SP AUSNET REVENUE RESET

An independent review

Prepared for

AUSTRALIAN ENERGY REGULATOR

PB Quality System:

Document Reference:	SPA2008Reset_v6_0.doc
Report Revision :	6_0
Report Status :	Final
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Date Issued :	16 August 2007

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EXECUTIVE SUMMARY

The Australian Energy Regulator, in accordance with its responsibilities under the National Electricity Rules is required to conduct an assessment of the appropriate revenue determination to be applied to the prescribed transmission services provided by SP AusNet (formerly SPI PowerNet) from 1 April 2008 and VENCorp from 1 July 2008. The previous revenue cap reviews for SPI PowerNet and VENCorp (both 2003-2007/08) were conducted by the Australian Competition and Consumer Commission's (ACCC). The AER assumed responsibility for the regulation of transmission revenues in the National Electricity Market from the ACCC on 1 July 2005.

PB has been engaged by the AER to conduct a review of SP AusNet in support of the AER undertaking these revenue determination assessments. The overall objective of this review by PB is to undertake an assessment of the historic (ex-post) and forecast (ex-ante) expenditure proposals for both capital expenditure (capex) and operational expenditure (opex) – as submitted to the AER by SP AusNet. This has enabled PB to formulate an independent view on the prudency and efficiency of the past expenditure and also the reasonableness of that proposed for the forthcoming regulatory period.

The review of SP AusNet capital expenditure extends to investment in replacement and refurbishment only. Capital expenditure associated with reinforcement, or augmentation, of the shared transmission network due, for example, to increased capacity requirements (e.g. demand growth), is initiated and planned by VENCorp – the not-for-profit government planning organisation. Victoria's transmission arrangements are unique within the National Electricity Market (NEM). SP AusNet owns, operates and maintains the vast majority of the high voltage transmission system and provides bulk transmission services to VENCorp under a network agreement and as a licensed Transmission Network Service Provider (TNSP). The review of VENCorp is the subject of a separate revenue reset review by the AER.

The expenditure reviewed in this report is that proposed by SP AusNet for inclusion in the regulatory asset base (RAB) for the five year period from 1 April 2003 to 31 March 2008 (the current regulatory period) – the ex-post assessment; and that for the forthcoming six year period from 1 April 2008 to 31 March 2014 (the next regulatory period) – the ex-ante assessment.

TIMETABLE

The current regulatory period for SP AusNet ceases on 31 March 2008[1]. To comply with the NER, the AER is required to publish its final decision two months before the commencement of SP AusNet's next regulatory period. Therefore, the AER is required to publish its final decision by 31 January 2008. The new revenue determination for SPA will take effect from 1 April 2008.

SCOPE

In this independent review of the SPA expenditure proposals PB considers, examines and provides its expert opinion, on the following key submission items and expenditure categories.

- historic (ex-post) network capital expenditure (capex) over the current regulatory period
- future (ex-ante) network capex
- historic and future non-system capex (e.g. IT, vehicles, 'support-the-business' costs etc.)
- forecast operational expenditure (opex) for SPA
- service standards
- capital governance framework for SPA.

[1] The current regulatory period for VENCorp ceases on 30 June 2008, however, the AER plan to make the revenue reset determinations (decisions) at the same time.

The review of these items takes full account of the unique arrangements in Victoria between SPA and VENCorp.

In reviewing, and in developing our recommendations associated with these, PB has adopted the high-level methodology set out below.

PB'S APPROACH TO THE REVIEW

The approach adopted by PB is both well established and proven and recognises the benefits of a methodology which examines the expenditure proposals in a number of different ways. This multi-dimensional approach combines a high-level ('top-down') assessment with a detailed ('bottom-up') assessment of a number of (carefully) selected projects and expenditure items. Our approach also includes a review of the governance processes and policies employed by SPA in making its investment decisions.

This 'multi-pronged' approach to the review of SP AusNet has combined the following key elements:

- a review of SPA's governance systems, processes, policy and practice
- benchmarking and comparative analysis ('top-down')
    - impact of proposals on the average age of the SPA asset base
    - analysis at total expenditure level with other TNSPs (opex and capex)
    - a review of unit costs (obtained from detailed project reviews)
- a detailed examination of a selection of projects, ex-ante and ex-post ('bottom-up')
- PB's direct experience of other network businesses (including TNSP reviews).

Through this approach PB has developed an independent view on the SP AusNet proposals which it believes is robust, credible and defensible.

SP AUSNET PROPOSALS

The SP AusNet expenditure proposals associated with its revenue reset application can be summarized as follows:

Figure E1 gives the historic and forecast total capex – as proposed by SPA. The forecast (ex-ante) capex for 2008/09 to 2013/14 is approximately 53% higher than the actual expenditure of the previous five year period. The average annual capital spend for 2003/04 to 2007/08 was $91m [2] compared with a forecast annual capex of $140m for the next regulatory period.

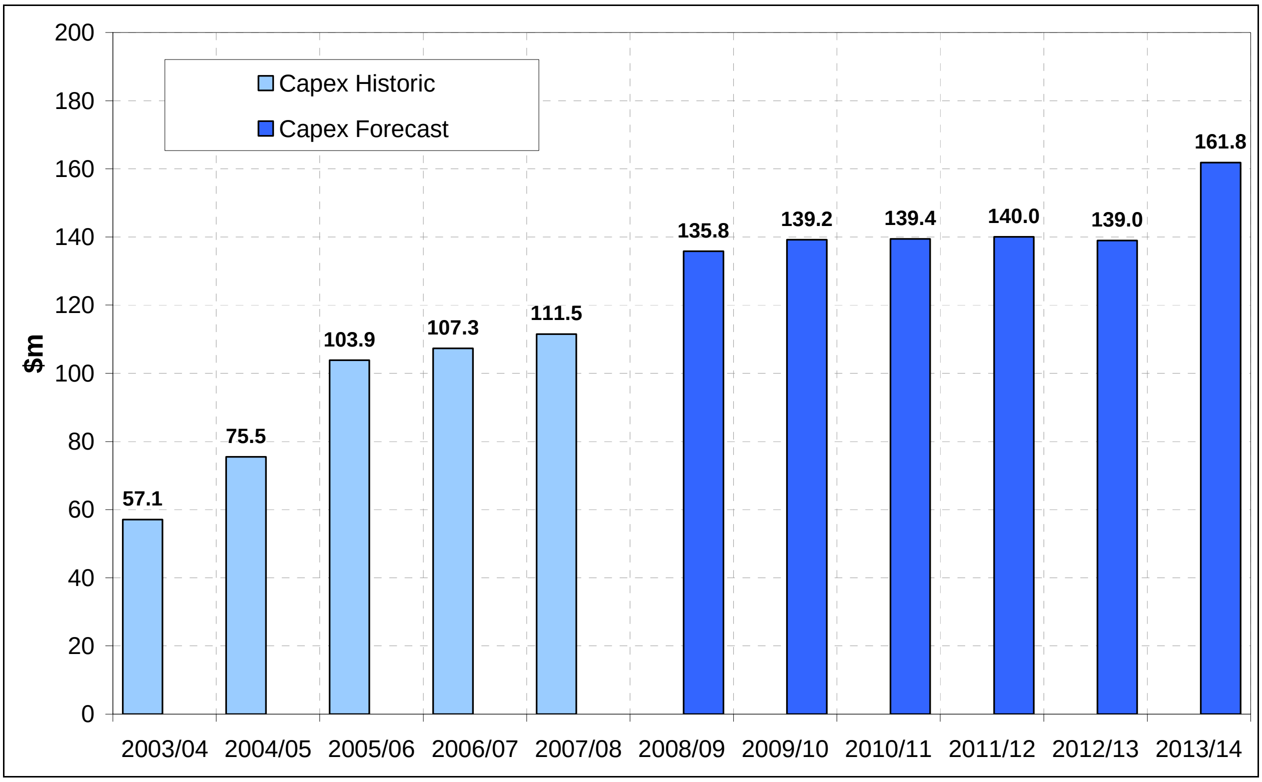
Figure E2 gives the historic and forecast total opex – as proposed by SPA. The forecast (ex-ante) opex for 2008/09 to 2013/14 is approximately 20% higher than the actual expenditure of the previous five year period. The average annual opex spend for 2003/04 to 2007/08 was $62m [3] compared with a forecast annual opex of $74m for the next regulatory period.

PB's review includes 18 detailed project reviews – 15 network capex projects (nine ex-post and six ex-ante) and three non-system capex projects. Our detailed project reviews cover 25% of the total proposed ex-post capex and 29% of the total proposed ex-ante capex.

[2] Real 2007/08.

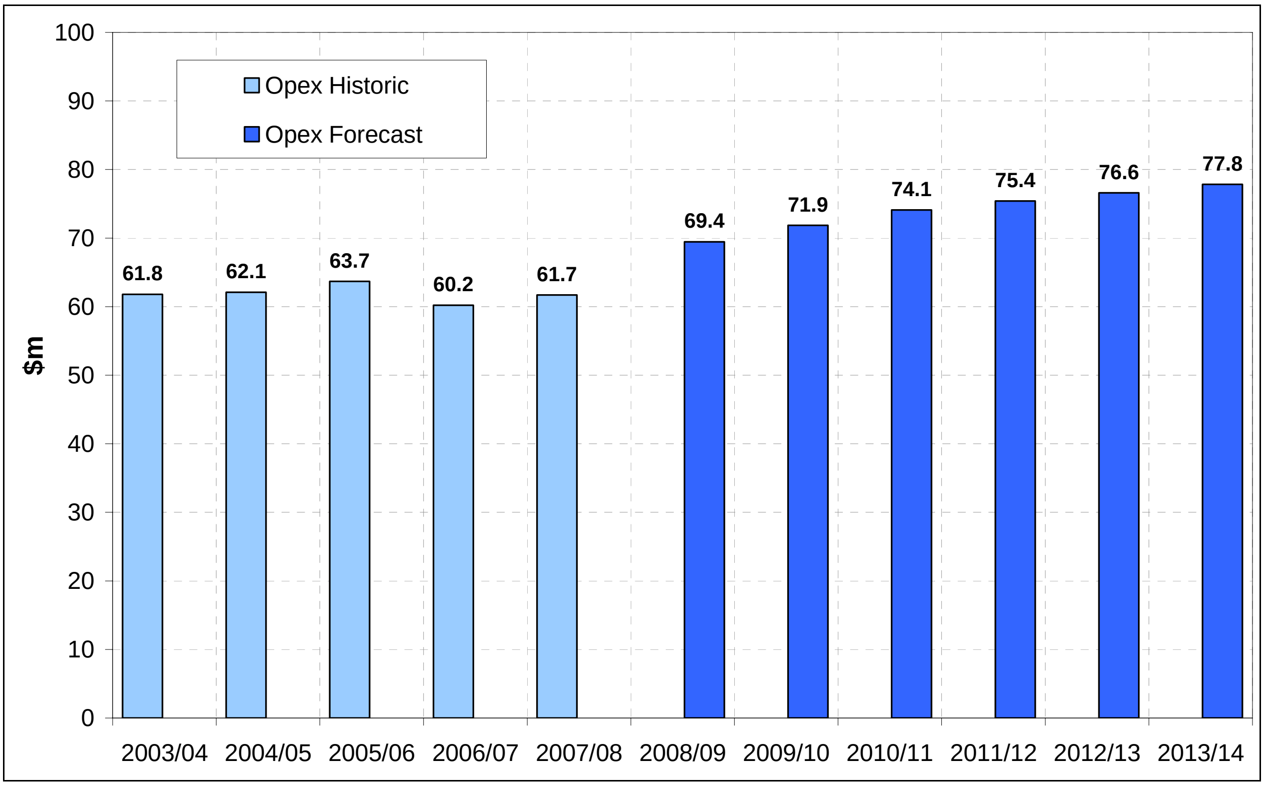
[3] Ibid.

Figure E1 – SPA actual and forecast capex (real 07/08)



Source: PB analysis

Figure E2 – SPA actual and forecast opex (real 07/08)



Source: PB analysis

Through its comprehensive review of the SP AusNet revenue reset proposal and the SP AusNet organisation, processes and systems, PB has been able to formulate the following key conclusions:

Capital governance and investment decision making

As part of the review, and through the detailed project reviews, PB has examined the processes and systems associated with SPA's investment decisions and the management of its transmission assets. PB makes the following observations regarding SPA's governance processes and systems:

- SPA has well structured and well documented policies and processes to support its core transmission service provision role, and the responsibilities and accountabilities within the business are clearly defined

- typical of a well governed, integrated corporation, SPA has a business structure and has established a number of committees to appropriately support its asset management and investment approval and decision making processes

- SPA's processes and practices are highly conscious of the regulatory framework within which it operates and attempts to address its regulatory needs as an integrated aspect of its operations

- given SPA's management oversight, its capital approval thresholds, its detailed procurement manual and its capex optimisation and prioritisation process, PB considers the internal framework is effective at capturing capex and opex efficiencies

- SPA's project execution tracking process is contemporary and auditable, but has not prevented some projects running over budget and, in the view of PB, there are examples of poor project management.

PB makes the following observations regarding SPA's asset management strategy:

- SPA's asset management strategy is contemporary and fosters a strong incentive for continual improvement, evidenced by SPA seeking an independent benchmarking review of its Asset Management Strategy

- the detailed use of quantitative risk modelling and assessment processes is of a very high quality and in PB's opinion would be close to best practice; the capability of SPA to systematically identify individual asset risk and track its network, program and asset risk profiles over time is to be commended

- SPA's risk model application is highly focussed on the probability of failure aspect of the risk and as the model evolves improvements could be made to the treatment of failure consequences

- SPA has gone to reasonable lengths to advise that the detailed risk model outputs form only one input to its detailed engineering and economical assessments, and this is consistent with the evolving status of the models, however this also leads to the widespread use of 'engineering judgement' that is less transparent when considering the need and basis for investment

- SPA's economic evaluation practices are reasonable, however the assessment methodology is not well documented, and seems open to individual opinion on how to undertake assessments and errors. SPA appears to be addressing this issue through the use of standardised evaluation spreadsheets.

PB makes the following observations regarding SPA's co-ordination with other parties:

- the separation of responsibilities for asset management and replacement and augmentation of transmission in Victoria, appear to have highly focussed each business to their respective functions
- it is not clear how VENCorp and SPA co-ordinate or consistently apply the probability of failure information developed by SPA through its detailed asset risk models into the respective planning processes
- SPA interacts with VENCorp and other connected parties on a regular basis to ensure optimisation and efficiencies in capex plans are captured, and this is generally undertaken on a project by project basis
- the use of modern equivalents and co-ordinated augmentation/replacement projects are apparent and appear to be effective and efficient
- SPA's internal processes explicitly recognise and capture the flexibility required during iterative negotiations with connected parties, with the object of ensuring a holistically efficient approach to network investment.

