

- direction from the NSW Government to undertake the upgrade for the benefit of the environment
- demonstration of a prudent and efficient option via Chapter 5 of the NER
- under NER clause 5.6.4 and the regulatory test

Trigger 1 – Direction by the NSW Government to undertake the upgrade for the benefit of the environment

TransGrid has clarified that this trigger pertains to improving TransGrid's greenhouse gas emissions. PB's understanding of this trigger is that the NSW Government would direct TransGrid to upgrade this transmission line to improve its greenhouse gas emissions and in PB's view this is a specific and verifiable trigger.

As the trigger is the NSW government instructing TransGrid to upgrade the line, the trigger would generate the cost and therefore in PB's view this meets the requirement of generating the costs.

PB considers it is possibly that the NSW Government would direct TransGrid to upgrade a transmission in this manner, however this is uncertain consistent with the requirements of a contingent project. Therefore PB is of the opinion that this trigger component meets the NER requirements.

Trigger 2 – Demonstration of a prudent and efficient option via chapter 5 of the NER.

Chapter 5 of the NER relates to network connections. Demonstration of prudency in projects is discussed in Chapter 5.6.5A and is more commonly known as the Regulatory Test. From the original text, PB is of the view that the Regulatory Test is not a suitable trigger is not sufficiently specific or descriptive beyond the bounds of the scenario analysis undertaken by TransGrid. Therefore PB is of the view that demonstration of a prudent and efficient option via Chapter 5 of the NER does not meet the NER requirements for a contingent project in its own right.

When considering the generated cost, it is not possible to establish what costs would be generated via the regulatory test and therefore this option does not meet the NER requirements.

As the trigger is the generic description of satisfying the regulatory test, it is not possible to establish if the trigger will occur or may occur in the next regulatory period, therefore in PB's view this trigger may not be probable but uncertain in the next regulatory period.

Trigger 3 – Under NER clause 5.6.4 and the regulatory test

The final trigger component proposed by TransGrid is direction by the AEMC under the Last Resort Planning Power provisions to undertake the regulatory test. In PB's view, satisfactory application of the regulatory test in its own right is not a sufficiently specific or descriptive project trigger. Therefore, in PB's view this does not meet the terms of a contingent project under the NER requirements.

Table M-22: Darlington – Balranald – Buronga system upgrade, summary of review

Summary findings	expenditure			trigger event		
	no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
Original	✓	✓	✓ ($51 m)	×	×	×
Trigger 1	✓	✓	✓ ($51 m)	✓	✓	✓
Trigger 2	✓	✓	✓ ($51 m)	×	×	×
Trigger 3	✓	✓	✓ ($51 m)	×	×	×

Development of a second 500 kV link (PSR 131, POSE 5568B; POSE 6002)

PB's understanding is that this contingent project has been modified to be the development of a 500 kV transmission line from Hunter Valley – Central Coast 500 kV transmission line (Project ID 5567). The original proposal there was an allowance for the Hunter Valley – Central Coast in the forecast capex and this has now been removed. That is to say that there is no provision for this transmission line in the forecast capex and in PB's view this meets this NER requirement.

The trigger for the construction of the second line has been identified as a significant power station, interconnection or load development. In PB's view, this does not meet the NER requirements as the trigger is not sufficiently specific or descriptive beyond the bounds of the scenario analysis undertaken by TransGrid. As the load or generation has not been presented by TransGrid in a discrete manner, it is not possible to establish if the construction of either additional load or generation will increase the costs faced by TransGrid.

PB reviewed this project against the final NER trigger requirement that the project is probable, but uncertain and accept that it is possible for a generation scenario to be realised that may result in this line being required.

Table M-23: Development of a second 500 kV link, summary of review

Summary findings	expenditure			trigger event		
	no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
Original	×	✓	✓ ($331 m)	×	×	✓
Revised	✓	✓	✓ ($331 m)	×	×	✓

Yass to Wagga 500 kV double circuit transmission line (POSE 6009G)

TransGrid has supplied two possible options as that will act as triggers for the implementation of the Yass to Wagga 500 kV transmission line. These are:

- 200 MW increase in generation or import on the interconnector
- Under NER clause 5.6.4 and the regulatory test

Trigger 1 – 200 MW increase in generation or import on the interconnector

TransGrid has stated that an increase in generation in three areas may trigger investment and these three areas are:

- Wagga
- Jindera
- Buronga / Broken Hill

TransGrid has also included the comment that the increase in generation would also have to cause a network limitation on the transmission system in that area.

In the forecast planning scenarios there is an allowance for possible generation developments (56 separate projects are identified) and the first requirement of a contingent project is that there is no provision. PB is of the view that the additional 200 MW of generation would need to be over and above the generation already identified in the forecast capex program scenarios. On this proviso, PB is of the opinion that there is no provision already in the forecast capex program and the trigger is specific and verifiable.

As the generation is sited in a defined area, PB is of the view that the selected trigger is specific enough to demonstrate that the event will generate the cost. PB is also of the view that the probability of additional generation over and above the generation in the scenarios is unlikely, but possible. In PB's view an increase in generation of 200 MW over and above the generation already identified in the forecast capex program meets the terms of the NER for a contingent project.

TransGrid has also identified that increases to the Victorian export capability on the Snowy / NSW interconnector by 200 MW above the present capability is a suitable trigger. PB is of the opinion that this is a specific and verifiable trigger insofar that the trigger is an increase in export capacity from Victoria to NSW above the levels used in the scenario analysis. PB is also of the opinion that increasing the capacity of the current interconnector would generate the costs, and that the increase is probable but uncertain during the next regulatory period.

In PB's view, an increase of 200 MW on the interconnector or an increase of 200 MW of generation over and above the generation in the forecast scenarios meets the NER requirements of a contingent project.

Trigger 2 – Under NER clause 5.6.4 and the regulatory test

The final trigger proposed by TransGrid is direction by the AEMC under the Last Resort Planning Power provisions to undertake the regulatory test. As discussed in the prior section, it is PB's view that the regulatory test is not a sufficiently specific or descriptive trigger in its own right. Therefore, in PB's view this does not meet the requirements for a contingent project under the NER requirements.

PB notes that it is not possible to identify if the costs would be generated as clause 6.5.4 allows the AEMC to direct a participant to undertake a regulatory test, and it is not clear that the regulatory test will generate the cost.

Table M-24: Yass to Wagga 500 kV transmission line, summary of review

Summary findings	expenditure			trigger event		
	no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
Original	✓	✓	✓ ($329 m)	×	×	×
Trigger 1	✓	✓	✓ ($329 m)	✓	✓	✓
Trigger 2	✓	✓	✓ ($329 m)	×	×	×

Liddell – Tamworth 330 kV transmission line (POSE6003D)

TransGrid has proposed three alternative events that may act as a trigger. These are:

- a 200 MW increase in generation or export on the interconnector
- market benefits test results that indicate development is needed
- NER clause 5.6.4 and the regulatory test

Trigger 1 – 200 MW increase in generation or export on the interconnector

TransGrid has stated that an increase in generation in two areas may trigger investment and these two areas are:

- Tamworth
- Armidale

TransGrid has also included the comment that the increase in generation would also have to cause a network limitation on the transmission system between Liddell and Tamworth.

In the forecast planning scenarios there is an allowance for possible generation developments (56 separate projects are identified) and the first requirement of a contingent project is that there is no provision in the forecast capex allowance. PB is of the view that the additional 200 MW of generation would need to be over and above the generation already identified in the forecast capex program scenarios. On this proviso, PB is of the opinion that there is no provision already in the forecast capex program and the trigger is specific and verifiable.

As the generation is sited in a defined area, PB is of the view that the selected trigger is specific enough to demonstrate that the event will generate the cost. PB is also of the view that the probability of additional generation over and above the generation in the scenarios is unlikely, but possible. In PB's view an increase in generation of 200 MW over and above the generation already identified in the forecast capex program meets the terms of the NER for a contingent project.

TransGrid has also identified that increases to the Queensland export capability on the Queensland / NSW interconnector by 200 MW above the present capability is a suitable trigger. PB is of the opinion that this is a specific and verifiable trigger insofar that the trigger is an increase in export capacity from Queensland to NSW above the levels used in the scenario analysis. PB is also of the opinion that increasing the capacity of the current interconnector would generate the costs, and that the increase is probable but uncertain during the next regulatory period.

In PB's view, an increase of 200 MW on the interconnector or an increase of 200 MW of generation over and above the generation in the forecast scenarios meets the NER requirements of a contingent project.

