PB ASSOCIATES

ENERGY AUSTRALIA'S FORWARD (TRANSMISSION) CAPITAL EXPENDITURE REQUIREMENTS

An independent review

CONFIDENTIAL

Prepared for

AUSTRALIAN COMPETITION & CONSUMER COMMISSION

PB Associates *Quality System:*

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EXECUTIVE SUMMARY

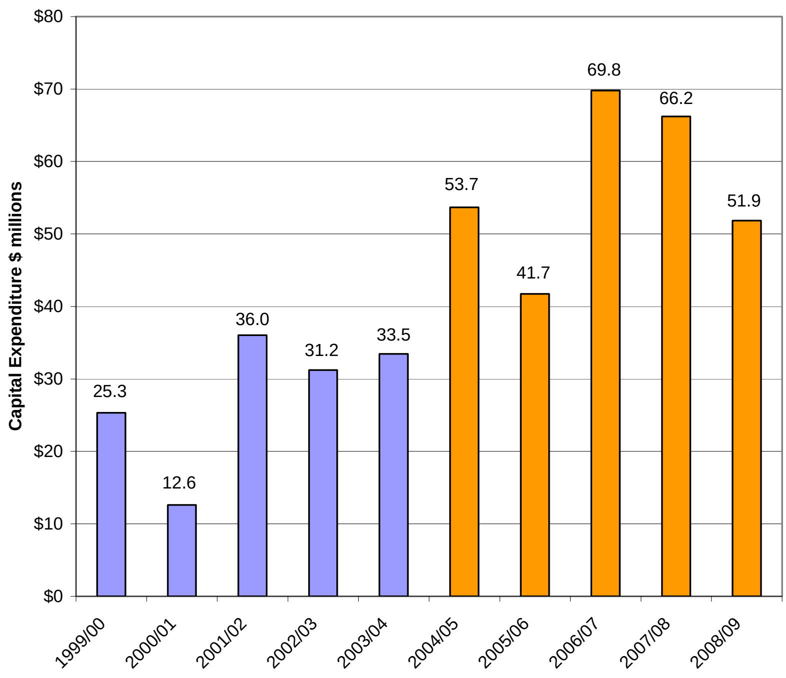
PB Associates has been engaged by the Australian Competition and Consumer Commission ("the ACCC") to undertake an independent review of Energy Australia's proposed capital programme for the five year period 1 July 2004 to 30 June 2009. It is intended that this will assist the ACCC in fulfilling its obligation to determine the appropriate levels of capital investment to allow Energy Australia ("EA") in respect of its regulated transmission business. PB Associates has conducted its review of the EA capital expenditure proposals in accordance with the timetable stipulated by the ACCC[1]. PB Associates has reviewed the proposed expenditure in the following of EA's capital investment categories:

- augmentation capital expenditure;
- asset replacement capital investment;
- excluded investments; and
- support-the-business (non-system) and compliance capital expenditure.

PB Associates has also undertaken an independent review of the EA governance framework and a review of the application of EA policies and practices associated with (transmission) capital investments.

The EA total capital forecast for 2004/05 to 2008/09 is approximately double the actual expenditure of the previous five year period. The total actual spend for 1999/00 to 2003/04 was $132 million compared with a forecast expenditure of $255 million for the next regulatory period. Figure 1 illustrates the change in expenditure levels[2].

Figure 1 – Energy Australia actual and forecast capital expenditure



1 The project initiation meeting between ACCC and PB Associates was held on Wednesday 3 November 2004. PB Associates' draft report was submitted to ACCC on 28 November 2004.

2 Note that actual (historic) expenditure is given as nominal values and the forecast values are presented in 2004 dollars.

PB Associates review includes nine key project areas[3] - seven in detail. This represents approximately 30% of the value of EA's proposed programme[4] and approximately 50% of the submission value if the remaining projects which EA has requested to be treated as Excluded investments, are discounted.

PB Associates review had led to the following conclusions:

- EA's investment formal decision-making framework is improving in its rigour and transparency;
- the policies and practices used by EA are reasonable and appropriate;
- some of the transmission assets are being planned for replacement ahead the time suggested by their condition assessments;
- EA's growth-related project proposals are prudent;
- the majority of EA's proposed compliance and non-system capex is appropriate and aligns with the requirements of the business; and
- deliverability may become an issue over the period in question.

PB Associates recommends that some of the proposed transformer replacement projects; the planned replacement of items of substation equipment and the replacement of a major overhead line circuit, could be deferred until the post-2008/09 regulatory period. This would reduce the capital expenditure by almost $50m. Furthermore, PB Associates believes that the majority of the costs associated with the proposed major refurbishment at the Ourimbah sub-transmission substation could be deferred for a number of years. Postponement of the Ourimbah works, as recommended by PB Associates, would reduce the capital expenditure by a further $16m.

PB Associates review of demand (growth) related projects did not reveal any projects which we believe are not warranted although we recommended that a number of these may be deferred. The suggested deferrals on these projects would reduce the allowed expenditure for the period by approximately $7m.

PB Associates also believe that the majority of the non-system (support the business) expenditure is reasonable and justified. We indicate that a more appropriate allocation of non-system costs between the transmission and distribution businesses would lead to a reduction in total non-system capital expenditure over the period of approximately $3.2m – principally reductions in the proposed IT spend. PB Associates recognises, however, that this is an issue for ACCC resolution and has not therefore recommended a reduction in IT system capital expenditure at this stage.

Table 1 shows PB Associates recommended levels for the EA forward transmission capital expenditure. Figures are five year totals and excluded projects are included in either asset replacement or augmentation – as appropriate.

A comparison of the expenditure levels given in EA's revised submission with the PB Associates recommended levels, on an annual basis, is given in Figure 2.

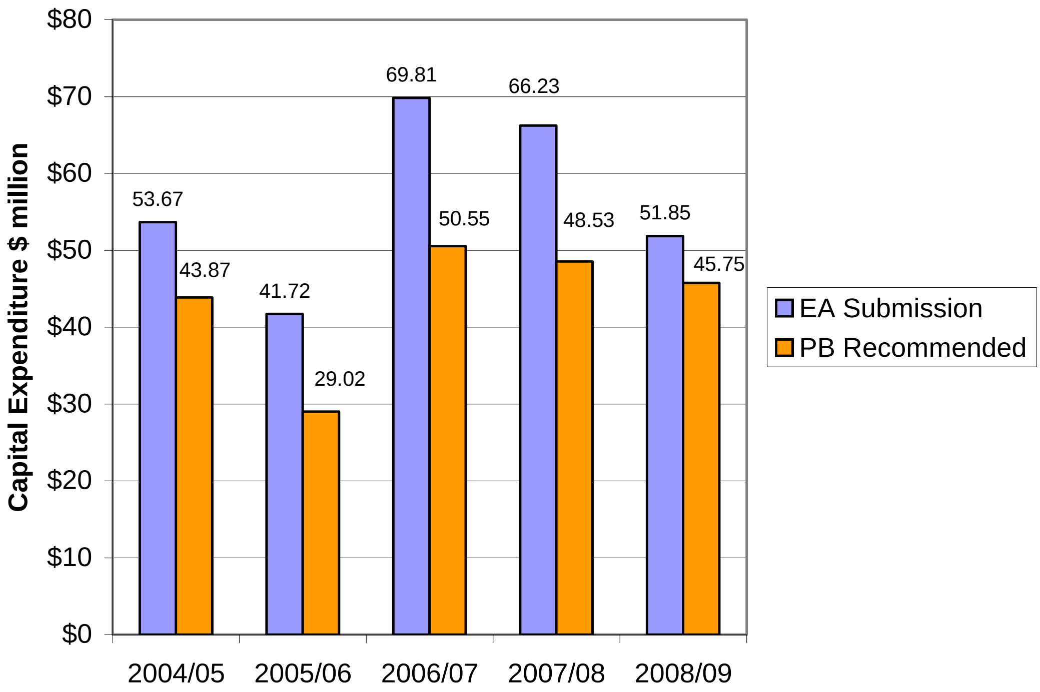
3 This included broader strategies such as the transformer replacement programmes.

4 This excludes non-system (support the business) capital expenditure.

Table 1 – Summary of PB Associates recommended expenditure levels (five year totals)[5]

Expenditure category		EA submitted	Proposed variation	PB recommended
Augmentation	main	$48.1m	-$1.1m	$47.0m
	excluded[6]	$47.2m	-	$47.2m
	total	$95.3m	-$1.1m	$94.2m
Replacement	main	$93.9m	-$48.5m	$45.4m
	excluded	$62.3m	-$16.0m	$46.3m
	total	$156.2m	-$64.5m	$91.7m
Non-system	main	$27.7m	$0.0m	$27.7m
	excluded	-	-	-
	total	$27.7m	$0.0m	$27.7m
Compliance	main	$4.1m	-	$4.1m
	excluded	-	-	-
	total	$4.1m	-	$4.1m
TOTAL		**$283.3m**	**-$65.6m**	**$217.7m**

Figure 2 – Summary of PB Associates recommendations



5 Note that the five year total figures are the simple arithmetic sum of the individual year totals (in 2004 dollars).

6 Excluded projects are those as proposed by EA in their submission.

1. INTRODUCTION

This section of the report provides background on the need for the work, describes the review approach undertaken by PB Associates and sets out the structure of the report.

1.1 BACKGROUND TO THE REVIEW

The National Electricity Code ("the Code") places an obligation on the ACCC to determine, on a periodic basis, the revenues which Energy Australia (EA) can collect with respect to its transmission assets[7].

1.1.1 The revised regulatory framework

Historically, the ACCC has set transmission revenues at the beginning of a regulatory period based on its consideration of required levels of network investment during the period. A review of actual capital expenditure is then undertaken at the end of the period and adjustments made in accordance with the ACCC's view of the prudency and efficiency with which investments, during the period, have been made.

The ACCC are of the view that this, so called, '*ex-post'* review framework has some problems and has moved to an '*ex-ante'* framework where an investment cap is set at the beginning of the regulatory period. The ex-ante regime places greater emphasis on conducting a rigorous review of forecast investment before the investment is undertaken. The ACCC considers that this approach has a number of advantages including providing greater certainty for stakeholders; improving the assessment framework for capital investments and moving towards a more light-handed regulatory regime.

1.1.2 Aims, objectives and scope of the review

The overall objective of this review is to undertake an assessment of the EA forward capital expenditure proposals in order to formulate an independent view on the prudency and efficiency of the principal capital investment categories. These are:

- augmentation capital expenditure;
- asset replacement investment;
- proposed excluded investments; and
- support-the-business (non-system) and compliance capital expenditure.

The expenditure reviewed in this report is EA's proposed transmission-related capital expenditure for the five year period 1 July 2004 to 30 June 2009.

The results and conclusions of this review by PB Associates will assist the ACCC in its obligation to determine the regulated revenue requirements associated with EA's transmission assets for the forthcoming regulatory period.

1.1.3 Process and project timetable

In accordance with its obligations under the Code, the ACCC is undertaking a review of the regulated revenues associated with the non-contestable elements of the EA

[7] The definition of a 'transmission asset' is set out in the Code and has previously been agreed between ACCC and the relevant parties – including EA.

transmission assets. The ACCC published its draft decision document in May 2004[8] with the intention that the revenue cap would apply for the period 1 July 2004 to 30 June 2009.

The ACCC has since reviewed and revised its regulatory principles for the determination of transmission revenues[9] and, in agreement with EA, is now undertaking a further review of the EA proposed programme of transmission asset capital investment which has been compiled on the basis of the new ex-ante regulatory model.

In order that EA could publish transmission prices by May 2004, the ACCC provided a provisional capital expenditure allowance which enabled EA to set, and publish, its prices associated with the transmission network. In doing this the ACCC used EA's proposed capital expenditure[10] to set the maximum allowed revenue (MAR).

The ACCC final decision on the revised EA transmission capital expenditure will be made public in April 2005. The new allowed revenue will take effect from 1 July 2005 and any required adjustments to account for the period July 2004 to June 2005 will be made in the final revenue cap decision.

The high-level project timetable is set out in Table 1-1.

Table 1-1 – Project timetable

Action	Date
Energy Australia (EA) revised submission	29 October 2004
PB Associates appointed by ACCC	5 November 2004
PB Associates' finalised draft report to ACCC	3 December 2004
EA review comments on final draft report	10 December 2004
PB Associates final report to ACCC	17 December 2004
Public forum (PB Associates to attend)	18 March 2005

A more detailed description of the PB Associates element of the review process is set out in Section 2

1.2 OUR APPROACH TO THE WORK

In this section we provide an overview of the methodology used by PB Associates in this review and the limits to, and exclusions from, the work.

1.2.1 Overview of methodology

In undertaking this review of the EA forward capital expenditure proposals, PB Associates has adopted a methodology which follows the following key steps:

- a review of the EA submission documentation;

8 NSW and ACT Transmission Network Revenue Caps – Energy Australia 2004/05-2008/09, ACCC, 28 April 2004. Available on the ACCC website at www.accc.gov.au.

9 'Statement of Principles for the Regulation of Electricity Transmission Revenues' (draft decision), ACCC, 18 August 2004 and 'Statement of Principles for the Regulation of Electricity Transmission Revenues – Background Paper' (draft decision), ACCC, 18 August 2004. Both documents are available on the ACCC website at www.accc.gov.au.

10 $183.8m.

- development of questions arising from initial review of submission – and subsequent issue to EA;
- an examination and review of the EA governance framework and internal approval procedures in order to gain an understanding of the environment within which EA makes its transmission investment decisions;
- a review of the application of EA policies and practices associated with (transmission) capital investments;
- a high level review of all proposed projects in the capital portfolio;
- a more detailed review of a selection of specific capital projects from the EA proposed forward capital expenditure plan; and
- the formulation of views and conclusions and the development and submission of an independent report to ACCC.

The examination and review of the governance framework and transmission planning policies and practices included a full day with key EA staff at EA offices in Sydney. Similarly, the detailed project review included two days on site at EA offices with the appropriate members of staff.

A more detailed description of the methodology and process adopted by PB Associates in undertaking this review is given in Section 2.

1.2.2 Limits to, and exclusions from, the work

For the avoidance of doubt, PB Associates' work in this review does not include:

- a review of EA distribution network costs;
- an examination of past EA transmission expenditure[11];
- a review of the *ex-ante* regulatory model; nor
- definitions of excluded investments of 'off-ramp' events[12].

The work is limited to a review of the forward transmission capital expenditure proposed by EA as part of its recent submission to ACCC[13].

1.3 REPORT STRUCTURE

Section 2 of this report describes the methodology which PB Associates has adopted in undertaking this review of EA's forward transmission capital investment programme. Section 3 provides a review of the EA internal arrangements associated with making investment decisions associated with owning, operating and maintaining its transmission assets. Section 4 reports on PB Associates' views on the entire capital programme.

Section 5 describes PB Associates findings of its detailed reviews of a number of sample projects and investment programmes. In each of the project review sections we set out the EA proposed expenditure, our recommended variation and PB Associates overall recommended level of expenditure. In Section 6 we summarise our findings and set out our recommendations and conclusions.

11 Other than to the extent required to formulate a view on the efficiency of proposed forward capital expenditure.

12 Although the PB Associates' review does include a review of the proposed Excluded investment projects within the EA submission.

13 'Revised Transmission Capital Investment Program', Energy Australia's submission to the Australian Competition & Consumer Commission, 29 October 2004.

2. METHODOLOGY

The PB Associates approach to the review of EA's capital programme is described in this section. The process was based on a series of well-defined project steps[14]. Each of these tasks was undertaken in accordance with a project work plan which was established at the start of the PB Associates review process. The principal project tasks are described below.

2.1 REVIEW OF EA SUBMISSION DOCUMENTATION

PB Associates undertook an initial review of the EA revised submission[15]. This included a preliminary assessment of the quality and quantity of the information provided by EA and enabled PB Associates to obtain an initial measure of the proposed forward investment plan – such as number, size and type of capital project in the programme.

This 'first-pass' review of the EA submission gave rise to a number of initial questions which were collated and issued to EA. Our questions covered the following subject areas:

- items of clarification associated with the overall (proposed) transmission capital investment programme;
- group strategies – such as asset replacement;
- clarification on asset replacement strategy;
- planning policy and criteria – including document requests;
- a number of initial questions on individual projects;
- generic issues associated with information provision (e.g. missing, unclear, required etc); and
- project specific issues (e.g. compliance with the EA Governance procedures).

2.1.1 PB Associates initial questions

PB Associates' list of initial questions was sent to EA shortly after the start of the review process. EA was asked to respond to the questions within one week of receiving them[16].

The compressed timescales associated with this review meant that PB Associates had limited ability to fully review any further information provided by EA after the question return date. EA were made aware of this at the start of the review process.

2.2 REVIEW OF GOVERNANCE FRAMEWORK

Before we could undertake a review of individual projects, PB Associates required a good understanding of the governance framework, decision-making processes and internal procedures associated with EA's capital investments. An important part of this project

14 The project initiation meeting between ACCC and PB Associates was held on Wednesday 3 November 2004. PB Associates' draft report was submitted to ACCC on 28 November 2004.

15 'Revised Transmission Capital Investment Program', Energy Australia's submission to the Australian Competition & Consumer Commission, 29 October 2004 (plus the full set of supporting Appendices).

16 PB Associates submitted its initial questions to EA on Tuesday 9 November 2004. EA provided responses to the questions on Wednesday 17 November 2004.

task was a meeting between PB Associates and appropriate EA staff[17]. This review included discussions with EA staff in the following areas:

- the investment planning process;
- internal decision making;
- capital approval;
- programme management; and
- documentation and systems.

The purpose of this element of the review was to enable PB Associates to formulate a view on whether the EA processes and procedures are reasonable and adequate; whether they are understood and implemented across the organisation and, ultimately, whether they are likely, in the view of PB Associates, to lead to prudent and efficient investment outcomes.

This initial site meeting also provided an opportunity for EA to seek clarification on any of the initial questions lodged by PB Associates on the 9 November 2004.

2.3 EXAMINATION OF POLICY AND PRACTICE

In this stage of the review PB Associates reviewed the key policies and practices which are applied by EA on a day-to-day basis to support the governance framework. In undertaking this task, PB Associates talked to key staff within EA and observed office practice. This section of the review also helped PB Associates gain a further understanding of the drivers behind some of the proposed individual capital investment schemes. In this task our review included:

- power system planning (philosophy, internal standards, documentation, planning criteria etc.);
- long-term network development strategies ('big picture');
- tools and applications used;
- links between asset replacement and augmentation investment;
- whole of life costing application (including capital and operating cost trade-offs;
- network data availability and integrity;
- links between service level outcomes in project capital evaluations;
- application of customer contribution policies;
- separation of distribution and transmission expenditures and charges;
- link between short-term and long-term investment;
- relationship between new customer connections and general augmentation capital;
- asset management plans; and
- specific policies (e.g. re-conductoring, voltage rationalisation, risk management; replacement of asset groups etc.)

PB Associates aimed to focus its efforts on the areas most relevant to its review of the forward capital plan.

17 This full day meeting took place at EA offices on Thursday 11 November 2004.

This task was undertaken alongside PB Associates' detailed review of selected capital projects[18].

2.3.1 Asset replacement

Specifically, for the proposed asset replacement programme we considered the following issues:

- designation of the asset/assets as transmission assets;
- the basis for the replacement capital forecast;
- evidence available to support the need for the project (e.g. age, condition assessments);
- how the assets have been/will be maintained to ensure they do meet their expected asset life;
- identification of elements of augmentation in the replacement programme– together with justification;
- the project costing methodology; and
- whether it is feasible to undertake the amount of work proposed in the time period.

Some of these issues will apply equally to augmentation (growth) projects.

2.4 HIGH LEVEL REVIEW OF PROJECTS AND INVESTMENT PROGRAMME

The scope of the review allowed for a detailed examination of a selected sample of projects contained within the capital expenditure submission. However, it was also important to undertake a high-level review of each project.

Along with the review of EA's investment framework and a detailed review of a number of key projects, this has allowed PB Associates to formulate a view on the entire EA submission with a reasonable level of confidence. The high-level project review is contained within Section 4.6 and addresses the following considerations for each of the proposed capital projects.

- information provided;
- justification for the proposed project;
- consideration of alternatives;
- cost estimates;
- strategic alignment; and
- risk of projects not proceeding.

In this section we have focused on the projects that are not likely to be categorised as Excluded investments, have not been subject to a detailed review and are not yet under construction.

2.5 DETAILED REVIEW OF SAMPLE PROJECTS

A sample of individual projects has been selected for detailed technical review. This forms an important part of the PB Associates review since, apart from giving us a more

18 Much of the information for this element of the review was collected at EA offices over the two days of Wednesday 17 November 2004 and Thursday 18 November 2004.

complete understanding of the individual projects in question – and therefore better equipping us to formulate a view on prudency and efficiency. The detailed project review also enables us to better understand EA's policies and practices with respect to the management of their transmission assets.

The projects selected for detailed review were agreed between ACCC and PB Associates and were forwarded to EA ahead of the two day on-site discussions[19]. Six specific projects were selected for more detailed scrutiny by PB Associates[20].

For the selected projects we examined the project documentation in detail, talked to the relevant network planning staff and explored the decision processes associated with the proposed works. In the detailed project review PB Associates sought sufficient information to enable a view to be formulated on a number of areas which included (but was not limited to):

- alignment of the development process with the investment governance framework;
- accuracy and completeness of project information;
- capital cost formulation (unit costs sources; uncertainties, contingencies);
- impact on other cost categories;
- links with other projects; and
- overall likely efficiency and effectiveness of the proposed works.

2.6 FORMULATE VIEWS AND REPORT ON FINDINGS

PB Associates will submit their independent report on the EA capital investment proposals in accordance with the ACCC timetable set out in Section1.1.3.

19 EA were notified of the initial list of projects on 9 November 2004. Following the first on-site meeting with EA and further discussions with ACCC, the list of projects was subsequently revised and re-issued to EA on 11 November 2004.

20 One of the 'projects' was, in fact, the entire 132kV transformer replacement programme.

3. REVIEW OF EA'S INTERNAL ARRANGEMENTS

This section of the report describes PB Associates' findings following our review of the environment and governance framework within which EA develops its capital investment programme. The section covers the following main areas of EA's network business activities.

- the EA organisation;
- the capital investment framework;
- internal decision making;
- EA policy and practice

3.1 THE EA ORGANISATION

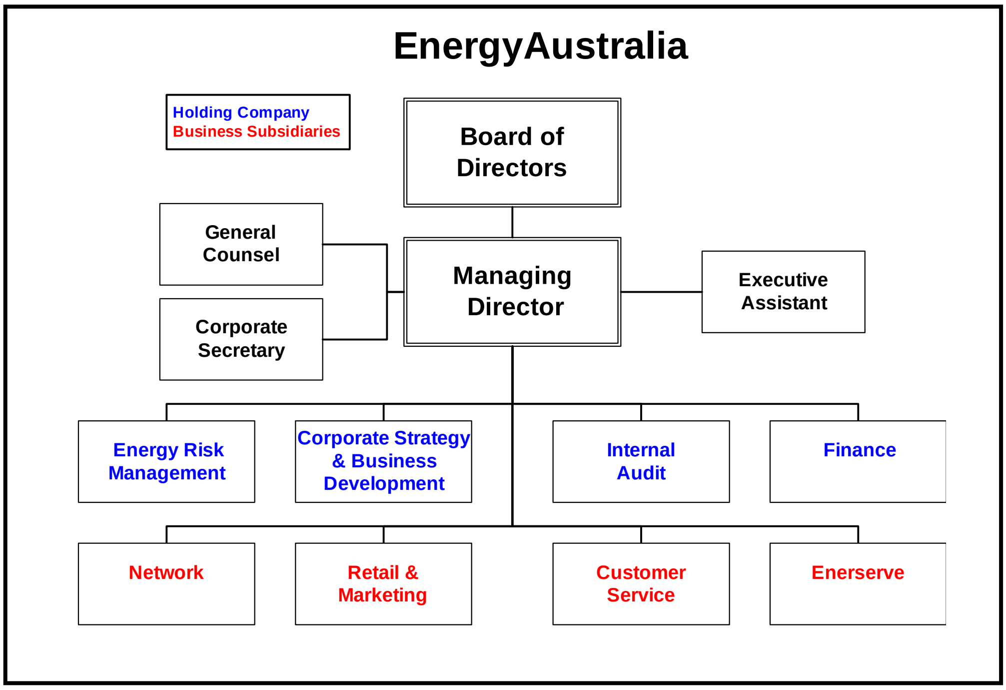
EA is a large utility that carries out a broad range of energy related activities including electricity transmission and distribution, electricity and gas retailing and energy related consulting and contracting services.

The business is structured under a holding company/subsidiary company model. The holding company carries out many of the corporate functions while there are four key subsidiaries:

- **Network** manages a large network asset infrastructure portfolio;
- **Customer Services** which provides the primary interface between EA and its customers;
- **Retail and Marketing** which conducts the energy marketing and sales activities; and
- **EnerServe** which provides a range of engineering, field services, contracting and consulting services for the EA network business and other external customers.

A high level organisational chart structure is shown in Figure 3-1.

Figure 3-1 - EA Business Structure

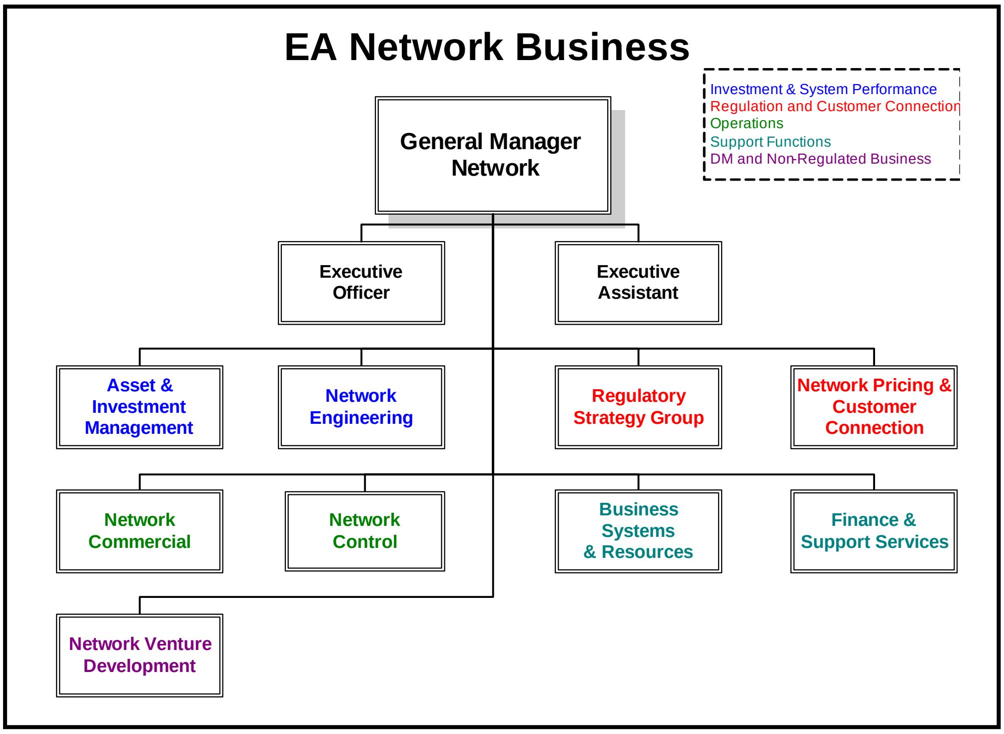


3.1.1 Overview of the network business

EA operates one of the largest electricity networks in Australia distributing electricity to the Sydney, Central Coast and Hunter regions in an area of over 20,000 square kilometres. The network business is responsible for providing electricity supply to over 1.4 million customers within that area.

An overview of the network business structure is shown in Figure 3-2.

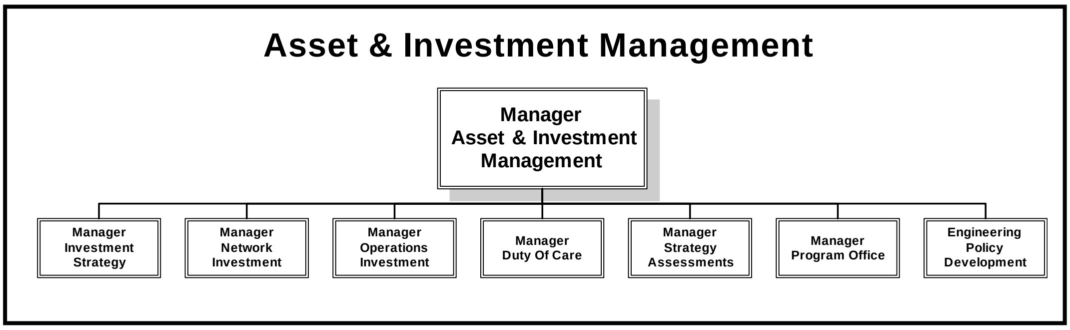
Figure 3-2 – EA Network business organisational structure



3.1.2 Network investment

The EA Asset and Investment Management (AIM) group is responsible for managing capital and operational investments in network assets. The group is structured along the lines shown in Figure 3-3[21].