High-level benchmarking and comparative analysis

- the expenditure levels proposed by SPA (and VENCorp), in the main, compare reasonably with TNSPs expenditure in other jurisdictions
- PB's high-level, age-based, replacement analysis suggests that the proposed ex-ante capex expenditure is higher than would otherwise be anticipated given SPA's stated approach to asset management, and their relatively sophisticated approach to asset risk modelling
- some unit costs seem a little high but PB believes that any adjustments are unlikely to materially alter the aggregate forecast capex requirement.

Historic (ex-post) network capex

- the detailed review of selected projects revealed evidence of reasonably prudent asset management through the application of appropriate investment decision-making processes
- in almost all cases examined the project implementation timing was reasonable
- in a number of the projects significant variations occurred during implementation
- in almost all cases examined it was clear that the project implementation was consistent with prudent asset management and good industry practice
- it is PB's view that on the balance of the available information that it is likely that SPA has been prudent and efficient with regard to the management of its ex-post capex
- based on the information provided by SPA, and PB's investigations and assessments, it is PB's view that ex-post network capex expenditure proposed by SPA is, in general, timely, reasonable and efficient.

PB's recommendation on historic network capex is summarised in Table E-1.

Table E-1 – Final recommendation for the total historic network capex to be included in SPA's RAB

Expenditure $m (nominal)	2003 stub period	03/04	04/05	05/06	06/07	07/08	March 08 WIP	Total[4]
Proposed total	24.4	38.6	58.4	76.5	93.3	103.3	21.9	416.2
Recommended total	24.4	38.6	58.4	76.5	93.3	103.3	21.9	416.2
Adjustments total	-	-	-	-	-	-	-	-
Adjustments total %	-	-	-	-	-	-	-	-

Source: PB analysis

Forecast (ex-ante) network capex

PB has undertaken a detailed review of six projects within SPA's forecast ex-ante allowance. The projects have covered all project categories and all asset types and comprise 29% of the proposed capex allowance of $795m. PB's general observations from this detailed review include:

- there is considerable evidence that SPA uses its detailed risk models as a preliminary and systematic tool to inform its general views
- SPA has presented reasonable and appropriate arguments to support the approach that run to failure is a less efficient and practical outcome compared to targeted and planned replacements
- the specification of transformers for replacement purposes appears to incorporate a moderate amount of augmentation
- the timing of some expenditure appears to be aggressive and PB believes that there may be a number of opportunities to prioritise tasks and prudently defer some expenditure.
- PB believes that SPA can make better use of the assets it releases as part of the progressive redevelopment
- there does not appear to be any capex allowance that should be re-classified as contingent projects.

PB's project-specific observations from this detailed review include the following:

- there is substantiated need for replacement of CBs at Hazelwood, but the scope of works is not efficient
- there is substantiated need for rebuilding the 220 kV switchyard at Richmond, but not all elements of the proposed scope of work are prudent and efficient
- there is substantiated need for replacing a number of high risk CTs, but SPA has been aggressive in the timing of the replacements and inefficient in development of its allowance
- SPA's transformer replacements outside the station rebuilds are supported in some cases only
- significant control and monitoring equipment (SCADA) upgrades and replacements are supported; however the need for some enhancements has not been demonstrated

4 The total column is shown only for consistency with the information submitted in SPA's Proposal Information Templates. PB recognises that this simple sum of the individual annual expenditure amounts may not be appropriate given that all historical cost information is expressed in nominal dollars.

- SPA's proposal for an allowance to respond to unforeseen events is inefficient
- SPA's use of 'S-curves' to establish capex profiles may, in some cases, overstate the time at which expenditure is likely to occur
- the cost estimating contingency factor included in station rebuild projects is not supported nor efficient
- there is no basis to make high level adjustments to SPA's forecast capex allowance outside the detailed project reviews
- the labour and material escalators adopted by SPA in its forecast capex are prudent and efficient.

As an outcome of our detailed project reviews (and a high-level adjustment to remove contingency allowances), PB's recommendation on an efficient and reasonable level of forecast capex for network investment is $676m, a reduction of 15% from the original proposal. This is shown in Table E-2.

Table E-2 – Final recommendation for SPA's total forecast network capex allowance

Expenditure $m ('as spent', real 07/08)	08/09	09/10	10/11	11/12	12/13	13/14	Total
Proposed total[1]	125.8	127.5	130.8	131.0	128.5	151.8	795.3
Recommended total	115.7	112.8	125.0	109.7	92.9	119.9	676.1
Adjustments total	(10.1)	(14.7)	(5.8)	(21.3)	(35.6)	(31.9)	(119.2)
Adjustments total %	(8%)	(12%)	(4%)	(16%)	(28%)	(21%)	(15%)

Note 1, excluding the minor adjustments proposed by SPA as part of our review for two projects.
Source: PB analysis

Non-system capex

PB's review of non-system capex has led to the following conclusions and recommendations:

- comparative analysis indicates that the total non-system capex proposal made by SPA is in line with similar businesses
- some of the inventory is subject to annual turnover and should therefore be removed from the value for capitalised spares
- the non-system capex should be adjusted to account for the reduction in vehicle replacement periods
- PB believes that errors in process have led to IT costs being overstated by approximately 4%

The recommendations resulting from PB's review of non-system historic capex is given in Table E-3.

Table E-3 – Final recommendation for the total historic non-system capex to be included in SPA's RAB

Expenditure $m (real 07/08)	2003	03/04	04/05	05/06	06/07	07/08	Total
Proposed total	6.3	13.1	10.8	22.5	11.2	8.3	72.1
Recommended total	6.3	13.1	10.8	22.5	11.2	6.9	70.8
Adjustments total	-	-	-	-	-	(1.3)	(1.3)
Adjustments total %	0%	0%	0%	0%	0%	(16%)	(2%)

Source: PB analysis

The recommendations resulting from PB's review of non-system forecast capex is given in Table E-4.

Table E-4 – Final recommendation for SPA's total forecast non-system capex allowance

Expenditure $m (real 07/08)	08/09	09/10	10/11	11/12	12/13	13/14	Total
Proposed total	10.0	11.7	8.6	9.1	10.5	10.0	59.8
Recommended total	9.4	11.1	8.0	8.5	9.9	9.4	56.2
Adjustments total	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(3.7)
Adjustments total %	(6.1%)	(5.2%)	(7.1%)	(6.7%)	(5.8%)	(6.1%)	(6.1%)

Source: PB analysis

Forecast operational expenditure

PB has undertaken a review of the SPA past (ex-post) opex and has used this to inform an independent view on the prudency and efficiency of the forecast (ex-ante) opex – as proposed by SPA. Following our review of the opex proposal, PB has arrived at the following conclusions:

- the insurance premium associated with the SPA regulated transmission assets has been incorrectly allocated. We recommend that the annual insurance premium is reduced by $1.36m (6.79%) over the next regulatory period

- the new arrangements for the provision of operation and maintenance services in northern and western Victoria should be factored into the 2006/07 base year reference point. This would result in a reduction in opex of $2.81m (2007/08) over the next 6 year regulatory period

- it appears that SPA has escalated all the external contractor costs for asset works even though they are already expressed in 2007/08 dollars. This has overstated external contractor costs by $1.12m over the next 6 year regulatory period

- external contractor costs included in some projects are too high. As a result, we recommend reductions ($2.55 million) in the cost of two projects over the next 6 year regulatory period

- the likely average annual real increase in labour costs over the next regulatory period will be 2.11%. This would result in a reduction in the total forecast recurrent opex costs of $6.42m (real 2007/08) over the next regulatory period

- the allowance for Asset Works (internal costs) should be reduced from $2.25m per annum to $2.12m per annum (2007/08). This adjustment would result in a saving of $0.76m (2007/08) over the next 6 year regulatory period

- inclusion of $118.7m of assets into the RAB will have a 30% smaller impact on recurrent maintenance than that suggested by SPA. This will result in a $3.98m (2007/08) opex reduction over the next regulatory period

- the allowance made by SPA for self insurance is higher than necessary and we recommend a reduction of $6.9m (2007/08) in total over the next (6 year) regulatory period

- the SPA opex model does not adequately reflect the impact of the proposed asset replacement and refurbishment program when forecasting future recurrent maintenance.

The adoption of our recommendations results in total forecast controllable opex forecasts for the 6-year regulatory period of $416.3m (real, 2007/08 dollars), a reduction of $28.9m from the SPA submitted forecast for controllable operating forecasts of $445.2m. The result of re-running the (SPA) opex model to include all of the PB recommended adjustments is presented in Table E-5.

Table E-5 – Final recommendation for SPA's total controllable opex forecast

Expenditure $m (real 07/08)	08/09	09/10	10/11	11/12	12/13	13/14	Total
Proposed total	69.4	71.9	74.1	75.4	76.6	77.8	445.2
Recommended total	65.9	68.1	69.6	70.1	71.1	71.5	416.3
Adjustments total	(3.5)	(3.8)	(4.5)	(5.3)	(5.5)	(6.3)	(28.9)
Adjustments total %	(5.0%)	(5.3%)	(6.1%)	(7.0%)	(7.2%)	(8.1%)	(6.5%)

Source: PB analysis

Service standards

PB has undertaken a review of the targets, weightings and other parameter values proposed by SPA for the nine incentive parameters that form the service target performance incentive scheme. PB is able to make the following comments:

- incentive targets should include customer augmentation works, adjustments for the proposed capital works program and a 7-day cap on events impacting the average outage duration parameter

- the assumptions underpinning some targets were found to be unsupported and we recommend that the targets are tightened

- parameter weightings were found to be appropriate but the caps and collars should be adjusted

- of eight additional exclusions only three have been found to be appropriate.

In summary, PB recommends that the values for the nine performance parameters shown in Table E-6 be included in SPA's performance incentive scheme.

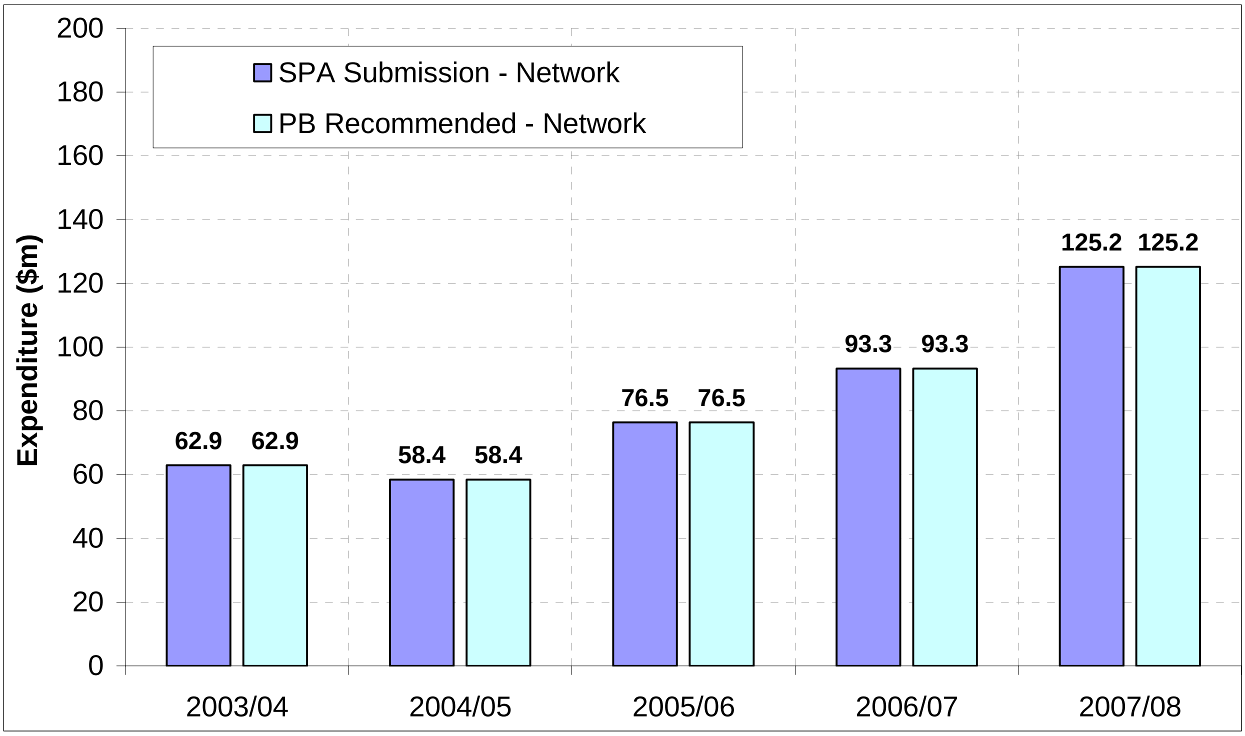
Table E-6 – Recommended performance incentive scheme

Measure	Unit	Max Penalty	Start Penalty	Target	Start Bonus	Max Bonus	Weighting (%)
Circuit Availability – total	%	98.41	98.73	98.73	98.73	99.05	20
Circuit Availability – peak critical	%	98.76	99.53	99.53	99.53	99.92	20
Circuit Availability – peak non-critical	%	98.95	99.53	99.53	99.53	99.81	5
Circuit Availability – intermediate critical	%	97.71	99.09	99.09	99.09	99.78	2.5
Circuit Availability – intermediate non-critical	%	97.94	99.10	99.10	99.10	99.68	2.5
Loss of supply events > 0.05 system minutes	number	9	6	6	6	3	12.5
Loss of supply events > 0.3 system minutes	number	4	1	1	1	0	12.5
Average Outage Duration – lines (capped 7 days)	minutes	667	382	382	382	98	12.5
Average Outage Duration – transformers (capped 7 days)	minutes	556	412	412	412	268	12.5