Trigger 2 – market benefits test support indicate development is needed

In PB's view this trigger in its own right is not sufficiently specific or descriptive beyond the bounds of the scenario analysis undertaken by TransGrid. Therefore PB is of the view that demonstration of market benefits does not meet the NER requirements for a contingent project.

When considering the generated cost, it is not possible to establish what costs would be generated via the regulatory test and therefore this option does not meet the NER requirements.

As the trigger is the regulatory test, it is not possible to establish if the trigger will occur or may occur in the next regulatory period, therefore in PB's view this trigger may not be probable but uncertain in the next regulatory period.

Trigger 3 – Under NER clause 5.6.4 and the regulatory test

The final trigger proposed by TransGrid for this investment is direction by the AEMC under the Last Resort Planning Power provisions to undertake the regulatory test. As discussed in the prior section, it is PB's view that the satisfactory application of the regulatory test is not a sufficiently specific or descriptive trigger in its own right. Therefore, in PB's view this does not meet the terms of a contingent project under the NER requirements.

Table M-25: Liddell – Tamworth 330 kV transmission line, summary of review

Summary findings	expenditure			trigger event		
	no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
Original	✓	✓	✓ ($163 m)	×	×	×
Trigger 1	✓	✓	✓ ($163 m)	✓	✓	✓
Trigger 2	✓	✓	✓ ($163 m)	×	×	×
Trigger 3	✓	✓	✓ ($163 m)	×	×	×

Tamworth – Armidale 330 kV transmission line (POSE 6290D)

TransGrid has proposed three alternative events that may act as a trigger for this investment need and these are:

- a 200 MW increase in generation or export on the interconnector
- market benefits test support indicate development is needed
- NER clause 5.6.4 and the regulatory test

Trigger 1 – 200 MW increase in generation or export on the interconnector

TransGrid has stated that an increase in generation in two areas may trigger the investment, and these two areas are:

- Tamworth
- Armidale

TransGrid has also included the comment that the increase in generation would also have to cause a network limitation on the transmission system between Liddell and Tamworth.

In the forecast planning scenarios there is an allowance for possible generation developments (56 separate projects are identified) and the first requirement of a contingent project is that there is no provision in the forecast capex allowance. PB is of the view that the additional 200 MW of generation would need to be over and above the generation already identified in the forecast capex program scenarios. On this proviso, PB is of the opinion that there is no provision already in the forecast capex program and the trigger is specific and verifiable.

As the generation is sited in a defined area, PB is of the view that the selected trigger is specific enough to demonstrate that the event will generate the cost. PB is also of the view that the probability of additional generation over and above the generation in the scenarios is unlikely, but possible. In PB's view an increase in generation of 200 MW over and above the generation already identified in the forecast capex program meets the terms of the NER for a contingent project.

TransGrid has also identified that increases to the Queensland export capability on the Queensland / NSW interconnector by 200 MW above the present capability is a suitable trigger. PB is of the opinion that this is a specific and verifiable trigger insofar that the trigger is an increase in export capacity from Queensland to NSW above the levels used in the scenario analysis. PB is also of the opinion that increasing the capacity of the current interconnector would generate the costs, and that the increase is probable but uncertain during the next regulatory period.

In PB's view, an increase of 200 MW on the interconnector or an increase of 200 MW of generation over and above the generation in the forecast scenarios meets the NER requirements of a contingent project.

Trigger 2 – market benefits test support indicate development is needed

In PB's view this trigger in its own right is not sufficiently specific or descriptive beyond the bounds of the scenario analysis undertaken by TransGrid. Therefore PB is of the view that demonstration of market benefits does not meet the NER requirements for a contingent project.

When considering the generated cost, it is not possible to establish what costs would be generated via the regulatory test and therefore this option does not meet the NER requirements.

As the trigger is the regulatory test, it is not possible to establish if the trigger will occur or may occur in the next regulatory period, therefore in PB's view this trigger may not be probable but uncertain in the next regulatory period.

Trigger 3 – Under NER clause 5.6.4 and the regulatory test

The final trigger proposed by TransGrid for this investment is direction by the AEMC under the Last Resort Planning Power provisions to undertake the regulatory test. As discussed in the prior section, it is PB's view that the satisfactory application of the regulatory test is not a sufficiently specific or descriptive trigger in its own right. Therefore, in PB's view this does not meet the terms of a contingent project under the NER requirements.

Table M-26: Tamworth – Armidale 330 kV transmission line, summary of review

Summary findings	expenditure			trigger event		
	no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
Original	✓	✓	✓ ($130 m)	×	×	×
Trigger 1	✓	✓	✓ ($130 m)	✓	✓	✓
Trigger 2	✓	✓	✓ ($130 m)	×	×	×
Trigger 3	✓	✓	✓ ($130 m)	×	×	×

QNI upgrade – series compensator (POSE 4342A)

TransGrid has proposed two alternative events that may act as a trigger. These are:

- market benefits test support indicate development is needed
- Under NER clause 5.6.4 and the regulatory test

The expected cost of the solution varies between $60m to $120m dependent on the exact lines to be compensated. The NER requires that the project reasonably reflects the cost, but as the cost can vary by 100% and it is not possible to identify what the actual solution will be, in PB's view this does not meet the reflective criteria of a contingent project.

In reviewing the potential scope, PB found that scope appears to relate to providing prescribed services only and has no association with any negotiated services.

Trigger 1 – market benefits test support indicate development is needed

In PB's view this trigger is not sufficiently specific or descriptive beyond the bounds of the scenario analysis undertaken by TransGrid. Therefore PB is of the view that demonstration of market benefits does not meet the NER requirements for a contingent project.

When considering the generated cost, it is not possible to establish what costs would be generated via the regulatory test and therefore this option does not meet the NER requirements.

As the trigger is the regulatory test, it is not possible to establish if the trigger will occur or may occur in the next regulatory period, therefore in PB's view this trigger may not be probable but uncertain in the next regulatory period.

Trigger 2 – Under NER clause 5.6.4 and the regulatory test

The final trigger proposed by TransGrid is direction by the AEMC under the Last Resort Planning Power provisions to undertake the regulatory test. As discussed in the prior section, it is PB's view that the regulatory test is not a sufficiently specific or descriptive trigger. Therefore, in PB's view this does not meet the terms of a contingent project under the NER requirements.

Table M-27: QNI upgrade – series compensator, summary of review

Summary findings	expenditure			trigger event		
	no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
Original	✓	×	✓ ($60 - $120 m)	×	×	×
Trigger 1	✓	×	✓ ($60 - $120 m)	×	×	×
Trigger 2	✓	×	✓ ($60 - $120 m)	×	×	×

Interconnection development from Victoria (POSE 4338)

TransGrid has proposed two alternative events that may act as a trigger. These are:

- market benefits test support indicate development is needed
- Under NER clause 5.6.4 and the regulatory test

TransGrid originally proposed that this project would cost $33m/. This is below the limit set by the NER. TransGrid has stated that the cost has not been defined at this stage, therefore the cost is not known. As the NER requires that the cost exceeds the required limit and that the cost is reflective, in PB's view it is not possible to ascertain that these two requirements have been met.

Trigger 1 – market benefits test support indicate development is needed

In PB's view this trigger is not sufficiently specific or descriptive beyond the bounds of the scenario analysis undertaken by TransGrid. Therefore PB is of the view that demonstration of market benefits does not meet the NER requirements for a contingent project.

When considering the generated cost, it is not possible to establish what costs would be generated via the regulatory test and therefore this option does not meet the NER requirements.

As the trigger is the regulatory test, it is not possible to establish if the trigger will occur or may occur in the next regulatory period, therefore in PB's view this trigger may not be probable but uncertain in the next regulatory period.

Trigger 2 – Under NER clause 5.6.4 and the regulatory test

The final trigger proposed by TransGrid is direction by the AEMC under the Last Resort Planning Power provisions to undertake the regulatory test. As discussed in the prior section, it is PB's view that the regulatory test is not a sufficiently specific or descriptive. Therefore, in PB's view this does not meet the terms of a contingent project under the NER requirements.

Table M-28: Interconnection development from Victoria, summary of review

Summary findings	expenditure			trigger event		
	no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
Original	✓	✓	× ($33 m)	×	×	×
Trigger 1	✓	×	× ($33 m)	×	×	×
Trigger 2	✓	×	× ($33 m)	×	×	×

Bannaby – Yass reinforcement (POSE 4342A)

TransGrid has supplied two possible options as that will act as triggers for the implementation of the Yass to Wagga 500 kV transmission line. These are:

- 200 MW increase in generation or import on the interconnector
- Under NER clause 5.6.4 and the regulatory test

Trigger 1 – 200 MW increase in generation or import on the interconnector

TransGrid has stated that an increase on generation in five areas may trigger this investment and these five areas are:

- Yass
- Canberra
- Wagga
- Jindera
- Buronga / Broken Hill

TransGrid has also included the comment that the increase in generation would also have to cause a network limitation on the transmission system in that area.