Figure 3-3 – Network Asset investment Group



3.1.3 Network engineering

The network engineering group provides planning, design and other engineering services for the network business. AIM is the principal beneficiary of Network Engineering's services.

3.1.4 Service provision – EnerServe

EnerServe provides a range of design and field services associated with maintaining and augmenting the EA network infrastructure. All capital project work is either carried out, or managed by, EnerServe – including initial implementation design and costing work.

3.2 THE CAPITAL INVESTMENT FRAMEWORK

In their submission to the ACCC, EA has provided details of their recently introduced Network Investment Governance Framework which has been designed to increase the rigour with which EA approaches the development of regulated network investments. This new process builds on a well established existing approach to network development.

3.2.1 The established EA project development process

Prior to the introduction of the new governance framework in the last year, EA's investment management decisions followed a process which, in the view of PB Associates, is broadly typical of a number of distribution network businesses.

Large projects, defined as being of a value greater than $5m, are subject to Board approval. EA's project development process, before the introduction of the new governance framework, is summarised below.

- network constraints are identified through EA's spatial forecasts;
- specific (and general) condition information is collected to assist in the identification of priority areas for network development;

[21] From a physical network perspective the Hunter region has only limited interconnection at the sub-transmission/distribution level with the larger Sydney/Central Coast region. Consequently, from an operational (business) perspective the Hunter region has a separate planning function area within Network Engineering that manages those planning functions.

- a Value Management (VM) process is used on priority areas to develop plans and strategies;
- high level cost estimates are developed and used as an input to the VM decision making process;
- VM study recommendations are developed by EA's network planning department. This is undertaken in conjunction with EA's internal service provider EnerServe;
- augmentation proposals were referred to an internal demand management team only when demand management (DM) is seen, by network, as being a viable option[22];
- for reliability-driven augmentation – which represents the majority of EA's augmentation programme – EA follows the Code requirements of selecting the option that has the lowest net present value cost that meets the required technical standards;
- a business case is drawn-up to define the costs and benefits of the preferred option;
- the plans are approved by the Asset Investment Manager and more detailed engineering costs are developed; and
- the appropriate level of approval is sought (depending on project value) once the detailed network development plan is developed.

Many of these development procedures still form an important part of the new EA governance process.

3.2.2 The new Governance framework

EA has recently identified a need to improve its investment decision making and the tracking of project expenditure. This has resulted in the implementation of a new governance framework. Since July 2004, all new network developments have been initiated under the new governance arrangements[23]. The key processes associated with the new governance framework are summarised below and shown diagrammatically in Figure 3-4.

The key steps and processes in EA's governance framework are as follows.

1. Identify the issues where network requirements are defined in terms of constraints, reliability improvements, duty of care obligations (safety, health, environment, regulatory etc), equipment condition and augmentation for customer connections. In this step of the process the '*needs'* are identified and documented to produce an 'Identification of Needs Document'. This is a key document in the project development process.

2. Develop feasible alternative solutions – including appropriate cost estimates.

3. Planning and justification for the selection of the most appropriate option[24].

22 Under the new governance arrangements, any growth-driven constraint (where the proposed investment is likely to be greater than $1m) is referred to the DM group for a strategic screening test to determine the viability of various DM options. If the likely investment is estimated to be less than $1m, Asset Management decides whether or not to refer the constraint to the DM group.

23 The majority of the projects in the EA capital submission pre-date the new governance arrangements. Some attempts have been made by EA to absorb these older projects into the new process.

24 Under EA's new governance framework, projects >$10m may require an independent review at the discretion of GM-Network.

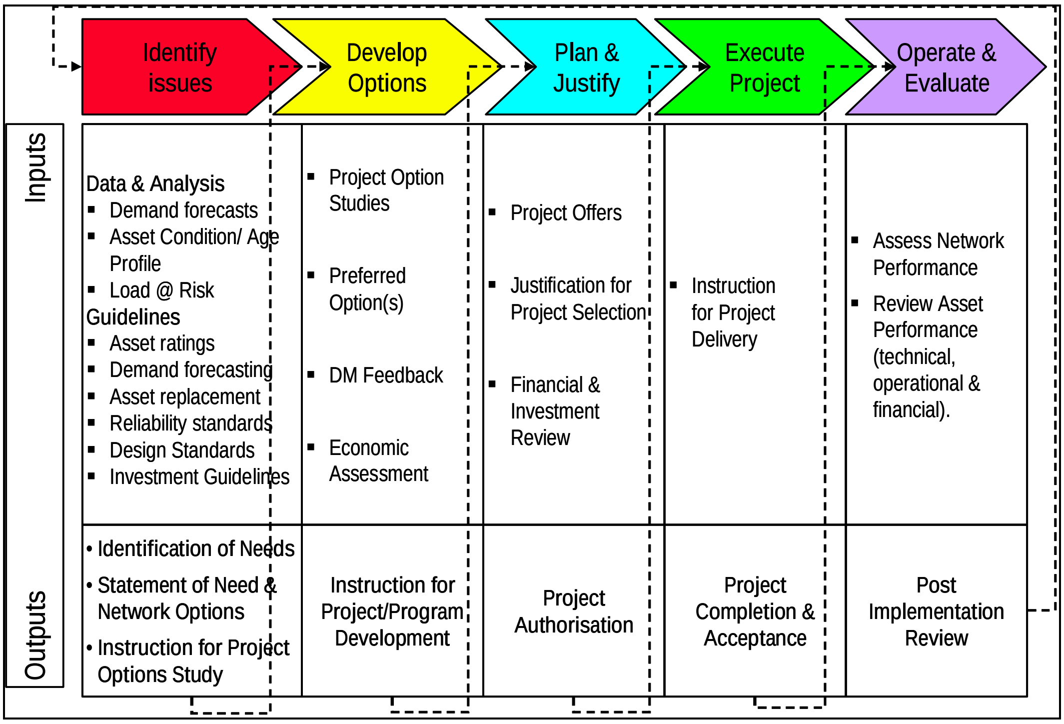
4. Project execution where the selected option is delivered.

5. Operation and evaluation where post implementation reviews may be undertaken to examine the effectiveness of the solution.

Figure 3-5 summarises some of the outputs from each of the governance steps as well as providing an overview of the roles played by various parts of the network business.

While the overall process is of relevance to the evaluation of EA's capital expenditure submission, of primary significance to the PB Associates review are the first three steps – i.e. justification for the project; consideration of all feasible alternatives and that the costs and relative merits of each of the projects have been adequately evaluated.

Figure 3-4 - Outline of the new EA governance framework



Courtesy of Energy Australia

Figure 3-5 – Outputs of EA Governance Process Steps

Investment Governance Process - Outputs

	Identify issues	Develop Options	Plan & Justify	Execute Project	Operate & Evaluate
Network Engineering	• Asset rating Guidelines • Network Modelling • Capacity Reviews • Technical Analysis • *Instruction for Project Options Study*	• Technical direction of project options studies • Technical assurance	• Technical scope (design standards) • Approve & issues technical documents (DNP,SNP, Concept design)	• Technical clarification	▪ Data & system feedback
Asset & Investment Management.	• Annual Capital Planning • *Identification of Needs* • (*Statement of Need & Network Options*)	• Instruction for Project/ Program Development • Risk Assessment Framework • Value Management Policy & Facilitation • Investment Evaluation Guidelines	• Economic assessment of options • Financial & Investment Review • Project Authorisation	• Variation approval	▪ Post Implementation Review
Demand Management	• Publication of compliance documents.	• DM Project Options Report	• DM Project Offer	• DM Project Management & Delivery	▪ DM Operational & Contract Management.
Commercial	• LT Planning of Service Provider Requirements		• Issue request for project offers • Commercial framework	• Document commercial arrangements • Manage variation process • Project Completion & Acceptance	

Courtesy of Energy Australia

3.2.3 PB Associates view on the EA capital investment framework

EA do not differentiate between transmission and distribution assets in the way in which it makes its investment decisions. The EA investment framework does not require prospective developments to be treated any differently by virtue of their designation as either distribution and or transmission assets. PB Associates believe that this is appropriate since it would seem to encourage a coordinated approach to network development and discourage sub-optimal investment.

PB Associates has reviewed EA's new capital governance framework and believes that it provides a sound basis for the identification, analysis and development of effective network development. We believe that EA is likely to make significant improvements to its investment decision making processes if it continues to pursue the path it has set for itself in establishing the new processes. PB Associates notes that EA has attempted to absorb a number of older projects into the new governance framework.

PB Associates notes, however, that the process is only relatively new and EA acknowledges that the majority of the projects proposed in the capital expenditure submission have either not been developed under, or not completely followed, all of the processes required under EA's new investment governance framework. It is apparent to PB Associates that although, under the 'old' framework, EA may well have carried out some, or all, of the necessary steps, in many cases this was informal and (relatively) poorly documented[25].

Furthermore, PB Associates found there to be a significant variation in the level of detailed information provided for each project. However, we are aware that EA's submission includes projects at various stages of development – ranging from projects presently under construction, to projects where there is an identified need but for which option development is at an early stage. This goes some way to account for the varying levels of project specific information across EA's proposed project portfolio.

25 It should be noted that EA cooperated fully with PB Associates in this review – providing the level of information required for individual project assessments to be made.

In Appendix A we list each proposed project and indicate whether it forms part of the new governance framework together with its present status.

Demand management

The Demand Management (DM) group has been separated from the Asset Management Group and is incorporated in the Network Ventures Group. EA claim that this separation allows the DM group to work as independent consultants to Asset Management for DM projects. Asset Management is provided with both supply side options from Network Engineering and demand side options from DM group[26].

We would advocate an increased level of integration of the DM group into the investment decision making process to ensure that demand side prospects and opportunities are more formally pursued for the deferral of network capacity constraint projects.

We recognise that the time taken to explore DM options can often be mis-aligned with the development path for 'traditional' solutions, and that very often DM can only contribute (comparatively) small demand reductions, nevertheless, we believe there to be some merit in further developing the role of the DM group in the EA investment decision making framework.

3.3 INTERNAL DECISION MAKING

The AIM group has primary responsibility for managing the process through to the stage of authorising investment in nominated projects. While AIM may recommend the adoption of various projects or work programs, the final approval is subject to EA's capital approval procedures.

PB Associates has been advised that EA's procedures now require a Value Management Study to be undertaken for individual augmentation projects with a cost in excess of $5m.

There are a number of guidelines that have been developed by EA to assist in the assessment of each of the steps associated with developing network project – from identification through to post implementation evaluation. These guidelines have been developed in the functional areas of asset rating, load forecasting, asset replacement prioritisation, network reliability planning and network design.

PB Associates has either reviewed or discussed practices with EA staff in relation to a number of these documents and believes that all have been developed using sound (and reasonable) engineering and commercial principles.

EA's internal decision making processes have historically been somewhat informal at each of the various stages. EA relies, to a great extent, on the relevant experience and judgement of engineering staff without necessarily requiring extensive supporting technical and commercial documentation. This reliance on technical staff, in the formulation of network project options, is common across network businesses of this type.

EA has restructured the network business with the AIM group now providing a focus for capital and operational investment management. The current structure, together with the new capital governance investment framework, provides a more rigorous basis for EA staff to formally identify project needs, identify potential options to satisfy identified capital requirements needs and compare competing options on an investment efficiency basis. The requirement for documentation of the various steps of the process, with an associated review by AIM, should allow EA to more comprehensively consider project alternatives objectively and improve internal decision making right the way through the project development process.

[26] PB Associates notes that projects estimated to be less than $1m are referred to the DM group at the discretion of Asset Management.

PB Associates is not aware of any formal EA guidelines to assist with this option formulation process – which may otherwise promote a consistent approach to the development of viable alternatives.

3.3.1 Capital approval procedures

EA are currently developing a set of formal investment evaluation guidelines which are to incorporate requirements, inter alia, for the application of the Regulatory Test where this is required under the National Electricity Code.

EA has an established approval hierarchy for capital expenditure. The current capital expenditure approval delegations used within EA are as set out in Table 3-1. This relates to network related capital expenditure.

Table 3-1 - EA Capital Expenditure internal approval levels

Project Value	Approval level
< $1m	Manager AIM
< $2m	General Manager Network
< $5m	Managing Director
> $5m	EA Board

As a matter of course EA does not publish a regulatory test on a project until is has been the subject of Management Board approval in accordance with the above approval guidelines[27]. For future large projects EA intends to obtain an independent review of alternative solutions identified under the regulatory test.

In addition to its involvement in the capital authorisation process described, EA's Board Sub-committee also investigates projects having significant expenditure variations.

3.4 EA POLICY AND PRACTICE

In this section we describe some of the functions undertaken by EA in pursuit of the development of its transmission network.

3.4.1 Power system planning

The power system planning tools and procedures used by EA in the development of its network are typical of a distribution asset management business.

3.4.1.1 Strategic planning

At the transmission planning level EA has regular joint planning meetings with TransGrid to discuss projects of mutual interest[28].

EA has historically used a 10 year planning horizon for all of its major network assets but it is currently considering introducing a longer time horizon for transmission assets. A 15

[27] PB Associates notes that, until recently, it was a requirement to conduct the Regulatory Test process within 12 months of project commencement. This 12 month requirement has subsequently been dropped. The most appropriate time to run the Test may be influenced by the regulatory treatment of the associated project cost estimates.

[28] These are typically held every two to three months.

year planning horizon for transmission and sub-transmission assets is espoused in the NSW Treasury asset valuation guidelines.

As part of its longer term planning approach EA has published longer term strategic plans for the Sydney CBD area and the Hunter region. As part of this review PB Associates has considered the alignment of submitted individual projects with EA's overall strategic planning.

3.4.1.2 Reliability Criteria

EA has established its system planning reliability criteria in its Network Management System Procedures. PB Associates has reviewed the relevant document associated with EA planning standards[29].

Under this procedure major infrastructure development projects are to be assessed through a Value Management process in accordance with the Australian/New Zealand standard. The process includes consideration of alternatives to network construction – such as demand management.

As part of the procedure EA has documented guidelines or reliability criteria to be used as a filter for the purpose of establishing if further investigation is required within certain network asset areas. EA uses a mix of deterministic and risk management criteria which vary according to the size and nature of the network loads. Some of the key criteria which are of relevance to the transmission projects are described below.

General Principles

The EA general principles associated with network reliability criteria are listed below. These are:

- under normal system conditions, with all system equipment in service, the loading on each element is not to exceed the recurrent cyclic rating of that element;
- voltage levels will remain within acceptable limits during first contingency outages;
- the loading on each element is not to exceed the emergency cyclic rating of that element; and
- at worst, minor load curtailments may be necessary to meet the above criteria if unplanned outages occur at times of peak load.

132 kV lines and Sub-Transmission Substation (STS) transformers

For STS transformers the reliability criteria are:

- deterministic (n-1) criteria for 132kV lines and sub-transmission (132/66kV or 132/33kV) substation transformers; and
- the Inner Metropolitan 132kV system utilises modified (n-2) criteria related to the simultaneous outage of Cable 41[30] and any 132kV feeder or 330/132kV transformer or an outage of any section of 132kV busbar.

Zone Substations

29 EA System Reliability Planning Standards dated 22/12/2003.

30 Cable 41 is a 330kV cable owned and operated by TransGrid. The cable runs between TransGrid's Sydney South and Beaconsfield substations and has a cyclic rating of 660MVA. It is one of two TransGrid circuits which are of high strategic importance in the support of Sydney CBD.

For Zone substation the reliability criteria are:

- network loads of less than 3MVA will be supplied by a single transformer; and
- for network loads above 3MVA, sufficient redundancy will be provided to keep the risk of load shedding during first contingency outages to less than 1% per annum.

3.4.2 Asset management

In this section we describe some of the polices and practices associated with EA's management of its transmission assets.

3.4.2.1 EA's high-level strategy

EA's asset and investment management replacement/refurbishment strategy document[31] summarises the EA approach to managing the replacement and refurbishment of its network assets. The high level strategies incorporate condition monitoring, risk management aspects (setting limits for percentage of assets exceeding the regulatory asset life), and seeking to improve the asset base (aim to reduce the percentage of the asset base exceeding the regulatory standard asset life to 10% in the next 10 years).

3.4.2.2 EA's medium-level strategy

The medium level strategies include considering the age and condition of specific asset categories, reviewing asset failures/faults, formulating replacement programs and prioritising these plans. Replacement timing is to be determined from a Failure Mode, Effects and Criticality Analysis (FMECA). The policies and strategies described represent good industry practice and should provide a prudent and efficient capital replacement programme if implemented rigorously by EA. Section 3.6 of the EA policy document notes that this strategy has only recently been put in place, and so the collection and analysis of required data has only recently been initiated. The procedure states that the current replacement priorities have been developed based on a comprehensive array of asset information. PB Associates understands this to include condition reports, and general historical records.

3.4.2.3 EA are developing a risk assessment approach to asset management

Prior to July 2004, EA generally followed a policy of identifying assets as due for replacement when they reached the end of their (regulatory) standard asset lives or when augmentation was needed to meet forecast load growth. From 1999, EA also started developing new approaches to asset maintenance and has now moved away from time-based maintenance to Reliability Centred Maintenance (RCM). Part of this strategy involves the use of Condition Risk Assessment (CRA), based on principles from Australian Standard 4360:1999[32] and is customised for EA's specific asset base and operational situation.

For risk assessment, EA's regulated transmission assets have been divided into the following five main categories:

- buildings;
- HV switchgear;

[31] Policy document ARR 01.01 Asset & Investment Management – Replacement/Refurbishment Strategies and Policies (Issue Date 12/10/04).

[32] Now superseded by AS/NZS 4360:2004.

- transformers and reactors;
- underground feeder cables and overhead lines; and
- capacitor banks.

Under this strategy, a risk rating for operating items of equipment is prepared, divided into three periods and presented on a matrix showing, by coded category, recommended replacement time envelopes:

- less than 5 years;
- between 5 and 10 years; and
- between 10 and 20 years.

EA's network risk matrix is shown in Figure 3-6.

Figure 3-6 - Network risk matrix

Likelihood		Consequences				
		1	2	3	4	5
		Insignificant	Minor	Moderate	Major	Catastrophic
A	Almost Certain	A1	A2	A3	A4	A5
B	Likely	B1	B2	B3	B4	B5
C	Possible	C1	C2	C3	C4	C5
D	Unlikely	D1	D2	D3	D4	D5
E	Rare	E1	E2	E3	E4	E5

Risk Rating

Extreme	Immediate Action Required
High	Senior Management Attention Needed
Moderate	Management Responsibility Must Be Specified
Low	Manage By Routine Procedures

Note: AS4360 (Risk Management - 1999) Hazard and Risk Rating Matrix Amended to reflect EA business drivers.

EA has allocated their own definitions against this standard industry risk assessment methodology. This includes an assessment of consequences based on the perceived impact the following:

- safety;
- environmental;
- reliability;
- property damage;
- liability claims; and
- adverse publicity.

Reliability consequence is further defined by EA according to the amount of load lost and the duration for which it is lost.

Likelihood of occurrence is defined in terms of the experience and frequency of such events occurring both within EA and within the industry in general.

EA had been undertaking condition assessments of transformers and other items routinely in the past, but had not been collating or coordinating condition information under the umbrella of an overall asset management and risk assessment system. From July 2004, the new system provides EA with a coordinated company wide system for asset management and assessment of risks.

EA has indicated that detailed condition and risk assessment has generally allowed asset life to be extended past standard asset life – although there have been some cases where it has shown that asset life for a particular item is shorter than standard[33].

In 2004, EA engaged consultants SKM to undertake comprehensive studies on asset age and asset replacement, resulting in two reports, 'Transmission Network Age Projection, October 2004' and 'Aged Asset Replacement Projection, September 2004'. These reports examined various scenarios for replacement and the capital expenditure implications for EA and provide EA with replacement periods for transmission assets by type and location – based on age. The SKM modelling does not take into account asset specific assessments, but, instead, bases the life of assets on their standard or regulatory assumed lifetimes[34].

3.4.2.4 Refurbishment definitions

EA has two standards for refurbishment of transformers – 'mid-life' and 'major'.

Mid-life refurbishment includes tightening the winding (which usually requires the whole winding being removed from the tank), replacing the bushings, major overhaul of the tap-changer, repairing rust and painting the entire Transformer[35].

Major refurbishment includes the rewinding of the entire HV or LV winding, replacing the bushings, major overhaul of the tap-changer, repairing rust and painting the entire transformer.

3.4.3 Augmentation investment

Augmentation investment is required to support additional load growth requirements or for supply to new customers connections. Augmentation criteria can be traced back to the reliability criteria discussed in Section 3.4.1.2.

3.4.3.1 Load forecasting

EA has developed a spatial network forecasting process incorporating the following key elements:

33 An example of shorter life is: some relatively modern transformers where a combination of less conservative design compared with older transformers, plus relatively high initial loadings, have contributed to premature ageing of insulation.

34 Based on an extract from the SKM report 'Aged Asset Replacement Projection', Sept 2004, Exec Summary.

35 EA advise that the approximate cost of a mid-life refurbishment (for transmission zone transformers) is $80,000 and $230,000 for a major refurbishment. The costs for larger transmission transformers may be more. Note also that these estimates exclude transportation costs and any additional costs which may be associated with the installation of spare transformers.

- historical load analysis (both summer and winter) using 4 months of Zone substation SCADA data involving data normalisation associated with situations such as abnormal switching or outage contingencies;
- determination of future growth rates using trend-lines as the initial approach and reviewed for any known non-trend factors e.g. spot loads, land releases etc;
- publishing of the forecasts for high medium and low scenarios[36]; and
- input into sub-transmission forecasts by 'rolling up' zone substation forecasts.

Since load data is gathered at the zone substation level, diversity is applied by considering zone substation loads at the time of total system maximum demand peak and then aggregating at STS level. PB Associates notes that this approach may not factor in any potential geographic diversity at peak loading times although this is carried out as a separate exercise for the Hunter region and the combined Sydney Central Coast region.

EA also use a 'top down' approach to load forecasting – using econometric techniques based on historical data and forecast data from external sources[37] and then factoring in anticipated customer number increases and average customer usage projections. The top down forecasts and bottom up zone substation forecasts are aligned to ensure consistency.

3.4.3.2 Load flow studies

EA undertakes load-flow studies on either a project specific basis or on a routine basis. Studies are run for normal operating system conditions and also for the system operating with all credible contingencies.

The load forecasting information is used as the basis for the loads incorporated into the load flow models. Network asset equipment ratings are maintained within a database and updated as augmentation and other network changes are undertaken.

The load-flow software is able to identify network elements that may not meet the required reliability criteria and further analysis is undertaken in these cases.

3.4.3.3 Risk assessment

At the Zone substation level EA has adopted a 'Substation Load Risk Assessment' approach in establishing a probability-based risk profile for zone substation assets. This approach involves assessing the coincident probability of load exceeding the firm rating of the network element – including the coincidence of an outage of another critical network element. The failure of the network element under its maximum normal capacity is also factored into the analysis.

3.4.4 Customer connection

During the course of the current regulatory review period there have been no capital contributions recovered from customers connecting to the transmission network.

EA has advised PB Associates that connection contribution principles have been developed following negotiations between EA and a large customer for supply to a development near Kurri[38]. EA are of the view that these principles should apply equally

[36] Note that EA generally uses the medium scenario for network planning purposes.

[37] National Institute of Economic and Industry Research (NIEIR) data for example.

[38] The customer subsequently decided to take an initial lower capacity supply and to therefore be connected to EA's distribution network.

to both transmission and distribution connections. These arrangements are described below and are similar to those which currently apply to the developers of underground residential subdivisions.

- customer to pay (or provide) dedicated connection line(s);
- customer to pay for (or provide) dedicated substation site works, buildings and non-recoverable equipment;
- Energy Australia to provide recoverable equipment for the substation (generally the transformer(s) and some switchgear);
- customer to provide a bank guarantee to the value of the recoverable equipment for a period of 5-10 years; and
- bank guarantee to be released provided that the loading on the substation reaches a sufficient level.

A critique of EA's connection policy is outside of the scope of this review. PB Associates understands that Energy Australia's policy for customer contributions[39] has been forwarded to ACCC.

3.4.4.1 Procedural Considerations

PB Associates has reviewed the documentation provided by EA in relation to the procedural aspects relating to this section of the report and had a number of discussions with various EA staff in relation to certain of these procedures. PB Associates considers that the approaches taken by EA are sound and appropriate and in some cases clearly at an advanced stage.

[39] Known to EA as ES8.

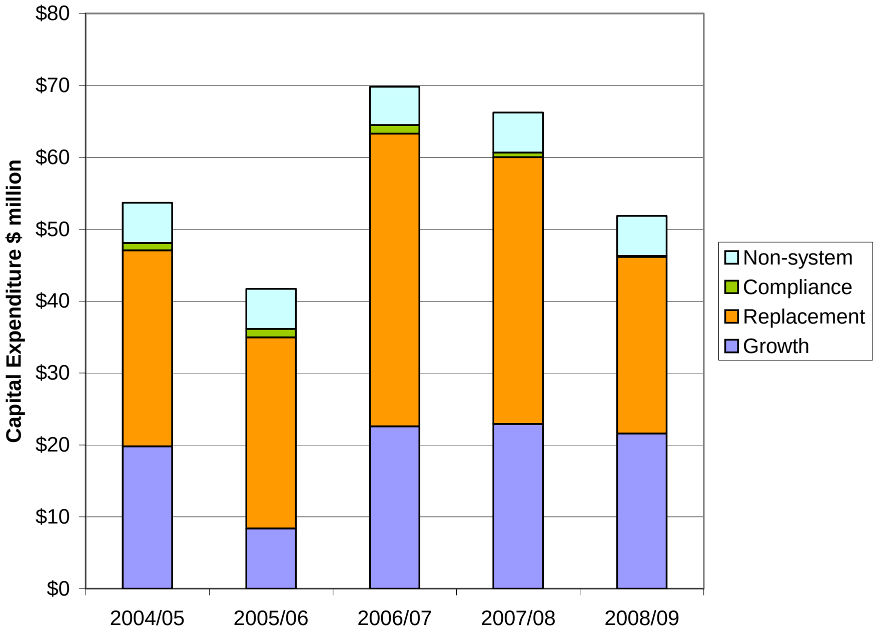
4. REVIEW OF CAPITAL PROGRAMME

In this section we present PB Associates findings of a high-level review of the proposed EA forward capital programme. As part of this section of the work we have reviewed all of the proposed projects in the EA submission. Some projects which we have identified as key projects, but which have not being subject to a detail review, have been given special attention in this section. The high level comments on the remainder of the projects can be found in Appendix A. PB Associates findings of its detailed review of the sample projects are reported in Section 5 of this report.

4.1 SUMMARY OF THE PROPOSED EXPENDITURE PROGRAMME

Energy Australia's revised transmission capital investment programme for the period 2004-2009[40], describes a total capital expenditure requirement for the period of $255.6 million. In addition to this is $27.7m over the same period for non-system expenditure items[41]. The capital projects described are divided into three major categories being Growth, Replacement and Compliance. Figure 4-1 illustrates the level of expenditure forecast by category for each year.

Figure 4-1 – Energy Australia forecast capital expenditure 2004/05 to 2008/09



The average capital expenditure level is $57 million per year with the replacement expenditure representing approximately 55 percent of the total, growth related projects 34 percent and the remainder for compliance projects and non-system expenditure.