Source: PB analysis

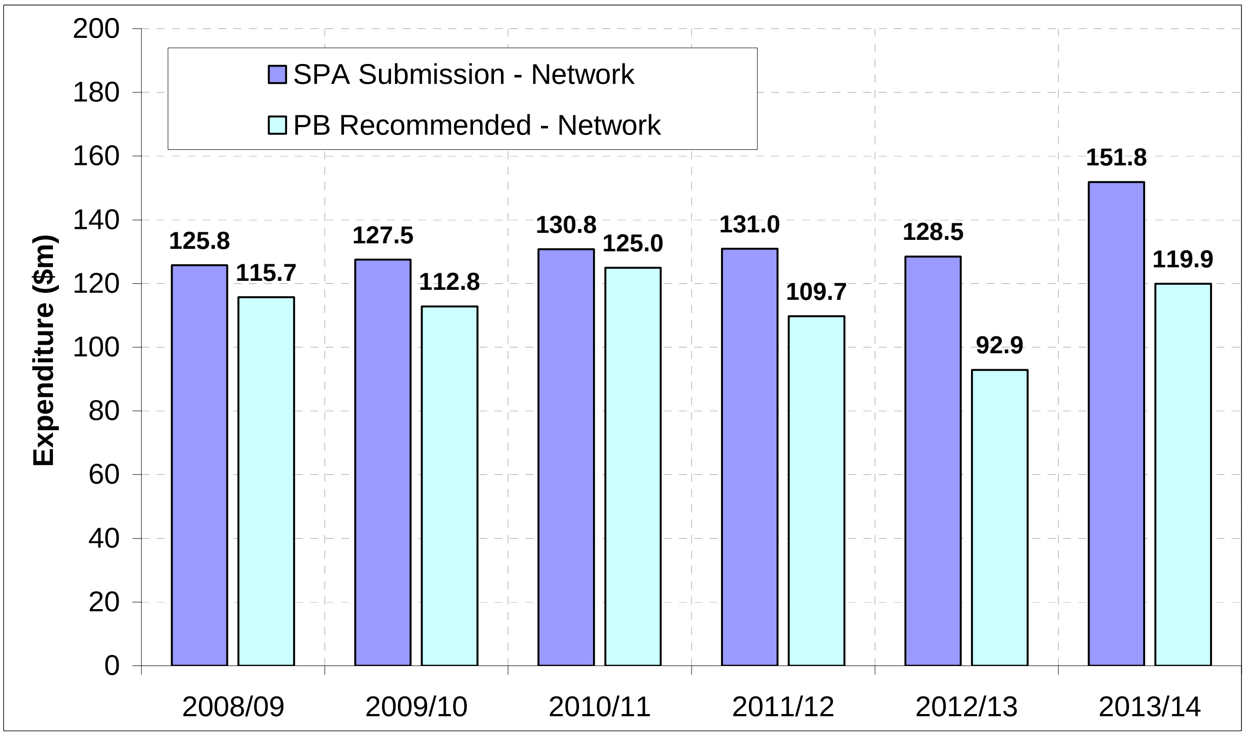
Summary of PB expenditure recommendations

Figure E3 – Adjustments to historic (ex-post) network capex ($m nominal)



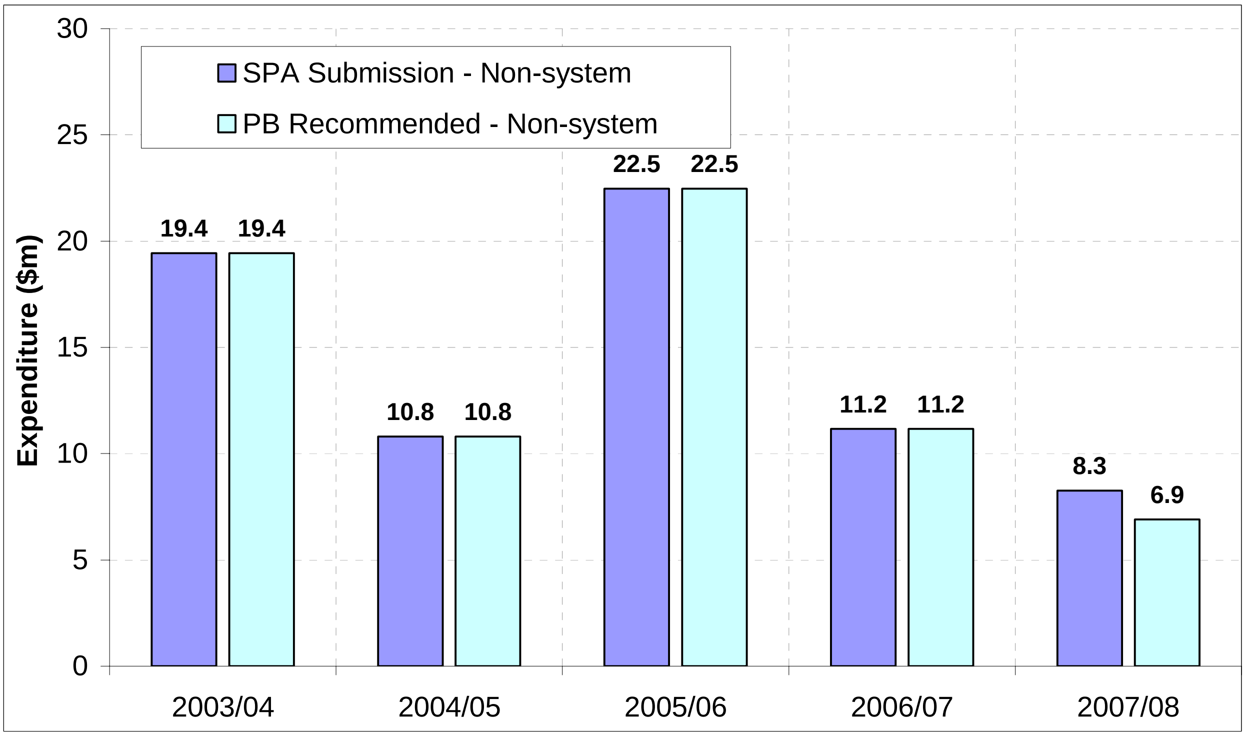
Source: PB analysis

Figure E4 – Adjustments to forecast (ex-ante) network capex ($m real 07/08)



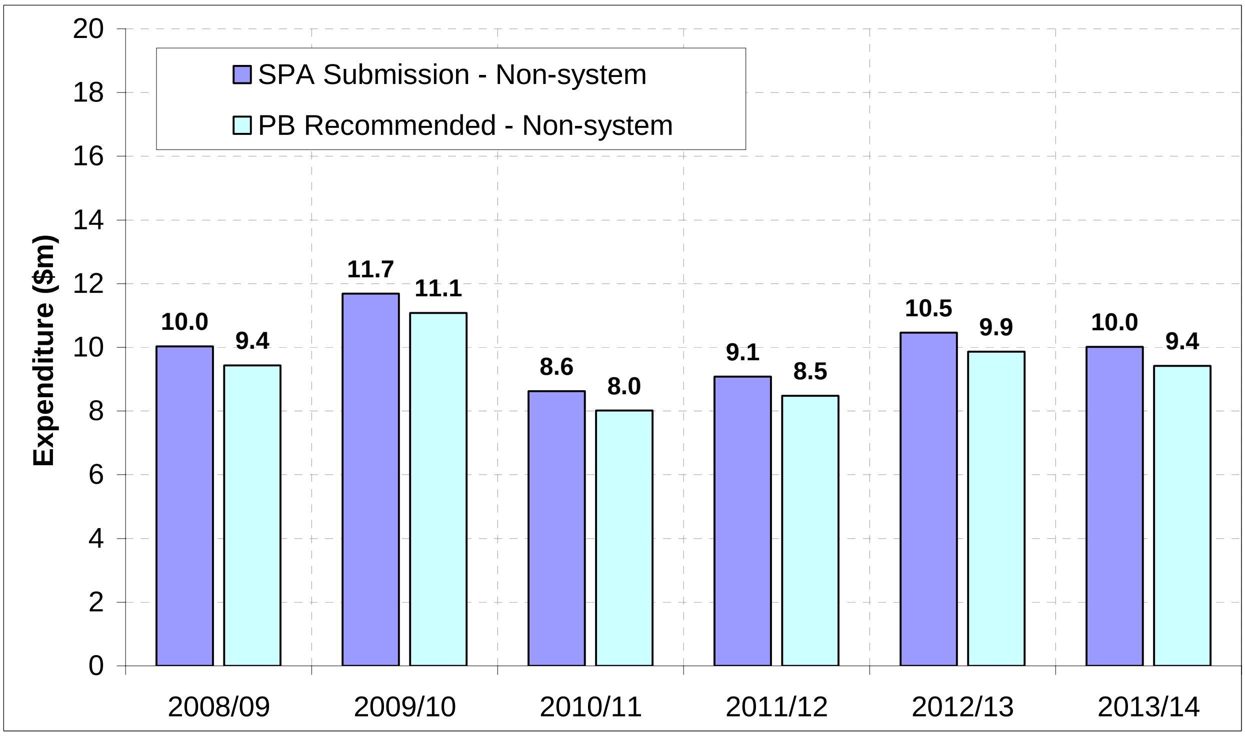
Source: PB analysis

Figure E5 – Adjustments to historic (ex-post) non-system capex ($m real 07/08)



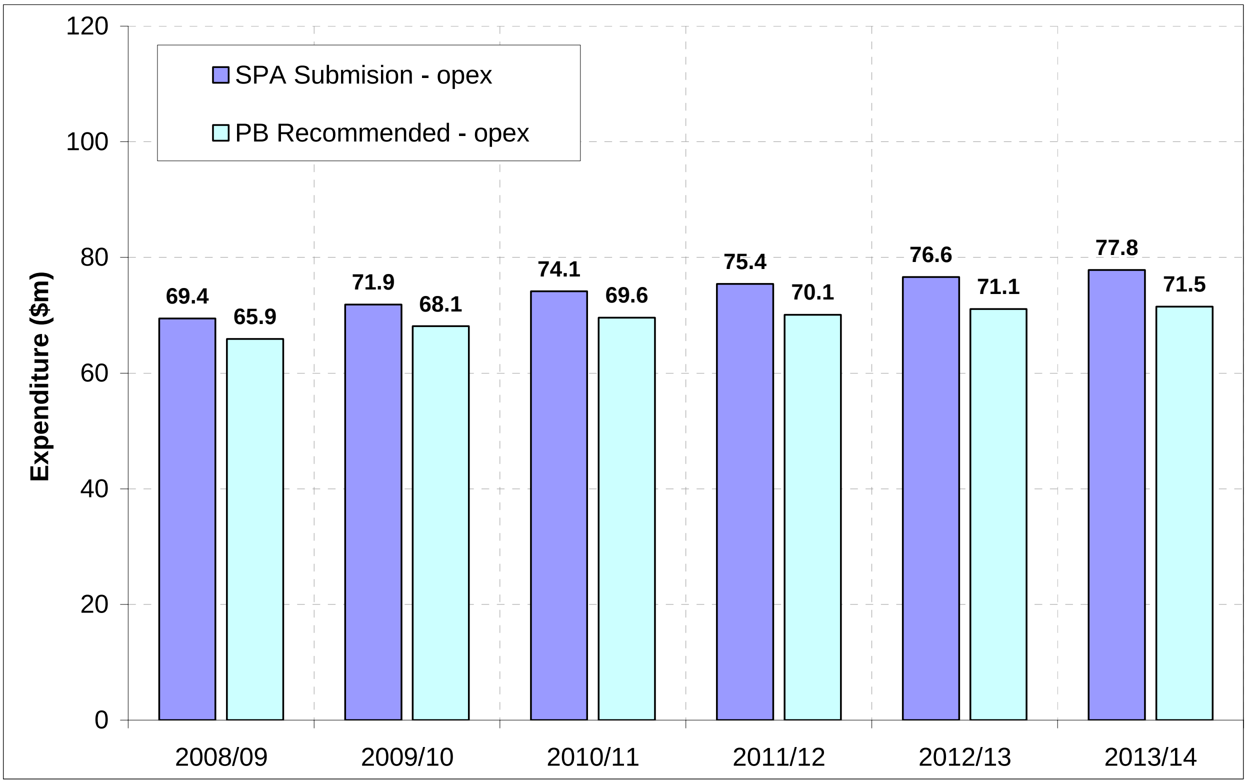
Source: PB analysis

Figure E6 – Adjustments to forecast (ex-ante) non-system capex ($m real 07/08)



Source: PB analysis

Figure E7 – Adjustments to forecast (ex-ante) opex ($m real 07/08)



Source: PB analysis

1. INTRODUCTION

In this section of the report we provide some background to the review, together with an overview of the requirements of the engagement in the context of the Victorian transmission arrangements and describe the PB approach to the work. We also set out details of the structure of this report.

1.1 BACKGROUND TO THE REVIEW

The Australian Energy Regulator (AER), in accordance with its responsibilities under the National Electricity Rules (Rules)[5], is required to conduct an assessment of the appropriate revenue determination to be applied to the prescribed transmission services provided by SP AusNet (formerly SPI PowerNet) from 1 April 2008 and VENCorp from 1 July 2008. The previous revenue cap reviews for SPI PowerNet and VENCorp (both 2003–2007/08) were conducted by the Australian Competition and Consumer Commission's (ACCC). The AER assumed responsibility for the regulation of transmission revenues in the National Electricity Market from the ACCC on 1 July 2005.

SP AusNet (SPA) submitted its revenue proposal and proposed negotiating framework and pricing methodology to the AER on 28 February 2007. The AER conducted a preliminary examination of SPA’s proposal, as required by the Rules[6]. Additional information was submitted by SPA on 30 April 2007 to satisfy the requirements of the AER’s Submission Guidelines and the Rules.

As part of the inquiry, the AER has engaged the services of PB Strategic Consulting[7] (PB) to undertake a review of SPA’s past and forecast capital expenditure (capex) — including its capital governance framework, forecast operational expenditure (opex), and service standards.

1.2 PROJECT OBJECTIVE

PB has been engaged by the AER to conduct a review of SPA in support of the AER undertaking these revenue determination assessments. This work involves conducting a review of, and providing advice to the AER on, SPA’s capex, its opex and its service standards proposals.

PB is aware of the requirements of the Rules placed on the AER[8] as well as the Statement of Principles for the Regulation of Electricity Transmission Revenues[9]. In undertaking its review, PB has employed a proven methodical approach, which addresses each of the specific items in the AER terms of reference. This approach is described in more detail in Section 1.4 of this report.

The overall objective of this review is to undertake an assessment of the historic (*ex-post*) and forecast (*ex-ante*) expenditure proposals for (replacement) capex and forecast opex — as submitted to the AER by SPA. This has enabled PB to formulate an independent view on the prudency and efficiency of the past expenditure and also the reasonableness of that proposed for the forthcoming regulatory period. The review of SPA capital expenditure extends to

5 The National Electricity Rules, Chapter 6A.

6 Ibid — clause 6A.11.1.

7 Formerly known as ‘PB Associates’.

8 Including the recent amendments to Chapter 6A released on 16 November 2006.

9 Including the Statement of Principles for the Regulation of Electricity Transmission Revenues — background paper, 8 December 2004, and applicable references to the Draft Statement of Regulatory Principles (DRP), 1999.

investment in replacement and refurbishment only. Capital expenditure associated with reinforcement, or augmentation, of the shared transmission network due, for example, to increased capacity requirements (e.g. demand growth), is initiated and planned by VENCorp — the not-for-profit government planning organisation. The (unique) relationship between VENCorp and SPA is described in more detail in Section 1.3.1[10].