In the forecast planning scenarios there is an allowance for possible generation developments (56 separate projects are identified) and the first requirement of a contingent project is that there is no provision in the forecast capex allowance. PB is of the view that the additional 200 MW of generation would need to be over and above the generation already identified in the forecast capex program scenarios. On this proviso, PB is of the opinion that there is no provision already in the forecast capex program and the trigger is specific and verifiable.

As the generation is sited in a defined area, PB is of the view that the selected trigger is specific enough to demonstrate that the event will generate the cost. PB is also of the view that the probability of additional generation over and above the generation in the scenarios is unlikely, but possible. In PB's view an increase in generation of 200 MW over and above the generation already identified in the forecast capex program meets the terms of the NER for a contingent project.

TransGrid has also identified that increase to the Victorian export capability on the Snowy / NSW interconnector by 200 MW above the present capability is a suitable trigger. PB is of the opinion that this is a specific and verifiable trigger insofar that the trigger is an increase in export capacity from Victoria to NSW above the levels used in the scenario analysis. PB is also of the opinion that increasing the capacity of the current interconnector would generate the costs and PB is of the opinion that the increase in probable but uncertain in the next regulatory period.

In PB's view, an increase of 200 MW on the interconnector or an increase of 200 MW of generation over and above the generation in the forecast scenarios meets the NER requirements of a contingent project.

Trigger 2 – Under NER clause 5.6.4 and the regulatory test

The final trigger proposed by TransGrid is direction by the AEMC under the Last Resort Planning Power provisions to undertake the regulatory test. As discussed in the prior section, it is PB's view that the regulatory test is not a sufficiently specific or descriptive. Therefore, in PB's view this does not meet the terms of a contingent project under the NER requirements.

PB note that it is not possible to identify if the costs would be generated as clause 6.5.4 allows the AEMC to direct a participant to undertake a regulatory test, and it is not clear that the regulatory test will generate the cost.

PB reviewed the trigger against the final probability and uncertainty requirement, and in PB view it was not possible to establish if this trigger is probable in the next regulatory period. It is also noted that under Chapter 5.6.4 the AEMC is obligated to consider investments in a timely and efficient manner. Therefore, PB is of the view that this trigger does not meet the NER requirements for a contingent project.

Table M-29: Yass reinforcement, summary of review

Summary findings	expenditure			trigger event		
	no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
Original	✓	✓	✓ ($45 m)	×	×	×
Trigger 1	✓	✓	✓ ($45 m)	✓	✓	✓
Trigger 2	✓	✓	✓ ($45 m)	×	×	×

CBD supply – 330 kV cable into the CBD

TransGrid has provided additional information on the trigger that would drive the need to install a 330 kV cable into the Sydney CBD. The supplemental data states that the retirement of any one of three 132 kV circuits would trigger the investment. The three cables are listed in Table M-30.

Table M-30: Cables identified as the trigger for the CBD cable contingent project

Cable number	cable name
919	Willoughby to Dalley Street
929	Lane Cove to Willoughby
928/3	Lane Cove to Dalley Street

TransGrid has identified that this trigger is active when three conditions are met.

1. Retirement of any one of the three cables in Table M-30

2. TransGrid or EnergyAustralia not being able to meet the terms of Schedule 5.1 of the NER and

3. TransGrid and EnergyAustralia jointly demonstrate that the option meets the investment requirements of chapter 5 of the NER.

In reviewing the scope and cost, based on the limited information provided by TransGrid, PB is of the view that the scope of installing a 330 kV cable on retirement of a single 132 kV cable appears in excess of the NER requirement and does not represent a reflective expenditure level. The NER requires that the scope for contingent projects should reasonably reflect an efficient cost in achieving the objectives of a prudent operator. In PB's view, and without the aid of detailed technical assessment, in the first instance a reflective cost would be the replacement of the under-performing single 132 kV cable with a similar unit by EnergyAustralia when compared with the prospect of a $650m capital investment. As presented, the installation of a 330 kV cable has inherent additional capacity compared to the cables proposed retirement. PB also considers a contingent project of such significant cost should be accompanied by a considerable level of technical detail pertaining to the underlying need, consistent with the projects materiality implications. There may be significant opportunity to implement the ideal solution in a staged manner using several projects of limited scope.

PB reviewed the revision of the trigger of the retirement of single cable against the NER and PB agrees that it is a specific and verifiable trigger, however, the replacement of a single 132 kV cable with a 330 kV cable appears to generate higher costs than the NER allows. That is to say that although the increased costs relate to a specific location, the installation of the 330 kV cable is a transmission network benefit rather than resolution of an issue. In PB's view this project generates higher costs than the trigger causes and therefore does not meet the terms of the NER.

PB subsequently considered the second and third conditions that would apply to the trigger. The two conditions are discussed below.

TransGrid or EnergyAustralia not being able to meet Schedule 5.1 of the NER

Schedule 5.1 of the NER stipulates the performance requirements for Registered Participants and more specifically transmission network service providers (TNSPs) and distribution network service providers (DNSPs). The schedule covers all technical services provided for by TNSPs and DNSPs. PB is of the view that not being able to meet Schedule 5.1 of the NER is not a suitable trigger as it is not sufficiently specific or descriptive. Therefore PB is of the view that not being able to meet Schedule 5.1 of the NER does not meet the NER requirements of a contingent project.

Demonstration that the option meet the investment requirement of chapter 5 of the NER

Chapter 5 of the NER relates to network connections. Demonstration of prudency in projects is discussed in Chapter 5.6.5A and is more commonly known as the Regulatory Test. From the original text, PB is of the view that the Regulatory Test is not a suitable trigger and is not sufficiently specific or descriptive beyond the bounds of the scenario analysis undertaken by TransGrid. Therefore PB is of the view that demonstration of a prudent and efficient option via Chapter 5 of the NER does not meet the NER requirements for a contingent project.

When considering the generated cost, it is not possible to establish what costs would be generated via the regulatory test and therefore this option does not meet the NER requirements.

PB is still of the view that the retirement of a 132 kV cable is a probable event in the next regulatory period and that it is uncertain when the retirement will occur. Therefore this meets the terms of the NER for a contingent project.

Table M-31: CBD supply – cable into CBD, summary of review

Summary findings	expenditure			trigger event		
	no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
Original	✓	✓	✓($650 m)	×	×	✓
Revised	✓	×	✓($650 m)	×	×	✓

Visy Gadara Mill local area support (PES 6218)

TransGrid has presented further information on the trigger for this contingent project. The trigger has been clarified as a four stage conditional event.

1. emergence of one or more spot loads in the areas of Yass – Tumut – Gadara or Wagga
2. the spot load not being part of the forecast load growth in the revenue determination
3. the spot loads resulting in TransGrid being unable to meet the requirements of Schedule 5.1 of the NER
4. TransGrid demonstrating that the option meets the investment requirement of chapter 5 of the NER.

Each of these conditions are reviewed below

Emergence of spot loads in the areas of Yass – Tumut – Gadara or Wagga

TransGrid state that a spot load may emerge in the areas listed, PB considered the NER requirements and note that there is no minimum specified volume to the spot load; therefore PB is not able to establish if the scope and cost proposed is reflective of what a prudent operator would require. Therefore in PB's view an unspecified spot load does not meet the requirements of the NER for a contingent project, it would need to be quantified and associated to the networks existing transfer capacity.

Subsequent analysis against the trigger requirements, PB was not able to establish what the trigger was as the volume is not specified and additionally, we were not able to establish if the trigger would generate the cost. PB is of the opinion that as the trigger is unspecified this does not meet the NER requirements.

The spot load was not part of the forecast load growth in the revenue determination

PB considered this condition that the spot load was not part of the original forecast load growth and PB is of the view that this is a fundamental requirement of the contingent project in that the contingent project is an event that is driven by a specific and verifiable event. Inclusion of a trigger in the forecast revenue determination would not meet this NER requirement. Therefore, PB is of the view that this is effectively a repetition of part of the requirement of a trigger for a contingent event.