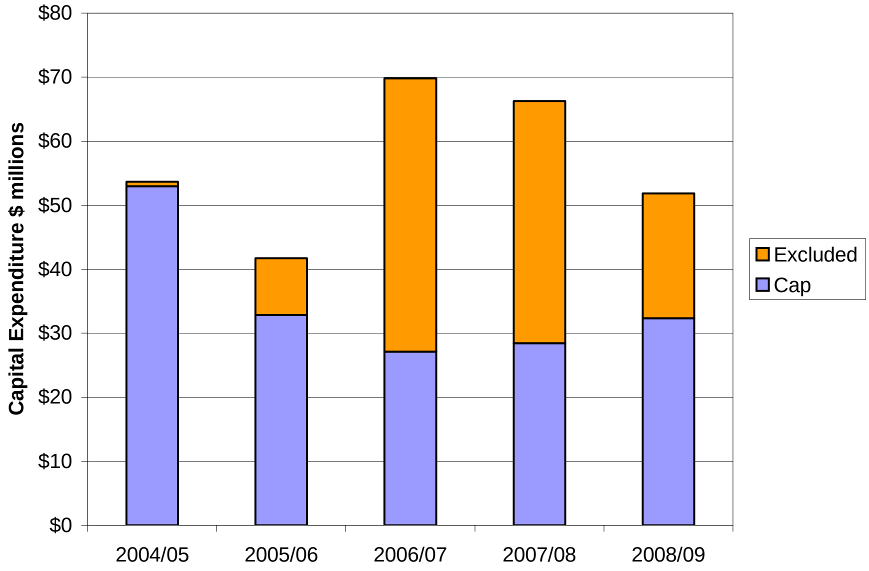
Approximately 61 percent of the capital forecast is for expenditure to be included in the proposed cap whilst the remainder are categorised as excluded projects. Figure 4-2

40 'Revised Transmission Capital Investment Program', Energy Australia's submission to the Australian Competition & Consumer Commission, 29 October 2004.

41 This is unchanged from EA's initial submission (dated September 2003) and provides for IT; vehicles and plant; office equipment and furniture; land and buildings.

illustrates the ratio of Cap to Excluded projects for each of the five years in the regulatory period.

Figure 4-2 – Capital expenditure by cap and excluded projects



When compared with historic capital expenditure levels the 2004/05 to 2008/09 forecast represents a significant increase. The total capital forecast for 2004/05 to 2008/09 is approximately double the actual expenditure of the previous five year period. The total actual spend for 1999/00 to 2003/04 was $139 million compared with a forecast expenditure of $283 million[42] for the next regulatory period. Figure 4-3 provides a graphical illustration of the change in expenditure levels[43].

The increase in capital expenditure is mainly associated with asset replacement projects. The comparison between historic levels of replacement capital expenditure and that forecast by EA is illustrated in Figure 4-4[44].

42 Includes $27.7m for non-system capital expenditure.

43 Note that all expenditure values are presented in 2004 dollars.

44 It should be noted that the value of the EA transmission asset base increased in the period 2004/05 following a re-classification of some assets from 'distribution' to 'transmission' as result of a change in operation and their corresponding definition under the Code. This should be considered when comparing past and future replacement capital expenditure.

Figure 4-3 – Energy Australia actual and forecast capital expenditure

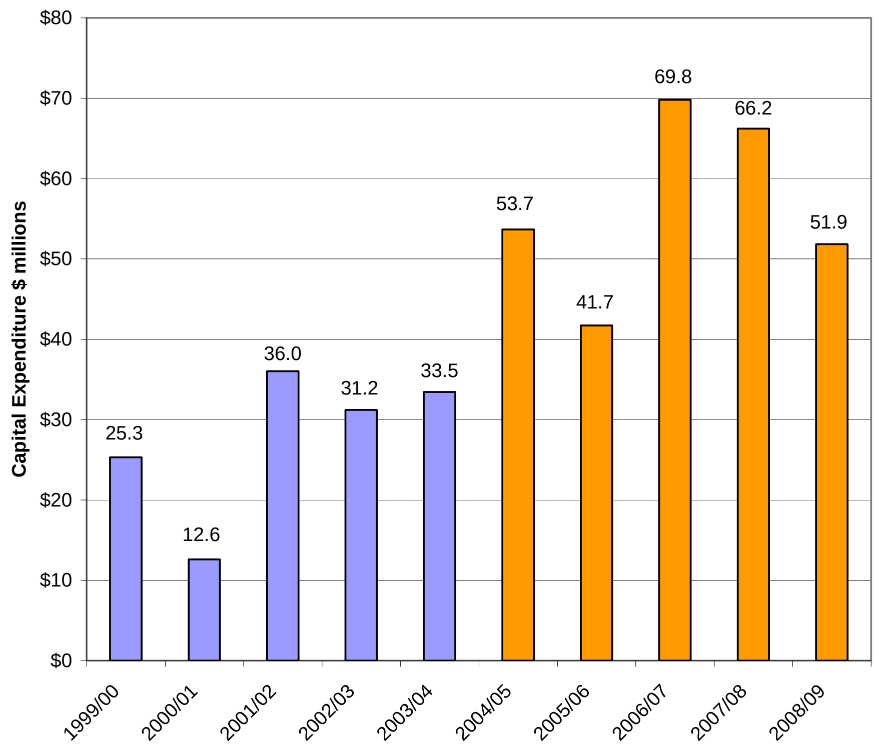
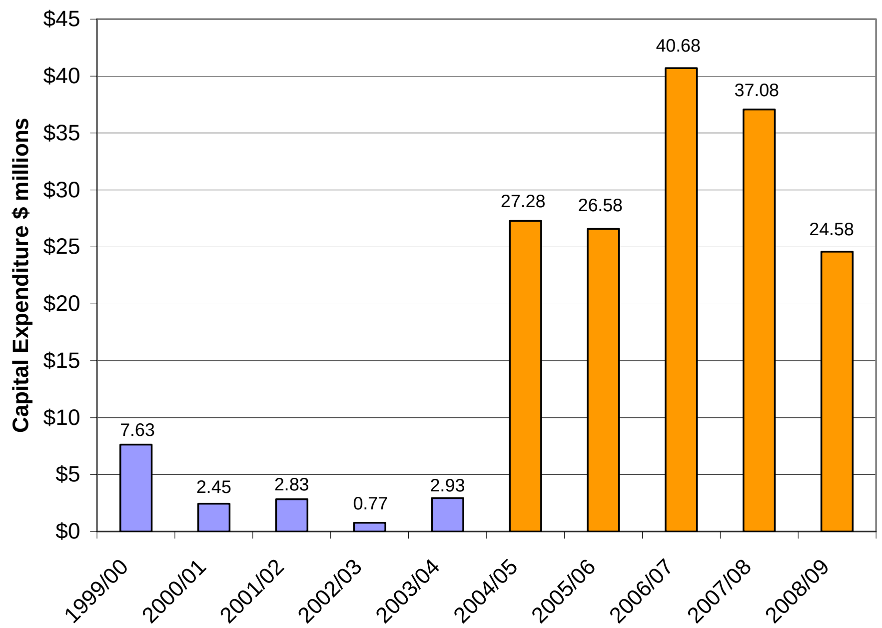


Figure 4-4 – Energy Australia actual and forecast replacement expenditure



4.2 UNIT COSTS

Costs used by EA in the submission have been derived from a number of different sources. The actual source for a given project depends on its position in the project life cycle.. EA has indicated that cost estimates for projects at an early stage of planning are usually prepared using internally sourced generic unit rates. As the level of detail increases during project design and preparation, the estimated project completion cost becomes more accurate and will often reduce[45].

Sources used by EA in the development of projects costs for the capital expenditure submission include:

- NSW Treasury Draft: 'Valuation of Electricity Network Assets, A Policy Guideline for NSW DNSPs, May 2003' (guidelines);
- SKM replacement cost data prepared in 2002;
- SKM reports prepared during 2004;
- EA internal preliminary unit rate estimating data – normally from previous project data;
- manufacturers' budget estimates and quotations; and
- service provider (EnerServe) costs – detailed estimates included in Project Offers.

4.2.1 Internal consistency

The scope of this study by PB Associates has not provided for detailed comparison for cost consistency. However, EA appear to have used similar unit costs for similar items in substations, in particular, transformers and switchgear.

4.2.2 External benchmarking

As the NSW Treasury draft 'Guidelines' (May 2003) have been used by SKM, much of the cost estimation within projects uses these guidelines as a basis, although adjustments have been made for other factors.

4.3 AUGMENTATION PROJECTS

Table 4-1 shows EA's proposed augmentation (growth-related) projects for the five year period 2004/05 to 2008/09 inclusive[46].

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45 EA advised PB Associates that, historically, they have tended to under estimate the costs of circuit construction due to unexpected easement issues and longer actual route lengths.

46 'Revised Transmission Capital Investment Program', Energy Australia's submission to the Australian Competition & Consumer Commission, 29 October 2004, Page 28, Table 1.

Table 4-1 – EA proposed augmentation projects

ACCC AUGMENTATION			
PROJECT	**CAP**	**EXCLUDED**	**TOTAL**
Cap			
Haymarket & Campbell St Substation	3.2		3.2
Installation of Beresfield Sub-transmission Substation	12.6		12.6
Transmission Boundary Metering	2.3		2.3
Kurri Distribution Connections	0.6		0.6
132kV Development in Newcastle Western Corridor	8.5		8.5
Gosford STS Capacitor Installation	0.6		0.6
Drummoyne Zone Substation Constraint	4.2		4.2
Additional Distribution Connections from Tomago STS	1.4		1.4
Minor Augmentation of Inner Metropolitan 132kV Network	4.9		4.9
West Gosford Zone Constraint	3.9		3.9
Macquarie Park Zone Constraint	3.8		3.8
Upgrade Feeder 926	0.7		0.7
132kV Network Development in Mid-Southern Central Coast	0.8		0.8
Possible Kurri harmonic filter	0.6		0.6
Excluded			
Major Inner Metropolitan 132kV Network Development		35.6	35.6
Lower hunter 132kV Network Development		11.6	11.6
Tunnel Arbitration		Confidential	Confidential
Unconfirmed Customer Connections	Indeterminate	Indeterminate	Indeterminate
TOTAL AUGMENTATION	**48.0**	**47.3**	**95.3**

4.4 ASSET REPLACEMENT

Table 4-2 shows a summary of EA's proposed $156 million replacement capital expenditure forecast. The forecast is made up of eight main projects with costs between $12.7 and $36.7 million per project.

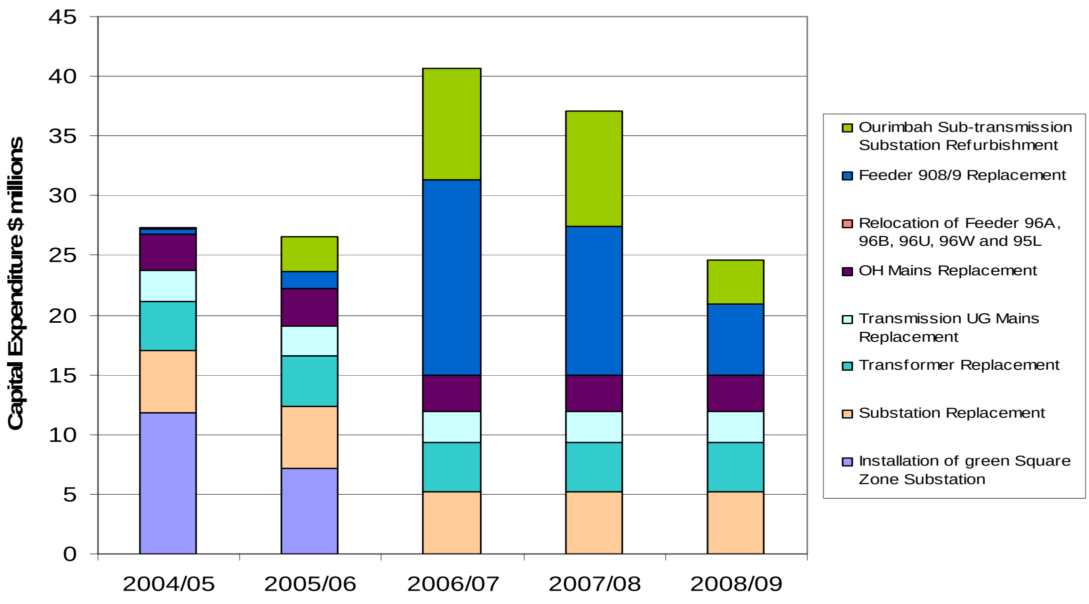
Table 4-2 Replacement Capital Expenditure by Project

ACCC REPLACEMENT			
PROJECT	**CAP**	**EXCLUDED**	**TOTAL**
Cap			
Installation Green Square Zn	19.0		19.0
Substation Equipment	26.0		26.0
Transformers	20.8		20.8
UG Mains	12.7		12.7
OH Mains	15.4		15.4
Relocation 132kV Feeders 96A 96B 96U 96W & 95L	0.0		0.0
Excluded			
Replace 132kV Feeder 908 / 909		36.7	36.7
Ourimbah STS Refurbishment		25.7	25.7
TOTAL REPLACEMENT	**93.9**	**62.4**	**156.3**

Figure 4-5 illustrates the expenditure proposed for each project by the year in which it is forecast to be spent. Expenditure for the Green Square substation is forecast to be complete by 2005/06, whereas other projects such as the Ourimbah Sub-transmission Substation Refurbishment are not due to commence until 2005/06 and will continue throughout remainder of the regulatory period.

The overall asset replacement programme has been devised to reduce the present 7% (2004) of assets above their standard lives to 4% in 2009. EA has acknowledged that asset replacement during the current regulatory period has been relatively low and that this has contributed to a relatively high level of capital expenditure in the Revised Submission.

Figure 4-5 Replacement Capital Expenditure by Project and by Year



4.4.1 Replacement criteria

For transmission assets, EA has undertaken individual condition assessment of all major items, and generic assessment of items, systems and installations where individual assessment is not possible, for example, underground cables.

For major items such as transformers, EA has detailed condition assessment reports and where it is known that the condition of an item or group of items is poor and likely to require replacement, relevant details are submitted to the Network Investment section for consideration of any augmentation requirements and demand management opportunities.

EA also considers the standard age of the assets and applies a dual approach of both condition assessment and consideration of asset life.

EA has an overall objective to ensure that no more than 10% of the total asset base (in dollar terms) exceeds the standard regulatory life. EA apply different approaches to asset replacement for distribution and transmission in this respect. In distribution, for example, it is permitted for some asset categories (such as poles and lines) to have up to 40% of assets (dollar value) above the standard life – whereas for transmission assets, the proportion above their regulatory life in any one category is limited 10%.

The proportion of assets which exceeds the standard age is given in Table 4-3[47].

Table 4-3 - Transmission assets groups over standard age

Asset groups over standard age			
Asset Groups	Total RC for Asset Group (excluding WIP and easements) ($m)	Theoretical Std Life of the Asset Group	Assets over Standard Life (%)
TS	397	52	4.1%
ZN	2008	50	8.9%
TMOH	379	50	11.4%
TMUG	1586	45	25.6%

Key to EA abbreviations:

TS: Transmission substation

ZN: Zone substation

TMOH: Transmission overhead mains

TMUG: Transmission underground mains

PB Associates requested that EA elaborate further on why the target for transmission assets should be 10% beyond standard lives compared to 40% for distribution; and how this aligns with the balance of maintenance effort/focus.

EA highlighted the fact that the assets which are in excess of their regulatory age are primarily 'simple' assets with few failure modes. EA has advised that the asset class "Sub-transmission[48]" is the asset class with the largest percentage of assets above regulatory age. This age profile is driven by large amounts of 33kV HSL cables installed between 1930 and 1960. EA advise that this cable is a relatively simple technology with few failure modes and a generally short repair time.

EA has advised that transmission cables, on the other hand, are all complex pressure type cables (whether gas or oil) which have more failure modes than simple non-pressure type cables and have much longer repair times. EA has advised that complexity and repair times results in both higher maintenance costs and a significant impact on system security whilst equipment is out of service.

EA believe that both these factors make it necessary to adopt different criteria for the age limits for transmission and distribution mains.

PB Associates accept that transmission circuits are often of strategically higher importance than distribution cables and that they are undoubtedly more expensive and more time consuming to repair when subject to a fault. However, the time to repair and the strategic importance are the reasons such circuits are planned and constructed with an amount of system redundancy.

PB Associates remain to be convinced that the complexity of cable construction and the cost of repair should be the drivers behind the extent to which an asset is permitted to operate beyond it standard (economic) life. We believe that this decision should be

47 Based on information provided by EA in its response to PB Associates 'initial questions'.

48 EA advise that this asset class comprises predominantly underground distribution mains.

based on a sound condition and risk assessment process – such as that advocated and already being progressed by EA.

It should be noted that for all transmission transformers, EA's risk assessment resulted in the view that the asset should be replaced earlier than suggested by its regulatory standard asset life. The same applied for the majority of distribution transformers – although PB Associates understands that condition assessments have resulted in some distribution assets being allocated an expected life in excess of the standard asset life.

4.5 EXCLUDED PROJECTS

Excluded projects are those investments which are considered to be significant but uncertain. In such cases it is appropriate to remove the projects from the main exante allowance. This may be because of a significant level of uncertainty associated with its requirement or timing or because the investment is outside the reasonable control of EA. If the project is sufficiently large (in value) such that if it was included in the cap, and it did not proceed, it would give rise to a variation in regulated revenues of more than 10%, then the investment would be classified as an excluded project.

EA may also apply to the ACCC for specific projects to be excluded from the main exante allowance even if the 10% threshold is not satisfied. The ACCC will exercise its discretion in such cases. Investments excluded from the main allowance should be linked to clear investment drivers such as major new customer connections or new generation facilities[49].

EA's proposed Excluded projects fall into both replacement and growth (augmentation) categories and are listed in Table 4-4.

Table 4-4 – EA submitted Excluded projects

Project Name	Type	Submission Project No.	Submission page No.
Major Inner Metropolitan 132kV Network Development..	Growth	E1	62
Lower Hunter 132kV Network Development	Growth	E5	73
Tunnel Arbitration	Growth	E6	77
Unconfirmed Customer Connections	Growth	E4	69
Replace 132kV feeder 908/909	Replacement	E2	64
Ourimbah STS Refurbishment	Replacement	E3	66

The proposed Ourimbah project and the Lower Hunter 132kV project have been the subject of detailed reviews by PB Associates. Our findings of this review can be found in Section 5.2. An outline of each of the remaining four projects, as proposed by EA for Excluded status, is included below.

4.5.1 Major Inner Metropolitan 132kV Network Development

The operation of the EA 132kV Inner Metropolitan Network is inter-dependent on TransGrid's transmission network. EA has indicated that this project is necessary due to system demand growth and is subject to joint planning with TransGrid. The proposed overall capital expenditure total is $35.6M, which is around 15% of the proposed capital expenditure for the period 2004/05 to 2008/09.

49 As per the ACCC definition of Excluded projects – 'Statement of Principles for the Regulation of Electricity Transmission Revenues, ACCC, Draft Decision, 18 August 2004.

It is clear that this project is dependent on TransGrid's plans for the surrounding transmission system and therefore that EA has limited technical influence over what eventuates in the TransGrid system.

The EA revised submission provides sufficient information to confirm that the proposed expenditure for the project is necessary and will be of magnitude similar to that proposed by EA and that at this early stage of planning, there is uncertainty over the scope of the project. We believe that it is highly likely that the project expenditure will be large enough to allow it to be excluded. However, due to early stage of planning and the uncertainty in scope, PB Associates is unable to make any further comments on the prudency or efficiency of the proposed expenditure.

4.5.2 Tunnel Arbitration

EA constructed a cable tunnel between Haymarket substation and Surry Hills as part of the Haymarket project. The construction company has lodged a claim for a substantial variation in relation to this project. Due to the uncertain nature of the outcome, EA has requested that the prospect of the additional expenditure be assigned Excluded investment status.

PB Associates has only received limited information on this proposed project and is not able to provide any further comment on the prudency or efficiency of the proposed expenditure. EA has agreed to provide the ACCC with details of the claim (on a confidential basis) to enable ACCC to make a more informed decision on this potential additional cost. PB Associates recommends that ACCC make a decision on whether or not to exclude these costs after reviewing the details of the claim.

4.5.3 Unconfirmed customer connections

PB Associates confirms that the scope and magnitude of expenditure for shared transmission assets related to new customer connections is unknown. We therefore conclude that, in many instances, the level of uncertainty is likely to be high and in such cases it may be appropriate for the ACCC to assign excluded investment status to these projects.

4.5.4 Replace 132kV Feeders 908 and 909

Feeders 908/909 are two aged 132kV cable circuits connected between Bunnerong and Canterbury substations. The cables are 48 years old and have route length of 15.4km. We understand from EA that the cable is no longer manufactured and that there is only approximately 100m of spare cable left for use in repairs. The cables have faulted on five occasions since 1990 – with repair times varying between three and six months[50]. Furthermore, EA claim that the existing routes make access for fault repair difficult[51].

PB Associates confirms that studies and consents for this project are not sufficiently advanced at this stage for the project to be costed to a high degree of accuracy. Information supplied by EA indicates that there is potential for cable failure and their assessment is that it should be replaced within the next 5 years. The two alternatives proposed involve replacing the cables with modern cables[52] of higher capacity on different routes.

50 As advised by EA. Note that PB Associates has not confirmed forced outage information on these circuits.

51 PB Associates understands that the existing feeder route includes 3km within the boundary of Sydney Airport and 800m under traffic lanes in General Holmes Drive.

52 Such as solid dielectric cables.

PB Associates concludes that regardless of final project details, the costs for this project as proposed will be high and have a high probability of being in excess of $30m. The existing cables provide 180MVA (nominal capacity) between Bunnerong and Canterbury zone substations. The only two options proposed are for replacement of these existing cables. It is possible that there are other viable options.

4.6 HIGH LEVEL PROJECT REVIEW

In addition to the detailed review of a sample of proposed projects[53], PB Associates has also undertaken a high level review of all other projects in the submission. For each of these projects of we have included a brief comment on:

- information provided;
- justification for the proposed project;
- consideration of alternatives;
- cost estimates;
- strategic alignment; and
- the risk of the project not proceeding

This review is based, in most cases, only on the information provided by EA in its submission. This high level review is provided in Appendix A of this report.

Where the project has been subject to a detailed review we have referred to the appropriate section of the report.

53 The detailed project reviews are included in Section 5.

5. DETAILED REVIEW OF SAMPLE PROJECTS

PB Associates' assessment of the EA forward capital plan is based on a multi-faceted review approach. The approach adopted is to examine, review and assess:

- the EA governance framework and approval procedures;
- EA policy and practice associated with capital expenditure;
- the 'high-level' indicators associated with all of the proposed projects in the capital portfolio; and
- a selection of individual projects in some detail.

In this section we describe PB Associates' findings of a detailed review of a number of individual projects.

5.1 SELECTION OF PROJECTS FOR DETAILED REVIEW

A detailed review of individual projects can not only enable an understanding of the costs and benefits of the specific project in question but can also lead to a better understanding of the costs and benefits of a the wider programme of investment – particularly where there are common approaches and cost elements involved.

The sample projects selected for detailed review are:

- Excluded project No.3 – Ourimbah refurbishment;
- Excluded project No.5 – Lower Hunter 132kV Network Development;
- augmentation project No.5 – 132kV Development in Newcastle Western Corridor;
- augmentation project No.7 – Drummoyne Zone substation constraint;
- augmentation project No.10 – West Gosford Zone Constraint;
- replacement programmes in general – particularly No.17 – Transformer replacement; and
- support the business (non network) capital expenditure.

During our review there were two further areas which were not selected for detailed scrutiny but which PB Associates felt warranted further exploration than that afforded in the high level review. These are:

- Macquarie Park Zone substation constraint; and
- replacement of substation equipment and mains replacement.

PB Associates' review, in these two additional areas, is included at the end of this section.

5.2 OURIMBAH REFURBISHMENT (EXCLUDED PROJECT NO.3)

The Ourimbah substation functions as an important node in the EA Central Coast transmission and distribution system. The substation was built in 1959 and has been in service for around 45 years – although some major plant items were added over a 9 year period and are therefore around 36 years old. The substation is now being impacted by load growth in surrounding areas and some main plant items are nearing the end of their standard asset lives.

The 132kV/33kV transformers are rated at 40/60, 45/60 and 45/60 MVA. PB Associates notes that two of these 132/33kV transformers were manufactured in 1967 and 1968 and have been in service less than 40 years, while transformer 1 (45/60MVA) was manufactured in 1959 and is 45 years old. Condition assessments, in 2002, by oil analysis, for all of these transformers show only minor issues.

It should be noted that EA's standard substation life is 45 years, but under EA's Condition Risk Assessment (CRA) strategy, the majority of Ourimbah's main plant items are in the 'moderate' C2 risk category, posing no immediate risk, but reaching a point where the risk category will move to a risk rating of 'High'[54] within 5 years.

Consultants SKM were recently engaged by EA to undertake an asset and remaining life assessment. The report includes details of remaining plant lives at Ourimbah – based on condition assessment and load constraints of remaining assets[55]. PB Associates notes that based on condition, some critical items, such as 132kV circuit breakers, have a remaining life of 5 years, although many major items of high capital value have remaining lives of 10 to 43 years.

PB Associates has assumed that the SKM report supersedes the EA CRA – although it is not clear to PB Associates the extent to which condition assessment of all of the substation assets has been undertaken in support of SKM's views on the remaining asset life.

5.2.1 Justification

The main drivers presented by EA for this project are the need to replace some components of the Ourimbah substation within 5 years, impending load constraints imposed by the substation 132kV bus bars (and some switchgear) and the general increase in maximum load on the substation.

Without significant augmentation to Ourimbah or the addition of substations in the surrounding region, the forecast maximum load for Ourimbah in 2004 is 116MVA (winter) and 157MVA (summer) in 2013. EA has proposed to increase the capacity of the main substation transformers from 60MVA to 120MVA to provide a firm capacity in excess of 240MVA. With a major modification to convert Berkeley Vale substation to 132kV supply, it would be possible to offload 40MVA from Ourimbah and defer the need for refurbishing Ourimbah for reasons of load constraint.

5.2.2 Alternatives

In their report, SKM identify three capacity-based alternative solutions and one age related option. Furthermore, EA has indicated that there is a Southern Central Coast Value Management study underway at present. EA has indicated that this study has identified 26 options to deal with Southern Central Coast issues.

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54 See Section 3.4.2.3 for a description of EA's risk assessment framework.

55 'Ourimbah 132kV sub-transmission substation refurbishment – Part 1 Condition and remaining life assessment', Section 5, August 2004. A confidential report by SKM to Energy Australia,

The SKM options are summarised in Table 5-1.

Table 5-1 - Summary of SKM Ourimbah options

OPTION	SUMMARY DESCRIPTION	COST (NPC*) in SKM report (including contingency)
1	Acquisition of adjacent land and new (green fields) 132kV switchyard and 132kV transformer yard[56]	$18.3m
2	Staged rebuilding of the existing site.	$21.4m
3	Staged rebuilding of the existing site in a layout different to Option 2.	$21.7m
4	Allows for transfer of load to other substation and Ourimbah modifications staged over an extended period.	$18.7m

* At a discount rate of 7.5%

5.2.3 Costs

The costs in the EA expenditure submission propose a project based on the SKM Option 2 to replace Ourimbah assets and increase the capacity of the substation. The overall expected construction cost is $25.7m which includes for interest during construction (IDC) at 7.5% (one off), increases in labour and material unit rates and a contingency of 20%. Proposed project preparation starts in 2004/2005 and the project is due for completion in 2008/2009.

5.2.3.1 EA submitted

EA's submission incorporated a total expenditure of $25.6m to be spent in the current Regulatory period as their base cost. EA then assigned a 70% probability that the project would be carried out on time with a 30% probability that it would be deferred by one year to arrive at the cost estimates submitted as shown in the Table 5-2.

Table 5-2– EA Submitted expenditure for Ourimbah substation refurbishment

Forecast Expenditure in $2004 ($m)				
2004/05	2005/06	2006/07	2007/08	2008/09
0.1	2.9	9.3	9.7	3.6

5.2.3.2 PB Associates comments

PB Associates considers that: it may be possible to achieve economies of scale for major plant items such as transformers where the "$ per MVA" cost reduces significantly. Despite there being the prospect of such costs advantages, on the basis of the forecast load of 157MVA in 2013, it is less than clear to PB Associates how the overall capacity of the proposed 3 x 120MVA transformers included in the proposal can be justified. The proposed transformer capacity would provide Ourimbah substation with a firm capacity of nearly 290MVA in 2009 – on the assumption that the 120MVA transformers can accept a 20% overload under certain conditions.

56 Option 1 requires the purchase of adjacent properties which are not included in the estimated price.

PB Associates recognised that to enable the Ourimbah substation capacity to be almost 100% available while additions and modifications are undertaken is a major challenge in planning and implementation for EA. Whilst PB Associates is of the view that the options identified by SKM are technically realistic, some of the individual costings are higher than PB Associates would have expected.