The expenditure reviewed in this report is that proposed by SPA for inclusion in the regulatory asset base (RAB) for the 5-year period from 1 April 2003 to 31 March 2008 (the current regulatory period) — the ex-post assessment; and that for the forthcoming 6-year period from 1 April 2008 to 31 March 2014 (the next regulatory period) — the ex-ante assessment.

It is intended that the results and conclusions of this review by PB will assist the AER in its obligation to determine the regulated revenue requirements associated with SPA's transmission assets going forward.

Process and project timetable

The current regulatory period for SPA ceases on 31 March 2008[11]. To comply with the NER, the AER is required to publish its final decision 2 months before the commencement of SPA's next regulatory period. Therefore, the AER is required to publish its final decision by 31 January 2008. The new revenue determination for SPA will take effect from 1 April 2008.

The PB review timeline, and its coordination with the AER timetable, is shown in Table 1-1. A more detailed description of the PB element of the review process is set out in Section 1.4.1.

Table 1-1 – Project timetable

Action	Date
SPA submit revenue proposal to AER	28 Feb 2007
PB appointed by AER	March 2007
Public forum	10 May 2007
PB draft report to AER	29 June 2007
SPA comment on PB draft report[12]	27 July 2007
PB final report to AER	3 Aug 2007
AER to release its draft decision (and publication of PB report)	31 Aug 2007
AER to release its final decision	31 Jan 2008

10 The review of VENCorp's expenditure proposals is subject to a separate regulatory review by the AER and is addressed in a separate PB report.

11 The current regulatory period for VENCorp ceases on 30 June 2008; however, the AER plan to make the price reset determinations (decisions) at the same time.

12 This initial review of PB's report by SPA is limited to comments on errors of fact and confidentiality.

1.3 OVERVIEW AND CONTEXT

This section provides an outline of the transmission arrangements in Victoria, provides some background of SPA, and describes the regulatory context within which the PB review has taken place.

1.3.1 Transmission in Victoria

Victoria's transmission arrangements are unique within the National Electricity Market (NEM). SPA owns, operates and maintains the vast majority of the high voltage transmission system and provides bulk transmission services to VENCorp under a network agreement and as a licensed Transmission Network Service Provider (TNSP).

The role of VENCorp

VENCorp is the monopoly provider of shared transmission network services in Victoria, acquiring bulk network services from SPA and from other service providers under network agreements[13]. VENCorp is responsible for planning and directing augmentation to the shared network as an independent entity. VENCorp is a not-for-profit organisation and does not own transmission assets itself. SPA continues to plan, design and build customer connections to the shared network (e.g. load and generation connections).

The separation of the network asset owner (SPA) from the investment decision-maker (VENCorp) in this way is unique within the NEM. In other Australian states the transmission business has responsibility for planning and augmentation, as well as for the replacement, refurbishment and maintenance of ageing assets[14].

While VENCorp does not own transmission assets, its revenue cap has been determined in accordance with the Victorian derogation in Part A of Chapter 9 of the NER[15].

The arrangements support the model of having multiple transmission network owners with the aim of promoting competitiveness. Significant augmentations are procured on a competitive basis. In this regard, SPA competes with other third-party transmission network service providers for the right to construct, own and operate the augmentation assets. Any transmission services provided by SPA on a competitive (contestable) basis are deemed to be a non-regulator transmission service and such services are not subject to economic regulation under Chapter 6A of the Rules. Where augmentations are not suitable for procurement on a competitive basis, such as where there is a high level of integration with the existing (shared) interconnected network, then VENCorp (or a distribution business) may request that SPA provides the augmentation on a non-contestable basis.

The relationship between the main parties in the Victorian electricity transmission arrangements is given in Figure 1-1. The diagram shows that except for providing connections to the network, SPA has no contractual interface with the users of the transmission network. The commercial arrangements for the provision of network services and the corresponding payment of Transmission Use of System Charges (TUoS) are established between VENCorp and the network users (distributors and generators).

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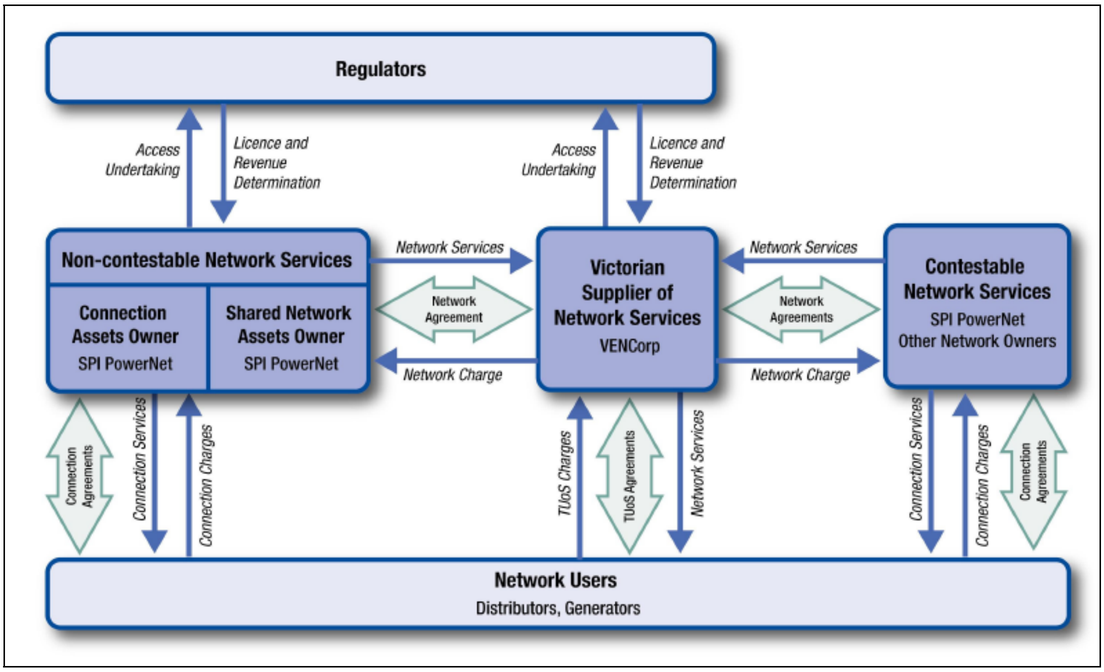
13 SP AusNet is presently responsible for the provision of virtually all of TNSP services to VENCorp with third-party TNSPs providing a small percentage of contestable transmission services to VENCorp.

14 PB notes that the Electricity Supply Industry Planning Council (ESIPC) in South Australia has some responsibility for overseeing the planning activities of the South Australian electricity transmission business, ElectraNet.

15 PB has also been engaged by the AER to undertake a (concurrent) review of the forecast opex, past and forecast network augmentation and capital governance framework associated with VENCorp. This review is the subject of a separate PB report.

Figure 1-1 – Contractual relationships under the Victorian transmission arrangements



Source: SP AusNet revenue proposal document

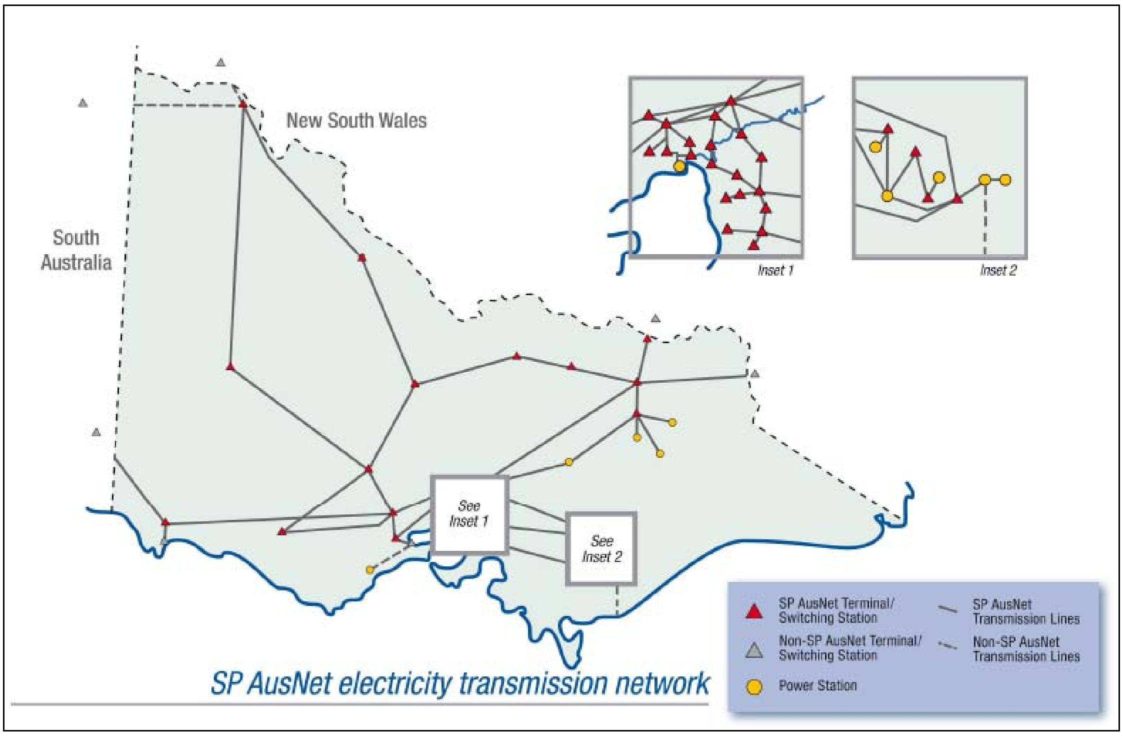
1.3.2 About SPA

SPA is a major energy network business that owns and operates key (regulated) electricity transmission and distribution assets located in Victoria, Australia. SPA also owns and operates a gas distribution network in Victoria. The SPA assets include the following:

- a 6,574 kilometre electricity transmission network indirectly servicing all electricity consumers across Victoria
- an electricity distribution network delivering electricity to approximately 580,000 customer supply points in an area of more than 80,000 square kilometres of eastern
- Victoria; and a gas distribution network delivering gas to approximately 510,000 customer supply points in an area of more than 60,000 square kilometres in central and western Victoria.

The Victorian electricity transmission network is a key strategic asset servicing Australia's second largest economy and the NEM. SPA report that its transmission network serves in excess of 1.8 million households and 280,000 businesses transferring over 45 million megawatt-hours (i.e. 45 GWh) of energy annually over its transmission wires. The SPA geographic electricity transmission region is shown in Figure 1-2.

Figure 1-2 – The SPA electricity transmission area



Source: SP AusNet revenue proposal document

SPI Management services, a wholly owned subsidiary of Singapore Power Internal Pte Ltd, provides management services to both the SPA transmission and distribution businesses. The management company provides a range of management services to SPA including (but not limited to) employee management, business management, management of regulatory compliance, finance and accounting, IT management, legal and company secretarial services and general administration and company reporting. The management company charges the transmission business a fee for the provision of these management services. SPA advises that the costs of management services are allocated between the distribution and transmission business on a direct (causal) basis, where possible, or else on the basis of appropriate drivers. The transmission management fee is passed through into the regulated costs[16].

1.3.3 Changes since the last SPA revenue cap review

In December 2002 the ACCC, in accordance with its responsibilities under the then national electricity code (NEC), finalised its decision on the appropriate revenue cap to apply to the Victorian electricity transmission network, owned and operated by SPI PowerNet (subsequently to become SPA) and planned by VENCorp. This decision outlined the maximum revenues that may be earned by SPI PowerNet's transmission network for the 5-year-and-3-month period from 1 January 2003 to 31 March 2008[17].

In making this (2002) decision, the ACCC set transmission revenues at the beginning of the regulatory period based on its consideration of required levels of network investment during the period in question. 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 (a so-called 'ex-post'

16 PB understands that the Management Company receives additional revenues through incentive arrangements and that these incentives payments are excluded from the regulated costs.

17 The decision also outlined the maximum revenues that may be earned by VENCorp for the five and a half year period from 1 January 2003 to 31 June 2008.

review framework). A prudency review of the investments during the period 1 January 2003 to 31 March 2008 forms a part of this current review by PB and the AER.

The move to an ex-ante framework

In 2004, the ACCC — being of the views that the 'ex-post' review framework held a number of disadvantages — 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 expenditure before the investment is undertaken. The ACCC considered that this approach provides greater certainty for stakeholders, improves the assessment framework for capital investments, and succeeds in moving towards a more light-handed regulatory regime.

In November 2006, further changes to the Rules introduced some more prescriptive regulatory guidelines aimed at improving the price reset revenue review process.

This review by PB includes an independent view of the prudency and efficiency of SPA's proposed capex for the next regulatory period.

Transitional arrangements

The move from an ex-post to an ex-ante regime has process implications for the regulatory price reset reviews for each transmission business. The present review of the SPA revenue proposals includes an ex-post review of the efficiency and prudency of the expenditure associated with the (current) regulatory period, together with the establishment of an appropriate level of forward (future) expenditure associated with the requirements of setting an ex-ante revenue cap. Under the new ex-ante arrangements, there will be no assessment of prudency or efficiency at the end of the next regulatory period.

Prudency test

Under the transitional arrangements, the AER is required to apply a prudency test for investment undertaken by SPA in the current regulatory period. For augmentation investments the AER will apply the Regulatory Test as an initial test in the prudency of the investment. For 'non-augmentation' and 'support the business' (non-system) investment — which covers all of the SPA expenditure proposals — the AER will apply the prudency test by reviewing the processes conducted by the SPA in assessing the need for investment, selecting the appropriate project, and then delivering that project.

1.3.4 The regulatory framework and process

The ex-ante arrangements continue to provide the businesses with an incentive-based (CPI-X) framework. The form of regulation is the establishment of a revenue cap to apply to SPA for the regulatory period (of at least 5 years). In setting the maximum allowable revenue (MAR) for the next regulatory period the AER uses the 'building block' model. The MAR is determined, in its simplest form, as the sum of the return on capital[18], depreciation, opex plus an allowance for tax[19]. An asset-base roll-forward equation is used to adjust the value of the RAB to reflect depreciation and capital expenditure within the period.

Under the revised regulatory framework, the focus is placed on providing capital investment efficiency incentives at the start of the regulatory period. The framework provides for an ex-ante capex allowance and a provision for contingent projects.