The spot loads resulted in the TransGrid being unable to meet the requirements of Schedule 5.1 of the NER

Schedule 5.1 of the NER stipulates the performance requirements for Registered Participants and more specifically transmission network service providers (TNSPs) and distribution network service providers (DNSPs). The schedule covers all technical services provided for by TNSPs and DNSPs. PB is of the view that not being able to meet Schedule 5.1 of the NER is not a suitable trigger as it is not sufficiently specific or descriptive. Therefore PB is of the view that not being able to meet Schedule 5.1 of the NER does not meet the NER requirements of a contingent project.

TransGrid demonstrate that the option meets the investment requirement of chapter 5 of the NER.

Chapter 5 of the NER relates to network connections. Demonstration of prudency in projects is discussed in Chapter 5.6.5A and is more commonly known as the Regulatory Test. From the original text, PB is of the view that the Regulatory Test is not a suitable trigger is not sufficiently specific or descriptive beyond the bounds of the scenario analysis undertaken by TransGrid. Therefore PB is of the view that demonstration of a prudent and efficient option via Chapter 5 of the NER does not meet the NER requirements for a contingent project.

When considering the generated cost, it is not possible to establish what costs would be generated via the regulatory test and therefore this option does not meet the NER requirements.

As the volume of the spot load is not specified, it is not possible to establish if the spot load is probable, that is to say that as the spot load is no longer associated with the expansion plans of a large industrial energy user, it is not possible to establish what would cause the trigger to occur. Therefore it is not possible to ascertain if the trigger is probable but uncertain in the next regulatory period.

Table M-32: Visy Gadara Mill local area support, summary of review

Summary findings	expenditure			trigger event		
	no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
Original	✓	✓	✓($54 m)	✓	×	✓
Revised	✓	×	✓($54 m)	×	×	×

Williamsdale – Cooma 3rd circuit (PES 6261)

The additional supporting information provides four conditions to the trigger event. The four conditions are

1. one or more generators to be connected to the transmission network in the Cooma area
2. the generator has not formed part of the revenue determination
3. TransGrid is not able to meet the terms of Schedule 5.1 of the NER and
4. TransGrid demonstrates that the option meets the investment requirements of chapter 5 of the NER.

One or more generators to be connected to the transmission network in the Cooma area

TransGrid states that the generator may emerge in the Comma area, PB considered the NER requirements and note that there is no minimum specified volume of generation and therefore PB is not able to establish if the scope and cost proposed is reflective of what a prudent operator would require. Therefore in PB's view an unspecified volume of generation does not meet the requirements of the NER for a contingent project, it would need to be quantified and associated to the networks existing transfer capacity.

Subsequent analysis against the trigger requirements, PB was not able to establish what the trigger was as the volume is not specified and additionally, we were not able to establish if the trigger would generate the cost. PB is of the opinion that as the trigger is unspecified this does not meet the NER requirements.

The generator did not form part of the revenue determination

PB is in agreement that this condition meets the terms of a contingent project in that the generator is in addition to the generation listed in the revenue determination.

TransGrid are not able to meet the terms of Schedule 5.1 of the NER and

Schedule 5.1 of the NER stipulates the performance requirements for Registered Participants and more specifically transmission network service providers (TNSPs) and distribution network service providers (DNSPs). The schedule covers all technical services provided for by TNSPs and DNSPs. PB is of the view that not being able to meet Schedule 5.1 of the NER is not a suitable trigger as it is not sufficiently specific or descriptive. Therefore PB is of the view that not being able to meet Schedule 5.1 of the NER does not meet the NER requirements of a contingent project.

TransGrid demonstrate that the option meets the investment requirements of chapter 5 of the NER.

Chapter 5 of the NER relates to network connections. Demonstration of prudency in projects is discussed in Chapter 5.6.5A and is more commonly known as the Regulatory Test. From the original text, PB is of the view that the Regulatory Test is not a suitable trigger is not sufficiently specific or descriptive beyond the bounds of the scenario analysis undertaken by TransGrid. Therefore PB is of the view that demonstration of a prudent and efficient option via Chapter 5 of the NER does not meet the NER requirements for a contingent project.

When considering the generated cost, it is not possible to establish what costs would be generated via the regulatory test and therefore this option does not meet the NER requirements.

The NER requirement that the project is probable but uncertain, PB is of the view that there is a possibility that a different generator other than those specified in the revenue reset is connected to the transmission system, but it is uncertain. In PB's view this meets the terms of the NER for contingent projects.

Table M-33: Williamsdale – Cooma 3rd circuit, summary of review

Summary findings	expenditure			trigger event		
	no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
Original	✓	✓	✓($40 m)	×	×	✓
Revised	✓	×	✓($40 m)	×	×	✓

Orange 330 / 132 kV substation (PES 6262)

TransGrid has presented further information on the trigger for this contingent project. The trigger has been clarified as a four stage conditional event.

1. emergence of one or spot loads in the areas of Central West and Western NSW
2. the spot load was not part of the forecast load growth in the revenue determination
3. the spot loads resulted in the TransGrid being unable to meet the requirements of Schedule 5.1 of the NER
4. TransGrid demonstrate that the option meets the investment requirement of chapter 5 of the NER.

Each of these conditions are reviewed below.

Emergence of spot loads in the areas os of Central West and Western NSW

TransGrid state that a spot load may emerge in the areas listed, PB considered the NER requirements and note that there is no minimum specified volume to the spot load, therefore PB is not able to establish if the scope and cost proposed is reflective of what a prudent operator would require. Therefore in PB's view an unspecified spot load does not meet the requirements of the NER for a contingent project.

Subsequent analysis against the trigger requirements, PB was not able to establish what the trigger was as the volume is not specified and additionally, we were not able to establish if the trigger would generate the cost. PB is of the opinion that as the trigger is unspecified this does not meet the NER requirements.

The spot load was not part of the forecast load growth in the revenue determination

PB considered this condition that the spot load was not part of the original forecast load growth and PB is of the view that this is a fundamental requirement of the contingent project in that the contingent project is an event that is driven by a specific and verifiable event. Inclusion of a trigger in the forecast revenue determination would not meet this NER requirement. Therefore, PB is of the view that this is effectively a repetition of part of the requirement of a trigger for a contingent event.

The spot loads resulted in the TransGrid being unable to meet the requirements of Schedule 5.1 of the NER

Schedule 5.1 of the NER stipulates the performance requirements for Registered Participants and more specifically transmission network service providers (TNSPs) and distribution network service providers (DNSPs). The schedule covers all technical services provided for by TNSPs and DNSPs. PB is of the view that not being able to meet Schedule 5.1 of the NER is not a suitable trigger as it is not sufficiently specific or descriptive. Therefore PB is of the view that not being able to meet Schedule 5.1 of the NER does not meet the NER requirements of a contingent project.

TransGrid demonstrate that the option meets the investment requirement of chapter 5 of the NER.

Chapter 5 of the NER relates to network connections. Demonstration of prudency in projects is discussed in Chapter 5.6.5A and is more commonly known as the Regulatory Test. From the original text, PB is of the view that the Regulatory Test is not a suitable trigger is not sufficiently specific or descriptive beyond the bounds of the scenario analysis undertaken by TransGrid. Therefore PB is of the view that demonstration of a prudent and efficient option via Chapter 5 of the NER does not meet the NER requirements for a contingent project.

When considering the generated cost, it is not possible to establish what costs would be generated via the regulatory test and therefore this option does not meet the NER requirements.

As the volume of the spot load is not specified, it is not possible to establish if the spot load is probable, that is to say that as the spot load is no longer associated with the expansion plans of a large industrial energy user, it is not possible to establish what would cause the trigger to occur. Therefore it is not possible to ascertain if the trigger is probable but uncertain in the next regulatory period.

Table M-34: Orange 330 kV substation, summary of review

Summary findings	expenditure			trigger event		
	no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
Original	✓	×	✓($63 m)	×	×	✓
Revised	✓	×	✓($63 m)	×	×	×

Williamsdale 330 / 132 kV substation (PES 5564)

TransGrid provided additional information on the trigger to this project in that the trigger has been revised to be the issuance by the ACT Government of planning and environmental approvals. The original trigger was identified as the ACT government examining the regulatory and planning approvals required in order to increase the security requirements for electricity supply to the ACT and modifying the regulatory and planning approvals.

In PB's view the ACT government approving planning and environmental applications is not a suitable trigger as TransGrid is obligated under schedule 5.1 of the NER to provide certain service standards. In PB's view TransGrid are only allowed to exceed the requirements of the NER if the ACT Government modifies the regulatory requirements imposed on TransGrid. The presented information does not meet the NER requirement of the reflective cost that a prudent and efficient operator would incur.

PB reviewed the subsequent information provided by TransGrid and is of the opinion that there was no additional data provided, rather further clarity on the original information. PB has the same view as the original proposal.