The high proportion of the total cost being associated with the purchase of transformers suggests that the project costs may be sensitive to fluctuations in world metal prices and exchange rates. PB Associates believes that it is, therefore, reasonable to provide for this in the project costings. However, labour and local materials also represent a significant proportion of the cost of Option 2 and since EA appear to have already allowed for labour and material rate escalation, it may not be appropriate to include provision for this variation in the cost estimates.

If other planned projects which would reduce demand on Ourimbah, such as Berkeley Vale, do not proceed, some, but not all, of the Ourimbah plant items will need to be replaced within 5 years – based on condition.

PB Associates believes that the approaches proposed by SKM are technically feasible although SKM still allow for (three) 120MVA transformers – rather than transformers of a lower rating. However, PB Associates considers that although there may be some items that require replacement within 5 years, significant parts of the substation have a longer life and replacement should be deferred for these items.

Our expenditure recommendation for the period 2004/05 to 2008/09 is based on SKM's Option 2. A deferral of the project by 2 years means that a significant proportion of the costs will fall in the regulatory period beginning 2009/10. We are also of the view that the transformer costs could be reduced by 20% – based on the installation of transformers of less than 120MVA rating i.e. having a size which more closely aligns with the forecast demand[57]. In addition, PB Associates has not seen evidence to suggest that a 20% contingency amount is necessary or appropriate for Ourimbah and so this has also been removed from our recommendations. The 7.5% interest during construction has been retained.

PB Associates recommended variations are given in Table 5-3.

Table 5-3– Recommended variations for Ourimbah

Forecast Expenditure in $2004 ($m)				
2004/05	**2005/06**	**2006/07**	**2007/08**	**2008/09**
-0.1	-2.9	-9.2	-7.2	+3.4

5.2.3.3 PB Associates recommended expenditure

The PB Associates new project total estimate is $19.7m. The suggested timing of this expenditure is given in Table 5-4.

Table 5-4 – PB Associates recommended project costs for Ourimbah substation

:Forecast Expenditure in $2004 ($m)						
2004/05	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**
		0.1	2.5	7.0	7.0	3.1

The recommended expenditure for the 2004/05 to 2008/09 period is given in Table 5-5.

57 Based on PB Associates' transformer cost data base.

Table 5-5 - PB Associates recommended expenditure for Ourimbah

Forecast Expenditure in 2004 ($m)				
2004/05	2005/06	2006/07	2007/08	2008/09
0	0	0.1	2.5	7.0

5.2.4 Conclusions and Recommendations

PB Associates considers that regardless of whether other EA distribution and transmission system augmentation occurs, completing major refurbishment for Ourimbah during the 2004/05 to 2008/09 regulatory period is not presently justified. Subject to thorough condition assessment of critical items (or confirmation that it has already been undertaken), we do, however, believe that project planning for refurbishment should commence and work should start towards the end of the 2004/05 to 2008/09 period.

It is also recommended that a regulatory test is undertaken to provide justification for the selection of 132/66kV and 132/33kV 120MVA transformers, as these seem to be oversized for the prospective future loads. It should also be noted that increasing transformer size will increase fault levels and possibly increase the cost of other plant items.

5.3 LOWER HUNTER 132KV NETWORK DEVELOPMENT (EXCLUDED PROJECT NO.5)

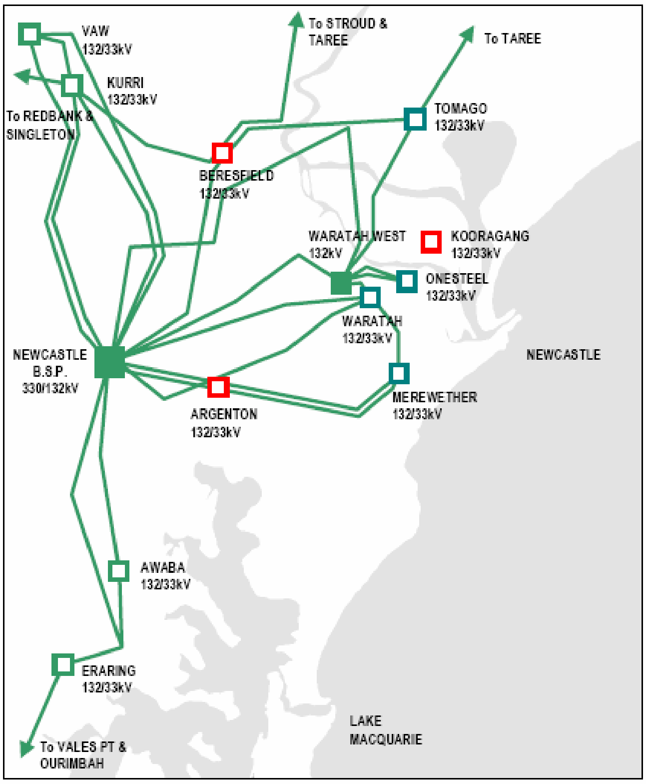
EA has proposed the Lower Hunter 132kV Network Development Project as an Excluded investment project. A number of major 330kV and 132kV assets in the Newcastle/Lower Hunter region are either approaching, or have reached, their current capacity limits.

The reason for EA's request for this project to be treated as Excluded relates to the complex inter-relationship between TransGrid's planning options associated with the 330kV network and EA's planning for the region. This joint planning process has identified a number of options which are currently under consideration. EA has developed a number of potential augmentation options in response to four key options that TransGrid have been considering. Until TransGrid's final option is determined EA's final augmentation options cannot be finalised and consequently there is potential for a significant variation in EA's cost outcomes.

The approach to developing options to meet the continued strong demand growth in the Lower Hunter is complex and path-dependent. By necessity, PB Associates has considered a detailed range of options in order to fully assess this potential investment.

Figure 5-1 provides a general geographic overview of the 132kV network that serves the Lower Hunter region. It is important to note that significant components of this network are distribution assets and therefore not relevant to this review.

Figure 5-1 –Geo-schematic of the Lower Hunter 132 kV Network



5.3.1 Justification

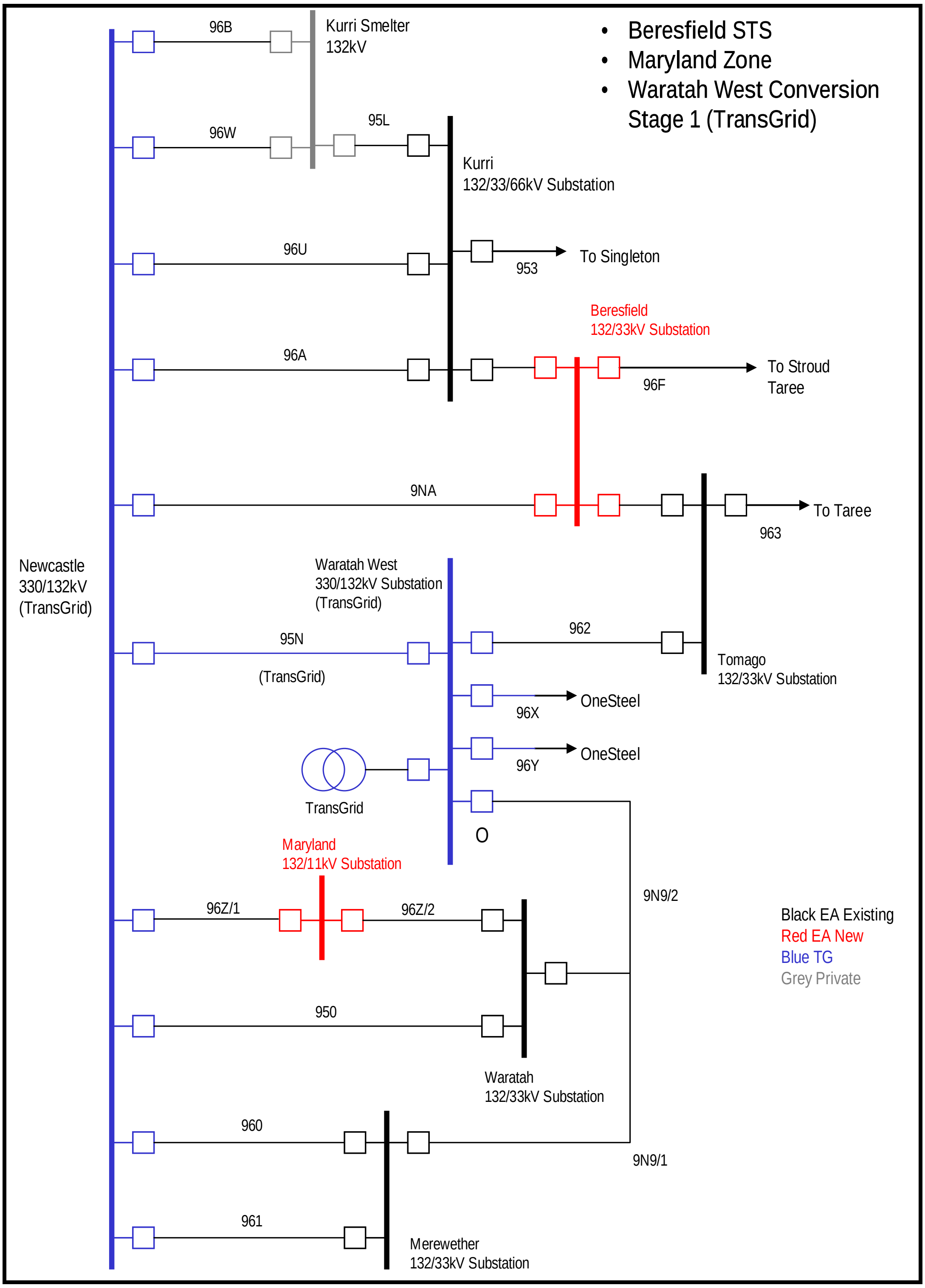
There are number of major projects either currently under construction or recently completed which impact the Lower Hunter 132kV network. These include the Beresfield Sub-transmission Substation (STS) project which is due for completion in 2005 and TransGrid's installation of a 330/132 kV transformer at its Waratah West Substation.

For the purpose of considering the future augmentation options the single line diagram in Figure 5-2[58], which reflects the state of the network following the completion of the abovementioned projects, is a useful reference point. It should be noted that the diagram also includes the proposed new Maryland Zone substation which is designated a distribution asset.

TransGrid's Newcastle 330/132 kV substation is heavily loaded even with the installation of the new Waratah 330/132 kV transformer. With the strong load growth in the region and the potential for capacity expansion at Tomago aluminium smelter (in addition to recent capacity expansions) TransGrid is considering its options to establish more capacity in the Lower Hunter region.

58 Sourced from PowerPoint document provided by EA 18 November 2004.

Figure 5-2 – Single Line Diagram of Relevant Lower Hunter 132 kV Network Assets (as at 2005)



A pressing concern for EA relates to 132kV Feeders 9NA and 962 which will both be heavily overloaded in the event of a contingency involving the loss of the other feeder and may require peak load shedding in 2006/2007 on single contingency outages if augmentation is not carried out. Figure 5-3 which is a copy of an output summary of single contingency overloads arising out of EA's load flow analysis of the Lower Hunter 132kV network at peak load times which shows the overloading issue.

Figure 5-3 – Summary of feeder demands (Waratah contingent overloads)[59]

Line	Bus A	Bus B	Current(A)	Rating(A)	Percent	Case	Outage	Limited By
952/3	3229 NEWCASTLE 132.0kV	7234 952 TEE 132.0kV	729.19	726	100	7	95A	Conductor/cables
962	7241 WARATAHWES 132.0kV	7265 TOMAGO 132.0kV	812.33	800	102	9	9NA/1	Bay Equipment at Bus B
9NA/1	3229 NEWCASTLE 132.0kV	0 BERESRING4 132.0kV	941.28	728	129	37	962	Conductor/cables
9NA/2	0 BERESRING3 132.0kV	7265 TOMAGO 132.0kV	745.17	728	102	37	962	Conductor/cables
9NA/1	0 BERESRING4 132.0kV	0 BERESFIELD 132.0kV	941.35	934	101	37	962	Conductor/cables

The above overload situation can be addressed in a number of ways with the most efficient manner dependent upon on TransGrid's preferred option for augmentation of the 330 kV network.

Load diversity in the region (at the sub-transmission level) is worsening and this is beginning to present a major issue for EA. Peak loadings on the 132kV network have been impacted significantly and tend to increase the extent of overall maximum demand increases at peak times. Partially as a result of this phenomenon (but primarily as a result of general load growth) there are also other feeders in the region that are heavily loaded and EA advise that capital investment may be required to carry out major upgrades within the next ten years.

If the more immediate work is not carried out in the current regulatory period then it is clear that required reliability under certain single contingency outage scenarios will not be met.

5.3.2 Strategic alignment

The Lower Hunter 132kV network has been the subject of considerable scrutiny by EA and the overall situation in the Lower Hunter region has been the subject of joint planning discussions. EA has produced a number of reports which have examined aspects of the future supply situation. These include:

- Hunter Planning Report 85-00 – Lower Hunter 132 kV Network Supply Development Strategy Options;
- Hunter Network Development Plan 2003-2012; and
- Hunter Planning Report 62-04 – Waratah Issues Report

Additional references have been made in EA's 2004 Transmission Planning Annual Report.

EA has also made a reference in their capital expenditure submission to considerations for the establishment of new reliability planning standards for areas such as the Newcastle region. Any improved reliability standards criteria would have a substantial effect on investment requirements in the Hunter region.

PB Associates believe that EA has given significant attention to considering options for the Lower Hunter 132 kV supply network over a number of years and the proposed

59 'Revised Transmission Capital Investment Program', Energy Australia's submission to the Australian Competition & Consumer Commission, 29 October 2004 – supporting Appendix No.8. PB Associates has not verified these studies.

project, whilst still subject to some uncertainty in terms of its final form, is consistent with the long term strategic outlook for the region's network development.

5.3.3 Alternatives

In considering augmentation alternatives associated with this project there are two option levels that need to be considered. The first relates to TransGrid's options for the augmentation of the 330kV network while the second level relates to EA's requirements to augment the 132kV network efficiently and prudently in the light of a given TransGrid option.

The EA alternatives are considered as a subset of the current TransGrid options (as advised by EA) which are discussed in turn below.

5.3.3.1 TransGrid Option 1 – second 330/132 kV transformer at Waratah West

This was the original option being contemplated by TransGrid and involved the installation of a second 330/132kV transformer at Waratah West. This option is shown diagrammatically in Figure 5-4. This includes details of augmentation works that EA is proposing to carry out in response to this option[60].

The work proposed by EA involves establishing a new 132kV feeder between TransGrid's Newcastle substation and the new Beresfield STS and a new 132kV feeder between TransGrid's Waratah West and EA's Tomago STS.

In addition, a new 132 kV feeder is proposed for connection between Waratah West and EA's Waratah STS to support load growth in the region. Depending on the actual configuration of open points on the 132kV network this could be classed as either a transmission or a distribution asset. With open points as shown in Figure 5-4 this would be classified as a distribution asset. Due to uncertainties in this regard, and the strong interconnection associated with the clearly defined transmission network, EA has included 50% of this project cost as Transmission asset expenditure for the purpose of the ACCC capital expenditure submission.

EA has estimated that the two 132kV feeders would be expected to cost $9.5m and the Waratah West 132kV arrangements $4.0m[61].

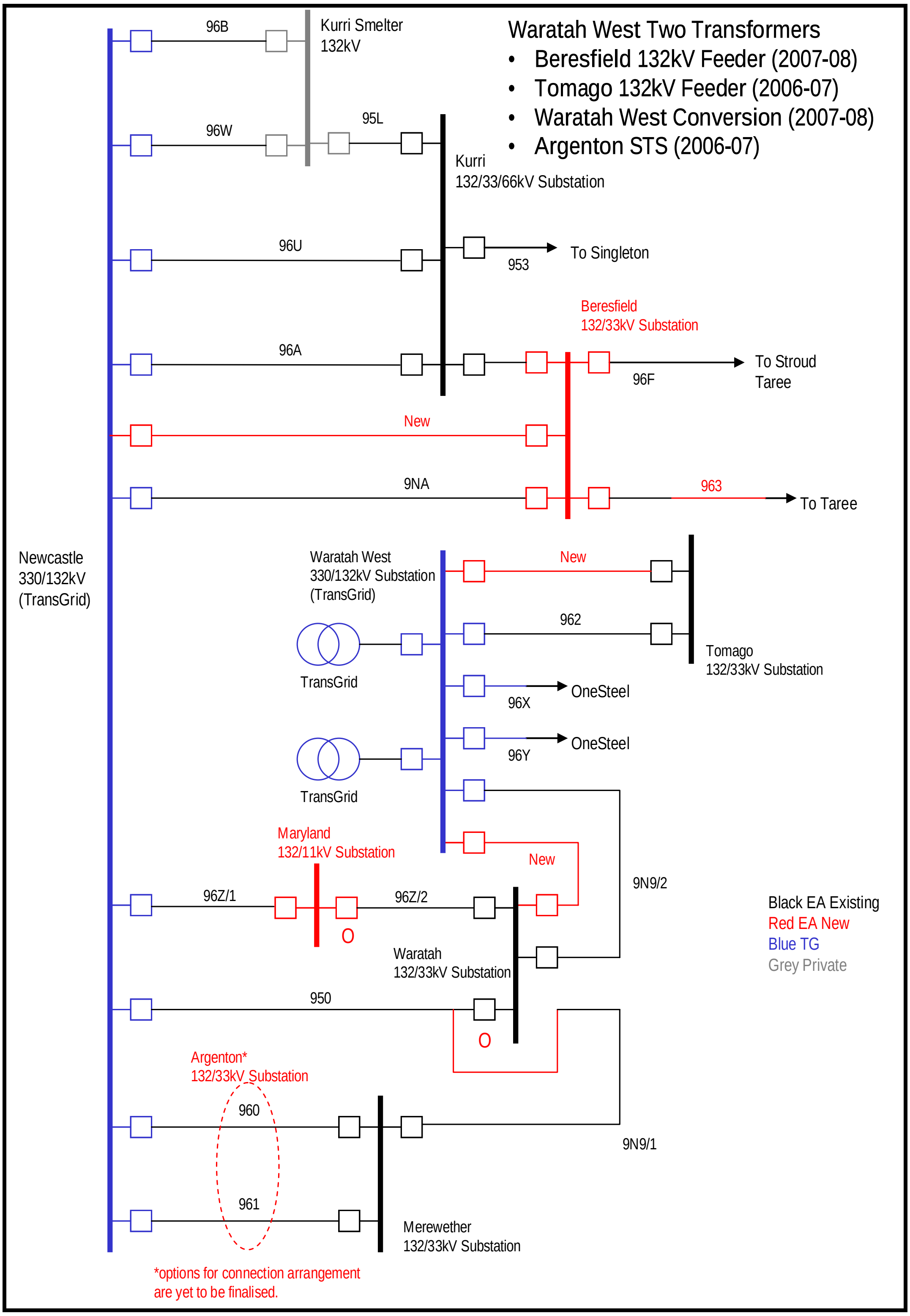
In planning the work EA has scheduled the Tomago feeder in advance of the Beresfield feeder but this can be changed without impacting on reliability if route selection and construction issues allow one to be carried out in advance of the other. The majority of the work for the Tomago feeder is planned for the calendar year 2006 while the greater part of the expenditure on the Beresfield feeder is scheduled for 2006/2007.

Due to the very high load levels and the high growth rates EA has not considered demand management options as presenting credible alternatives to delaying the proposed work. PB Associates consider this to be a reasonable decision.

60 It should be noted that the Argenton STS project is a distribution project that would be carried out regardless of which TransGrid option is selected.

61 PB Associates has discussed the basis for the costings with EA and it is clear that they are only estimates given that investigation of line routes is still being undertaken.

Figure 5-4 – TransGrid option 1 – Waratah West second transformer



In discussions with PB Associates, EA advised that they had not considered the application of capacitors at the sub-transmission level to assist in the deferral of the augmentation work. Examination of power factor levels at peak loads indicates that capacitor installations could potentially defer the projects but no cost benefit analysis on this aspect has been carried out by EA. EA has indicated that they would consider this option as the TransGrid options became clearer.

Figure 5-5 provides details of the power factors in the Hunter 132kV network.

Figure 5-5 – Excerpt from EA 2004 summer load forecast

HUNTER 132kV NETWORK SUMMER DEVI		Recorded	Peak Forecast									
		MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA
LOAD-POINT	Power Factor	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Argenton STS	0.93		0	0	129	137	145	154	147	128	136	144
Awaba STS	0.95	164	147	150	77	80	82	85	87	90	93	96
Beresfield STS	0.92		45	89	94	100	106	114	121	130	139	149
Eraring STS	0.95	47	44	48	46	48	51	53	56	59	62	66
Kurri STS	0.85	171	133	138	150	150	157	159	167	176	185	194
Liddell SS	1.00	35	36	34	41	41	36	36	36	36	36	36
Merewether STS	0.85	290	309	323	312	316	256	264	274	283	293	304
Mitchell Line STS	0.85	53	55	61	69	76	82	84	86	88	90	92
Muswellbrook STS	0.85	46	48	46	48	50	51	53	55	57	60	62
Singleton STS	0.92	137	136	142	147	146	150	153	157	161	166	170
Tomago STS	0.90	148	144	113	119	125	131	96	100	104	109	114
Waratah STS	0.93	115	112	114	98	100	143	147	151	155	159	163
Waratah-Comsteel	0.94	57	59	59	59	59	59	59	59	59	59	59
Maryland Zone	0.90		17	18	19	20	22	23	25	27	28	30
Rothbury Zone	0.90	11	12	13	0	11	11	18	19	20	21	22
West Wallsend Zone	0.90		0	0	0	0	0	0	15	16	17	21
Tomaree Zone	0.95		0	0	0	0	0	43	45	47	49	52
Steel River Zone	0.95		0	0	0	0	15	15	16	16	16	16
Elermore Vale Zone	0.90		0	0	0	0	0	0	0	30	31	32
Kurri Smelter	0.92	333	325	325	325	325	325	325	325	325	325	325
OneSteel/Industry	1.00	46	50	50	50	50	50	50	50	50	50	50

5.3.3.2 *TransGrid Option 2 – establish 132 kV supply point ex Tomago Substation*

This option involves TransGrid providing 132kV supply to EA from its existing substation at Tomago.

The two sub-options associated with this option are shown diagrammatically in Figure 5-6 and Figure 5-7. In each case EA has proposed alternative augmentation in response to each TransGrid option.

The first sub option is EA's present preferred option although EA advise that further investigation work needs to be carried out. Under this option three 132kV feeders (6.5km long) would need to be constructed from TransGrid Tomago to EA's Tomago substation at an estimated cost of $8.6m. In addition EA are proposing a new 11 km long feeder from Tomago to Beresfield to be constructed at an estimated cost of $4.6m.

EA has also considered that a high-speed protection arrangement will need to be fitted in conjunction with this work in order to comply with recent NEC requirements on fault clearing times. Based on a unit rates of between $40,000 and $50,000 per km for retro fit of the existing overhead earth wire for Tomago to Waratah West and $40,000/km for the Kurri to Beresfield section, EA estimates a total of $1.1m would need to be spent on communications while protection upgrades would likely cost in excess of $0.5m.

Figure 5-6 – TransGrid Option 2 – Tomago Substation – EA sub-option 1

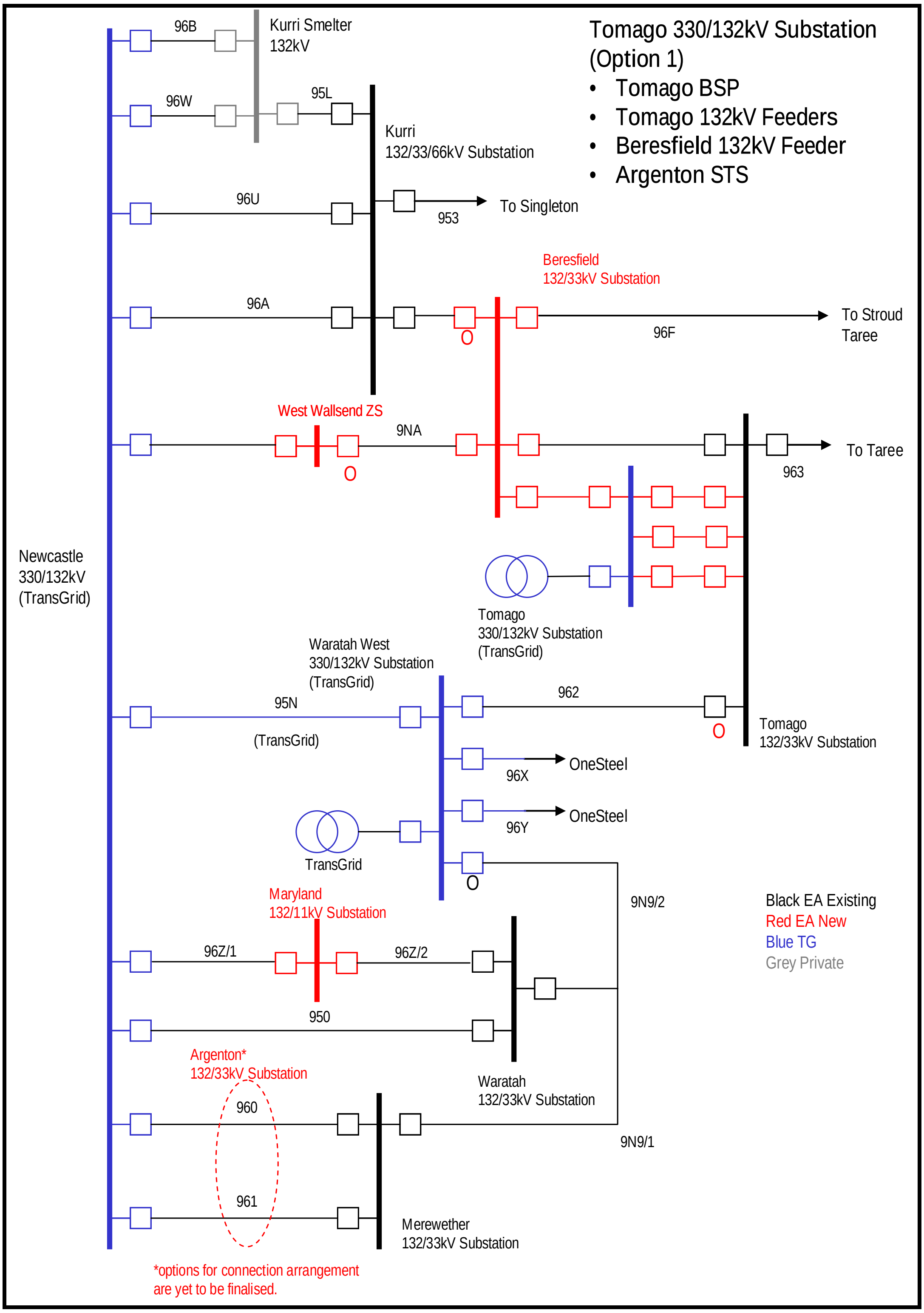
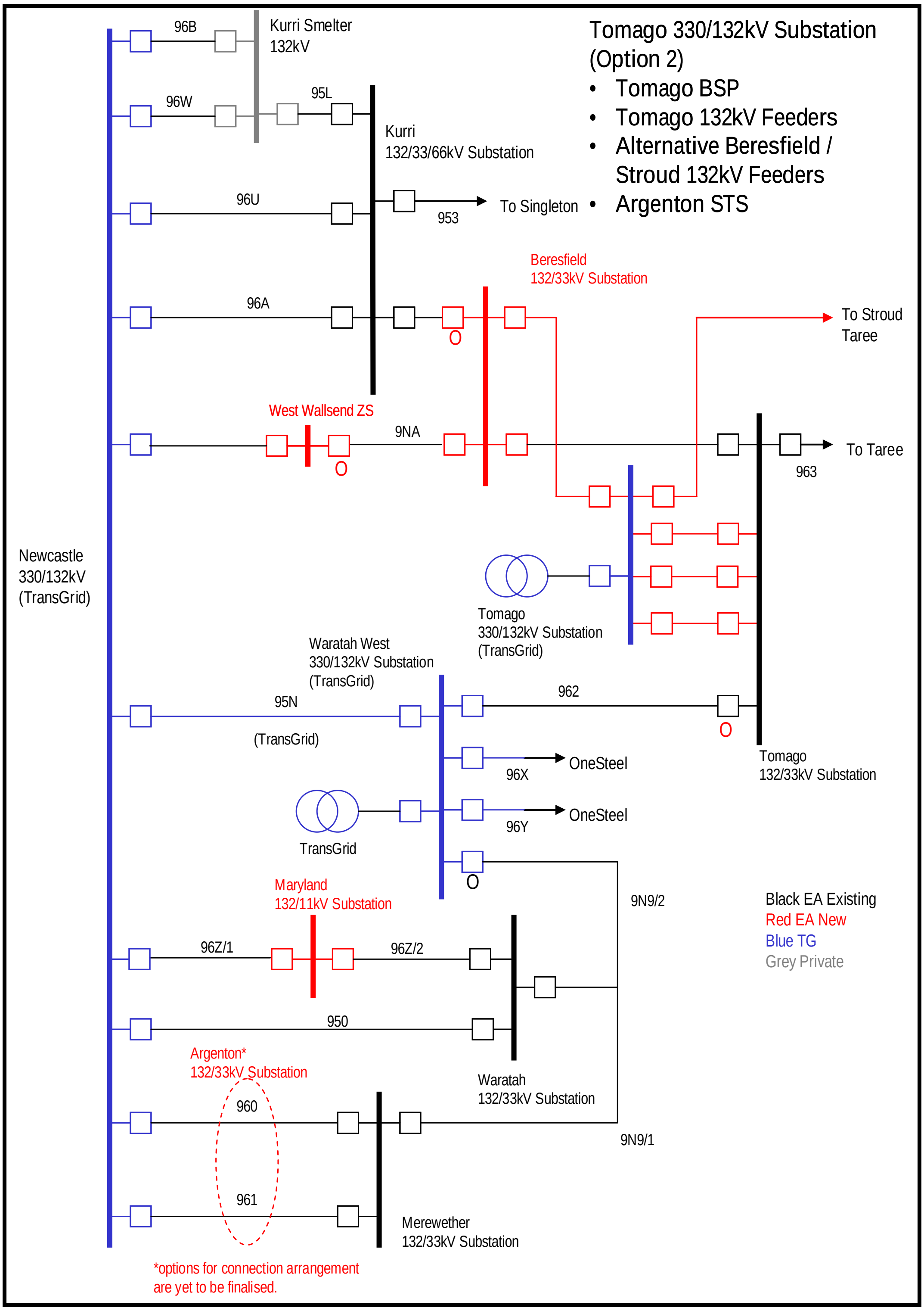