18 Weighted Average Cost of Capital (WACC) times the value of the Regulatory Asset Base (RAB).

19 Inclusion of the term for business (income) tax is a consequence of the application of a post-tax (nominal) WACC. Where previously, a pre-tax (real) WACC has been applied, no separate allowance for tax was included in the allowed revenue calculation.

Ex-ante allowance

The ex-ante allowance sets expectations on the level of investment which will be rolled into the RAB at the end of the regulatory period. It covers the majority of SPA's forecast expenditure.

The AER will determine the ex-ante allowance on the basis of an assessment of expected investments during the regulatory period. An important feature is that the allowance does not include approval of capex at a project-specific level. Although the AER may have included specific (expected) projects in determining the revenue allowance, this does not mean that SPA is obliged to develop those particular projects during the regulatory period.

With regard to the investments covered by the ex-ante capex allowance, the calculation of the closing RAB at the end of the regulatory period will be in accordance with the written down value of the *actual* investment during the period in question[20].

Contingent projects

The allowance for contingent projects is to provide for large and uncertain investments. The AER will exclude a project from the main ex-ante capex allowance if the expected error resulting from including the project in the main allowance is more than 10% of the total revenue required[21]. Projects excluded from the main allowance must be linked to defined drivers or 'triggers', such as the potential establishment of a new large single load customer or a new generator. Contingent project status will not normally be granted where expenditure is linked to more general drivers such as regional load growth etc.

By definition, contingent projects are most often associated with reinforcement of the shared transmission network as a result of new connectees. As this type of augmentation work is the responsibility of VENCorp under the Victorian arrangements, the AER does not anticipate the need for SPA to apply for projects to be excluded on the basis of being contingent. There are no contingent projects included in the SPA revenue proposal reviewed by PB.

1.4 APPROACH TO THE WORK

In this section we provide an overview of the methodology used by PB in this review and the limits to, and exclusions from, the work. We also set out the structure of the report and provide details on the presentation of expenditure amount in the report.

In this independent review of the SPA expenditure proposals, PB has considered, examined and provided its expert opinion, on the following key submission items and expenditure categories.

- historic (ex-post) network capital expenditure (capex) over the current regulatory period
- future (ex-ante) network capex
- historic and future non-system capex (e.g. IT, vehicles, 'support-the-business' costs etc.)
- forecast operational expenditure (opex) for SPA
- service standards
- capital governance framework for SPA.

20 Compendium of Electricity Transmission Regulatory Guidelines, AER, August 2005.

21 Quantified in terms of its impact on the maximum allowed revenues (i.e. return plus deprecation).

The review of these items has taken full account of the unique arrangements in Victoria between SPA and VENCorp. In reviewing and in developing our recommendations associated with these items, PB has adopted the high-level methodology set out below.

1.4.1 PB methodology (high level)

The approach adopted by PB is both well established and proven, and recognises the benefits of a methodology which examines the expenditure proposal in a number of different ways. This multi-dimensional approach combines a high-level ('top-down') assessment with a detailed ('bottom-up') assessment of a number of (carefully) selected projects and expenditure items. Our approach also includes a review of the governance processes and policies employed by SPA in making its investment decisions.

In summary, the PB multi-pronged approach to the review of SPA has combined the following key elements:

- a review of SPA's governance systems, processes, policy and practice
- benchmarking and comparative analysis ('top-down')
- impact of proposals on the average age of the SPA asset base
- analysis at total expenditure level with other TNSPs (opex and capex)
- a review of unit costs (obtained from detailed project reviews)
- a detailed examination of a selection of projects, both ex-ante and ex-post ('bottom-up')
- PB's direct experience of other network businesses (including TNSP reviews).

Each of these elements of the PB methodology is described more fully below.

Review of the SPA governance, systems and processes

An important part of the PB review is a review of the governance framework within which SPA makes it investment decisions. The culture of the business can have a major impact on the way in which the business invests. PB has examined the structure, strategies, policies, processes and procedures adopted by SPA in the development of its expenditure proposals, and has used the outcome of this review to reach an independent view on the robustness and appropriateness of the SPA proposal.

In undertaking our review, we have also considered the interface between SPA and VENCorp with a view to determining whether, in the view of PB, there is effective coordination between the two organisations[22].

The outcome of the PB review of SPA's investment decision-making framework is set out in Section 2 of this report.

Benchmarking and comparative analysis

In the experience of PB, the underlying drivers associated with the expenditure on a large and complex electricity transmission network are seldom simple and are often affected by a number of local and network-specific issues. This usually means that conclusions which result from the direct comparison with other businesses need to be drawn with care. Nevertheless, PB believes that this top-down benchmarking provides an extremely valuable high-level 'sense-check' — often providing focus and direction for more detailed analysis and review. PB believes that this represents an important element of the development of an independent view of prudency and efficiency.

22 A full review of the merits (or otherwise) of the Victorian arrangements for electricity transmission is outside of the scope of this expenditure proposal review.

As with any benchmarking or comparison exercise, the results must be read with an understanding of the assumptions made and knowledge of any inconsistencies between data sets. PB's benchmarking and comparative analysis of the SPA revenue reset proposal is included in Section 3 of this report.

Detailed project reviews

The detailed project reviews are a key aspect of the PB approach and provide a 'bottom-up' assessment of selected elements of the proposed expenditure program. Most of the detailed project review analysis undertaken by PB as part of this review is for capital expenditure (network system capex and non-system capex) — although our review has also focused on specific elements of the opex.

The detailed review and assessment of a selection of specific projects has enabled us to:

- confirm (or otherwise) adherence with SPA's own investment decision making and governance framework
- obtain a detailed understanding of the project in order to ascertain the robustness and reasonableness of the proposed project costs
- identify items which have some systemic, or generic, characteristics or qualities which may lead to adjustments across the wider capex program
- gain an understanding of the prevailing business culture and attitudes.

PB's findings following its detailed review of selected projects are described in Sections 4 and 5 of this report. Detailed analysis, which underpins our recommendations on each specific project review, is included in the appendixes to this report[23].

The PB experience of other TNSP expenditure plans

In undertaking a review of the SPA expenditure proposals, the PB project team has drawn on its experience of expenditure reviews of network businesses in general, and electricity transmission businesses in particular. While most of this team expertise will manifest itself in each of the main 'prongs' of the approach described above, the direct experience of the team in transmission price resets add an additional value dimension to the methodology.

The multi-faceted approach described above aims to reflect an economic and pragmatic balance between the effort required to undertake the independent review, and the robustness and credibility of the review findings and recommendations.

1.4.2 Assessment of prudency and efficiency

PB has considered prudency and efficiency in the context of the high-level review framework set out above.

Prudency

In the context of transmission capital expenditure, we consider *prudency* as being the careful and practical management, or stewardship, of the transmission system. It can be viewed as the ability to identify both the required objective (need) and also when it should be addressed (timing). It can also be though of as being the exercise of carefully managing the capex process to achieve the required objective (need). When dealing with an electricity transmission system, the required objective can include a complex and interacting set of requirements (objectives) – such as reduce asset failure risk, minimise maintenance costs, comply with standards and regulatory obligations, etc. Hence there are a range of factors that influence the question of prudent expenditure.

23 A list of projects which have been subject to a detailed review by PB, together with the relevant appendixes, can be found at the end of the contents page located at the front of this report.

These factors include:

- asset failure risks and asset condition
- maintenance and operational practices
- compliance obligations
- external stakeholder requirements
- available technology (know-how)
- feedback and post implementation review of previous work (learning).

Prudency can also be considered as that level of ownership, management and investment decision-making that might reasonably be expected from a TNSP exercising good industry practice and operating under similar conditions.

Efficiency

Efficiency of expenditure can be thought of as the ability to accomplish the required objective (or functional specification) at the optimum level of expenditure (scope and cost). Hence there are a range of (primarily technical) factors that influence the question of efficient expenditure given the nature of the need for expenditure; in particular:

- project scope (work bundling)
- site conditions (constraints, environment, latent matters, etc)
- equipment availability
- procurements processes
- equipment type and specification requirements
- network characteristics and network operations
- adjacent works
- documentation quality (record quality).

Further to this, the issues of prudency and efficiency are not independent. That is, the factors that influence the question of prudency also influence the question of efficiency and vice-versa. Moreover, these factors can influence in varying and sometimes contradictory ways. Trade-offs may need to be made that can impact on efficiency, and which can speak to the issue of prudency. Hence, prudent and efficient management, while embodying objective elements, is very much a subjective skill that requires considerable expertise, and know-how (i.e. technology)[24].

As part of our detailed review, PB has assessed SPA's asset management framework and how it facilitates prudent and efficient expenditure as evidenced by:

- station rebuild approach, as required
- equipment risk assessment
- project cost estimating
- targeted asset by asset replacements, as required, and
- competitive procurement practices, etc.

In assessing prudency and efficiency of SPA's ex-post and ex-ante capex expenditure, PB has applied consideration of the factors outlined in this section to the detailed reviews, as well to the broader capex programs, processes, procedures and systems.

24 Reference should also be made to Section 2.2.6.

1.4.3 Review process

The process adopted by PB in undertaking this review is summarised by the steps below.

1. introductory ('kick-off') meeting with AER and SPA[25]
2. discussion/meeting with SPA on organisation and high-level governance issues[26]
3. SPA presentation to PB on submission detail[27]
4. series of meetings between PB and SPA to discuss on opex, capex (system and non-system) and service standards
5. SPA advised of projects selected for detailed review and scrutiny[28]
6. PB review project information 'packs' and issue follow-up questions to SPA
7. further on-site meetings with SPA staff on specialist expenditure items
8. internal analysis and deliberation by PB
9. production of independent draft review report.

The PB process set out above has been completed in a time of approximately 3 months.

An issues register was established to log questions and queries

A register was established as a means of formally recording issues and questions which arose during the review process to record all of the questions and ensure that responses are logged and outstanding queries tracked. SPA took responsibility for maintaining and issuing the register (to both AER and PB) on a weekly basis[29].

Following the submission of SPA's revenue proposal[30], and the subsequent submission of additional information at the request of AER[31], PB sought further information from SPA as part of its review of the proposals, principally through meetings and additional (formal) questions. These were duly recorded on the issues register.

SPA must satisfy the AER that its proposal meets the requirements of the Rules

Under the new Chapter 6A framework for transmission determinations, PB understands that the onus is on the TNSP to positively satisfy the AER that its proposal meets the requirements of the Rules. The AER must not approve a proposal if it is not so satisfied. This review by PB aims to assist the AER making its determination in this respect.

It is important to note that the onus is not on PB, nor the AER, to 'extract' information from SPA in order to undertake its review; rather that SPA is obliged to provide sufficient

25 Thursday 22 March 2007 at AER offices in Melbourne. This included a summary presentation to AER and PB (by SPA) of the expenditure proposals.

26 Wednesday 28 March 2007 at SPA offices, Melbourne.

27 Thursday 29 March 2007 at SPA offices, Melbourne.

28 Projects were selected jointly by PB and AER.

29 The issues register was updated and distributed on a daily basis towards the end of the information gathering stage when the number of requests (and responses) was high.

30 28 February 2007.

31 The AER conducted the preliminary examination of SP AusNet's proposal required under clause 6A.11.1 of the NER. Additional information was sought from SP AusNet by 30 April 2007 to satisfy the requirements of the AER's Submission Guidelines and the NER.

information for the purposes of supporting its expenditure claims[32]. In this report PB aims to clearly identify any elements of PB's conclusions that are based on gaps, omissions or inadequacies in the information that has been provided by SPA.

1.4.4 Validity of expenditure figures

Following the submission of its proposal, SPA submitted additional information following a formal request by the AER. PB commenced its review on the basis of the expenditure figures contained within this proposal.

During the review by PB, and as a result of the detailed project examinations and discussions with relevant experts within the business, SPA has, in some cases, revised the basis for some of its expenditure plans. Any such departures from the original proposals are highlighted in the appropriate section of this report.

Representation of costs

In accordance with the AER's submissions requirements (and the SPA proposal), the following standards have been adopted for the representation of expenditure amounts.

- all historic (ex-post) amounts are presented in nominal terms[33]
- all forecast (ex-ante) amounts are presented in real terms (2007/08).

Some project costs, as obtained from SPA and referenced as such in the detailed project reviews in this report, are presented in 2006/07 dollars. Where this is the case a footnote has been added in the relevant section. Unless noted as an exception, all other forecast costs are in 2007/08 terms.

Where comparisons and trending of historic and forecast expenditures have been undertaken, nominal expenditure amounts may have been converted to 2007/08 real values. Where this has occurred it has been achieved using (consistent) published actual CPI rates and is clearly indicated in the relevant section of the report[34]. In some of the PB analysis, the 2002 determination figures have also been converted to 2007/08 terms to allow like-for-like comparison with the ex-post expenditure proposals — as presented in the current submission (suitably converted from nominal to 2007/08 real as described above).

'As commissioned', 'as spent' and interest during construction

Under the previous ex-post regulatory regime the assessment for inclusion of capital expenditure into the regulatory asset base is undertaken on an 'as commissioned' basis. Under the forward looking ex-ante regime, the assessment is made on an 'as incurred' basis. Under the 'as commissioned' regime, an allowance is made for finance during construction (FDC) — essentially, interest payments associated with the purchase of assets which are not yet commissioned and do not, therefore, form part of the transmission system RAB. FDC is not charged under the ex-ante regime, where efficient expenditure is added to the RAB at the time at which the expenditure is incurred.

In order to facilitate the transition from the ex-post to the ex-ante regime, in respect of the timing of inclusion of efficient expenditure into the RAB, there is a requirement to determine (estimate) the value of any work in progress (WIP) as at 31 March 2008. This WIP represents asset expenditure that has been *incurred* but is not yet *commissioned*. Under the previous (ex-post) framework, this WIP expenditure would attract an amount in respect of FDC and, when

32 PB not asking for information does not, in itself, represent an omission by PB in its responsibilities to provide the AER with an (independent) view on the prudency and efficiency of the levels of expenditure proposed by the businesses.

33 The ex-post period is from 1 January 2003 to 31 March 2008.

34 Actual CPI rates used and their application have been approved by AER.

commissioned, would eventually be rolled into the RAB and would earn a regulated return. The WIP as at 31 March 2008 (March 08 WIP), if deemed to be prudent and efficient, will be capitalised and rolled into the RAB. All expenditure from 1 April 2008 will be rolled into the RAB on an *as incurred* basis with no allowance FDC.