Table M-35: 330 kV substation at Williamsdale, summary of review

Summary findings	expenditure			trigger event		
	no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
Original	×	×	✓($35 m)	✓	✓	✓
Revised	×	×	✓($35 m)	✓	✓	✓

Reactive support at six sites

The subsequent information provided by TransGrid relates to two conditions for the trigger. The two conditions are

1. Unable to satisfactorily conclude contracts for reactive support

2. TransGrid demonstrate that the option meets the investment requirement of chapter 5 of the NER.

Unable to satisfactorily conclude contracts for reactive support

TransGrid noted that they currently do not contract for reactive support from any generators. This contingent project is to allow TransGrid to construct reactive plant should, in the future the requirement for reactive plant be needed and TransGrid is unable to contract successfully with a generator. PB highlights that the aggregate cost of the contingent projects is made up of a series of smaller individual projects that may be efficiently justified in their own right.

PB reviewed this trigger against the NER and in our opinion the trigger is not specific or verifiable as the volume of reactive support is not specified. We are not able to establish if the scope and cost proposed is reflective of what a prudent operator would require. Therefore in PB's view an unspecified reactive load does not meet the requirements of the NER for a contingent project.

Subsequent analysis against the trigger requirements, PB was not able to establish what the trigger was as the volume is not specified and additionally, we were not able to establish if the trigger would generate the cost. PB is of the opinion that as the trigger is unspecified this does not meet the NER requirements.

TransGrid demonstrate that the option meets the investment requirement of chapter 5 of the NER.

Chapter 5 of the NER relates to network connections. Demonstration of prudency in projects is discussed in Chapter 5.6.5A and is more commonly known as the Regulatory Test. From the original text, PB is of the view that the Regulatory Test is not a suitable trigger is not sufficiently specific or descriptive beyond the bounds of the scenario analysis undertaken by TransGrid. Therefore PB is of the view that demonstration of a prudent and efficient option via Chapter 5 of the NER does not meet the NER requirements for a contingent project.

When considering the generated cost, it is not possible to establish what costs would be generated via the regulatory test and therefore this option does not meet the NER requirements.

Table M-36: Reactive support at Bayswater, summary of review

Summary findings	expenditure			trigger event		
	no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
Original	✓	×	✓($36 m)	×	×	×
Revised	✓	×	✓($36 m)	×	×	×

M.4 Further update dated 12 September 2008

Subsequent to the update on 26 August 2008, TransGrid provided further information on 12 September 2008 on 13 projects. The projects are listed in Table M-37.

Table M-37: Projects with updated information supplied on 12 September 2008

Project	Capital cost ($m)
Development of a second 500 kV link	$330
Yass to Wagga 500 kV double circuit transmission line	$329
Liddell – Tamworth 330 kV	$163
Tamworth – Armidale 330 kV line	$130
QNI upgrade – series compensator	$120
Interconnection development from Victoria	$33
Bannaby – Yass reinforcement	$45
Gadara / Tumut local area support (originally Visy Gadara Mill local area support	$54
Cooma Area (originally Williamsdale – Cooma 3rd circuit)	$40
Orange 330 kV substation	$63
330 kV supply to Williamsdale	$35
SVC	$40
Reactive support at Bayswater	$36

If no additional information was supplied, PB has not included those projects in the list above.

Development of a second 500 kV link (PSR 131, POSE 5568B; POSE 6002)

TransGrid has included further clarification on the trigger events for this project. This project has three augmentations and three triggers. PB has reviewed the appropriateness of the augmentations, and subsequently the revised triggers. The three augmentations are:

1. construction of a 500 kV double circuit transmission line from Hunter Valley to Eraring (estimated at $270.5m)
2. transfer of the Bayswater unit 1 & 2 to a 500 kV connection (estimated at $31m)
3. 3rd kemps Creek 500/330 kV transformer (estimated at $30m).

The trigger has been identified as three possible scenarios:

1. power station larger than 400 MW in the northern or western NSW
2. increase in the import from Queensland by 400 MW

3. a spot load in the Newcastle area exceeding 200 MW.

PB has not identified any expenditure in the forecast for any of these events. The triggers are discussed in more detail below.

Power station larger than 400 MW in the northern or western NSW

TransGrid has identified three augmentations in relation to this trigger. The augmentations are:

1. construction of a 500 kV double circuit transmission line from Hunter Valley to Eraring.

2. transfer of the Bayswater unit 1 & 2 to a 500 kV connection

3. 3rd kemps Creek 500/330 kV transformer

TransGrid has stated that an increase in generation in two areas may trigger the required investment, and these two areas are:

- Northern NSW

- Western NSW

The NER requires that the contingent project cost is reflective of an efficient cost in achieving the objectives. However, in the review of this specific trigger (400 MW generator in the northern and western NSW) PB acknowledges that the construction of a 500 kV transmission line will achieve the objective, but the transfer of the Bayswater units 1 & 2 and a 3 Kemps Creek 500 / 330 kV transformer do not appear to be required to achieve the objective. These two items are discussed in detail below.

Transfer of Bayswater unit 1 & 2

TransGrid has provided comment that the transfer of Bayswater Units to 500 kV requires new generator transformers. When examining this requirement against the NER requirements we were not able to establish how installing new generator transformers at Bayswater would achieve the objectives of improving power flow from the northern or western power station development. Therefore in PB's view, this is not a reflective cost and should not be included as part of the overall development for the required work.

Kemps Creek 500 / 330 kV transformer

The third part of the overall development is the installation of a third 500 MVA transformer at Kemps Creek. In relation to the trigger of a 400 MW generator in the northern or western area of NSW, the generation is sited in an area distant from Kemps Creek and PB has not been able to establish that the installation of this transformer achieves the objective of improving power flow from the Hunter Valley to Eraring. On this basis, In PB's view this does not meet the requirement of the NER and should not be included as part of this development.

PB is of the view that the probability of additional generation over and above the generation in the scenarios is unlikely, but possible. In PB's view an increase in generation of 400 MW over and above the generation already identified in the forecast capex program does meet the terms of the NER for a contingent project.

Increase in the import from Queensland by 400 MW

The NER requires that the contingent project cost is reflective of an efficient cost in achieving the objectives. However, in the review of this specific trigger (Increase in the import from Queensland by 400 MW) acknowledges that the construction of a 500 kV transmission line will achieve the objective, but the transfer of the Bayswater units 1 & 2 and a 3 Kemps Creek 500 / 330 kV transformer does not appear to achieve the objective. These two items are discussed in detail below.

Transfer of Bayswater unit 1 & 2

TransGrid has provided comment that the transfer of Bayswater Units to 500 kV requires new generator transformers. When examining this requirement against the NER requirements we were not able to establish how installing new generator transformers at Bayswater would achieve the objectives of improving power flow from the northern or western power station development. Therefore in PB's view this is not a reflective cost and should not be included as part of the development work.

Kemps Creek 500 / 330 kV transformer

The third part of the overall development is the installation of a third 500 MVA transformer at Kemps Creek. In relation to the trigger of an increase in the interconnector flow from Queensland by an additional 400 MW, the interconnector is sited in area distant from Kemps Creek. PB was not able to establish that the installation of this transformer achieves the objective of improving power flow from the Hunter Valley to Eraring. In PB's view this does not meet the requirement of the NER and should not be included as part of this development.

TransGrid has also identified that increase to the Queensland export capability on the Queensland / NSW interconnector by 400 MW above the present capability is a suitable trigger. PB is of the opinion that this is a specific and verifiable trigger insofar that the trigger is an increase in export capacity from Queensland to NSW above its current capacity. PB is also of the opinion that increasing the capacity of the current interconnector would generate the costs and PB is of the opinion that the increase in probable but uncertain in the next regulatory period.

In PB view the development of a 500 kV double circuit transmission line triggered by an increase of 400 MW on the interconnector or an increase of 400 MW of generation over and above the generation in the forecast scenarios meets the NER requirements of a contingent project. But the transfer of Bayswater units 1 & 2 and Kemps Creek 500 / 330 kV transformer does not.

Spot load in the Newcastle area exceeding 200 MW

The trigger for the construction of the second line has been identified as a load development of 200 MW in the Newcastle over and above the expected demand forecast. In reviewing the scope and cost, based on the information provided by TransGrid, PB is of the view that the scope of installing a 500 kV double circuit transmission line from the Hunter Valley to Eraring is in excess of the NER requirement for a reflective expenditure and classifying a contingent project. The NER requires that the scope reasonably reflects an efficient cost in achieving the objectives and the cost that the costs are that of a prudent operator would require to achieve the objectives.