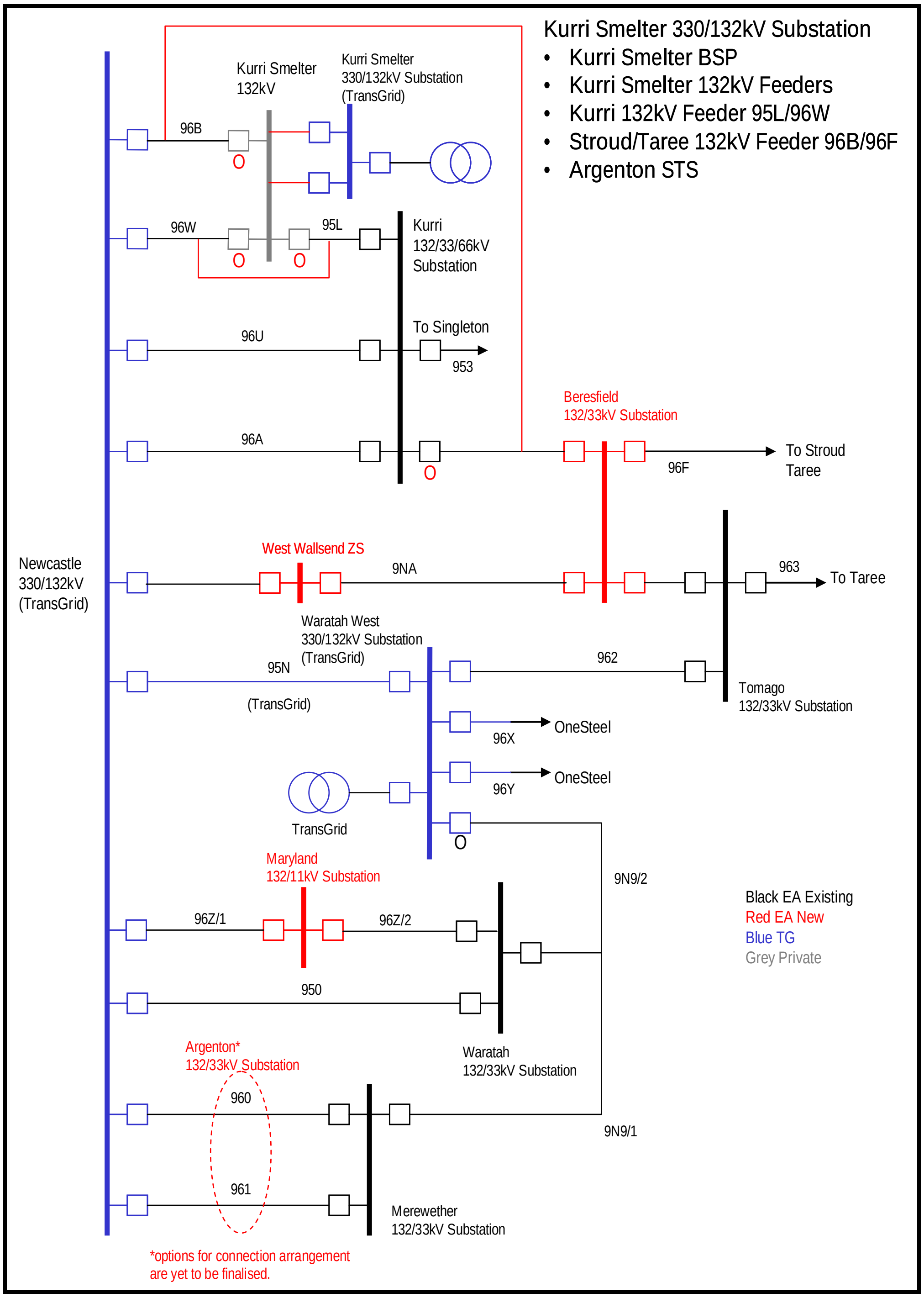
Figure 5-7 – TransGrid Option 2 – Tomago Substation – EA Sub-Option 2



5.3.3.3 TransGrid Option 3 – construct a new Kurri 330/132 kV Substation

This option involves TransGrid constructing a new 330/132kV substation in the vicinity of the Kurri Smelter. Under this arrangement EA would propose to construct two feeders from the TransGrid substation to the smelter and rearrange feeder configurations at either Tomago or Beresfield STS. A possible arrangement for this option is shown in Figure 5-8.

Figure 5-8 - TransGrid Option 3 – Kurri Substation proposal



EA has estimated the total cost of these works to be around $3m but they have indicated that the nature and timing of the work could be impacted by a potential project to relocate feeders 96A, 96B, 96U, 96W and 95L if the RTA proceeds with the contemplated F3 road widening works.

PB Associates notes that under this option EA will still need to carry out additional augmentation work as contemplated under Option 1 in order to relieve overload situations forecast in 2008.

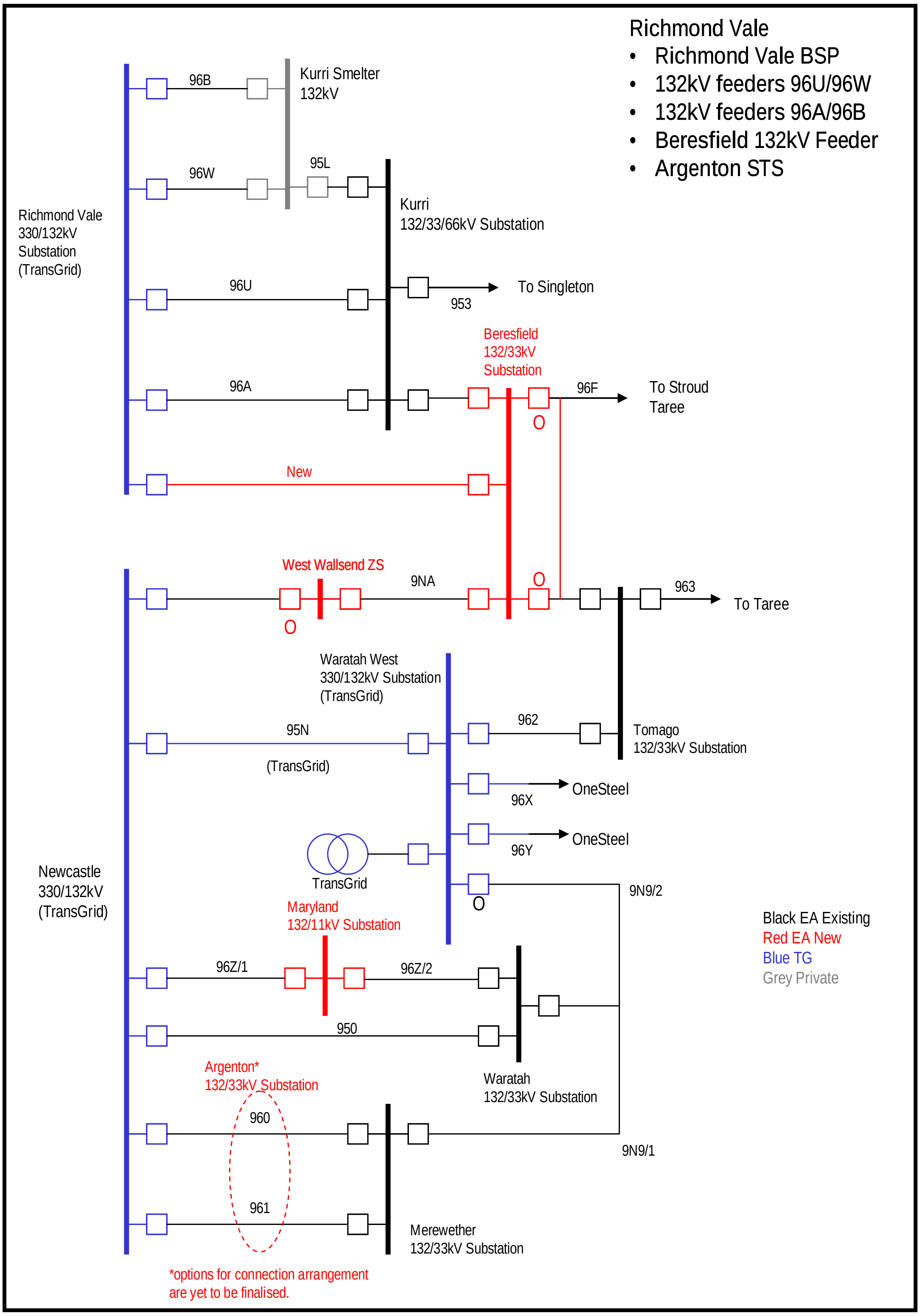
5.3.3.4 TransGrid Option 4 – construct a new 330/132 kV substation at Richmond Vale

TransGrid have provided an option to construct a new 330/132kV substation at Richmond Vale. A diagrammatic layout of this option is incorporated in Figure 5-9.

EA believes that it will need to install two new feeders to connect to existing feeders 96U and 96W together with a requirement to construct two new 132kV feeders connecting to existing feeders 96A and 96B. EA estimates the total cost of this construction work would be around $7m.

A further new feeder would need to be connected from Richmond Vale to Beresfield at an anticipated cost of around $9m including protection and communication upgrades required for feeders 9NA and 962.

Figure 5-9 – TransGrid Option 4 – Richmond Vale Substation



5.3.4 Risk of projects not-proceeding

Based on the 2004 forecasts used by EA, the diversified average maximum demand growth on the overall Hunter 132 kV network is projected to be between 2.5% and 3.5% for each of the next 5 years and if the Upper Hunter region and Kurri Smelter are excluded the annual increase ranges from 3.5% to 4%.

Due to the nature of load growth in the Hunter Region (both historical and forecast) PB Associates believes that significant augmentation work needs to be carried out in the Lower Hunter 132 kV network within the next 10 years and some of this needs to be carried out within the 2004/05 to 2008/09 regulatory period.

PB Associates believes that this project should be treated as an Excluded investment. This is based on both the nature and timing of EA's augmentation options – particularly given that it is not able to estimate expenditure levels, with significant accuracy, given the dependency on TransGrid options and the fact that EA still have work to do in formulating detailed options and cost benefit analyses once the TransGrid option picture becomes clearer.

5.3.5 Costs

EA has used estimated line routes and used other estimation techniques in considering the costs of new feeder constructions. Some of the costings provided by EA incorporate allowances for wetlands and river crossings and many have factored in the actual costs of a distribution line that is currently being constructed to Nelsons Bay. The costs provided by EA range from $300,000 per km to over $400,000 per km. These rates are significantly in excess of those included in the NSW Treasury Asset Valuation guidelines and PB Associates believes that they should be validated when the ACCC reviews the project on an Excluded investment basis.

5.3.5.1 EA submitted

In its submission to the ACCC, EA has provided a forecast capital expenditure on this project as per the cost break up incorporated in Table 5-6. These figures were derived from base cost expenditure estimates of $0.3m in 2004/05, $4.5m in 2005/06, $5.2m in 2006/07 and $1.5m in 2007/08. EA has assumed probabilities of 70% associated with this project proceeding as per these base estimates, a 15% probability that the expenditures would be delayed by 1 year and a 15% probability that the Waratah substation component would be delayed to arrive at the probability weighted figures included in their submission.[62]

Table 5-6– EA Submitted expenditure for Lower Hunter 132 kV network

Forecast Expenditure in $2004 ($m)				
2004/05	2005/06	2006/07	2007/08	2008/09
0.2	3.3	5.2	2.7	0.2

5.3.5.2 PB Associates comments

PB Associates believes that while the estimates provided by EA has a low confidence factor associated with their likely accuracy, it is very difficult, at this stage, to make a substantive case to adjust these to new figures. PB Associates has a number of reservations about the timing and the cost estimates used, even in EA's base case estimate, and suggests that the ACCC reconsider the project once a preferred course of action becomes clearer.

62 EA Spreadsheet, *Probability Analysis*, forwarded to PB Associates by email on 17 November 2004.

Table 5-7– Recommended variations

Forecast Expenditure in $2004 ($m)				
2004/05	2005/06	2006/07	2007/08	2008/09
0.0	0.0	0.0	0.0	0.0

5.3.5.3 PB Associates recommended expenditure

Without advocating the figures proposed by EA, PB Associates recommends that the proposed capital expenditure allowances be used (if needed) in the ACCC's considerations and that the project be considered as an Excluded investment.

Table 5-8– PB Associates recommended expenditure for Lower Hunter 132 kV Network

Forecast Expenditure in $2004 ($m)				
2004/05	2005/06	2006/07	2007/08	2008/09
0.2	3.3	5.2	2.7	0.2

5.3.6 Conclusion

PB Associates is of the view that this project should be considered as an excluded project for the purposes of evaluating EA's transmission capital expenditure requirements.

EA has demonstrated that they are very much aware of a range of options that are available to deal with emerging constraints in the Lower Hunter 132 kV network but they need to determine TransGrid's preferred approach in the (reasonably) near future in order to carry out more substantive evaluation of alternatives – including detailed costing comparisons of various options.

EA has made the ACCC aware that they are discussing changes to the existing planning standards with TransGrid. The outcome of these discussions could significantly impact the future capital expenditure requirements for the Lower Hunter. PB Associates notes that the transmission level in the region is already becoming constrained under the current deterministic (n-1) reliability standards.

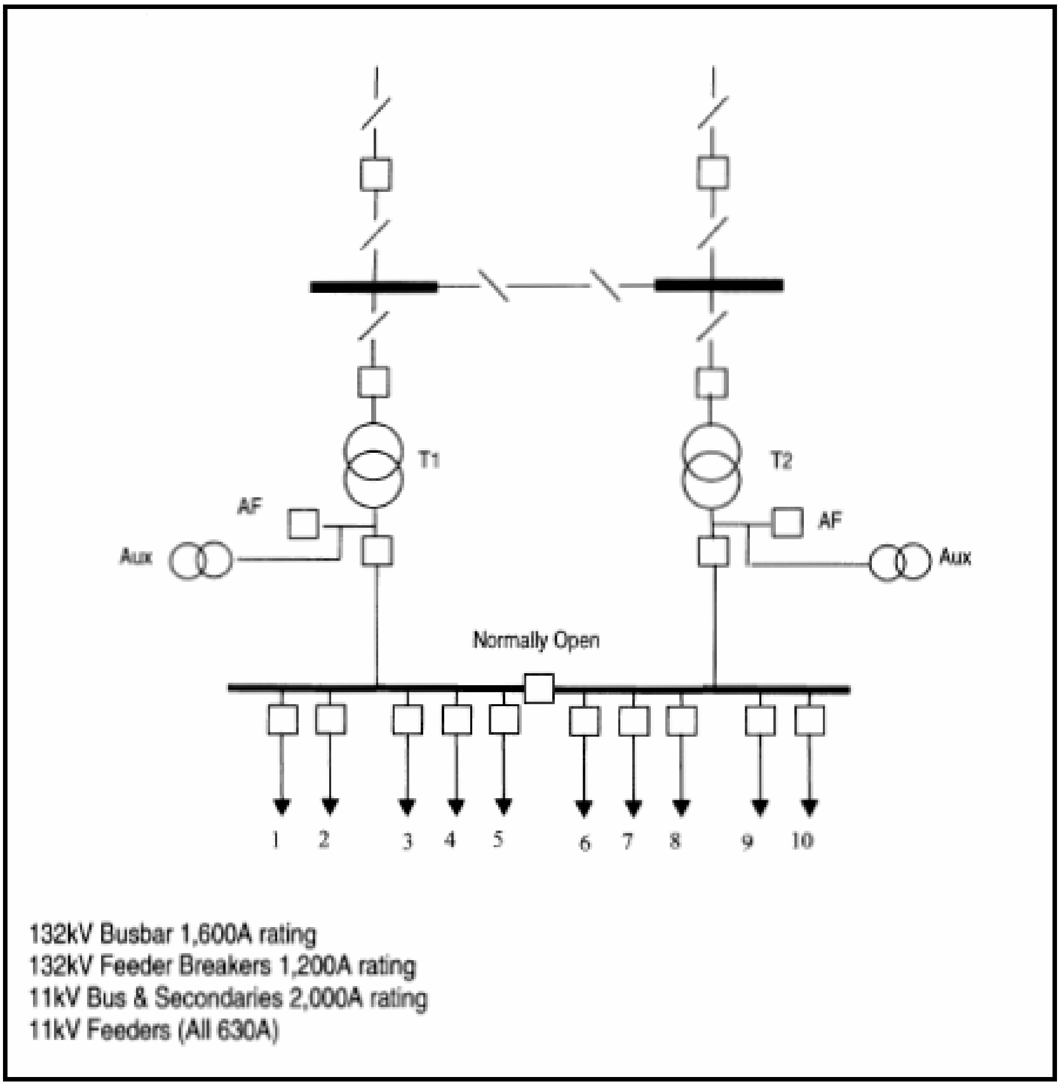
5.4 132KV DEVELOPMENT IN NEWCASTLE WESTERN CORRIDOR (AUGMENTATION PROJECT NO.5)

EA has an expectation that a new Zone Substation will be required in the western Newcastle area which is planned to be integrated into the 132kV transmission network in the Lower Hunter Region.

This project has been identified on EA's 2004 Transmission Annual Planning Report[63] and includes the establishment of a new two transformer 132/11kV Zone Substation in the Cameron Park area of Western Newcastle. A schematic diagram of the proposed substation layout work is shown in Figure 5-10.

[63] Energy Australia, *Transmission Annual Planning Report*, 2004.

Figure 5-10 –Schematic diagram of the proposed West Wallsend substation



The driver for the project is continued residential and light industrial load growth emanating from new land release developments in the suburbs of Edgeworth, West Wallsend, Estellville, Holmesville and Cameron Park. EA has advised that load is currently growing at approximately 5MVA per annum in this region.

The release of 3800 lots is currently underway (or in the process of being allocated) for which EA has assessed a requirement for an additional 15MVA of substation capacity. A new retail town centre is planned for the adjacent Estellville and a light industrial subdivision at Cameron Park is 30% completed for which another 3MVA of demand is projected. EA is considering acquiring land within this subdivision for the purpose of establishing the proposed Zone substation facility.

The new Tasman Mine is being located to the far west of the current developments and expects to require 4MVA of network capacity from 2006. The closure of the Gretley Colliery has provided some load relief but the closure in itself could lead to the development of a further 6 square km of land in the region.

5.4.1 Justification

Three distribution system zone substations Cardiff, Edgeworth and Wallsend currently supply the Western Newcastle area. Peak load growth is such that these substations have experienced peak load above their firm rating. The anticipated growth is expected to require three new substations to be built in the region. Two substations, Maryland (to be built in 2006) and Argenton (2007), are distribution projects and will have load transferred to them from Wallsend, Cardiff and Edgeworth substations – all of which are anticipated to exceed their firm ratings in the near future.

The proposed West Wallsend Zone substation is currently proposed for completion by 2009/2010 in order to relieve future constraints primarily on the Edgeworth and Wallsend Zone substations where otherwise load shedding may be required in the event of single contingency outages.

The forecast maximum demands for the relevant Zone substations were included in a table provided in the EA submission to the ACCC and an excerpt is incorporated in Figure 5-11 below for ease of reference.

Figure 5-11 – EA Forecast Zone substation demands – Western Newcastle area

Zone Substation	Rating MVA	2003	2004	2005	2006	2007	2008	2009
Argenton	50	0.0	0.0	0.0	0.0	24	27.49	29.16
Cardiff	22.9	28.94	32.39	34.17	36.06	22.05	21.27	22.46
Edgeworth	22.9	30.7	32.45	34.69	24.91	21.92	24.58	15.23
Maryland	37.5	0.0	0.0	0.0	17.66	22.89	24.49	24.21
Wallsend	27.1	33.95	30.6	33.57	29.08	27.25	29.3	27.5
West Wallsend	37.5	0.0	0.0	0.0	0.0	0.0	0.0	18

* Highlighted cells indicate that the substations are forecast to be loaded in excess of their respective firm ratings

5.4.2 Strategic alignment

This proposed project is identified in EA's strategic planning document for the Newcastle and Upper Hunter regions of EA's network supply area[64]. The western Newcastle region has been identified as the major growth area for the Newcastle/Lake Macquarie area and EA has recognised the significance of this in their longer term planning.

With the increased density of residential developments EA are migrating from the region's original 33/11kV Zone substations towards higher capacity 132/11kV Zone substations which are to be fed directly from the 132kV network. EA are proposing that the substation can be either connected to the existing 9NA 132 kV feeder or the proposed new feeder connecting to the new Beresfield 132/33 kV Sub-transmission substation (STS).

EA's proposed approach with this project is consistent with its longer term planning strategies.

5.4.3 Alternatives

EA has identified 3 options to relieve the forecast constraints in 2009 including:

- construction of a new 132kV zone substation at West Wallsend to be supplied via the adjacent 132kV feeder 9NA[65]. EA has estimated the cost of this project

64 Energy Australia, *Hunter Network Development Plan – 2003 to 2012*.

65 PB Associates notes that a new 132 kV feeder could be used.

at $10.8m based on estimates for a similar zone substation being built at Maryland;

- constructing the new 132kV zone substation at West Wallsend but delaying the establishment of the substation by 2 years by installing additional 11kV feeders, connected to Maryland zone substation. EA has estimated $2.1m for the cost of the 11kV feeder augmentations staggered over two consecutive years with a cost of $1.2M in the first year; or
- constructing a new 33kV zone substation at West Wallsend and supply via 12km of new overhead 33kV feeder. EA has estimated the cost of this option as being in the order of $11.5m based on costs for a similar project at Nulkaba and Beresfield.

The proposed option represents the lowest NPV cost of these options. The third option is clearly the highest cost option and may have other limitations in terms of overall capacity to accommodate future load growth. PB Associates has compared the NPV of the first two options to produce the NPV comparison shown in Table 5-9. This comparison confirms EA's assertions based on their estimated costs.

Table 5-9 – NPV Comparison of West Wallsend deferral option

Project Option	Discount rate 12%	Discount rate 9%	Discount rate 6%
Construct Zone Substation as proposed	$6.2m	$7.1m	$8.2m
Carry out staged 11 kV feeder augmentation and defer substation construction by 2 years.	$6.8m	$7.9m	$9.2m

Discussions with EA staff have indicated that other options have been considered including the installation of capacitors and supply from regions further to the west.

Capacitors have been installed at Cardiff recently but EA advise that due to space limitations, and new construction clearance requirements, there is insufficient room in Edgeworth and Wallsend substations to accommodate capacitor installations.

Development growth to the west of Newcastle has started to lead to voltage regulation problems on existing 11 kV feeder systems and EA has strategically decided to plan for Zone substations in the actual growth area. Supply to the area from existing Zone substations further to the west is not practicable as the F3 freeway is located between those substations and the developing area. PB Associates are of the view that this would only be a short-term solution.

No demand management initiatives have been investigated at this point in time.

5.4.4 Risk of projects not-proceeding

Local government has identified the western Newcastle corridor as the growth area for the region and consequently PB Associates concurs with EA's view that this project will be required at some stage in the future.

Consequently, PB Associates believes that timing of the investment is the key issue for consideration in the ACCC's current review. EA is projecting maximum demand increases of between 6% and 7.5% for the next 5 years for each of Edgeworth, Wallsend and Maryland (once commissioned) in the area. In the period 2000 to 2002 the average demand growth was 4% at Edgeworth although there was an increase of nearly 20% in last year's very hot summer. From PB Associates' experience the projected load growth figures are at the high end of normal expectations for regional load growth. PB Associates believe that there is some doubt that this project will proceed as per the proposed plan timeframe. Our view is that it is not unreasonable to assume that the investment may be deferred.

5.4.5 Costs

EA has based their cost estimates on recent design work for the Maryland 132/11kV substation. The costing is based on two 132 kV transformers (37.5MVA rating), ten 11kV feeders with a split 11kV bus and an "H" arrangement for the 132kV busbar. Incorporating an allowance of $460,000 for 132 kV feeder construction to supply the proposed substation EA has estimated the project cost to be $10.8m.

PB Associates has applied the NSW Treasury Asset Valuation Guidelines and arrived at a cost of $9.3m including the same allowance for 132 kV feeder construction work. This represents a 16% difference in costs against those proposed by EA. EA has allowed a 10% contingency in their costings which PB Associates believes to be reasonable given the uncertainties associated with the construction of this project.

PB Associates believes that EA's estimated costs are not unreasonable although they may be marginally higher than we might expect.

5.4.5.1 EA submitted

EA has provided a forecast capital expenditure for this project as per the cost disaggregation given in Table 5-10. These figures were derived from base cost expenditure estimates of $0.6m in 2006/2007, $2.5m in 2007/2008, $5.0m in 2008/2009 and $2.7m in 2009/2010[66].

EA has further assigned probabilities of 80% associated with this project proceeding (as per these base estimates); 10% probability that the expenditures will be delayed by 1 year and a 10% probability that the project will be advanced by one year to arrive at the probability weighted figures included in their submission[67]

Table 5-10 – EA submitted expenditure for Newcastle West 132 kV augmentation

Forecast Expenditure in $2004 ($m)				
2004/05	2005/06	2006/07	2007/08	2008/09
	0.1	0.8	2.7	4.9

5.4.5.2 PB Associates comments

PB Associates has reviewed the costs used by EA in their base case costing and believe that they are within reasonable expectations. Consequently PB Associates recommends that the underlying cost structures for the project be accepted.

PB Associates notes the high forecast load growths underpinning the forecasted timing of the network constraint and consequently the timing of the project and has some doubt that the project will need to commence at the time suggested by EA. According to the Hunter Network Development Plan the project was originally scheduled for completion in 2010. PB Associates notes that this is the same date proposed in EA's 2004 Transmission Planning Report.

66 Note that this is outside of the regulatory period in question.

67 Energy Australia Spreadsheet, *Probability Analysis*, forwarded to PB Associates by email on 17 November 2004.

EA's submission has indicated that the project needs to be completed before summer 2009. PB Associates believes that there is sufficient uncertainty about the size of the load growth increase to discount the possibility of the project being brought forward for a year and believes that there is a higher probability of the project being deferred. Consequently PB Associates recommends using a 75% probability of the project proceeding on time and a 25% probability of a one-year delay. These variations result in the changes shown in Table 5-11.