1.4.5 Limits to, and exclusions from, the work

The work undertaken by PB is limited to an independent review of the SPA *expenditure* proposals and an assessment of the proposed service standards. The work undertaken by PB does not aim to address issues associated with WACC, depreciation (including economic, or standard, asset lives) or transmission use of system prices. The scope of PB's work also excludes deliberations on tax and interest during construction.

1.5 REPORT STRUCTURE

The structure and sequencing of this report covers:

- a review of SPA's internal arrangements, including governance and processes
- a review of expenditure program, including benchmarking
- a review of historic and 'work in progress' capex, including detailed ex-post project reviews
- a review of forecast capex, including detailed ex-ante project reviews
- a review of historic and forecast non-system capex, including detailed ex-post and ex-ante project reviews
- a review of opex, including recurrent and non-recurrent costs and capex-opex trade-off
- a review of proposed service standards, including definitions and targets
- PB's conclusions and recommendations.

Amongst other references, the detailed project reviews are included in the appendixes to this report.

2. REVIEW OF INTERNAL ARRANGEMENTS

In this section of the report we describe the SP AusNet (SPA) governance, systems and investment decision-making processes, set out PB's processes for undertaking the review of SPA's internal arrangements and provides our independent views on their effectiveness.

2.1 GOVERNANCE AND SYSTEMS

Corporate governance deals with the set of policies, processes, and regulations affecting the way in which a business is directed and administered. It is a multi-faceted subject that captures issues ranging from accountability and stakeholder relationships through to a focus on economic efficiencies and optimisation.

In this section we describe and evaluate SPA's internal organisation, policies and procedures as they relate to the ongoing development of its network and the management of its expenditure. The purpose of the evaluation is to confirm that SPA's capex and opex justification and investment processes are effective in ensuring that its regulated allowance is sufficient to meet its legal and regulatory obligations but, at the same time, ensuring that unnecessary or inefficient expenditure is avoided.

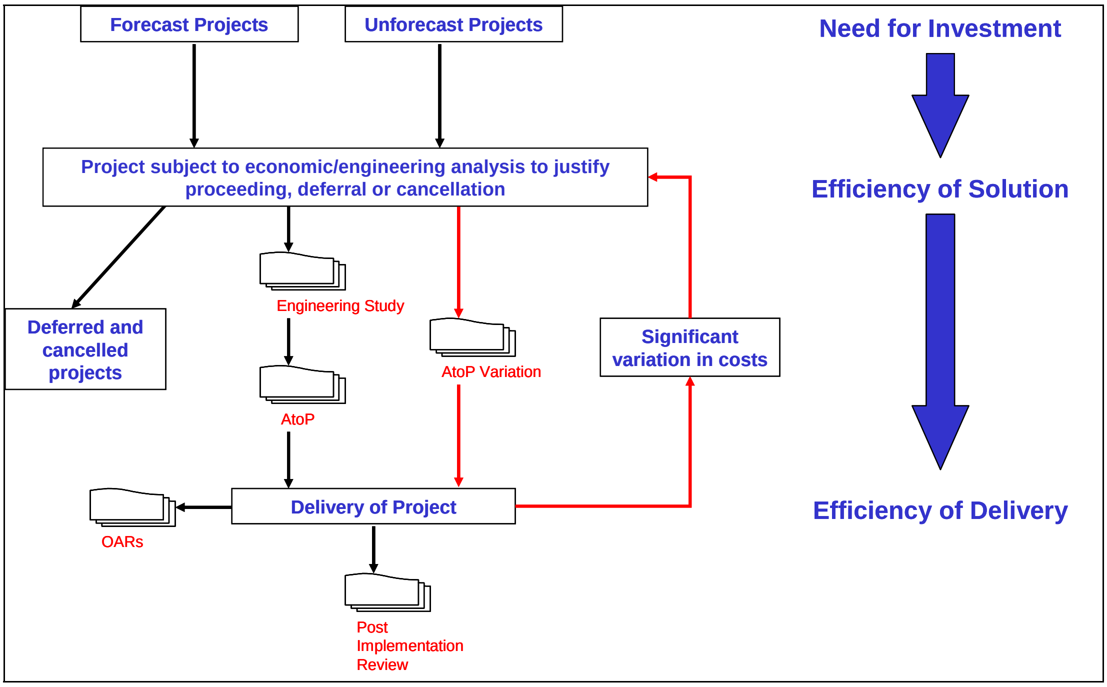
SPA's structure, with eight General Managers reporting to a Board of Directors through a Managing Director is representative of the other businesses in the electricity industry, and reflective of a major corporation listed on the Australian Stock Exchange. PB has been provided with a number of relevant position descriptions relating to the development of SPA's electricity revenue proposal and found each of these to provide clear descriptions of the role, accountabilities and measures of performance, including direct references to the regulatory process.

2.1.1 Practices and processes

As part of its governance processes, SPA employs a number of relevant policies and procedures related to its expenditure and its asset management and engineering core business.

A schematic overview of SPA's project assessment process is shown in Figure 2-1, and some key aspects of this process are discussed in further detail below.

Figure 2-1 – SPA project assessment process



Source: SPA presentation, 29/03/2007.

Project engineering and economic assessment

For all projects, irrespective if they have been forecast or not, SPA undertakes detailed engineering analysis, often involving external independent parties, particularly for large station rebuilds. To capture process efficiencies, large volumes of work are typically combined into programs, rather than specific individual projects. SPA's technical analyses are supported through generalised and in some cases specific economic analyses that attempt to replicate the reliability limb of Regulatory Test to the best extent possible. This involves some consideration of the 'do nothing' option - but focuses strongly on other network alternatives, and a number of sensitivity studies on key input parameters. The outcomes of SPA's engineering and economic assessments are usually based on a least-cost approach as opposed to a cost–benefit approach.

Authority to Proceed approvals

Authority to Proceed (AtoP) documentation and approvals form a key role in SPA's internal processes. They contain a summary of the engineering and economic analyses, plus they capture a risk analysis[35] associated with a project's objective. The AtoPs effectively include the business case, formalise roles and accountabilities, and set out the scope of work and the internal budget against which the project out-turn costs are evaluated. Any variation to either scope or budget of a project after the AtoP approval process requires a variation and re-approval using consistent delegations of authority. All budgeted and unbudgeted capex and opex must be approved by the appropriately delegated officer through an AtoP.

Project approval committee

SPA's project approval committee (PAC) considers and evaluates all projects requesting approval of a value equal to or greater than $250k (excluding GST). The PAC meets weekly and the charter of the committee defines its roles to:

- approve the capital works program
- approve modifications to the capital works program

35 Including financial, program, construction and operation, outage and other risks.

- assess and approve well-documented projects and proposals consistent with the strategic direction of the company
- ensure projects achieve their desired objectives.

Authorities and delegations

SPA has formal documented delegations in place that have been examined by PB in this review. This information has not been included in this report for reasons of confidentiality.

Project execution tracking

SPA's project execution tracking (PET) is covered by detailed policy and procedure, which aim to establish a uniform approach to the initiation (approval) and monitoring of projects throughout their life cycle. The policy applies to all capital projects, non-recurring projects and significant opex, and the workflow functionality is structured around a detailed 90-stage procedure with systematic instructions. Roles and accountabilities are clearly defined within the policy and actual progress is tracked through an auditable database which contains all relevant project documentation.

Capex prioritisation

SPA has developed and implements a capex prioritisation and optimisation process that captures the different elements of the transmission asset management strategy and converts these into an annual capital portfolio for detailed implementation and delivery.

The process includes:

- establishing outcome measures and targets
- defining and evaluating candidate projects
- developing an optimal selection
- approving optimal candidates.

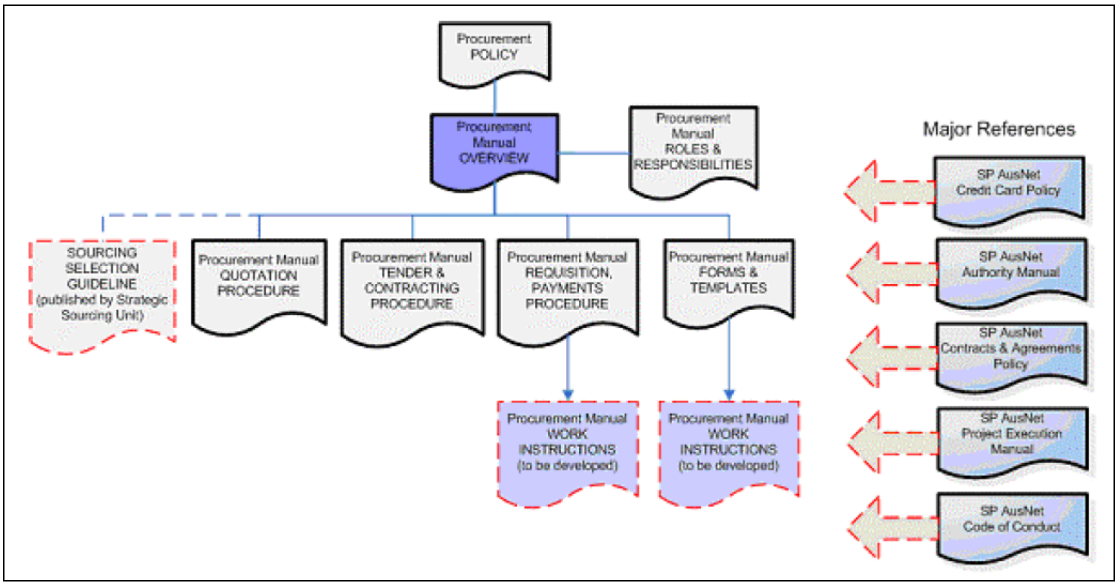
Procurement policies and practices

SPA has a detailed and documented Procurement Manual that covers the businesses policy and processes associated with its purchase of materials, equipment and services.

The purpose of the manual is to establish the framework within which SPA can effectively and efficiently procure goods and services on appropriate terms while leveraging spend, managing risks, and ensuring regulatory and legal compliance relevant to its contacts and orders.

The framework is captured schematically in Figure 2-2.

Figure 2-2 – SPA's procurement document hierarchy



Source: SPA, Procurement Manual – Buying for SP AusNet, 01/06/2006.

The policy outlines SPA's purchase path options, where effectively and purchase exceeding $250k requires a formal tender process and purchases below this level require varying degrees of written quotations.

The manual also captures the role of the PAC and EAC, and specifies clear separation of duties.

Order Approval Requests

Order Approval Requests (OARs) are used to gain approval from SPA's Expenditure Approval Committee (EAC). Effectively the EAC is the body that approves the award of tenders in accordance with SPA's documented tender and contracting procedures. The OARs cover analysis of all tenders and evaluation criteria.

Post-implementation reviews

SPA has initiated a process through which all major projects are subject to an external post-implementation review (PIR). The purpose of the reviews is to explain the basis of cost over-runs and to provide a feedback loop to ensure continuous improvement.

Allocation of costs

SPA allocates its costs associated with regulated and unregulated activities at the time of deriving the regulatory accounts to ensure that only regulated costs relating to its electricity business have been included in its proposal. Furthermore, where possible the regulated transmission business costs are allocated on a direct causal basis, and where this cannot be done SPA allocates costs across its different regulated businesses using an appropriate driver such as relative RAB value, or relative employee numbers. These matters are discussed further in Section 7.

2.2 ASSET MANAGEMENT

In its Transmission Network Service Provider (TNSP) role, SPA has developed an Asset Management Strategy (AMS) that provides a framework in which to achieve its stated objective of reliable, efficient, safe and environmentally responsible provision of network services. The AMS has developed over time to underpin SPA's realisation of its strategic asset management objectives, and support achievement of regulatory and business performance targets. The stated aims of the AMS are to[36]:

- maintain a stable and sustainable network asset failure risk profile to ensure supply reliability in accordance with customers' needs and preferences
- meet operational service targets for network reliability and availability
- comply with operational codes and regulations including occupational health and safety, environmental and security legislation
- optimise total capital, operating and maintenance costs over each asset's entire life cycle.

SPA's asset management strategy follows the Publicly Available Specification (PAS) 55 framework established by the UK Institute of Asset Management. This framework is based on best practice asset management principles, and focuses on continual improvement across five key areas:

- developing policy and strategies
- capturing information and developing plans to meet the desired strategies
- implementing the plans and operating towards the goals
- monitoring progress, investigating results and initiating change
- reviewing the asset management process to ensure ongoing suitability.

The documentation states that the purpose of the AMS is to provide technical direction for the responsible stewardship of Victoria's electricity transmission assets. In particular, SPA note that this stewardship involves a commitment to sustainable risk, value and performance levels, as well as skilled and expert management of critical assets through rigorous analysis, sophisticated policy and robust operating processes.

The scope of the AMS involves a planning horizon to 2020, and covers all of SPA's Victorian electricity transmission assets; in particular:

- transmission lines, power cables, easements and access tracks
- terminal and switching stations, depots, buildings and civil infrastructure
- protection, control, metering, communications equipment and stations
- related functions and facilities such as spares, maintenance and test equipment
- asset management processes and systems such as SCADA and asset management information systems (including MAXIMO).