In PB's view a more reflective cost would be the single 500 kV transmission line or upgrading existing 330 kV transmission lines. As presented the installation of a 500 kV double circuit transmission line has inherent additional capacity than what would bee needed to meet a 200 MW spot load over and above the forecast demand increase in the Newcastle area. PB is of the opinion that a this trigger does not meet the NER requirements of reflective expenditure under the NER.

Transfer of Bayswater unit 1 & 2

TransGrid has provided comment that the transfer of Bayswater Units to 500 kV requires new generator transformers. When examining this requirement against the NER requirements we were not able to establish how installing new generator transformers at Bayswater would achieve the objectives of meeting a 200 MW spot load in the Newcastle area. Therefore in PB's view this is not a reflective cost and should not be included as part of the development work.

Kemps Creek 500 / 330 kV transformer

The third part of the overall development is the installation of a third 500 MVA transformer at Kemps Creek. In relation to the trigger of a 200 MW spot load in the Newcastle area is sited in area distant from Kemps Creek. PB was not able to establish that the installation of this transformer achieves the objective. In PB's view this does not meet the requirement of the NER.

Table M-38: Development of a second 500 kV link, summary of review

Summary findings	expenditure			trigger event		
	no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
Original	×	✓	✓ ($331 m)	×	×	✓
Revised	✓	✓	✓ ($331 m)	×	×	✓
400 MW generator in northern or western NSW						
500 kV DC line	✓	✓	✓ ($270 m)	✓	✓	✓
Bayswater	✓	×	✓ ($31 m)	✓	×	✓
Kemps Creek	✓	×	✓ ($30 m)	✓	×	
400 MW import from Queensland to NSW						
500 kV DC line	✓	✓	✓ ($270 m)	✓	✓	✓
Bayswater	✓	×	✓ ($31 m)	✓	×	✓
Kemps Creek	✓	×	✓ ($30 m)	✓	×	✓
200 MW spot load in the Newcastle area						
500 kV DC line	✓	×	✓ ($270 m)	✓	×	✓
Bayswater	✓	×	✓ ($31 m)	✓	×	✓
Kemps Creek	✓	×	✓ ($30 m)	✓	×	✓

Yass to Wagga 500 kV double circuit transmission line

TransGrid has added further information to the trigger event. The additional information is in two forms.

- Wind farm developments output exceeding 200 MW
- Extended area to include Snowy area

Each trigger event will be examined below

Wind farm developments output exceeding 200 MW

TransGrid has extended the requirement of a generator with an output exceeding 200 MW from a coal-fired or gas-fired generator to the concatenation of wind farms with a combined output of 200 MW.

In PB's view an increase in the generating capacity of 200 MW over and above the scenarios identified in the forecast scenarios is a specific and verifiable trigger and meets the requirements for a contingent project.

Extended area to include Snowy area

TransGrid has extended the area that the generation can be located to include the Snowy area. PB reviewed this location and in PB's view this area is specific enough to meet the terms of the NER. In PB's view the following triggers meet the NER requirement s for a contingent project

Trigger 1 – Generation of 200 MW over and above the generation scenarios already identified in the forecast scenarios in the areas of Wagga; Jindera; Buronga; Broken Hill and Snowy areas.

Trigger 2 – Increase in the import capacity to NSW from Victoria by 200 MW

Table M-39: Yass to Wagga 500 kV transmission line, summary of review

Summary findings	expenditure			trigger event		
	no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
Original	✓	✓	✓ ($329 m)	×	×	×
Trigger 1	✓	✓	✓ ($329 m)	✓	✓	✓
Trigger 2	✓	✓	✓ ($329 m)	✓	✓	✓

Liddell – Tamworth 330 kV tranmssion line

TransGrid has revised the three triggers for this project. The new triggers are:

- 600 MW of generation in Tamworth or Armidale area
- 600 MW increase in the import capacity of the Queensland interconnector
- 200 MW increase in the export capacity of the Queensland interconnector

Each trigger is evaluated below.

600 MW of generation in Tamworth or Armidale area

TransGrid has stated that an increase on generation in two areas. The two areas are

- Tamworth
- Armidale

TransGrid has also included the comment that the increase in generation would also have to cause a network limitation on the transmission system between Liddell and Tamworth.

In the forecast planning scenarios there is an allowance for possible generation (56 scenarios are for generation connections) and the first requirement of a contingent project is that there is no provision. PB is of the view that the additional 600 MW of generation would be over and above the generation already identified in the forecast capex program. On this proviso, PB is of the opinion that there is no provision already in the forecast capex program and the trigger is specific and verifiable.

As the generation is sited in an approximate area, PB is of the view that the selected area is specific enough to demonstrate that the trigger will generate the cost. PB is also of the view that the probability of additional generation over and above the generation in the scenarios is unlikely, but possible. In PB's view an increase in generation of 600 MW over and above the generation already identified in the forecast capex program does meet the terms of the NER for a contingent project.

600 MW increase in the import capacity of the Queensland interconnector

TransGrid has also identified that increase to the Queensland export capability on the Queensland / NSW interconnector by 600 MW above the present capability is a suitable trigger. PB is of the opinion that this is a specific and verifiable trigger insofar that the trigger is an increase in export capacity from Queensland to NSW above its current capacity. PB is also of the opinion that increasing the capacity of the current interconnector would generate the costs and PB is of the opinion that the increase in probable but uncertain in the next regulatory period.

200 MW increase in the export capacity of the Queensland interconnector

TransGrid has also identified that increase to the Queensland import capability on the Queensland / NSW interconnector by 200 MW above the present capability is a suitable trigger. PB is of the opinion that this is a specific and verifiable trigger insofar that the trigger is an increase in export capacity from Queensland to NSW above its current capacity. PB is also of the opinion that increasing the capacity of the current interconnector would generate the costs and PB is of the opinion that the increase in probable but uncertain in the next regulatory period.

Table M-40: Liddell – Tamworth 330 kV transmission line, summary of review

Summary findings	expenditure			trigger event		
	no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
Original	✓	✓	✓ ($163 m)	×	×	×
Trigger 1	✓	✓	✓ ($163 m)	✓	✓	✓
Trigger 2	✓	✓	✓ ($163 m)	✓	✓	✓
Trigger 3	✓	✓	✓ ($163 m)	✓	✓	✓

Tamworth – Armidale 330 kV transmission line

TransGrid has revised the three triggers for this project. The new triggers are:

- 300 MW of generation in Tamworth or Armidale area
- 300 MW increase in the import capacity of the Queensland interconnector
- 200 MW increase in the export capacity of the Queensland interconnector

Each trigger is evaluated below.

600 MW of generation in Tamworth or Armidale area

TransGrid has stated that an increase on generation in the Armidale area and has also included the comment that the increase in generation would also have to cause a network limitation on the transmission system between Liddell and Tamworth.

In the forecast planning scenarios there is an allowance for possible generation (56 scenarios are for generation connections) and the first requirement of a contingent project is that there is no provision. PB is of the view that the additional 600 MW of generation would be over and above the generation already identified in the forecast capex program. On this proviso, PB is of the opinion that there is no provision already in the forecast capex program and the trigger is specific and verifiable.

As the generation is sited in an approximate area, PB is of the view that the selected area is specific enough to demonstrate that the trigger will generate the cost. PB is also of the view that the probability of additional generation over and above the generation in the scenarios is unlikely, but possible. In PB's view an increase in generation of 600 MW over and above the generation already identified in the forecast capex program does meet the terms of the NER for a contingent project.

600 MW increase in the import capacity of the Queensland interconnector

TransGrid has also identified that increase to the Queensland export capability on the Queensland / NSW interconnector by 600 MW above the present capability is a suitable trigger. PB is of the opinion that this is a specific and verifiable trigger insofar that the trigger is an increase in export capacity from Queensland to NSW above its current capacity. PB is also of the opinion that increasing the capacity of the current interconnector would generate the costs and PB is of the opinion that the increase in probable but uncertain in the next regulatory period.

200 MW increase in the export capacity of the Queensland interconnector

TransGrid has also identified that increase to the Queensland import capability on the Queensland / NSW interconnector by 200 MW above the present capability is a suitable trigger. PB is of the opinion that this is a specific and verifiable trigger insofar that the trigger is an increase in export capacity from Queensland to NSW above its current capacity. PB is also of the opinion that increasing the capacity of the current interconnector would generate the costs and PB is of the opinion that the increase in probable but uncertain in the next regulatory period.