Table 5-11– Recommended variations

Forecast Expenditure in $2004 ($m)				
2004/05	**2005/06**	**2006/07**	**2007/08**	**2008/09**
0.0	-0.1	-0.3	-0.7	-0.5

5.4.5.3 *PB Associates recommended expenditure*

Reflecting PB Associates view that there is a 25% probability that the project may be deferred by one year, Table 5-12 shows PB Associates recommended expenditure allowances for the 132kV Development in the Newcastle Western Corridor (West Gosford) Augmentation project. Deferral of the project would result in additional capital expenditure falling outside the current 2004/05 to 2008/09 regulatory review period.

Table 5-12– Recommended expenditure for Newcastle West 132 kV augmentation

Forecast Expenditure in $2004 ($m)				
2004/05	**2005/06**	**2006/07**	**2007/08**	**2008/09**
0.0	0.0	0.5	2.0	4.4

5.4.6 Conclusion

Having reviewed this project PB Associates are of the view that EA has examined reasonable alternatives to the project, that the project is justified, and that some capital expenditure will be incurred in the forthcoming regulatory period. EA's submitted base cost estimates are believed to be reasonable although marginally higher than expected. PB Associates does, however, have some doubt about the precise timing of the project. In particular PB Associates believes that it unlikely that the project will need to be advanced by one year and that there is a higher probability that the project would be deferred by one year. Consequently revised capital expenditure levels have been recommended for this project.

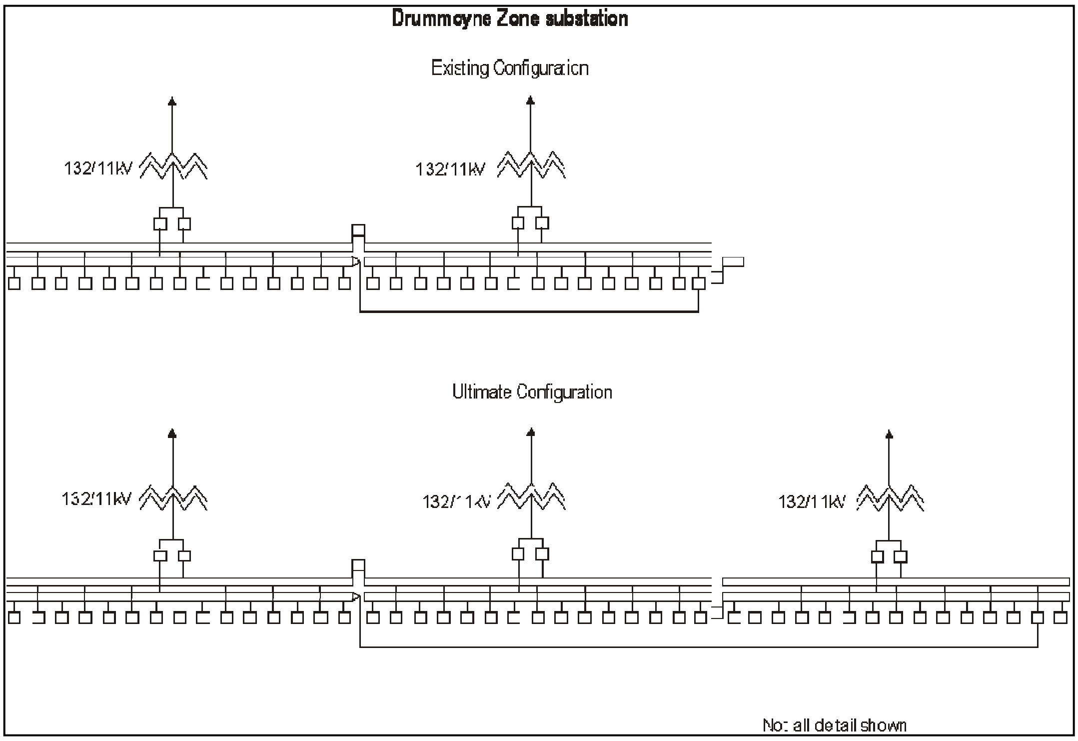
5.5 DRUMMOYNE ZONE SUBSTATION CONSTRAINT (AUGMENTATION PROJECT NO.7)

EA has indicated that the peak demand at the Drummoyne Zone substation is expected to reach and exceed firm capacity based on load growth forecasts over the next few years.

This project has been identified on EA's 2004 Transmission Annual Planning Report[68] and involves the upgrading of the existing 132/11kV Zone Substation from a two transformer to three transformer substation with the installation of another 50 MVA 132/11kV transformer with the associated extension of the existing 11 kV switchboard. A schematic diagram of the proposed work is shown in Figure 5-12.

[68] Energy Australia, *Transmission Annual Planning Report*, 2004.

Figure 5-12 – Schematic of proposed Drummoyne substation augmentation



5.5.1 Justification

EA has stated that the peak demand at the Drummoyne Zone substation is expected to reach firm capacity over the next few years and the adjoining substations have insufficient capacity to assist in managing the load growth at the Drummoyne substation.

With firm capacity ratings being exceeded Drummoyne Zone Substation would not be able to meet required minimum reliability standards requirements under single contingency outages and consequently network augmentation or non-network alternatives are required to rectify this potential situation. EA 'Identification of Need document'[69] indicates that the organisation has carried out a substation loading risk assessment which indicates that in the winter of 2006 the substation will exceed a 1% risk level.

The key element in this prediction is the forecast load increases in the area – with the EA analysis based on a projected 3.2% annual increase in maximum demand at the Drummoyne Zone Substation. EA advise that the fundamental driver for load growth in the area is urban renewal based customer increases as a result of new medium and high density residential developments.

5.5.2 Strategic alignment

EA has identified the impending constraint in its Transmission Planning reports. The Drummoyne substation was originally designed to be a three transformer substation.

Consideration had been given to using the fifth transformer at Five Dock Zone substation although Five Dock is a 33/11kV zone substation that is supplied from the, heavily

69 Appendix 16 to the EA revised submission – 'Energy Australia, *Identification of Need – Drummoyne Zone Substation*', 18 August 2004.

loaded, Homebush sub transmission substation (STS). EA is planning to reduce the load on the 33kV sub-transmission network and proceeding with the proposed option will result in loads being connected at the 132kV sub-transmission/transmission level – in keeping with EA's planning philosophy.

Consequently PB Associates believes that this project aligns with EA's overall network planning strategy.

5.5.3 Alternatives

EA identified two options for overcoming the constraint:

- extend the existing 11kV switchboard and install a third 132/11 kV transformer. Cost = $4.0M (Budget estimate only + - 20% accuracy).
- install another zone substation in the area to cater for the expected load growth. EA has projected a budget cost of $20m based on the expected costs of Green Square zone substation.

PB Associates believes that it is unlikely that a zone substation could be constructed in the area within the required timeframe. Regardless of this, we believe that EA's proposed option represents the least cost solution.

Details of other options that have been considered by EA are provided in an internal EA memorandum attached to the EA submission[70]. These include load transfers to adjoining zone substations and the installation of capacitors to defer the augmentation work.

PB Associates believes that whilst load transfers to adjoining substations are possible in the short term, the neighbouring Leichhardt, Burwood and Five Dock Substations will be either at, or near, their firm ratings around the same time as Drummoyne is predicted to exceed the nominated 1% substation loading risk assessment limit.

EA has dismissed the option of installing capacitors given that at peak loads the power factor is already 0.95 at Drummoyne and consequently the installation of capacitors will only provide 150amps of reduced substation loading. PB Associates concurs with the load reduction capability of the capacitors but notes that 150amps is equivalent to over one year of forecasted winter maximum demand growth so consequently should have the potential to defer the project by one year.

To consider if this is viable PB Associates carried out an NPV analysis of the benefits of installing capacitors at a capital cost of $300,000 (based on NSW Treasury Asset Valuation Guidelines) and thereby deferring the expenditures proposed by EA for the augmentation work by one year. The results of this comparison are included in Table 5-13. The benefits of deferring the augmentation are marginal at best and consequently PB Associates believes that the option selected is the least cost option.

70 Energy Australia Network Memorandum, *Options to Alleviate Loading at Drummoyne*, 9 August 2004.

Table 5-13– NPV of deferral of substation augmentation

Project Option	Discount rate 12%	Discount rate 9%	Discount rate 6%
Augment Zone Substation as proposed	$2.98m	$3.20m	$3.46m
Install 11 kV Capacitors and defer Augmentation by 1 year	$2.93m	$3.21m	$3.54m

PB Associates has been advised that EA had not originally considered demand management options for deferring the augmentation work but have now commissioned a demand management study in the area. However, given their experience with lead times associated with demand management project implementations to date they are not confident of achieving sufficient load reductions to allow for augmentation deferrals. PB Associates concurs with EA's view on this aspect.

5.5.4 Risk of projects not-proceeding

PB Associates is of the firm view that this project will need to be completed at some stage in the future. The Drummoyne Zone Substation has been designed as a three transformer substation and load growth in the area will eventually justify carrying out the proposed works. Most of the load growth is due to the establishment of higher density residential developments in the area.

Consequently the likely timing of the project is the key issue for consideration in this review. EA is projecting maximum demand increases of just over 3% for the next 5 years in the area. The recorded maximum demand increase from winter 2003 to winter 2004 was actually 4.9%. PB Associates is not able to offer any contrary views with respect to the forecast demand increases.

5.5.5 Costs

EA has based their cost estimates for the Drummoyne Zone Substation on the design estimates for their Sefton Zone substation 132/11 kV transformer installation with an additional amount of $100,000 allowed to cater for the connection of the proposed new 11kV switchgear panels to the older (25 years old) existing Drummoyne 11kV switchgear. The submitted costs for the project were $4.0m which included a contingency amount of approximately $450,000 reflecting a 10% contingency on all items except for a 25% contingency on civil works; estimated SCADA costs; switchgear wiring and a miscellaneous component (value $50,000).

Using the standard rates incorporated in the NSW Treasury Guidelines for electricity network asset valuations, PB Associates estimated the cost of the EA submission option at just over $3.6m[71] excluding the contingency amounts, PB Associates' estimated costs are approximately 2% higher than those calculated by EA. PB Associates believes that the contingency amounts used by EA are reasonable allowances for a project of this type.

In arriving at these estimates PB Associates used EA's proposed design criteria and did not carry out a detailed evaluation on the number of feeder panels required for an optimum 11 kV switchboard design.

71 PB Associates has assumed the same SCADA installation costs as EA has used and the equivalent of $100,000 for additional 11kV switchgear connections.

5.5.5.1 EA submitted

EA has provided a forecast capital expenditure on this project as given in Table 5-14. These figures were derived from base cost expenditure estimates of $0.8 million in 2005/2006, $2.7 million in 2006/2007 and $0.6 million in 2007/2008. EA then assumed probabilities of 80% associated with this project proceeding as per these base estimates and 20% probability that the expenditures would be delayed by 1 year to arrive at the probability weighted figures included in their submission[72].

Table 5-14 – EA submitted expenditure for Drummoyne Zone substation

Forecast Expenditure in $2004 ($m)				
2004/05	2005/06	2006/07	2007/08	2008/09
0.0	0.8	2.7	0.6	0.0

5.5.5.2 PB Associates comments

PB Associates believes that the cost base provided by EA is reasonable and the project is justified. In terms of project timing, PB Associates has no information to suggest that the load projections supplied by EA are incorrect and consequently accepts that the probability weightings used by EA to produce their forecast capital expenditures are reasonable. Accordingly, no variations to the submitted capital expenditure levels are proposed.

Table 5-15 – Recommended variations

Forecast Expenditure in $2004 ($m)				
2004/05	2005/06	2006/07	2007/08	2008/09
0.0	0.0	0.0	0.0	0.0

5.5.5.3 PB Associates recommended expenditure

Since PB Associates believes the expenditure levels forecast be EA are reasonable, PB Associates recommend that the proposed levels be accepted for the forthcoming Regulatory period.

Our recommended level of capital investment is given in Table 5-16.

Table 5-16 – PB Associates recommended expenditure for Drummoyne

Forecast Expenditure in $2004 ($m)				
2004/05	2005/06	2006/07	2007/08	2008/09
0.0	0.8	2.7	0.6	0.0

5.5.6 Conclusion

Having reviewed this project PB Associates are of the view that EA has examined reasonable alternatives to the project and that the project is justified as submitted by EA. Accordingly, PB Associates recommends that the capital expenditure levels submitted for the Drummoyne Zone Substation Constraint project be accepted.

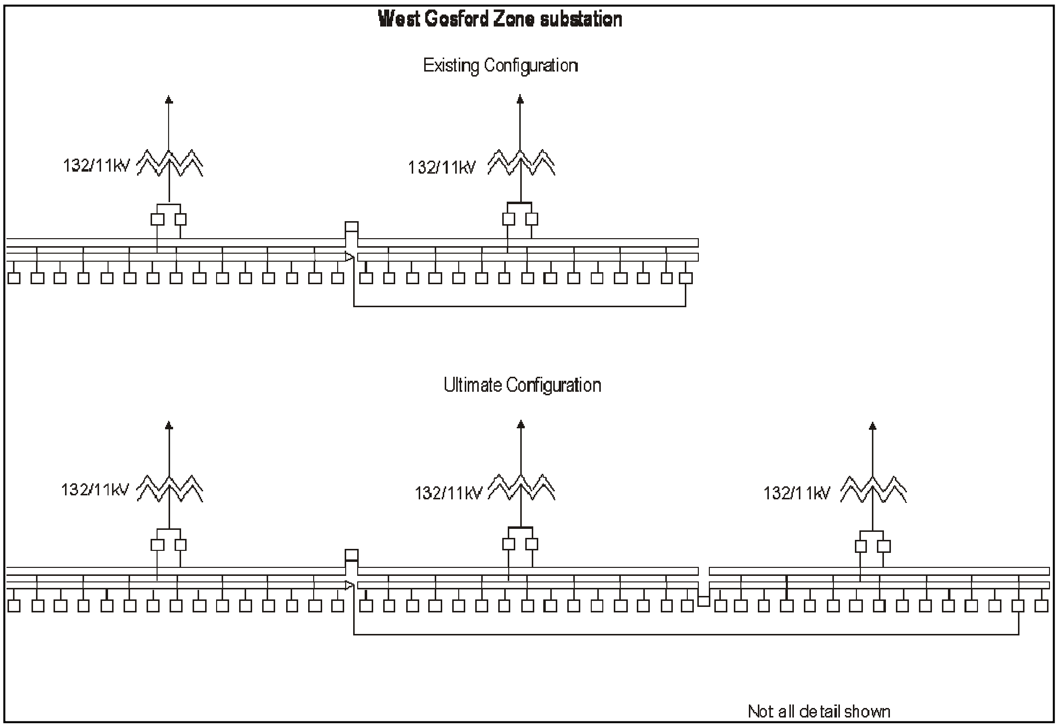
72 Energy Australia Spreadsheet, *Probability Analysis*, forwarded by email on 17 November 2004.

5.6 WEST GOSFORD ZONE CONSTRAINT (AUGMENTATION PROJECT NO.10)

EA has described the West Gosford Zone Constraint project as a possible project – that is likely to proceed in the 2004/05 to 2008/09 regulatory period, although there is some uncertainty about the timing of the project.

The project involves the upgrading of the existing 132/11kV Zone Substation from a two transformer to three transformer substation with the installation of another 50MVA 132/11kV transformer with the associated extension of the existing 11kV switchboard. A schematic diagram of the proposed work is incorporated in Figure 5-13.

Figure 5-13 – Proposed West Gosford zone substation augmentation



5.6.1 Justification

The justification for this project is initially based around a perceived need to relieve constraints associated with the:

- loadings on Zone Substations adjacent to West Gosford including Lisarow, Erina and Avoca Zone Substations; and
- associated capacity constraints in the 66 kV sub-transmission network supplying Erina and Avoca Zone substations

As a result of these distribution system issues EA is proposing to transfer 11kV feeder loads onto West Gosford Zone Substation. This load transfer coupled with projected load growth in the Central Coast/Gosford area leads to a forecast exceedance of the West Gosford Zone substation firm rating within five years.

EA is forecasting continuing high load growths in Central Coast region. Analysis of individual zone substation forecasts included in the EA submission indicates maximum demand growth projections in the range of 3.5% to 6%. If these projections are correct then significant augmentation work will be required throughout the Central Coast distribution and sub-transmission/transmission network.

EA has carried out detailed substation loading risk assessments associated with the Erina and Avoca substations. Such an analysis has not been conducted on West Gosford Zone substation yet and the identification of needs document for the West Gosford project[73] that was incorporated in EA's submission to the ACCC does not specifically address the full range of options outlined in EA's new capital governance process. PB Associates has subsequently received additional information in relation to considerations of other options and these are discussed further below.

5.6.1.1 Existing distribution system constraints

Erina Zone substation operated at over 110 % of its firm rating last summer and work is required to relieve this situation. EA has proposed transferring 11 kV feeder load to West Gosford substation to resolve this immediate issue.

Other constraints are emerging with the overloading of Avoca and Lisarow Zone substations being current issues.

5.6.1.2 Existing sub-transmission system constraints

Erina and Avoca zones are currently supplied from Gosford sub-transmission substation (STS) via a 66kV feeder ring. The present 66kV supply to Erina is via 66kV feeder directly from Gosford STS ringed with another 66kV feeder from Avoca Zone substation. Since Erina and Avoca share 66kV feeder capacity, the total capacity available from the two zones depends on the 66kV network capacity.

At present the 66kV network supplying Erina and Avoca is loaded to capacity during first contingency outages.

5.6.2 Strategic alignment

EA has been planning to relieve the 66kV sub-transmission network supplying the Avoca and Erina Zone substations for some time with a view to the eventual establishment of Wamberal Sub-transmission Substation. EA has commenced an internal process to conduct a Value Management study associated with the entire lower Central Coast area.

West Gosford Zone Substation was designed as a three transformer installation and is currently fitted with only two transformers.

The proposal to transfer load to West Gosford Zone substation is consistent with the longer term planning goals to relieve the 66kV sub-transmission network in the region and to satisfy the short terms issues particularly associated with the overloading of Erina Zone substation. The requirement to then up-rate West Gosford Zone substation as the transferred load and anticipated load growth take it above its current firm rating is consistent with the long term design considerations for that substation.

5.6.3 Alternatives

In their submission EA has identified three options to overcome the constraints identified in establishing the need for augmentation work.

These are to:

- extend the existing 11kV switchboard at West Gosford Zone Substation and install a third 132/11kV transformer at an estimated cost of $3.9m;

[73] Energy Australia, *Identification of Need – West Gosford Zone Substation*, 19 August 2004.

- install another zone substation in the area to cater for the expected load growth. The costs of this option is estimated by EA to be approximately $17m[74]; or
- install 2 x 11kV feeders from Somersby zone substation so that 8.5MVA can be transferred away from West Gosford zone substation. This option would provide short term load relief at West Gosford with an EA estimated (budget) cost of $2.5m.

In the submission EA did not address alternatives to the initial requirement to actually transfer load to West Gosford Zone substation but has provided PB Associates with a document outlining the issues with the overloaded distribution assets (Erina and Avoca Zone substation) and outlining other related sub-transmission issues[75]. While this is a distribution planning issue PB Associates are of the view that the proposed load transfers reflect a sound planning approach.

In their submission EA indicated that economic analysis identified the West Gosford Zone substation as being the least cost option. Clearly the new zone substation option is not a least cost option. In their submission EA incorporated an NPV analysis of deferring the augmentation of the zone substation for a period of 5 years by transferring load to Somersby zone substation which is currently under utilised[76]. The analysis was carried out at discount rates of 6%, 9% and 12% and results are summarised in the Table 5-17.

Table 5-17 – NPV analysis of West Gosford augmentation deferral

Project Option	Discount rate 12%	Discount rate 9%	Discount rate 6%
Augment Zone Substation as proposed	$1.6m	$2.0m	$2.4m
Switch Load to Somersby and Defer Zone Substation by 5years	$1.9m	$2.5m	$3.4m
PB Calculation of Augmentation Option	$2.2m	$2.5m	$2.9m
PB Calculation of Deferral Option	$2.7m	$3.3m	$4.0m

When EA carried out its NPV analysis it was assumed that the augmentation would take place in 2011/12 with the deferral option resulting in augmentation taking place 2016/17. In their submission EA has proposed that the augmentation be completed in 2008/09 and consequently if a deferral was required this would also take place in that financial year with the augmentation delayed until 2013/14. PB Associates has reflected this timing in an NPV comparison which is shown in the bottom two rows of Table 5-17. The relative merits of the two project approaches does not change with the base option augmentation project case representing the least cost option.

In discussions with EA it is clear that they had considered other options including the installation of capacitor banks. PB Associates has reviewed information from EA records that identifies the power factor at peak loads at West Gosford as being already at, or near, unity power factor[77]. On this basis PB Associates do not believe that power factor correction is an option worth pursuing.

74 PB Associates is advised by EA that this is budget estimate only having a +/-25% accuracy and is based upon expected costs for the installation of Green Square zone substation.

75 Energy Australia, Identification of Needs – Erina and Avoca Zone Substations, 24 September 2004.

76 Operating at 29% of form rating in 2004.

77 Energy Australia Document Excerpt, *Zone Transformer Power Factors*, provided by hand 18 November 2004.

Some screening studies had been conducted on demand management initiatives to defer the augmentation work but with the high level of growth in the Central Coast area these were considered to be ineffective in deferring the proposed augmentation.

5.6.4 Risk of projects not-proceeding

PB Associates is of the firm view that this project will need to be completed at some stage in the future. The West Gosford Zone Substation has been designed as a three transformer substation and load growth in the Central coast region will eventually justify carrying out the proposed works. Consequently the likely timing of the project is the key consideration for the present review.

EA is projecting maximum demand increases associated with a number of substations in the Central Coast as being in the order of 3.5% to 6% for the next 5 years. PB Associates considers these to be reasonably high projections which are based on recent high growth trends in the area. The project could be delayed if the predicted load growth does not materialise at the forecast rate.

5.6.5 Costs

EA has based their cost estimates for the West Gosford Zone Substation on the design estimates for their Sefton Zone substation 132/11 kV transformer installation. The submitted costs for the project were $3.9 million which included a contingency amount of approximately $450,000 reflecting a 10% contingency on all items except for a 25% contingency on civil works, estimated SCADA costs, switchgear wiring and a miscellaneous component (value $50,000).

Using the standard rates incorporated in the NSW Treasury Guidelines for electricity network asset valuations, PB Associates estimated the cost of the EA submission option at just over $3.5m[78] If the contingency amounts are excluded, then PB Associates estimated costs are 2% higher than those calculated by EA. Given the current planning status of the project PB Associates believes that the contingency amounts used by EA are reasonable allowances[79].

In arriving at these estimates PB Associates used EA's proposed design criteria and, for example, did not carry out a detailed evaluation on the number of feeder panels required for an optimum 11 kV switchboard design.

PB Associates has not carried out a detailed examination of all components of EA's proposed costings but we are of the view that they appear to be within the boundaries of reasonable expectations.

5.6.5.1 EA submitted

EA has provided a forecast capital expenditure on this project as per the cost break up incorporated in Table 5-18. These figures were derived from base cost expenditure estimates of $1m in 2007/2008 and $2.9m in 2008/2009. EA has then assumed probabilities of 75% associated with this project proceeding as per these base estimates; a 10% probability that the expenditures would be delayed by 1 year and a 15% probability that the expenditures would need to be advanced by 1 year – in order to arrive at the probability weighted figures included in their submission[80].

78 Assuming the same SCADA installation costs as used by EA. PB Associates has not verified these costs.

79 Particularly in recognition that PB Associates has used the 2002 NSW Treasury Guideline rates as its basis for comparison.

80 Energy Australia Spreadsheet, *Probability Analysis*, forwarded by email on 17 November 2004.

Table 5-18 – EA submitted expenditure for West Gosford

Forecast Expenditure in $2004 ($m)				
2004/05	2005/06	2006/07	2007/08	2008/09
0.0	0.0	0.16	1.26	2.46

5.6.5.2 PB Associates comments

PB Associates believes that the cost base provided by EA is justifiable. PB Associates has some reservations about the project timings proposed by EA and believes there is little chance that the project would need to be advanced by one year especially considering the relatively new condition of the West Gosford Zone Substation and the requirement for recent high load growth trends to achieve base case timing projections.

In PB Associates assessment it is more likely that there could be a one year delay in the project and that this should be assigned a probability of at least 25%. Consequently PB Associates recommends that the variations incorporated in Table 5-19 be made to the expenditure projections for this project.

Table 5-19 – Proposed variations to capital expenditure

Forecast Expenditure in $2004 ($m)				
2004/05	2005/06	2006/07	2007/08	2008/09
0.0	0.0	-0.16	-0.50	-0.04

5.6.5.3 PB Associates recommended expenditure

Reflecting PB Associates view that there is at least a 25% probability that the project may be deferred by one year, Table 5-20 incorporates recommended expenditure allowances for the West Gosford Augmentation project. Deferral of the project would result in capital expenditure falling outside the current 2004/05 to 2008/09 regulatory review period.

Table 5-20 – PB Associates recommended expenditure for West Gosford

Forecast Expenditure in $2004 ($m)				
2004/05	2005/06	2006/07	2007/08	2008/09
0.0	0.0	0.0	0.76	2.42

5.6.6 Conclusion

Having reviewed this project PB Associates are of the view that EA has examined reasonable alternatives to the project, the project is justified and that some expenditure will be incurred in the forthcoming regulatory period. EA's submitted base cost estimates are believed to be reasonable but PB Associates has some doubt about the precise timing of the project. In particular PB Associates believes that there is small probability of the need to advance the project by one year and a higher probability that the project would be deferred by one year. Consequently revised capital expenditure levels have been recommended for this project.

5.7 TRANSFORMER AND REACTOR REPLACEMENT (NO.17)

The transformer and reactor replacement programme proposed by EA includes transformers and shunt reactors. The total expenditure for the replacement of transmission transformers proposed by EA is $20.8m. This expenditure level is greater than the proposed transformer expenditure contained within EA's original submission to the ACCC[81].

Replacement details provided by EA are as follows given in Table 5-21.

Table 5-21 - Replacement transformers

132kV transformers & reactors (location)	Type	No. in submission	No. in revised submission
Chullora	Reactor	2	2
Rozelle	132/33kV 20/30MVA	0	2
Bunnerong North	132/33kV 60/120MVA	1	2
Canterbury	132/33kV 40/60MVA	1	4
Kurri	132/33kV 40/60MVA	1	3
Marrickville	132/11kV 35/40/45MVA	1	1
Tomago	132/33kV 40/60MVA	1	1

5.7.1 Justification

EA's revised submission indicates that the programme comprises two elements:

- replacement of failed transformers; and
- replacement of equipment that has reached the end of its service life (as opposed to standard asset life).

EA has advised PB Associates that equipment identified for the replacement programme has been selected on the basis of condition via a risk assessment. EA indicated during discussions that transformers defined as transmission assets have been condition assessed. Some of these condition assessments have been provided to PB Associates by EA[82].

The SKM report[83] also refers to transformer and reactor replacement requirements. It should be noted that EA are using a 50 year standard asset life for transformers, although they have recently adopted a 45 year life for substations[84].

Information on EA's transmission transformers and reactors and the EA associated risk classification is given in Table 5-22 and Table 5-23 respectively[85].

81 Transformer replacement expenditure was previously included within EA's zone and sub-transmission substation replacement programs.

82 The conditions assessments did not include Rozelle and Tomago substations.

83 Aged Asset Replacement Projection, SKM, September 2004.

84 PB Associates notes that EA also take the overall age and condition profiles of transformers into account in the development of their transformer replacement programme.

85 The risk replacement timescales given in Table 5-23 are based on information provided in the condition assessment spreadsheet provided by EA. PB Associates acknowledges that this initial replacement

Table 5-22 – EA transformers and reactor information

132kV Transformers & Reactors location	Type	Identified Risk Grading	Year of Installation	Equipment Age (years)
Chullora	2 x Reactors	B2	1974	30
Rozelle	2 x 132/33kV 20/30MVA	C2	1954	60
Bunnerong North	2 x 132/33kV 60/120MVA	C2, D2	1968	36
Canterbury	4 x 132/33kV 40/60MVA	C2	1961 & 1962	43 & 44
Kurri	3 x 132/33kV 40/60MVA	B2	1962 & 1963	42 & 41
Marrickville	1 x 132/11kV 35/40/45MVA	B2*	1972, 1976, 1982	22 to 32
Tomago	1 x 132/33kV 40/60MVA	B2	1981	24

Table 5-23 – EA transformer and reactor risk rating

132kV Transformers & Reactors location	Risk Replacement Timescale
Chullora	5-10 years
Rozelle	10-20 years
Bunnerong North	10-20 years, 20 years+
Canterbury	10-20 years
Kurri	5-10 years
Marrickville[86]	5-10 years
Tomago	5-10 years+

PB Associates comments as follows regarding each transformer or reactor replacement[87].