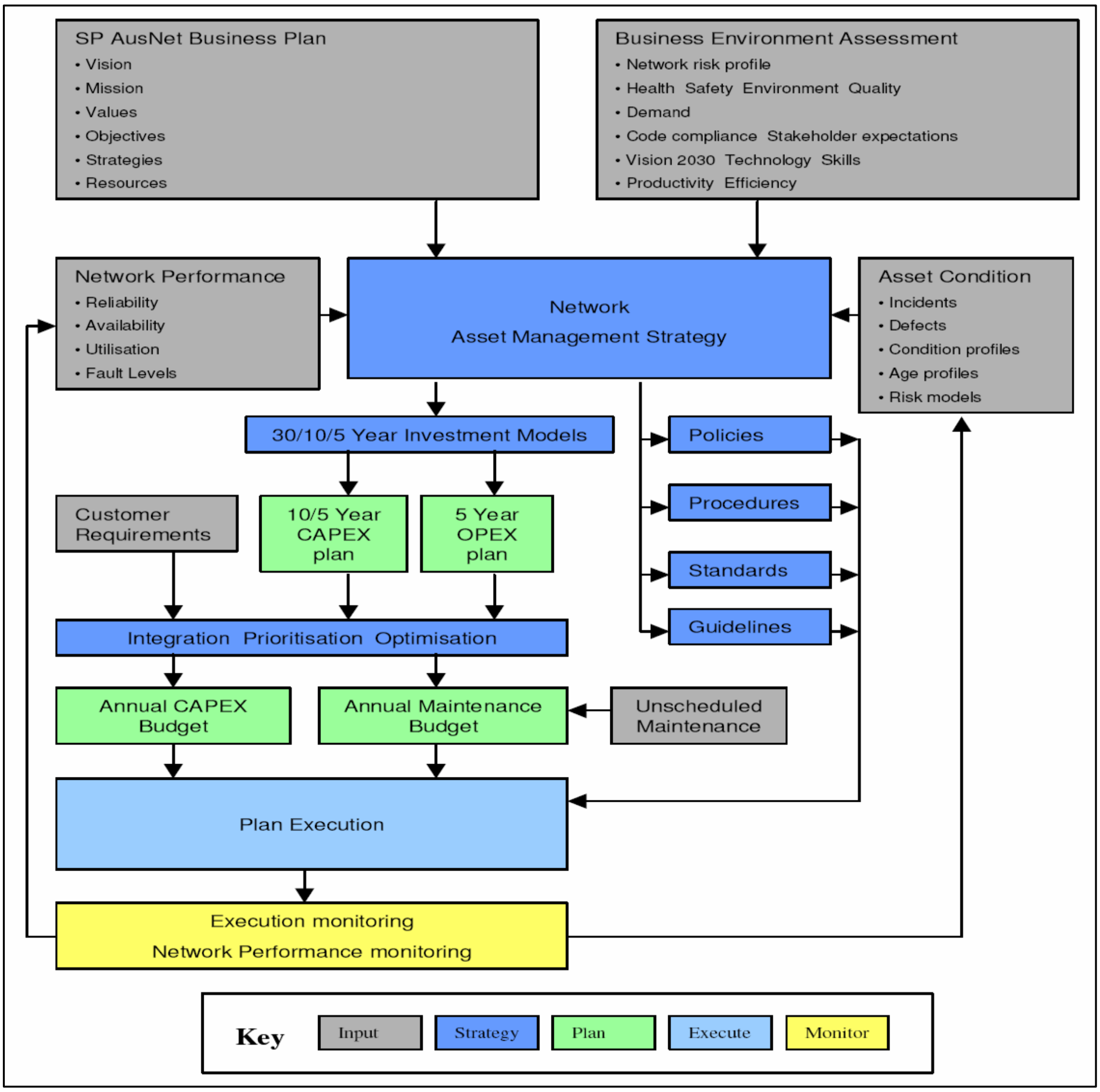
The following sections examine the key elements of the AMS, starting with an overview of the context of the AMS within SPA's asset management process. Consideration is then given to the supporting documentation structure, following which the primary drivers of the AMS are presented as background to the both the ex-post and ex-ante capital programs. SPA's risk assessment practices that underpin the development of its capex programs are then discussed, with particular reference to the risk models employed in this process. Finally, this discussion is developed into an overview of project assessment and program development.

36 Section 3.2.2. Electricity Transmission Revenue Proposal 2008/09 – 2013/14; SPA, 31/03/2007.

2.2.1 Process overview

As depicted in Figure 2-3, SPA's asset management process is developed around the AMS. At a high level, the inputs to this process include the corporate vision, business plans, and an assessment of the business environment that includes the regulatory framework. At a more detailed level, inputs include actual network performance metrics, asset condition information, and customer requirements. The outputs are short- and medium-term capex and opex plans, policies, procedures, and standards, as well as annual capex budgets.

Figure 2-3 – SPA asset management process



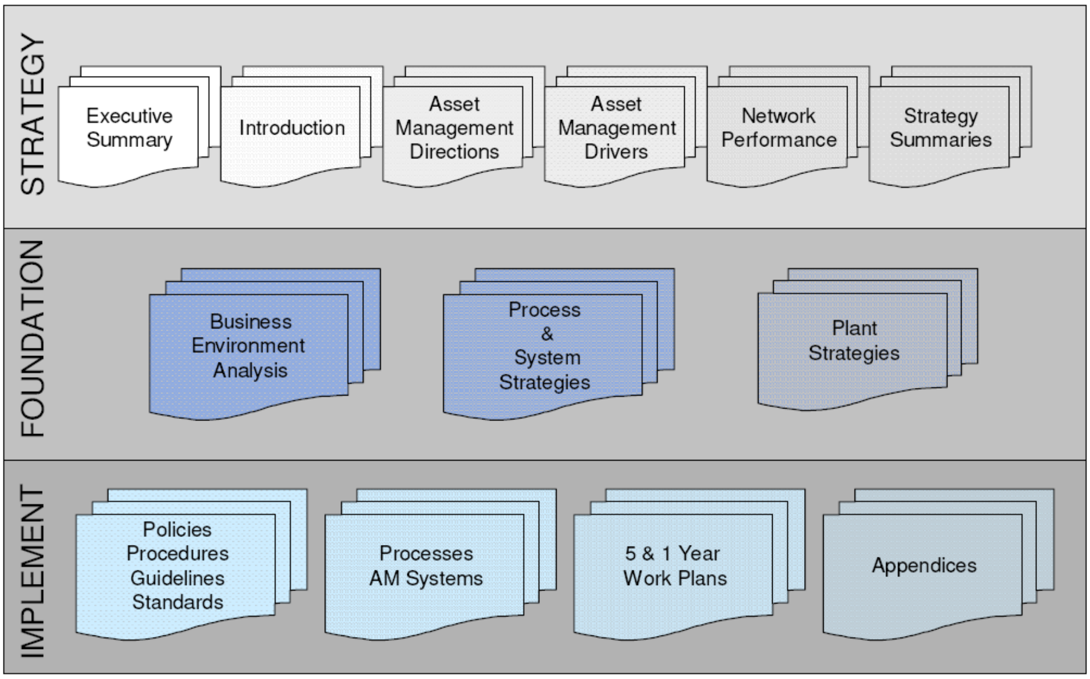
Source: Electricity Transmission Revenue Proposal 2008/09 – 2013/14; SPA, 31/03/2007.

2.2.2 Documentation

Supporting this asset management process is a documentation hierarchy that has the AMS at its core. This documentation structure is shown in Figure 2-4. At the highest level, the documentation captures asset management directions, drivers, and network performance. While the next level addresses assessment of the business environment, processes and system strategies, as well as plant strategies necessary to achieve the required performance outcomes. These documents address issues such as plant condition monitoring, program delivery, information systems, and records management. The lowest level addresses implementation issues, and how the asset management strategy is integrated with SPA's business systems and practices.

An outline of the documentation set that support SPA's asset management process is presented in Appendix A.

Figure 2-4 – Hierarchy of the AMS



Source: Electricity Transmission Revenue Proposal 2008/09 – 2013/14; SPA, 31/03/2007.

2.2.3 Drivers

The AMS identifies a number of drivers that influence network performance, and hence drive future network investment through the asset management process. SPA has identified these drivers as:

- reliability and availability expectations
- maintenance of asset condition and sustainable network and asset risk profiles
- demand growth and high equipment utilisation levels
- increasing network fault levels
- code compliance, and health and safety, environment and infrastructure security performance improvements
- efficiency demands
- emerging new technologies
- workforce skill demands.

To address these drivers, SPA has adopted a range of strategies through the AMS. For instance, to address reliability and availability expectations, and manage a sustainable network and asset risk profile, SPA has improved its risk modelling practices. This has involved the modelling of failure history, asset condition, and consequences, and the integration of these models into the development of SPA's maintenance, refurbishment and replacement programs. The details of this approach are discussed more fully in Section 2.2.4

below. Other examples include external and independent performance benchmarking[37] to assess SPA's asset management efficiency, and progressive workforce renewal through training and recruitment to address skilled workforce demands. Other strategies to address these drivers are set out in the AMS.

In general, through SPA's asset management process, each item of capex, and associated opex, is related to one or more of the drivers recognised in the AMS. As the AMS is derived from the business plan, and driven by network performance metrics, and asset condition information, each capex item also has a relationship to SPA's overall strategic direction as well as the performance of the network ands its elements. Asset management policies, procedures, and standards, also derive directly from the AMS, and hence capex and opex plans and budgets relate directly to policies, procedures, and standards. These relationships are shown clearly in Figure 2-3 and Figure 2-4 above.

2.2.4 Risk management

Risk management is a central element of SPA's approach to asset management, and is a key driver of project selection and maintenance activities. Implementation of SPA's risk management process is through a risk management framework. At the governance level of this framework SPA has a risk management policy under which the risk management framework defines the philosophy, principles, requirements, and risk management responsibilities. A Group Risk Committee oversees the process, and aligns the business objectives with the risk management strategy and approved risk appetite. Operationally, this framework is supported by a suite of risk models that assess reliability, availability, health, safety, environment, infrastructure security and code compliance risks[38]. This section focuses on providing a brief overview of SPA's risk models as background to SPA's capex programs.

SPA's approach to asset management includes detailed consideration of maintenance, refurbishment and replacement practices, and while asset age is recognised as a key indicator, the primary determinant is asset condition. Generally asset condition deteriorates with age; however, condition also depends on factors such as design, loading, operating cycles, environment, and a range of other factors that may differ from 'normal'. To address these factors, SPA employs quantitative asset condition and fleet risk models that guide the volume and timing of refurbishment and replacement. Essentially, these models are used to assess the condition of specific assets, and rank those assets for subsequent detailed review. While the fleet and network models provide an overview of the change in risk over time. SPA also employs program risk models that are used to guide decisions related to network performance[39]. Figure 2-5 shows the relationship between these risk models, as well as their various high-level elements.

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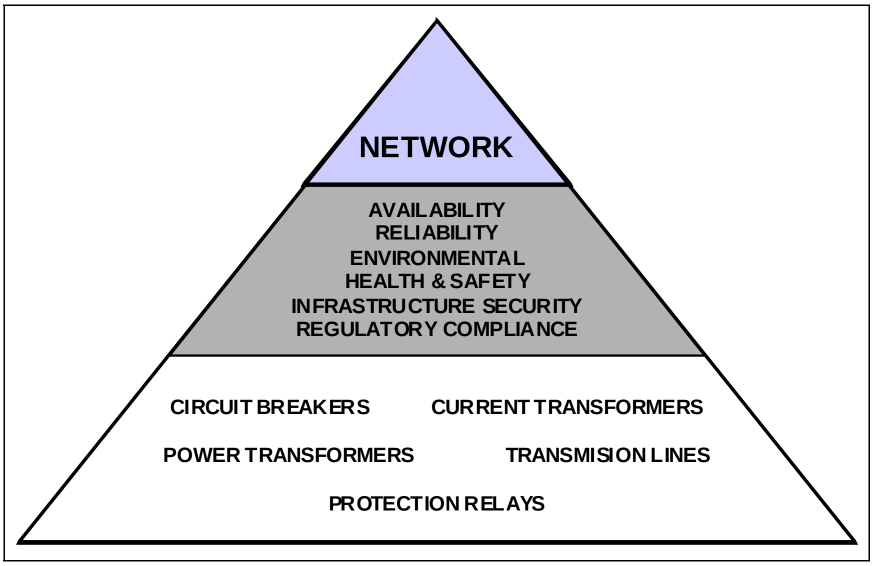
37 Electricity Transmission Regulatory Reset 2008/09 – 2013/14. Appendix A - Jervis Consulting Report. SPA, 2007.

38 Electricity Transmission Regulatory Reset 2008/09 – 2013/14. Appendix E – Asset Management Strategy. SPA, 2007.

39 AMS Victorian Electricity Transmission Network Risk Management. SPA, 2007.

Figure 2-5 – Risk model hierarchy



Source: AER Asset Management Presentation. SPA, 29 March 2007.

Historically and this covers the current regulatory period, SPA employed a 'bespoke' approach to modelling the equipment and network risks. This involved equipment condition assessment, and subsequent risk analysis of specific network elements (e.g. a terminal station where a significant proportion of the equipment was assessed to be in poor condition). This analysis was then incorporated into a project or program proposal.

With progressive refinement of this approach over recent years, SPA has developed (and continues to develop) a range of risk models that support a broader application of this risk based approach. While the overall risk assessment process is similar, the degree of application, automation, and sophistication has progressively improved[40]. Currently, SPA has a set of risk models available for the following equipment categories:

- circuit breakers
- current transformers
- power transformers
- transmission lines
- protection relays.

These models (except protection relays) calculate the probability of failure for each individual asset based on condition scores used in conjunction with life curves. The results are calibrated to align the model with recent failure history prior to forecasting expected future failure rates. This ensures that the models are reflective of the current state of the asset fleet. The condition scores and life curves used by the models are developed from test reports, incident reports, maintenance and defect records, as well as data gathered from the manufacturers experience, CIGRE[41] data, and other transmission utilities. For reference, an overview of the key aspects of each of the risk models is given in Table 2-1.

40 It is important to note that justification of SPA ex-post capex was largely based on the 'bespoke' approach, while the proposed ex-anti apex is essentially based on the current risk modelling framework, particularly the volume and timing which are guided by the current risk modelling framework.

41 CIGRE is the French-founded International Council on Large Electric Systems.

Table 2-1 – Key aspects of the asset models

Model	No. of elements	Measure	Trigger for analysis	No. of life curves used
Circuit breakers	1,018	Probability of failure	High and Very High categories.	72
Current transformers	1,120	Remaining life & probability of failure.	Remaining life <=10 years	3 — Short, Typical & Long
Line insulators	13,265	Condition >5.1 Short life >4.1 Typical Life <= 4.1 Long Life	Condition >5.1 and/or short life. However, as fatigue is not included in the model, all insulators were reviewed.	3 — Short, Typical & Long
Protection relay	2,308	Performance and functionality	High risk or <20% functionality of modern equivalent relay or replacement of associated primary equipment and <30% functionality	6 (details omitted)
Transformers There are four condition sub-models	217 tanks	Condition score and probability of failure	Condition score of 40 or more.	3 Short, Typical & Long for each of core and coil, oil, bushings and tap changers.

Source: Overview of Use of Risk Analysis in Capital Planning. SPA, 2007.

In order to assess the risk, the consequences of equipment failure must also be considered. SPA does this in terms of reliability, availability, health, safety, infrastructure security, environment and compliance. Various consequences are considered depending on the particular risk model. For example, the consequence calculation for the transmission line insulator risk model assesses the availability incentive cost, bushfire ignition, and conductor falling onto public thoroughfare (calculated for each span). While the consequence calculation for the current transformer model uses environmental damage, collateral damage, and health and safety factors to assess consequence irrespective of location and voltage. In addition to this, a detailed consequence assessment is undertaken for proposed projects, as not all scenarios and second-order events are covered at the risk model level[42].

Overall risk is then assessed by combining the probability of failure and the assessed consequences.

The output of the risk models is essentially a ranked list of individual assets (by type) based on the relative risk posed by each asset. This information is used to inform SPA's development of projects and programs through a process that involves expert review of the risk model results. This approach ensures that other relevant issues such as works programming and operational constraints are brought to bear in using the model results to drive project and program development. This application of the risk model outputs (as modified by expert opinion) to the development of capex projects and programs are discussed further in the following section.