Table M-41: Tamworth – Armidale 330 kV transmission line, summary of review

Summary findings	expenditure			trigger event		
	no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
Original	✓	✓	✓ ($130 m)	×	×	×
Trigger 1	✓	✓	✓ ($130 m)	✓	✓	✓
Trigger 2	✓	✓	✓ ($130 m)	✓	✓	✓
Trigger 3	✓	✓	✓ ($130 m)	✓	✓	✓

QNI upgrade – series compensator

TransGrid has supplied comment that states that the triggers for this project include the development of new generation in Queensland or NSW or closure in the NEM.

TransGrid also comment that this is a contingent project in Powerlink's revenue determination.

However, in PB's view TransGrid has not provided any additional information and therefore it is PB's view that the summary does not change.

Table M-42: QNI upgrade – series compensator, summary of review

Summary findings	expenditure			trigger event		
	no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
Original	✓	×	✓ ($60 - $120 m)	×	×	×
Trigger 1	✓	×	✓ ($60 - $120 m)	×	×	×
Trigger 2	✓	×	✓ ($60 - $120 m)	×	×	×

Interconnection development from Victoria

TransGrid has supplied comment that states that the triggers for this project include the development of new generation in Victoria or NSW or closure in the NEM.

However, in PB's view TransGrid has not provided any additional information and therefore it is PB's view that the summary does not change.

Table M-43: Interconnection development from Victoria, summary of review

Summary findings	expenditure			trigger event		
	no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
Original	✓	✓	× ($33 m)	×	×	×
Trigger 1	✓	×	× ($33 m)	×	×	×
Trigger 2	✓	×	× ($33 m)	×	×	×

Bannaby – Yass reinforcement (POSE 4342A)

TransGrid has added further information to the trigger event. The additional information is in two forms.

- Wind farm developments output exceeding 200 MW
- Extended area to include Snowy area

Each trigger event will be examined below

Wind farm developments output exceeding 200 MW

TransGrid has extended the requirement of a generator with an output exceeding 200 MW from a coal-fired or gas-fired generator to the concatenation of wind farms with a combined output of 200 MW.

In PB's view an increase in the generating capacity of 200 MW over and above the scenarios identified in the forecast scenarios is a specific and verifiable trigger and meets the requirements for a contingent project.

Extended area to include Snowy area

TransGrid has extended the area that the generation can be located to include the Snowy area. PB reviewed this location and in PB's view this area is specific enough to meet the terms of the NER. In PB's view the following triggers meet the NER requirement s for a contingent project

Trigger 1 – Generation of 200 MW over and above the generation scenarios already identified in the forecast scenarios in the areas of Yass; Canberra; Wagga; Jindera; Buronga; Broken Hill and Snowy areas.

Trigger 2 – Increase in the import capacity to NSW from Victoria by 200 MW

Table M-44: Yass reinforcement, summary of review

Summary findings	expenditure			trigger event		
	no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
Original	✓	✓	✓ ($45 m)	×	×	×
Trigger 1	✓	✓	✓ ($45 m)	✓	✓	✓
Trigger 2	✓	✓	✓ ($45 m)	✓	✓	✓

CBD supply – 330 kV cable into the CBD

TransGrid has provided additional information on the single trigger of TransGrid or EnergyAustralia not being able to meet the terms of Schedule 5.1 of the NER.

The additional information states that the requirement of schedule 5.1 of the NER pertains to the clauses relating to equipment ratings and voltage conditions. PB is of the view that not being able to meet generic equipment ratings and voltage conditions is not a suitable trigger as it is not sufficiently specific or descriptive. Therefore PB is of the view that it does not meet the NER requirements of a contingent project.

Therefore in PB's view the additional information still does not meet the NER requirements in cost reflectivity and a specific and verifiable trigger.

Table M-45: CBD supply – cable into CBD, summary of review

Summary findings	expenditure			trigger event		
	no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
Original	✓	✓	✓($650 m)	×	×	✓
Revised	✓	×	✓($650 m)	×	×	✓

Gardara / Tumut local area support (PES 6218)

TransGrid has presented further information on the trigger for this contingent project. The trigger has been clarified as a four stage conditional event.

1. emergence of one or spot loads totalling 20 MVA (or more)

2. the spot loads resulted in the TransGrid being unable to meet the requirements of Schedule 5.1 of the NER, particularly those relating to equipment ratings and voltage conditions

3. TransGrid demonstrate that the option meets the investment requirement of chapter 5 of the NER, particularly those relating to equipment ratings and voltage conditions.

Each of these conditions is reviewed below.

Emergence of spot loads totalling 20 MVA

TransGrid latest information is that a spot load totalling 20 MVA may emerge in the areas of:

- Yass
- Tumut
- Gadara
- Wagga

PB considered the NER requirements and note that there is no minimum single volume to the spot load. That is to say the latest information is equivalent to an allowance for load increases above the current forecast by 20 MVA. PB is not able to establish if the scope and cost proposed is reflective of what a prudent operator would require. Therefore in PB's view a general increase in load does not meet the requirements of the NER for a contingent project.

Subsequent analysis against the trigger requirements, PB was not able to establish what the trigger was as the volume is not specified and additionally, we were not able to establish if the trigger would generate the cost. PB is of the opinion that as the trigger is unspecified this does not meet the NER requirements.

The spot load was not part of the forecast load growth in the revenue determination

PB considered this condition that the spot load was not part of the original forecast load growth and PB is of the view that this is a fundamental requirement of the contingent project in that the contingent project is an event that is driven by a specific and verifiable event. Inclusion of a trigger in the forecast revenue determination would not meet this NER requirement. Therefore, PB is of the view that this is effectively a repetition of part of the requirement of a trigger for a contingent event.

The spot loads resulted in the TransGrid being unable to meet the requirements of Schedule 5.1 of the NER

The additional information states that the requirement of schedule 5.1 of the NER pertains to the clauses relating to equipment ratings and voltage conditions. PB is of the view that not being able to meet equipment ratings and voltage conditions is not a suitable trigger as it is not sufficiently specific or descriptive. Therefore PB is of the view that it does not meet the NER requirements of a contingent project.

Therefore in PB's view the additional information still does not meet the NER requirements in cost reflectivity and a specific and verifiable trigger.

TransGrid demonstrate that the option meets the investment requirement of chapter 5 of the NER.

The additional information states that the requirement of schedule 5.1 of the NER pertains to the clauses relating to equipment ratings and voltage conditions. PB is of the view that not being able to meet equipment ratings and voltage conditions is not a suitable trigger as it is not sufficiently specific or descriptive. Therefore PB is of the view that it does not meet the NER requirements of a contingent project.

Therefore in PB's view the additional information still does not meet the NER requirements in cost reflectivity and a specific and verifiable trigger.

As the spot load is not specific it amounts to the equivalent of load growth and therefore it is not possible to establish if the spot loads are probable, that is to say that as the spot loads are no longer associated with the expansion plans of a large industrial energy user, it is not possible to establish what would cause the trigger to occur. Therefore it is not possible to ascertain if the trigger is probable but uncertain in the next regulatory period.

Table M-46: Gardara / Tumut local area support, summary of review

Summary findings	expenditure			trigger event		
	no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
Original	✓	✓	✓($54 m)	✓	×	✓
Revised	✓	×	✓($54 m)	×	×	×

Cooma area (PES 6261)

The additional supporting information relates to three trigger events.

1. one or more generators totalling 225 MW[302] connected to the transmission network in the Cooma area
2. TransGrid are not able to meet the terms of Schedule 5.1 of the NER particularly those relating to equipment rating and voltage conditions
3. TransGrid demonstrate that the option meets the investment requirements of chapter 5 of the NER particularly those relating to equipment rating and voltage conditions.

One or more generators totalling 225 MW to be connected to the transmission network in the Cooma area

TransGrid has extended the requirement of a generator (or generators) with an output exceeding 225 MW that does not form part of the revenue determination.

In PB's view an increase in the generating capacity of 225 MW over and above the scenarios identified in the forecast scenarios is a specific and verifiable trigger and meets the requirements for a contingent project.

TransGridor EnergyAustralia being unable to meet the requirements of Schedule 5.1 of the NER

The additional information states that the requirement of schedule 5.1 of the NER pertains to the clauses relating to equipment ratings and voltage conditions. PB is of the view that not

302 In TransGrid's response the actual value was 225 MVA. PB has assumed that this is a typographic error as generation output is measured in MW. Therefore it is assumed to be 225 MW.

being able to meet equipment ratings and voltage conditions is not a suitable trigger as it is not sufficiently specific or descriptive. Therefore PB is of the view that it does not meet the NER requirements of a contingent project.

Therefore in PB's view the additional information still does not meet the NER requirements in cost reflectivity and a specific and verifiable trigger.