5.7.1.1 Chullora Reactors

Condition reports indicate severe thermal problems and discharge although the risk tabulation gives a B2 grading. It could reasonably be expected that these should be replaced.

timescale is, in many cases, modified by EA to account for other conditions and circumstances which are not provided for in the risk assessment.

86 The condition assessment for Marrickville No 4 transformer, built in 1982, indicates that close monitoring is required due to high furan levels relative to the age of the transformer.

87 PB Associates has not been able to fully reconcile the EA risk assessment, equipment ages and condition report details with the transformer and reactor replacement programme in all cases.

5.7.1.2 Rozelle Transformers

These units are 10 years past their 50 year standard asset life and could reasonably be considered due for replacement. However PB Associates notes that these transformers were not considered for replacement in the original Submission.

5.7.1.3 Bunnerong North Transformers Numbers 2 and 4

These transformers are 14 years short of their standard lives, although condition reports indicate thermal problems, and in the case of one transformer, suggests that cooling may be inadequate. In the absence of any loading information, it could be expected that for large assets only around 70% through their service lives with average loadings, further investigations and/or refurbishment would be valid options, rather than replacement. PB Associates notes that one transformer replacement was proposed in the original submission.

5.7.1.4 Canterbury Transformers Numbers 1 to 4

These transformers are around 7 years short of their standard lives and condition reports indicate signs of ageing. Two transformers show signs of significant problems although are classed as 'serviceable'. Further investigation and/or refurbishment would be options. PB Associates notes that one transformer replacement was proposed in the original submission.

5.7.1.5 Kurri Transformers Numbers 1 to 3

These transformers are around 8 years short of their standard lives and condition reports for two out of three transformers are satisfactory for their age. The third transformer does show some problems, but further investigation or refurbishment could be undertaken. PB Associates notes that one transformer was proposed for replacement in the original submission.

5.7.1.6 Marrickville Transformer Number 4

This transformer shows signs of high furans and as there is a spare transformer on site. PB Associates consider that it might not be unreasonable to expect that transformer Number 4 could be removed temporarily for further investigation or refurbishment. PB Associates notes that this transformer replacement was included in the original submission.

5.7.1.7 Tomago Transformer Number 2

Transformer 2 has a shorter life under the risk assessment criteria and a poor condition assessment indicating premature ageing of paper. The transformer unit is approximately half way through its service life[88] and so it may not be unreasonable to expected that de-tanking and inspection is undertaken prior to the consideration of refurbishment or replacement alternatives.

5.7.2 Alternatives

Alternatives for direct replacement based on condition assessment are not required under the current regulatory environment.

88 Year of manufacture 1980.

5.7.3 Costs

EA has included an allowance of $1.5m for replacement of failed equipment (non age related failure)[89] and an allowance of $19.3m for replacement of equipment which has reached the end of its service life. PB Associates notes that, according to EA's risk assessment table, the equipment listed above generally does not fall into the risk category requiring replacement during the 2004/05 to 2008/09 regulatory period. There are, however, transformers that are showing signs of age electrically and we consider that replacement of some of the proposed transformers is justified. PB Associates therefore recommends an allowance be made for transformer replacement as per Table 5-24.

Table 5-24 – PB Associates assessment of proposed transformer replacements

132kV Transformers & Reactors Location	Type	No in Submission	No in Revised Submission	PB Associates' Recommend-ation
Chullora	Reactor	2	2	2
Rozelle	132/33kV 20/30MVA	0	2	2
Bunnerong North	132/33kV 60/120MVA	1	2	0
Canterbury	132/33kV 40/60MVA	1	4	0
Kurri	132/33kV 40/60MVA	1	3	0
Marrickville	132/11kV 35/40/45MVA	1	1	0
Tomago	132/33kV 40/60MVA	1	1	0

5.7.3.1 EA submitted

EA has not provided a programme for this expenditure. We have assumed that the total replacement costs are spread evenly throughout the regulatory period.

Table 5-25 – EA submitted expenditure for transformer and reactor replacement

Forecast Expenditure in $2004 ($m)				
2004/05	2005/06	2006/07	2007/08	2008/09
4.16	4.16	4.16	4.16	4.16

5.7.3.2 PB Associates comments

PB Associates has estimated reductions in expenditure based on the recommendation in Table 5-24. Cost deductions have been based on the NSW Treasury valuation figures[90]. PB Associates recommended variations and recommended expenditure is given in Table 5-26 and Table 5-27 respectively.

89 Based on the SKM Asset Replacement Projection report, Table 10.

90 Draft Valuation of Electricity Network Assets, A Policy Guideline for NSW DNSPs. Note also that PB Associates' cost assessments and estimates include an additional $50,000 per transformer to allow for forced oil cooling, as the NSW estimates only allow for ONAN.

Table 5-26 – Recommended variations

Forecast Expenditure in 2004 ($m)				
2004/05	2005/06	2006/07	2007/08	2008/09
-2.34	-2.34	-2.34	-2.34	-2.34

Table 5-27 - PB Associates recommended expenditure for transformer replacement

Forecast Expenditure in 2004 ($m)				
2004/05	2005/06	2006/07	2007/08	2008/09
1.82	1.82	1.82	1.82	1.82

5.7.4 Conclusions

PB Associates concludes that the $1.5m allocated for replacement of failed equipment is prudent and based on sound principles. However, unless there are errors in the EA risk categories or condition assessments were undertaken well before 2004, PB Associates is of the view that not all of the transformers or reactors listed in the proposed replacement programme are prudent within the 2004/05 to 2008/09 regulatory period.

5.8 NON-NETWORK CAPITAL EXPENDITURE

Energy Australia has submitted non-network capital expenditure to an average of $5.6m per annum for the 2004/05 to 2008/09 regulatory period. The calculation of the transmission component of EA's non-system capital expenditure has been calculated on the same ratio as that of non-direct operating expenditure; a direct percentage of transmission assets against total network assets. That is 12.4% of total expenditures have been attributed to the transmission component of Energy Australia's business.

5.8.1 IT

In this section we report on PB Associates' review of EA's proposed IT expenditure.

5.8.1.1 Expenditure description

EA has submitted whole of business IT costs of between $25m and $26m per annum for the forecast regulatory period[91]. This is broken down across a number of projects as detailed in Table 5-28.

[91] Note that these figures are whole of business, and include Transmission and Distribution expenditures.

Table 5-28 – IT capital expenditure breakdown ($m)

Project	2005	2006	2007	2008	2009
Hardware & software upgrades	5.0	5.0	5.0	5.0	5.0
Asset Management	6.0	5.0	6.0	6.5	7.5
Outage Management	3.0	2.0	2.0	1.0	1.0
GIS	3.5	1.5	4.0	4.0	4.0
Proj. Management	3.0	1.0	1.0	2.0	2.0
Mobile Computing	1.0	1.0	3.0	4.0	4.0
Billing & metering systems	1.0	8.0	2.0	1.0	1.0
GEMS	0.5	0.5	2.0	0.5	0.5
Financial & reporting	2.0	1.0	1.0	2.0	1.0
Total	**25.0**	**25.0**	**26.0**	**26.0**	**26.0**

EA has noted in its regulatory submission that

> "*Energy Australia has many legacy IT systems. Rationalisation of the systems and platforms used by the former Orion Energy and Sydney Electricity has commenced…*".

PB Associates notes that the merger of Orion and Sydney Electricity occurred in 1996 and concurs with the business need for business system integration.

The recent historical EA capital expenditure on IT is provided in Table 5-29. It should be noted that a significant amount of IT expenditure had been approved by IPART over this period to enable the implementation of Full Retail Contestability (FRC). The average historical IT spend equates to $17.4m per annum, although this may be higher than a long-term average due to FRC.

Table 5-29 – Historical IT capital expenditure

Non System Capex – network allocation as per IPART Regulatory Accounts ($m)			
	2002	2003	2004
IT systems (includes FRC allowance)	29.9	10.6	11.8

EA has not provided any significant detail about how they estimated the cost of the IT upgrades, or an explanation of the benefits it expects to achieve as a result of these upgrades. Further EA does not quantify the costs incurred due to inefficiency of the existing systems. PB Associates is not aware of an EA business case for the proposed IT expenditures.

5.8.1.2 PB Associates comments

EA has provided descriptions on both the processes underpinning the IT strategy and the major IT programs. PB Associates has also been provided with a document that details the capabilities of the existing systems.

From the information provided, PB Associates concurs in general with the business need and overall level of expenditures as forecast. The forecast IT expenditures are higher than the historical expenditures when viewed on a per annum basis. However, the forecast IT expenditures have been reviewed by IPART's consultants as part of the recent distribution business revenue determination.

PB Associates has concerns regarding two areas of expenditure as they relate to a transmission business. These are:

- outage management, and
- billing and metering systems (including the GEMS system).

In these areas, PB Associates recognises that from a transmission and a distribution perspective both of these business processes are required. However, PB Associates has raised the question with EA concerning whether it is appropriate for these costs to be attributed to the transmission operations at the standard ratio of 12.4%. PB Associates notes that the distribution requirement for these two systems is significantly greater in terms of processing and data management than that of transmission.

In relation to the Outage Management System (OMS) Energy Australia has advised the following:

> "*The ACCC has been developing its service standard regime over the last two years in association with TNSP's and is in the process of finalising its application to EnergyAustralia for the 2004 – 2009 period. In its draft determination, the ACCC has required a wider range of network elements to be incorporated in the measurement of Transmission circuit availability than had previously been recorded. In terms of transmission circuit availability, Energy Australia is now required to record reactive plant availability as well as availability of feeders.*"

A key function of an Outage Management System is to capture and report outages and faults on the network. Transmission and distribution networks are fundamentally different. The nature of the distribution network means that the majority of outages will be directly attributable to this part of the network. Typically, only a very small proportion of network outages are attributable to the Transmission network.

PB Associates concurs with the EA statement above and recommends that a more cost reflective allocation of outage management system costs would be on a per record basis or customer minute basis.

In relation to billing and metering systems (including transfers), EA has provided the following supporting information:

> "*better integration and enhancement of the metering and billing systems to ensure compliance with market rules and capture of network revenue. A targeted outcome is that meter management, NMI management and Network billing will occur and in one system, reducing the need for incident resolution and checks.*"

The GEMS market interface system was previously allowed for in the IPART determination. The expenditure identified by EA as relating to the transmission business relates to additional expenditures

> "*as a result of soon-to-be determined new Business to Business standards which were not available at the time of the previous determination*".

Whilst PB Associates does not suggest that billing, market interface and/or metering are irrelevant to the transmission function, we are of the view that that the volume of transmission transactions in these areas is significantly less than those relating to the distribution network. From this perspective, PB Associates considers that an allocation proportional to related transactions or meter numbers may be more cost reflective.

PB Associates does not suggest that the expenditures submitted by EA are imprudent or inefficient, but that a more cost reflective allocation methodology may be appropriate. PB Associates recognised that the completion of the distribution expenditure review may have closed off any avenue for correcting this mis-allocation and will seek guidance from the ACCC in relation to this matter[92].

The total expenditure that PB Associates has identified as potentially being in question, should a more cost-reflective allocation policy be applied, is provided in Table 5-30.

Table 5-30 – Re-allocation of IT capital expenditure

Forecast Expenditure in 2004 ($m)				
2004/05	**2005/06**	**2006/07**	**2007/08**	**2008/09**
-0.56	-1.30	-0.74	-0.31	-0.31

Based on the above discussion and recognising that EA appears to have no immediate mechanism to recover any IT re-allocation cost reductions, PB Associates has included the total IT allocation as submitted by EA in its recommended IT capital expenditure. This is given in Table 5-31.

Table 5-31 – PB Associates recommended IT capital expenditure

Forecast Expenditure in 2004 ($m)				
2004/05	**2005/06**	**2006/07**	**2007/08**	**2008/09**
3.10	3.10	3.22	3.22	3.22

5.8.2 Vehicles and plant

Total network capital expenditure identified by EA in this area averaged around $12.5m to $13m in the early years of the last regulatory period and has increased to $17.6m in the last year.

EA has stated that the forecast capital expenditure contained in the submission was made on the basis of early estimates. The forecast capital expenditure is as provided in the Table 5-32.

Table 5-32 – EA submitted expenditure for vehicles and plant

Forecast Expenditure in 2004 ($m)				
2004/05	**2005/06**	**2006/07**	**2007/08**	**2008/09**
1.74	1.61	0.87	1.12	1.49

EA has provided latest budget forecasts for capital expenditure in this area as well as replacement policies and procedures.

EA has advised that the fleet capital programme is developed taking into consideration changes in technology, regulatory requirement, changes in work practices and the

92 PB Associates has re-confirmed with EA that the allocation of non-system capital expenditure has been made on a 87.6% to 12.4% split (distribution and transmission respectively) based on the respective asset group values. EA has also confirmed that the amount submitted and approved by IPART is exactly 87.6% of the total non-system capital expenditure (as described in the introduction to Section 5.8). EA has stated that no alterations or additions have been made to the non-system capital expenditure costs between the IPART and ACCC submissions.

general condition of the fleet. Plant and heavy vehicles are inspected annually to ascertain which units should be replaced on a condition basis.

In general the fleet is replaced based on the following criteria as summarised in Table 5-33.

Table 5-33 – Fleet Replacement Schedule

Vehicle Type	Criteria
Light Commercial	10 years or 100,000 km
Trucks	10 years or 150,000 km
Elevating work platforms	10 years
Crane/borers	15 years
Plant	On condition basis and suitability

PB Associates has reviewed the process and indicative replacement criteria specified by EA and agrees with the condition based approach. PB Associates also notes that the deterministic approach to forecast capital expenditure appears to reconcile with historical expenditures.

Based on the above, PB Associates considers that the forecast capital expenditure is reasonable and PB Associates does not recommend any alterations to the proposed expenditure levels.

5.8.3 Office equipment, furniture, land and buildings

EA office equipment and furniture expenditures have been projected to remain stable at current levels. Land and building expenditures have been phased with the distribution capital programme and future requirements of the network business for example, future rationalisation of Field Service Depots and offices.

Expenditure in this area, for the last regulatory period, varied but averaged around $5m per annum.

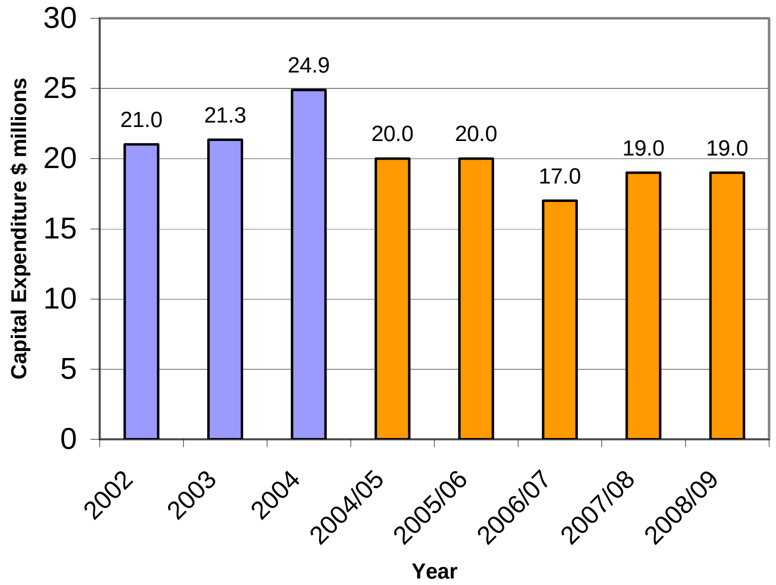
The forecast expenditure in this area includes;

- major fit-outs and upgrades to training facilities and some depots to cater for the significant increase in apprentices and new employees. The fit-outs are associated with the building upgrades and extensions listed below; and
- plant and equipment costs.

Building costs over the last 3 years comprised normal upgrades to depots and training facilities.

Figure 5-14 provides a comparison of the current non-system expenditures (excluding IT) with forecast expenditures. PB Associates notes that the forecast expenditures are slightly less than historical expenditures.

Figure 5-14 – Non-system capital expenditure excluding IT



In the next regulatory period, additional building costs have been forecast, in addition to normal upgrade on the basis of the following major projects:

- Abbot St, Newcastle Depot Upgrades ($0.86m);
- Training School Upgrade, Newcastle ($1.0m);
- Zetland Depot refurbishment Works ($2.5m); and
- Homebush Extensions ($2.9m)

EA has provided individual cost estimates for the above projects. The estimates are provided to a reasonable level of breakdown. PB Associates has compared a number of unit rates for the estimates provided and found the figures to be within a reasonable range.

The documentation provided by EA indicates that some works[93] would serve both EnerServe and the Customer Service group. PB Associates notes that the Customer Service group provides services to the retail and network businesses and that the EnerServe group undertakes both regulated and non-regulated activities. As the Zetland depot is a service depot, PB Associates is concerned that the allocation of these costs to transmission is appropriate. For the purposes of this report, PB Associates has assumed that the services provided by the Customer Services group at this depot revolve around new connections, outage management, emergency dispatch and/or reporting and that the services provided by EnerServe from this depot related to regulated services only. From this perspective the allocation of costs may be appropriate.

From the perspective of ring-fencing regulated activities, it is important to clarify whether the proposed depot refurbishment works will provide benefit to non-regulated activities undertaken by EA. Based on this it is important to understand whether the activities undertaken by EnerServe from the Zetland depot include non-regulated services, and/or whether the activities undertaken by the retail group at Zetland relate to contestable retail services. PB Associates recommends that ACCC seek further details from EA to clarify this position.

93 Zetland depot proposed refurbishment works.

PB Associates notes that the average contingency allowance applied to the above projects is in the order of 15%.

Based on PB Associates' review of the non-system capital expenditure (excluding IT), we are recommending that the submitted capital expenditure forecasts be accepted without alteration.

5.8.4 Total non-system (support the business) capital expenditure

The following section summarises the PB Associates recommendations in relation to non-system (support the business) capital expenditure.

5.8.4.1 Submitted

Based on a simple allocation ratio of distribution asset value to transmission asset value (approx. 12.4%), the total submitted non-system (support the business) capital expenditure is as described in Table 5-34.

Table 5-34 – EA submitted expenditure for non-system (support the business)

Forecast Expenditure ($m)				
2004/05	2005/06	2006/07	2007/08	2008/09
5.58	5.58	5.33	5.58	5.58

5.8.4.2 Variations

Table 5-35 gives the variations that PB Associates is recommending in relation to the EA submitted non-system (Support the Business) capital expenditure.

Table 5-35 – Recommended variations

Forecast Expenditure ($m)				
2004/05	2005/06	2006/07	2007/08	2008/09
0.0	0.0	0.0	0.0	0.0

5.8.4.3 Recommendation

Table 5-36 sets out the PB Associates recommended non-system (Support the Business) capital expenditure.

Table 5-36 – PB Associates recommended expenditure for non-system

Forecast Expenditure ($m)				
2004/05	2005/06	2006/07	2007/08	2008/09
5.58	5.58	5.33	5.58	5.58

5.9 ADDITIONAL PROJECT/PROGAMME REVIEWS

During our review there were two further areas which were not selected for detailed scrutiny but which PB Associates felt warranted further exploration than that afforded in the high level review. These are:

- Macquarie Park Zone substation constraint; and

- replacement of substation equipment and mains replacement.

Our observations and recommendations in each of these investment areas are described below.

5.9.1 Macquarie Park Zone Substation Constraint

EA's submission indicates that this project is required in order to relieve a forecast constraint on the Macquarie Park Zone substation which was designed for three transformers and is currently under-equipped.

5.9.1.1 Information provided

EA provided supporting information in the form of an identification of needs document and a separate *options* discussion memorandum. In the view of PB Associates there was insufficient information provided to support all of the claims made by EA in the submission.

5.9.1.2 Justification for project

The project is required to alleviate a forecast constraint due to forecast demand growth in the general area in North West Sydney around Epping and North Ryde. Macquarie Park Zone substation is expected to exceed its firm rating in 2008/2009 if additional load is transferred from neighbouring zone substations where Epping substation in particular is very heavily loaded.

Presently Macquarie Park has reasonable spare capacity to alleviate Epping substation and this will become greater when a large spot load comes off line in 2006. However EA has advised PB Associates that they expect that this spare capacity will be quickly absorbed by load transfers and forecast load growth.

5.9.1.3 Consideration of alternatives

EA has identified only one other option in the form of establishing a new zone substation in the area at a cost of $17m. In the information supporting the application EA has indicated that capacitor banks could be installed and may defer the need for augmentation by up to 2 years. Further information provided by EA indicates that the capacitor banks will only provide one year of deferral benefit[94]. Based on this PB Associates concurs with EA's view on the deferral benefits being for only one year.

On a 1 year deferral basis the capacitor installation costing $500,000 represents an almost equivalent NPV[95] to carrying out the project on time, while on a 2 year deferral basis the capacitor installation would have resulted in a least cost outcome.

5.9.1.4 Cost estimates

EA has indicated a cost of $5.6m in their submission comprising $4m for a new transformer and for extension of the 11kV switchboard and $1.6m for communications and protection upgrades. Insufficient information has been provided for PB Associates to consider the reasonableness of the communications and protection costs but the transformer and 11KV switchboard costs are consistent with the costs allowed for the Drummoyne and West Gosford Zone substation upgrades which have been assessed as reasonable by PB Associates in detailed reviews of those projects.

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94 EA Network Memorandum - *Macquarie Park Zone Substation Development – Response to PB Associates*, dated 9 December 2004, received by email 10 December 2004.

95 Depending on the discount rate chosen.

EA has arrived at their submission costs by assuming a 75% probability that the project will proceed on time; 10% that it will be advanced by a year and 15% that it would be delayed by a year. In their submission EA did not factor in any costs for the communications and protection work in the current regulatory period and so PB Associates assumed that the bulk of this work would be done outside of this regulatory period. Subsequently EA advised that this was an omission and have requested that the expenditure be incorporated into the current period.

5.9.1.5 Strategic alignment

The Macquarie Park Zone Substation was designed as a three transformer substation and consequently the proposed work is consistent with planning associated with the substation.

5.9.1.6 Risk of projects not-proceeding

PB Associates believes that the project will proceed but has some doubts about the proposed timings. The capacitor bank installation alternative would only be able to provide 1 year of deferral for the project and, based on an NPV assessment, is not considered the best option. PB Associates assigns a 10% probability that the project will be advanced by one year; a 75% probability of it being on time and a 15% probability of it being delayed by 1 year.

5.9.1.7 PB Associates comments

PB Associates considers that the project is necessary and, although there are some doubts about the timings of the project, PB Associates believes that the probability time weighting proposed by EA is not unreasonable. PB Associates recommended expenditures as shown in Table 5-37. The recommended variation is associated only with the communications and protection works which were not included in the submission but which have been discussed and agreed with PB Associates as part of this review.

Table 5-37 – Macquarie Zone Substation constraint recommendation

Forecast Expenditure in 2004 ($m)					
	2004/05	2005/06	2006/07	2007/08	2008/09
EA Submission			0.1	1.1	2.6
Recommended variation			+0.1	+0.4	+0.7
Recommended expenditure			0.2	1.5	3.3

5.9.2 Substation equipment and mains replacement

EA has provided for a significant amount of asset replacement capital expenditure in their submission as discussed in Section 4.4 of this report. PB Associates has considered the capital expenditure proposed on replacement transformers in Section 5.7 of this report. In this section PB Associates considers replacement expenditure proposed for (other) substation equipment and underground (UG) and overhead (OH) mains.

5.9.2.1 Information provided

EA has provided details of condition assessments of all major transmission assets including those scheduled for replacement in the period in question.

5.9.2.2 Justification for project

Justification for asset replacements is based (largely) on asset age.

5.9.2.3 Consideration of alternatives

EA has not provided a break up of the proposed asset replacement expenditure costs and consequently PB Associates has assumed that the work is spread evenly over the 5 year regulatory period. Much of the EA programme has been based on exceedance of asset lives despite the fact that EA carries out detailed condition assessment. PB Associates observes that EA has included a number of assets with EA condition assessments of C2, representing only a 'moderate' risk, and resulting in an EA estimated remaining life of 10 to 20 years.

PB Associates notes that none of the HV OCBs and none of the capacitor banks have been risk assessed by EA at a risk rating greater than C2. PB Associates is therefore of the view that, from the information provided, it would not be inappropriate to exclude these items of switchgear from the proposed replacement program.

Zone substation roof repairs are warranted and PB Associates believes that a $2m contingency for substation equipment failure is not unreasonable.

Underground mains cable replacement work is also considered to be reasonable.

The majority of the expenditure for OH mains replacement relates to Feeder 830 which has a condition assessment of C2 although the feeder was built in the 1930s. It is believed to be constructed predominantly with copper conductor with some annealing issues during system faults. While PB Associates notes the age of the feeder, the condition assessment indicates that the feeder does not need replacing for at least 10 years and consequently recommends that it be excluded from the expenditure levels for the 2004/05 to 2008/09 regulatory period pending the provision of more supporting information by EA.

5.9.2.4 Cost estimates

PB Associates has reviewed the costs utilised by EA and notes that these are based on the SKM proposed values – adjusted in some cases where SKM have used green-field costs on brown-field sites. PB Associates notes that EA has made further downward adjustments where it has determined that there are significant components of the asset that do not need replacing (usually connection equipment and civil infrastructure).

PB Associates believes that the unit costs used by EA in the submission are reasonable but in some cases is unable to assess the absolute costs because either the total number of units is not indicated (e.g. OH and UG mains lengths) or some of the unit costs are not available (e.g. major cable oil leak rectification work).

5.9.2.5 Strategic alignment

The proposed replacement programme strategically aligns to an asset-age based replacement philosophy and partially aligned to a condition assessment regime. PB Associates believes that EA has established a very good condition monitoring regime and that this should be the prime determinant for the replacement program.

5.9.2.6 Risk of projects not-proceeding

PB Associates believes that the project is capable of proceeding if approved.

5.9.2.7 PB Associates Recommendations

PB Associates recommends that the expenditure on substation equipment and mains replacement be reduced to reflect replacement on the basis of conditions assessment as set out in Table 5-38.

Table 5-38 – Substation equipment and mains replacement recommendation

PROJECT	EA submitted	Proposed variation	PB Recommended
Substation Equipment (excluding transformers)	$26.0m	-$23.2	$2.8m
UG Mains	$12.7m	$0	$12.7m
OH Mains	$15.4m	-$13.6	$1.8m
Total	**$54.1m**	**-$36.8**	**$17.3m**

6. CONCLUSION AND SUMMARY OF RECOMMENDATIONS

PB Associates has undertaken an independent review of Energy Australia's proposed capital programme for the five-year period 1 July 2004 to 30 June 2009.

PB Associates has reviewed the following principal capital investment categories:

- augmentation capital expenditure;
- asset replacement capital expenditure;
- excluded investments; and
- support-the-business (non-system) and compliance capital expenditure.

The initial part of the PB Associates review included an examination and review of the EA governance framework; a review of the application of EA policies and practices associated with (transmission) capital investments.

The second part of our review addressed the EA submitted programme. PB Associates undertook a high level review of all projects in the submission followed by a detailed review of a sample of individual projects. The detailed project review gave PB Associates a more complete understanding of the individual projects in question – better equipping us to formulate a view on prudency and efficiency. The detailed project review also enabled us to better understand EA's policies and practices with respect to the management of their transmission assets.

PB Associates enjoyed the full cooperation of EA throughout the process – with unhindered access to staff and information. The agreed project timetable was rigorously adhered to by all parties. These two issues allowed PB Associates to make its independent assessment within the timetable required by the ACCC.

PB Associates reviewed nine key project areas[96] – seven in detail. This represents approximately 30% of the value of EA's proposed programme[97] and approximately 50% of the submission value if the remaining Excluded projects[98] are discounted.

EA's Investment decision making framework is improving

We note that many of the capital investment projects proposed in the capital expenditure submission were initiated before EA's new governance procedures and do not, therefore, follow the new processes. Attempts have been made by EA to absorb some of the projects that pre-date the new framework into the new process – although this is by no means complete in the majority of cases. It is difficult for PB Associates to determine the extent that the lack of a formal process may have had on past investment decisions, although we not believe that this lack of process materially affects the justification for the projects that we have examined in this review. We believe that in most cases, many of the steps which are formalised in the new governance framework have been carried out, but in a less formal manner.