TransGrid demonstrate that the option meets the investment requirement of chapter 5 of the NER.

The additional information states that the requirement of schedule 5.1 of the NER pertains to the clauses relating to equipment ratings and voltage conditions. PB is of the view that not being able to meet equipment ratings and voltage conditions is not a suitable trigger as it is not sufficiently specific or descriptive. Therefore PB is of the view that it does not meet the NER requirements of a contingent project.

Therefore in PB's view the additional information still does not meet the NER requirements in cost reflectivity and a specific and verifiable trigger.

Table M-47: Cooma area, summary of review

Summary findings	expenditure			trigger event		
	no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
Original	✓	✓	✓($40 m)	×	×	✓
Trigger 1	✓	✓	✓($40 m)	✓	✓	✓
Trigger 2	✓	✓	✓($40 m)	×	×	✓
Trigger 3	✓	✓	✓($40 m)	×	×	✓

Orange 330 / 132 kV substation (PES 6262)

TransGrid has presented further information on three of the four trigger for this contingent project. The three triggers are:

1. emergence of one or spot loads totalling 40 MVA (or more) in the areas of Central West and Western NSW
2. the spot loads resulted in the TransGrid being unable to meet the requirements of Schedule 5.1 of the NER
3. TransGrid demonstrate that the option meets the investment requirement of chapter 5 of the NER.

Each of these conditions are reviewed below

Emergence of one or spot loads totalling 40 MVA (or more) in the areas of Central West and Western NSW

PB considered the NER requirements and note that there is no minimum single volume to the spot load. That is to say the latest information is equivalent to an allowance for load increases above the current forecast by 40 MVA. PB is not able to establish if the scope and cost proposed is reflective of what a prudent operator would require. Therefore in PB's view a general increase in load does not meet the requirements of the NER for a contingent project.

Subsequent analysis against the trigger requirements, PB was not able to establish what the trigger was as the volume is not specified and additionally, we were not able to establish if the trigger would generate the cost. PB is of the opinion that as the trigger is unspecified this does not meet the NER requirements.

The spot loads resulted in the TransGrid being unable to meet the requirements of Schedule 5.1 of the NER

Schedule 5.1 of the NER stipulates the performance requirements for Registered Participants and more specifically transmission network service providers (TNSPs) and distribution network service providers (DNSPs). The schedule covers all technical services provided for by TNSPs and DNSPs. PB is of the view that not being able to meet Schedule 5.1 of the NER is not a suitable trigger as it is not sufficiently specific or descriptive. Therefore PB is of the view that not being able to meet Schedule 5.1 of the NER does not meet the NER requirements of a contingent project.

TransGrid demonstrate that the option meets the investment requirement of chapter 5 of the NER.

Chapter 5 of the NER relates to network connections. Demonstration of prudency in projects is discussed in Chapter 5.6.5A and is more commonly known as the Regulatory Test. From the original text, PB is of the view that the Regulatory Test is not a suitable trigger is not sufficiently specific or descriptive beyond the bounds of the scenario analysis undertaken by TransGrid. Therefore PB is of the view that demonstration of a prudent and efficient option via Chapter 5 of the NER does not meet the NER requirements for a contingent project.

When considering the generated cost, it is not possible to establish what costs would be generated via the regulatory test and therefore this option does not meet the NER requirements.

As the volume of the spot load is not specified, it is not possible to establish if the spot load is probable, that is to say that as the spot load is no longer associated with the expansion plans of a large industrial energy user, it is not possible to establish what would cause the trigger to occur. Therefore it is not possible to ascertain if the trigger is probable but uncertain in the next regulatory period.

Table M-48: Orange 330 kV substation, summary of review

Summary findings	expenditure			trigger event		
	no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
Original	✓	×	✓($63 m)	×	×	✓
Trigger 1	✓	×	✓($63 m)	×	×	×
Trigger 2	✓	×	✓($63 m)	×	×	×
Trigger 3	✓	×	✓($63 m)	×	×	×

330 kV supply to Williamsdale

TransGrid provided additional information on this project stating that this is stage two of the development of higher security standards to the ACT.

The trigger however, has not been revised and is stated as the issuance by the ACT Government of planning and environmental approvals. The original trigger was identified as the ACT government examining the regulatory and planning approvals required in order to increase the security requirements for electricity supply to the ACT and modifying the regulatory and planning approvals.

In PB's view the ACT government approving planning and environmental applications is not a suitable trigger as TransGrid is obligated under schedule 5.1 of the NER to provide certain service standards. In PB's view TransGrid are only allowed to exceed the requirements of the NER if the ACT Government modifies the regulatory requirements imposed on TransGrid. The presented information does not meet the NER requirement of the reflective cost that a prudent and efficient operator would incur.

PB reviewed the subsequent information provided by TransGrid and is of the opinion that there was no additional data provided, rather further clarity on the original information. PB has the same view as the original proposal.

Table M-49: 330 kV substation at Williamsdale, summary of review

Summary findings	expenditure			trigger event		
	no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
Original	×	×	✓($35 m)	✓	✓	✓
Revised	×	×	✓($35 m)	✓	✓	✓

Voltage compensation (POSE 6098)

This project is the installation of voltage compensation equipment within the TransGrid network. The equipment is defined as either a 'statcom[303]' or a static VAr compensator (SVC)[304]. The request is for compensation dependent on two possible spot loads

- 50 MW on 132 kV system
- 200 MW on 330 kV system

The revised information does not specify a location and the NER requires that no allowance has been provided for in the forecast capital expenditure. PB has identified the current forecast capital expenditure has an allowance for SVC upgrades and refurbishment at Tamworth / Armidale (POSE 6098) and as the location not specific it is not possible to determine if there is some degree of allowance in the forecast capital expenditure, and therefore the NER requirement is not met.

50 MW on 132 kV system

The estimated cost of the project is $40m and is reflective of the cost of installing a 330 kV SVC with a range of +280 MVAr to -100 MVAr and all the associated switchgear at an established substation.

However as the location may be at 132 kV equipment at 132 kV is significantly cheaper than equipment at 330 kV. The requirement of the NER is to be reflective of the cost and in PB's view this does not meet the terms of the NER.

303 A statcom is a power electronics voltage-source converter based device that can act as either a source or sink of reactive AC power to an electricity network and if connected to a source of power can also provide active AC power/

304 A Static VAR Compensator (or SVC) is an electrical device for providing fast-acting reactive power compensation on high-voltage electricity transmission networks. SVCs are part of the Flexible AC transmission system (FACTS) family of devices.

SVCs are used both on bulk power transmission circuits to regulate voltage and contribute to steady-state stability; they also are useful when placed near high and rapidly varying loads, such as arc furnaces, where they can smooth flicker voltage.

PB cannot determine that the trigger of 50 MW load at 132 kV would generate the cost associated with a 330 kV SVC. Therefore, in PB view this does not meet the requirements of a contingent project under the NER terms.

200 MW on 330 kV system

The estimated cost of the project is $40m and is reflective of the cost of installing a 330 kV SVC with a range of +280 MVAr to -100 MVAr and all the associated switchgear at an established substation.

As the trigger is defined as 200 MW at 330 kV, it is possible to establish if the trigger will generate the increase in cost. In PB's view, the project does meet the requirements of a contingent project as defined in the NER.

Table M-50: Voltage compensation, summary of review

Summary findings	expenditure			trigger event		
	no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
Original	×	✓	✓($40 m)	×	×	✓
Trigger 1	×	×	✓($40 m)	✓	×	✓
Trigger 2	×	✓	✓($40 m)	✓	✓	✓

Reactive support at six sites

The subsequent information provided by TransGrid relates to the reactive power generation capabilities of the generating units. The trigger now states that TransGrid is unable to satisfactory conclude contract with the power station owners for the capability between the performance standard levels and the maximum levels.

In PB's review, the inability to be able to contract does not meet the NER requirements for a contingent project as it is not possible to establish any requirement for TransGrid to contract. That is to say that under the current requirement does not specify the volume of reactive support required over and above the performance standards and therefore being unable to contract an unspecified amount does not show reflective costs. Therefore in PB's view this does not meet the NER requirements.

When considering the trigger and the generated cost, it is not possible to establish the costs that would be generated via the trigger and therefore this option does not meet the NER requirements.

Table M-51: Reactive support at Bayswater, summary of review

Summary findings	expenditure			trigger event		
	no provision	reflective	exceeds limit ($33.4m)	specific and verifiable	generates cost	probable but uncertain
Original	✓	×	✓($36 m)	×	×	×
Revised	✓	×	✓($36 m)	×	×	×