PB Associates are of the view that EA is likely to make significant improvements to its investment decision making processes if it continues to pursue the path it has set for itself in establishing its new governance processes. Furthermore, we believe that the

96 This includes broader strategies such as the transformer replacement programmes.

97 This excludes non-system (support the business) capital expenditure.

98 As per EA's request. PB Associates notes that these may or may not be excluded at the determination of the ACCC.

processes enshrined in the new governance framework, if followed, are likely to lead to prudent and efficient investment outcomes in the future.

The policies and practices are reasonable and appropriate

In the course of its review of the EA capital programme PB Associates was able to gain an insight into the policies and practices which are applied by EA, on a day-to-day basis, to support the governance framework. PB Associates talked to key staff within EA and observed office practice.

EA plan and operate their network business in a manner which, in the experience of PB Associates, is not dissimilar to many other distribution businesses. Moreover, there would appear to be few, if any, differences in the way EA manages its transmission and distribution networks. EA manages all of its assets – including those designated as transmission – very much as a distribution network service provider. Given the characteristics and operating conditions of EA's transmission network, PB Associates do not necessarily believe this to be inappropriate. PB Associates believes that consistency in the management and operation of the EA transmission and EA distribution assets is likely to promote more efficient and effective technical solutions and to discourage perverse commercial decisions.

PB Associates notes, however, the need for regulatory separation but would support any initiative or mechanisms which attempt to minimise the extent to which the regulatory definitions improperly influence the technical design and operation of the EA transmission and distribution networks.

In the experience of PB Associates, EA's approach to: power system planning; long-term network development; asset management; load forecasting and information management is typical of many other distribution businesses – in both Australia and overseas – and is appropriate for the management of its network.

Some of the assets are being planned for premature replacement

EA's traditional approach to the replacement of assets based on standard lives is now being supplemented, and to some extent superseded, by the development of a replacement strategy based on a comprehensive regime of condition monitoring and risk management. PB Associates supports the development of EA's risk assessment framework and notes that EA now have a risk assessment for all of its transmission assets. PB Associates observes that in many cases, EA's condition and risk assessment has resulted in transmission assets being assigned an expected life shorter than that suggested by its age.

Our review highlighted a number of instances where assets were being planned for replacement ahead of the time suggested by EA's own condition assessment and subsequent risk rating. The EA replacement programme includes a number of assets whose condition assessment indicates only a 'moderate' risk rating – corresponding to an estimated remaining life of 10 to 20 years. In some cases this is the result of EA assessing the consequence of the asset failing as being 'minor' with only a 'possible' likelihood of occurrence. Replacement of these assets would appear not to be a priority and on this basis PB Associates recommends that they are removed from the replacement programme for the period 2004/05 to 2008/09.

In some instances this initial replacement timescale is modified by EA to account for other conditions and circumstances which are not provided for in the risk assessment. However, it is not clear to PB Associates how EA modifies its risk assessment outcome and on this basis we do not believe it unreasonable to use the risk assessment results as the basis for arriving at a recommended level of replacement expenditure.

PB Associates recommendation includes the removal of the proposed replacement of substation equipment (mainly high voltage circuit breakers) at a total cost saving for the period of $23.2m. PB Associates also recommends the deferral of the replacement of overhead line feeder 830 on the basis that EA's own risk assessment suggest that it does not need replacing for at least 10 years – at a saving of $13.6m. EA's underground mains cable replacement work is considered to be reasonable.

With respect to transformers and reactors, PB Associates agrees the $1.5m allocated for replacement of failed equipment is prudent and based on sound principles. However, unless there are errors in the EA risk categories or condition assessments, PB Associates is of the view that not all of the transformers or reactors listed in the proposed replacement programme will require replacement within the 2004/05 to 2008/09 regulatory period. We note that seven transmission transformers were included in the EA initial submission and that this has more than doubled to 15 in the revised submission. PB Associates has reviewed the proposed transformer replacement projects and is only able to satisfy itself that four transformers are in need of replacement in the 2004/05 to 2008/09 regulatory period. We therefore recommend that the remaining transformer replacement projects are removed from the investment plan – at a saving of $11.7m over the period.

PB Associates considers that plans to complete major refurbishment at the Ourimbah sub-transmission substation during the 2004/05 to 2008/09 regulatory period are not justified. Subject to thorough condition assessment of critical items we do, however, believe that project planning for refurbishment should commence and that work should *start* towards the end of the 2004/05 to 2008/09 period. Postponement of the Ourimbah works as recommended by PB Associates would defer approximately $16m to the post 2008/09 regulatory period.

PB Associates appreciate that in some instances a site augmentation strategy may lead to the wholesale replacement of all assets on a site – and that the condition of some of those assets might not warrant replacement – but this is a more efficient strategy than a piecemeal approach which may involve several site visits over a number of years which may lead to a long-term sub-optimal outcome. However, PB Associates has not seen any evidence to suggest that this is the case in the projects it has examined as part of this review – particularly the Ourimbah refurbishment scheme.

EA's growth-related project proposals are reasonable

PB Associates review of demand (growth) related projects did not reveal any projects which we believe are not warranted. In some cases, however, PB Associates believes that EA's estimation of the likely commencement date of some of the projects is overly optimistic. This has led to PB Associates recommending the deferral of some of the projects for which we undertook a detailed review. These projects include Newcastle West augmentation and West Gosford zone constraint.. Some additional works at Macquarie Park substation have also been identified as part of the review process which resulted in PB Associates recommending an additional $1.2m over the period. The net effect is a recommended reduction in allowed growth related capital expenditure of $1.1m for the period 2004/05 to 2008/09.

The use of demand management (DM) as an option, or part-option, was not fully explored in all project cases we reviewed. PB Associates expects this to improve as the DM section is now an integral part of the network process department.

The proposed compliance and non-system expenditure is appropriate and aligns with the requirements of the business

PB Associates has not reviewed the compliance projects in detail but a high level review would suggest that those proposed are appropriate in order for EA to fulfil its statutory obligations and to continue to development its operations in a responsible manner. PB Associates also believes that the majority of the non-system (support the business) expenditure is reasonable and justified.

In respect of IT PB Associates concurs in general with the business need and with the overall level of expenditures as forecast by EA. However, PB Associates has concerns regarding the Outage Management and the billing and metering systems – specifically the methodology used for the allocation of these costs to the transmission business. It is not clear to PB Associates whether it is appropriate for these costs to be attributed to the transmission operations at the standard ratio of 12.4%. PB Associates notes that the distribution requirement for these two systems is significantly greater in terms of processing and data management than that of transmission.

PB Associates considers that an allocation proportional to related transactions or meter numbers may be more cost reflective. PB Associates does not suggest that the expenditures submitted by EA are imprudent or inefficient, but that a more cost reflective allocation methodology may be appropriate. PB Associates also believes that the GEMS market interface system was previously allowed for in the IPART determination.

Nevertheless, PB Associates recognises that this is an issue for ACCC resolution and has not therefore recommended a reduction in IT system capital expenditure at this stage.

Deliverability may become an issue over the period

PB Associates has some concerns about deliverability of the capital programme given the recent large committed projects by Energy Australia, Integral Energy and Country Energy. We recommend that the ACCC seeks reassurances from EA in relation to their plans to resource to meet the expenditure commitments that have been proposed. In particular, PB Associates is of the opinion that the NSW market may not presently have the resources to deliver the electricity distribution commitments that have been made. However, PB Associates had not recommended any expenditure variations as a direct result of this observation.

Summary of PB Associates recommendations

Table 6-1 shows PB Associates recommended levels for the EA forward transmission capital expenditure. Figures are five-year totals and excluded projects are included in either asset replacement or augmentation – as appropriate.

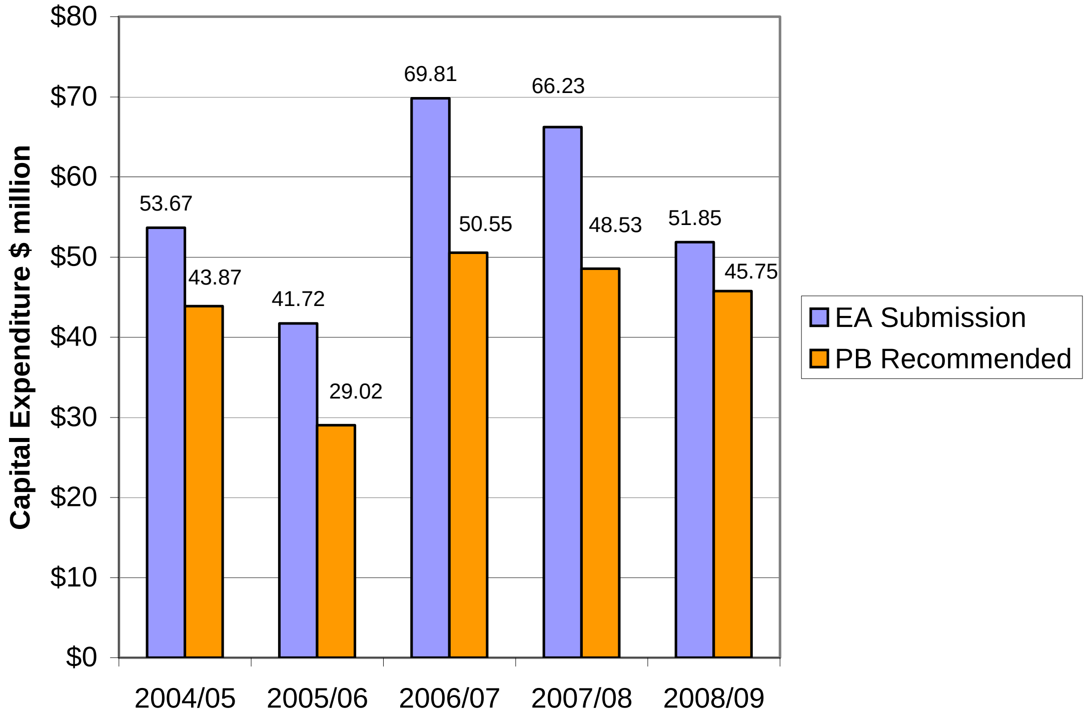
Table 6-1 – Summary of PB Associates recommended expenditure levels

Expenditure category		EA submitted	Proposed variation	PB recommended
Augmentation	main	$48.1m	-$1.1m	$47.0m
	excluded[99]	$47.2m	-	$47.2m
	total	$95.3m	-$1.1m	$94.2m
Replacement	main	$93.9m	-$48.5m	$45.4m
	excluded	$62.3m	-$16.0m	$46.3m
	total	$156.2m	-$64.5m	$91.7m
Non-system	main	$27.7m	$0.0m	$27.7m
	excluded	-	-	-
	total	$27.7m	$0.0m	$27.7m
Compliance	main	$4.1m	-	$4.1m
	excluded	-	-	-
	total	$4.1m	-	$4.1m
TOTAL		**$283.3m**	**-$65.6m**	**$217.7m**

99 Excluded projects are those as proposed by EA in their submission.

A comparison of the expenditure levels given in EA's revised submission with the PB Associates recommended levels, on an annual basis, is given in Figure 6-1. A project level breakdown of the submitted and recommended capital expenditure levels is given in Appendix C.

Figure 6-1 – Summary of PB Associates recommendations



APPENDIX A
Proposed project status

Appendix A – Proposed project status

PROJECT	INITIATED UNDER NEW CAPITAL GOVERNANCE FRAMEWORK	CAPITAL GOVERNANCE FRAMEWORK APPLIED RETROSPECIVELY	CAPITAL GOVERNANCE INFORMATION PROVIDED
Main (augmentation)			
Haymarket & Campbell St Substation	No	No	-
Installation of Beresfield Sub-transmission Substation	No	Yes	Identification of Needs, Options and Option Analysis, other detailed information
Transmission Boundary Metering	No	No	-
Kurri Distribution Connections	No		No
132kV Development in Newcastle Western Corridor	No	No	Detailed information provided but not in form of governance framework
Gosford STS Capacitor Installation	No	No	Detailed information provided but not in form of governance framework
Drummoyne Zone Substation Constraint	Yes (part)	n/a	Identification of Needs, very basic options provided, no detailed options analysis
Additional Distribution Connections from Tomago STS	No	No	-
Minor Augmentation of Inner Metropolitan 132kV Network	No		-
West Gosford Zone Constraint	Yes (part)		Identification of Needs, basic options provided, some options analysis.
Macquarie Park Zone Constraint	Yes (part)	n/a	Identification of Needs, basic options provided, no detailed options analysis
Upgrade Feeder 926	No	Yes	Identification of Needs
132kV Network Development in Mid-Southern Central Coast	No	No	Part of broader value management study
Possible Kurri harmonic filter	No	No	-
Min (replacement)			
Installation of Green Square Substation	No	No	Detailed information provided but not in form of governance framework
Substation Equipment	No	No	-
Transformer Replacement	No	No	-
Underground Mains Replacement	No	No	-
Overhead Mains Replacement	No	No	-
Relocation of Feeders 96A, 96B, 96U, 96W, 95L	No	No	-
Excluded			
Major Inner Metropolitan 132kV Network Development	No	No	-
Lower hunter 132kV Network Development	No	No	-
Tunnel Arbitration	No	No	-
Unconfirmed Customer Connections	No	No	-
Feeder 908/909 Replacement	No	No	-
Ourimbah STS Refurbishment	No	No	-
Non-system			
Compliance Projects	No	No	-
Compliance			
Compliance Projects	No	No	-

APPENDIX B
High level (information) review

HIGH-LEVEL (INFORMATION) REVIEW OF PROPOSED PROJECTS

Where the project has been subject to a detailed review we have referred to the appropriate section of the report.

The projects are listed in the following order:

1. 132kV Connections to Haymarket BSP and Campbell Street
2. Installation of Beresfield STS Augmentation
3. Transmission Boundary Metering
4. Kurri Distribution Connections
5. 132kV Network Development in Newcastle Western Corridor
6. Gosford Sub-transmission Substation Capacitor Installation
7. Drummoyne Substation Constraint
8. Additional Distribution Connections from Tomago STS
9. Minor Augmentation of Inner Metropolitan 132kV Network
10. West Gosford Zone Constraint
11. Macquarie Park Zone Constraint
12. Upgrade Feeder 926
13. 132kV Network Development in Mid-Southern Central Coast
14. Possible Kurri Harmonic Filter
15. Major Inner Metropolitan 132kV Network Development
16. Lower Hunter 132kV Network Development
17. Variation Claim for Haymarket Tunnel
18. Unconfirmed Customer Connections
19. Installation of Green Square Substation
20. Substation Equipment
21. Transformer Replacement
22. Underground Mains Replacement
23. Overhead Mains Replacement
24. Relocation of Feeders 96A, 96B, 96U, 96W, 95L
25. Feeder 908/909 Replacement
26. Ourimbah STS Refurbishment
27. Compliance Projects

1. 132KV CONNECTIONS TO HAYMARKET BSP AND CAMPBELL STREET

This project is currently under construction.

Information provided

The quality of supporting information provided with each project was reasonable and as expected for a project which is currently being constructed.

Justification for project

There are legal issues associated with this project and this is the reason given for the lack of detail provided for the additional costs incurred.

Consideration of alternatives

There were no alternatives considered for this project.

Cost estimates

Very little detail was provided but in the opinion of PB Associates the estimates provided are not unreasonable and are of the order that one might expect for a project of this type.

Strategic alignment

Not applicable

Risk of projects not-proceeding

Project is near completion.

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2. INSTALLATION OF BERESFIELD STS AUGMENTATION

Information provided

The quality of supporting information provided with each project was reasonable and as expected for a project which is currently being constructed.

Justification for project

The claim for extra costs lacks detail, apparently due to legal issues.

Consideration of alternatives

No information has been provided.

Cost estimates

Estimates have been provided, but without supporting detail.

Strategic alignment

Not applicable

Risk of project not proceeding

The project is near completion.

3. TRANSMISSION BOUNDARY METERING

Information provided

The quality of supporting information and background information is reasonable but PB Associates seeks the ACCC view on whether or not this capital expenditure is recoverable under the regulated revenue cap. PB Associates notes and concurs with EA's assertion that the work may not be contestable due to the requirement to undertake work in HV substation areas. However PB Associates believes that the costs may be recoverable from EA retail who PB Associates believes would be the party responsible under section 7.2.2 of the National Electricity Code.

Justification for project

An explanation of the purpose of the project has been adequately explained being to improve the accuracy of losses calculated in the NEM ex EA transmission assets.

Consideration of alternatives

Alternatives have not been identified although PB Associates has raised the possibility of not moving the meters and using factored calculations within the NEM although this would not be as accurate.

Cost estimates

Estimates and a limited amount of supporting detail have been provided, but appear sufficient for the submission.

Strategic alignment

Not applicable

Risk of project not proceeding

PB Associate believes that the project is nearing completion.

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4. KURRI DISTRIBUTION CONNECTIONS

Information provided

This is a relatively small project and although a limited amount of information has been provided, it is reasonable for the size of the project.

Justification for project

Short explanations have been provided to outline the background to each subproject. These are adequate.

Consideration of alternatives

No alternatives have been identified and for the types of subprojects are not applicable.

Cost estimates

Estimates with limited detail have been provided but are adequate for the submission.

Strategic alignment

Not applicable.

Risk of project not proceeding

Projects are already under construction.

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5. 132KV NETWORK DEVELOPMENT IN NEWCASTLE WESTERN CORRIDOR

A **detailed review** has for this project can be found in **Section 5.4**.

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6. GOSFORD SUB-TRANSMISSION SUBSTATION CAPACITOR INSTALLATION

Information provided

The quality of supporting information and background information is reasonable.

Justification for project

The justification provided is adequate for the type of project.

Consideration of alternatives

Three options have been identified and explained, although the explanation could provide more information in view of the prospective costs of options and implications for other projects.

Cost estimates

A cost estimate with limited detail provided is adequate for the type of project.

Strategic alignment

The project generally aligns with EA augmentation strategy.

Risk of project not proceeding

The project is under construction.

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7. DRUMMOYNE SUBSTATION CONSTRAINT

A **detailed review** for this project can we found in **Section 5.5**.

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8. ADDITIONAL DISTRIBUTION CONNECTIONS FROM TOMAGO STS

Information provided

The quality of supporting information and background information is reasonable.

Justification for project

This is a relatively small project and is partly under construction. Explanations provided are adequate.

Consideration of alternatives

No explanation of other options or the reason for no other options has been provided, but it is considered that for this situation, other options would be irrelevant.

Cost estimates

Typical rather than project specific information has been provided. More detailed project specific information would be appropriate.

Strategic alignment

This project generally aligns with EA's augmentation policies.

Risk of project not proceeding

The project is partly under construction and it is likely that the rest of the project will proceed.

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9. MINOR AUGMENTATION OF INNER METROPOLITAN 132KV NETWORK

Information provided

The quality of supporting information and background information is reasonable but not as much as could be expected for this type of project.

Justification for project

Limited information has been provided but reference to the Annual Planning Review has been made. More explanation would be useful.

Consideration of alternatives

Options have been identified, but insufficient explanatory information provided.

Cost estimates

Only limited information has been provided and more could be expected for this type of project.

Strategic alignment

This project generally aligns with EA's augmentation policies.

Risk of project not proceeding

Unknown, but load growth is likely to necessitate some action within this period.

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10. WEST GOSFORD ZONE CONSTRAINT

A **detailed review** for this project can we found in **Section 5.6**.

11. MACQUARIE PARK ZONE CONSTRAINT

This project is discussed in more detail **Section 5.9.1**.

Information provided

The quality of supporting information and background information is reasonable and as could be expected for this type of project.

Justification for project

The explanation provided gives detail appropriate for this size of project.

Consideration of alternatives

Two options have been identified although it is not clear whether other options could be considered.

Cost estimates

Only typical rather that project specific information has been provided an should be supplemented by further information.

Strategic alignment

This project generally aligns with EA's augmentation policies.

Risk of project not proceeding

Unknown, but will probably be underway during this period, as it is being driven by load growth and firm capacity could be exceeded.

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12. UPGRADE FEEDER 926

Information provided

The quality of supporting information and background information is reasonable and as could be expected for this type of project.

Justification for project

The explanation provided gives detail appropriate for this size of project.

Consideration of alternatives

Two options have been identified, although it is not clear whether other options could have been considered.

Cost estimates

Cost estimates provided would be better if in more detail.

Strategic alignment

This project generally aligns with EA's augmentation policies.

Risk of project not proceeding

Only planning is likely to be undertaken during this regulatory period.

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13. 132KV NETWORK DEVELOPMENT IN MID-SOUTHERN CENTRAL COAST

Information provided

The quality of supporting information and background information is reasonable and as could be expected for this type of project at an early stage of planning.

Justification for project

Limited information has been provided, considering the eventual large project likely during the next period (2010 onwards).

Consideration of alternatives

Two options have been identified and it could be expected that more options could have been identified.

Cost estimates

Cost estimates for preliminary work and consultation are satisfactory.

Strategic alignment

This project generally aligns with EA's augmentation policies.

Risk of project not proceeding

It is considered that the planning and consultation is not likely to be delayed.

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14. POSSIBLE KURRI HARMONIC FILTER

Information provided

The limited information provided is satisfactory for this small project.

Justification for project

Sufficient information has been provided to explain the supply quality issues driving the project.

Consideration of alternatives

No alternatives are required due to the narrow technical nature of this project.

Cost estimates

Preliminary cost estimates provided are appropriate for this type of project.

Strategic alignment

Not applicable.

Risk of project not proceeding

It is expected that the project will proceed to correct current harmonic problems.

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15. MAJOR INNER METROPOLITAN 132KV NETWORK DEVELOPMENT

Information provided

The information provided is reasonably comprehensive but it is hard to gain a clear impression of the overall project as it is being jointly planned by TransGrid.

Justification for project

The project relies on TransGrid's Annual Planning for justification.

Consideration of alternatives

Alternatives identified by TransGrid are listed, but insufficient detail has been provided.

Cost estimates

Cost information is not provided in sufficient detail to be useful for review.

Strategic alignment

It is not clear how this project aligns with EA's overall strategy.

Risk of project not proceeding

The project is likely to proceed but the actual scope is not clear due to early planning.

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16. LOWER HUNTER 132KV NETWORK DEVELOPMENT

A **detailed review** for this project can be found in **Section 5.3**.

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17. VARIATION CLAIM FOR HAYMARKET TUNNEL

Information provided

Only nominal information has been provided due to commercial sensitivity.

Justification for project

Contractor's claim for variation but no details have been provided.

Consideration of alternatives

Not applicable.

Cost estimates

Not available.

Strategic alignment

Not applicable.

Risk of project not proceeding

Not applicable.

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18. UNCONFIRMED CUSTOMER CONNECTIONS

Information provided

The projects are not able to be defined so the background information provided is satisfactory.

Justification for project

The justification is adequate and provides sufficient background on why the cost is required.

Consideration of alternatives

Not applicable.

Cost estimates

No amount has been identified but EA policy to deal with such expenditure has been referred to.

Strategic alignment

Not applicable.

Risk of project not proceeding

Unknown.

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19. INSTALLATION OF GREEN SQUARE SUBSTATION

Information provided

A reasonable amount of information has been provided and is appropriate for this type of project.

Justification for project

Three options have been considered and sufficient information provided.

Consideration of alternatives

EA has worked through alternatives, although it is not clear whether other alternatives should have been considered.

Cost estimates

Cost estimates have been provided to a high level of detail.

Strategic alignment

The project appears to be consistent with EA's replacement and augmentation policies.

Risk of project not proceeding

The project is underway.

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20. SUBSTATION EQUIPMENT

This project is discussed in **Section 5.9.2**

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21. TRANSFORMER AND REACTOR REPLACEMENT

A **detailed review** for this project can be found in **Section 5.7**

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22. UNDERGROUND MAINS REPLACEMENT

This project is discussed in **Section 5.9.2.**

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23. OVERHEAD MAINS REPLACEMENT

This project is discussed in **Section 5.9.2.**

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24. RELOCATION OF FEEDERS 96A, 96B, 96U, 96W, 95L

Information provided

Adequate information for the current level of project development has been provided.

Justification for project

Road realignment outside of EA control.

Consideration of alternatives

Not applicable.

Cost estimates

Limited detail has been provided, but some cost data has been derived from competitive quotes.

Strategic alignment

Not applicable.

Risk of project not proceeding

Not applicable.

25. FEEDER 908/909 REPLACEMENT

Information provided

Adequate information has been provided.

Justification for project

Project justification has been clearly defined.

Consideration of alternatives

No alternatives have been defined and it could be possible that other network alternatives are viable.

Cost estimates

Cost estimates are preliminary and in not in detail.

Strategic alignment

Generally aligns with EA risk assessment and replacement policies.

Risk of project not proceeding

The project could possibly be delayed due to external issues such as consultation.

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26. OURIMBAH STS REFURBISHMENT

A **detailed review** for this project can be found in **Section 5.2**.

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27. COMPLIANCE PROJECTS

Information provided

Information of adequate coverage and quality has been provided for a number of small projects.

Justification for project

Justification has been provided and is largely due to external and regulatory requirements.

Consideration of alternatives

Not applicable.

Cost estimates

Only limited information has been provided but is appropriate for these types of small projects.

Strategic alignment

Not applicable.

Risk of project not proceeding

These are likely to proceed.

APPENDIX C
Capital expenditure by project

	Reviewed		EA Submission TOTAL ($m)	PB Recommend TOTAL ($m)	Variation TOTAL ($m)
MAIN augmentation	Project 1	Haymarket & Campbell St Substation	3.20	3.20	0.00
	Project 2	Installation of Beresfield Subtransmission Substation	12.60	12.60	0.00
	Project 3	Transmission Metering	2.30	2.30	0.00
	Project 4	Additional Distribution Connections from Kurri STS	0.60	0.60	0.00
	Project 5	132kV development in Newcastle Western Corner	8.50	6.90	-1.60
	Project 6	Gosford Subtransmission Substation Capacitor Installation	0.60	0.60	0.00
	Project 7	Drummoyne Zone Substation Constraint	4.20	4.10	0.00
	Project 8	Additional Distribution Connections from Tomago STS	1.40	1.40	0.00
	Project 9	Minor Augmentation of Inner Metropolitan 132kV Network	4.90	5.00	0.00
	Project 10	West Gosford Zone Constraint	3.90	3.22	-0.66
	Project 11	Macquarie Park Zone Constraint	3.80	5.00	1.20
	Project 12	Upgrade Feeder 926	0.70	0.67	0.00
	Project 13	132kV Network Development in Mid-Southern Central Coast	0.80	0.76	0.00
	Project 14	Possible Kurri harmonic filter	0.60	0.60	0.00
MAIN replacement	Project 15	Installation of green Square Zone Substation	19.00	19.00	0.00
	Project 16	Substation Replacement	26.00	2.80	-23.20
	Project 17	Transformer Replacement	20.80	9.10	-11.70
	Project 18	Transmission UG Mains Replacement	12.70	12.70	0.00
	Project 19	OH Mains Replacement	15.40	1.80	-13.60
	Project 20	Relocation of Feeder 96A, 96B, 96U, 96W and 95L	0.00	0.00	0.00
EXCLUDED	Project 1	Major Inner Metropolitan 132kV Network Development	35.60	35.70	0.00
	Project 2	Feeder 908/9 Replacement	36.70	36.70	0.00
	Project 3	Ourimbah Sub-transmission Substation Refurbishment	25.70	9.60	-16.00
	Project 4	Customer Connections	-	0.00	0.00
	Project 5	Lower hunter 132kV Network Development	11.60	11.60	0.00
	Project 6	Variation Claim for Haymarket Tunnel	-	0.00	0.00
COMPLIANCE		Electronic Security	0.71	0.72	0.00
		OIL PCB	1.00	1.00	0.00
		Oil Containment	1.06	1.06	0.00
		Internal Fire Doors	0.83	0.83	0.00
		Fire Stopping	0.21	0.20	0.00
		Water Crossing	0.16	0.16	0.00
		Asbestos Removal	0.15	0.15	0.00
NON SYSTEM		IT	15.86	15.86	0.00
		Vehicles and plant	6.83	6.83	0.00
		Office equipment, furniture, land & buildings	4.96	4.96	0.00
TOTALS		Main (augmentation)	48.01	46.95	-1.06
		Main (replacement)	93.90	45.40	-48.50
		Excluded	109.60	93.60	-16.00
		Complicance	4.12	4.12	0.00
		Non system	27.65	27.65	0.00
		TOTAL ($m)	283.28	217.72	-65.56