42 For example in the CT risk models, SPA notes that there is no significant variance in consequence between locations or voltages (SPA email dated 19/06/07).

2.2.5 Project assessment and program development

As discussed in Section 2.2.4, SPA employs a suite of asset risk models that essentially provide a ranking of assets based on condition. In order to develop asset plans and programs, the asset model information (i.e. condition-based ranking) is used to identify specific assets that require further investigation. Expert review and analysis is then undertaken on the identified assets in order to develop potential asset works alternatives. This includes the development of scope of works definitions (at a planning level) for the identified (proposed) alternatives. This assessment can result in alternatives for repairs, monitoring, refurbishment, or replacement. Factors taken into account in this expert review process include:

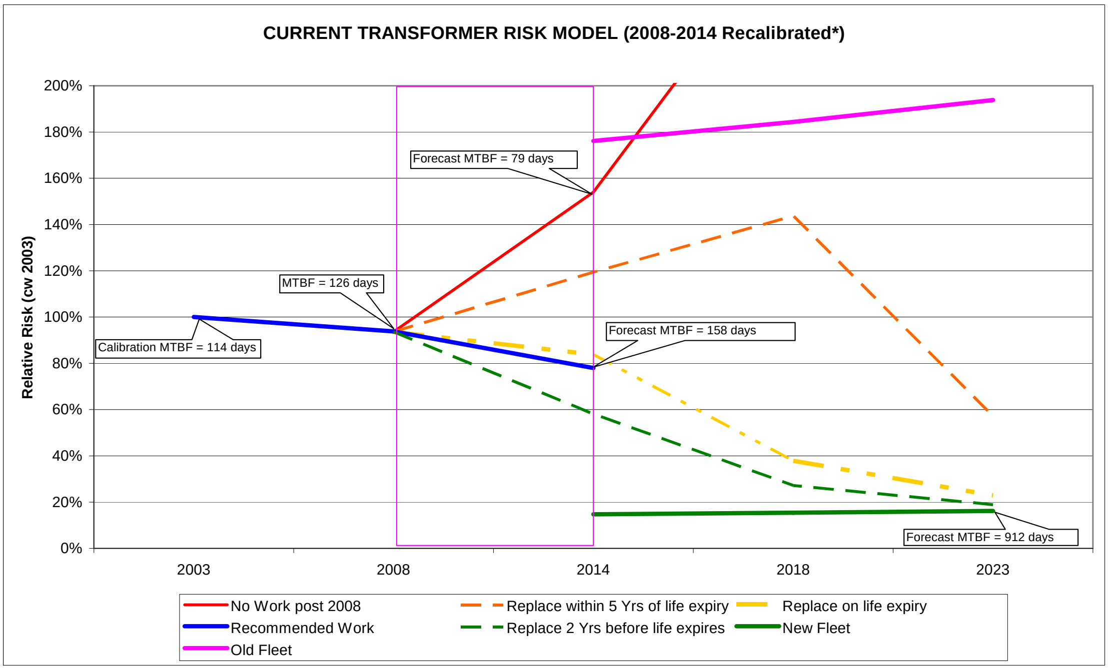
- interdependencies with other works
- failure consequences
- costs and benefits of combining works into economic work packages (i.e. projects and programs)[43]
- construction issues and outage impacts
- customer requirements and VENCorp requirements (see also Section 2.3)
- network operational issues
- OH&S risks
- environmental issues
- operating and maintenance cost impacts.

Hence, the risk models don't (of themselves) determine the works projects or programs, as these are the result of the broader asset management process.

In addition to the risk modelling and expert review process, fleet level assessment is also undertaken to determine the risk trends (see also Section 2.2.4). These trends are developed for the various proposed works scenarios identified (including 'do nothing'). Figure 2-6 shows an example of the results of this analysis as conducted by SPA to assess the impact of different management strategies on its current transformer fleet.

43 That is, where an asset may require replacement, it may be more cost-effective to combine this work with other works at the same location and produce an overall pack of work that can be implemented at a lower overall cost than the would be the case if the individual works were undertaken independently.

Figure 2-6 – Example of the fleet model output for current transformers



Source: Current Transformer Risk Model Presentation. SPA 24 March 2007.

Essentially, this analysis provides an overview of the trend of asset risk[44] for a particular asset class over the forecast period under various asset management scenarios. This enables the impact on network performance and safety to be assessed for scenarios being considered.

Under SPA's asset management process, once the available asset alternatives are identified and the scope of works developed, they are subject to an economic cost–benefit analysis using discounted cash flow to identify the least-cost alternative. This analysis takes into account estimates of capital costs, operational costs, maintenance costs, operational risks, the value of reliability and costs of involuntary supply interruptions, as well as the costs of any collateral damage associated with asset failure. In addition, in identifying and economically analysing the potential asset management alternatives, SPA must also take account of other factors such as compliance with standards, the NEC, and licence conditions.

In essence, SPA's project/program development process consists of the following steps:

- assets are risk ranked (condition ranked) based on the risk models
- data is organised by fleet, voltage and locations prior to engineering review
- expert review is undertaken to account for other relevant factors, and asset management alternatives are developed (scope of works developed)
- economic assessment of the alternatives is conducted to identify the least-cost alternative.

Once the least-cost alternative is identified, further work may be undertaken to finalise the scope of work for the preferred alternative. Refined cost estimates may be prepared, and initial design investigations may be carried out. Finally, an Authority to Proceed is prepared and submitted for approval through senior management and the board (if required). It must be stressed that this overall process may be iterative, and could be undertaken at various levels of detail as information regarding the proposed alternatives is developed through the process. Hence refinements, variations, and even other alternatives may be pursued through this process as the project/program develops.

44 SPA's asset risk models are essentially based on asset condition assessment, and hence the risk reflects the expected variation in asset condition over the forecast period.

2.2.6 Technology

In the above sections we have focused on the present state of SPA's asset management capability. However, it must be understood that SPA is on a path of continuous improvement through the development of its asset management technology. In this section we will briefly consider the key changes that have occurred in SPA's asset management technology over the current regulatory period.

Through PB's detailed review of SPA's proposed ex-ante and ex-post expenditure, PB has considered the progression of development of SPA's asset management technology. Of particular importance is the development of SPA's technology to manage the complexities of brownfield (live) terminal station redevelopment projects, as these projects represent a major element of both ex-post and ex-ante expenditures. The following observations are, in PB's view, indicative of the learning process that has occurred over the current regulatory period:

- project work programs were developed at a high level and did not explicitly address the logistical and access issues that arise on brownfield sites. While brownfield adjustments were made at the overall program level, this did not adequately address the complexities of these issues. SPA now conducts a detailed study of the sequencing of the proposed works. This enables more accurate work scheduling, project costing, and operational planning
- project cost estimating was based on a system of terminal station "construction block" costs (e.g. a 220 kV bay – as a single cost block). These block costs were based on greenfield cost estimates, which were then adjusted for the brownfield nature of the project through the use of a brownfield factor. SPA now employs a detailed estimating system the works at the equipment or component level and builds up the cost. While a brownfield factor is still employed, it is not applied as a general escalator to the project, but applied through a detailed work program that recognises the brownfield nature of the site
- assessment of equipment condition and attendant risks was undertaken using classical engineering analysis of test reports, maintenance reports, and specific equipment examination. Such a process is complex, costly, and time consuming. In addition, this approach may not efficiently focus work to the areas that represent the greatest risk. SPA now employ an equipment risk assessment methodology that is much more focused, draws together all the relevant data into a form more tractable to assessment, and supports the bundling of work into more efficient projects or programs. This has improved the ability of SPA to defined project scope
- equipment information, test and monitoring technology has also improved over the current regulatory period. SPA have developed and implemented a number of test and monitoring processes to improve the businesses understanding of the sate of its equipment. This has improved the ability of SPA to defined project scope
- SPA's experience with brownfield terminal station rebuild projects was very limited at the commencement of the regulatory period. Indeed, because of the nature of this work, such experience within the Australian industry is limited. SPA has now developed an improved understanding of the particulars of these projects in the context of the specifics of SPA terminal station arrangements. Consequently, the scope of works associated with more recent project is significantly improved over those of the very early projects.

At the commencement of the current regulatory period, SPA's asset management capability was, in PB's opinion, considerably less advanced that it currently is. There is clear evidence that SPA has significantly improved its technology over this period. Hence PB is of the view that SPA's proposed capital works are better scoped, and that the associated forward capex estimates will be considerably more accurate.

2.3 COORDINATION WITH VENCORP AND CONNECTED PARTIES

In order to develop and implement pragmatic, effective and efficient asset replacement projects that address the long-term needs of SPA and its stakeholders, it is important for SPA to pay careful attention to the needs and requirements of VENCorp and the connected parties. This is particularly the case given the Victorian transmission arrangements, where the responsibility for planning augmentation for future load growth is undertaken by other parties.

SPA deals with this in a systematic manner and on a project-by-project basis. It consults with the interested parties through regular joint planning meetings to ensure that economies of scale and incremental augmentation upgrades are captured where relevant. The benefits of a coordinated approach are two fold: project delivery costs can be minimised and the network performance is enhanced by minimising the number of outages required to carry out project works.

In practice, SPA has and is proposing to coordinated augmentation and replacement on a number of projects with VENCorp and distribution businesses:

- the installation of an additional 1,000 MVA transformer at Rowville involved VENCorp justifying the advanced replacement of a number of 220 kV circuit breakers
- the Malvern terminal station development incorporated asset replacement and augmentation
- proposals to augment transformer capacity as part of future station rebuild projects — for example, Richmond, Dederang, Bendigo.

SPA's AMS, specifically addresses the Victorian planning and regulatory framework.

VENCorp provides SPA with high-level functional specifications of plant to ensure that replacements projects are not to the detriment of VENCorp's mid- to long-term strategic development plans for the shared electricity transmission network.

2.4 PB COMMENTS AND CONCLUSIONS

As part of our high-level review of SPA's internal arrangements, and as informed through our detailed project reviews, PB makes the following observations regarding SPA's governance and systems:

- SPA has well-structured and well-documented policies and processes to support its core transmission service provision role, and the responsibilities and accountabilities within the business are clearly defined
- typical of a well-governed, integrated corporation, SPA has a business structure and has established a number of committees to appropriately support its asset management. investment approval, and decision-making processes
- SPA's processes and practices reflect that SPA is highly conscious of the regulatory framework within which it operates and the processes and practices attempt to address the organisation's regulatory needs as an integrated aspect of its operations
- given SPA's management framework, AtoP approval thresholds, detailed procurement manual and capex optimisation and prioritisation process, PB considers the internal framework is effective at capturing capex and opex efficiencies
- SPA's project execution tracking process is contemporary and auditable, but has not necessarily precluded some projects running over budget and examples of poor project management.

PB makes the following observations regarding SPA's asset management strategy:

- SPA's asset management strategy is contemporary and fosters a strong incentive for continual improvement, evidenced by SPA seeking an independent benchmarking review of its AMS
- the detailed use of quantitative risk modelling and assessment processes is of a very high quality and in PB's opinion would be close to best practice; the capability of SPA to systematically identify individual asset risk and track its network, program and asset risk profiles over time is to be commended
- SPA's risk model application is focused on the probability of failure aspect of the risk and, as the model evolves, improvements could be made to the treatment of failure consequences
- SPA has gone to reasonable lengths to advise that the detailed risk model outputs form only one input to its detailed engineering and economical assessments, and this is consistent with the evolving status of the models; however, this also leads to the widespread use of 'engineering judgement' that is less transparent when considering the need and basis for investment
- SPA's economic evaluation practices are reasonable; however, the assessment methodology is not well documented, and seems open to individual opinion on how to undertake assessments and errors. SPA appears to be addressing this issue through the use of standardised evaluation spreadsheets.

PB makes the following observations regarding SPA's coordination with other parties:

- the separation of responsibilities for asset management and replacement and augmentation of transmission in Victoria appear to have highly focused each business to their respective functions
- it is not clear how VENCorp and SPA coordinate or consistently apply the probability of failure information developed by SPA through its detailed asset risk models into the respective planning processes
- SPA interacts with VENCorp and other connected parties on a regular basis to ensure optimisation and efficiencies in capex plans are captured, and this is generally undertaken on a project by project basis
- the use of modern equivalents and coordinated augmentation/replacement projects are apparent and appear to be effective and efficient
- SPA's internal processes explicitly recognise and capture the flexibility required during iterative negotiations with connected parties, with an objective of ensuring a holistically efficient approach to network investment.

3. REVIEW OF THE EXPENDITURE PROGRAM

The approach adopted by PB in its review of the SP AusNet (SPA) expenditure proposals combines a high-level ('top-down') assessment with a detailed ('bottom-up') assessment of a number of selected projects and expenditure items. In this section we provide a general overview of SPA proposals and compare historic and (proposed) forecasts expenditures. We also set out the results of PB's high-level benchmarking and comparative analysis, undertaken as part of the 'top-down review' of the SPA proposals.

Specifically, the section includes details of the following items and analysis:

- an overview of the total business expenditure proposals
- benchmarking of the SPA proposals, at a total expenditure/business level, with other TNSPs (opex and capex)
- an assessment of the impact of the proposals on the average age of the SPA asset base
- a review of unit costs (obtained from detailed project reviews).

Each of these elements is describes in more detail below.

3.1 OVERVIEW OF THE EXPENDITURE PROGRAM

In this sub-section we provide a high-level summary of the past (ex-post) and proposed (ex-ante) expenditure proposals for both opex and capex.

3.1.1 Capex overview

Under the Victorian transmission arrangements, SP AusNet (SPA) is responsible for planning and execution associated with the operations, maintenance and replacement of the transmission network assets. While SPA does undertake augmentation works, this is at the behest of VENCorp and is executed through a Network Agreement between VENCorp and SPA. SPA is contractually bound to provide agreed network services to VENCorp in return for an agreed schedule of network charges.

The prudency and efficiency of *augmentation* works associated with the Victorian transmission network is, therefore, a function of the governance and investment decision-making processes of VENCorp. Network augmentation capex is subject to the Regulatory Test[45]. This is subject to a separate independent review by PB as part of this revenue determination process[46].

In the context of this regulatory review, capex is defined as expenditure that satisfies one or more of the following requirements (see below); relates to the purchase or construction of a new asset; increases the functionality of the asset; or extends the service life of the asset.

This section does not include augmentation capex

The overview and comparative analysis presented in this section is associated only with network replacement capex and non-system capex. The analysis does not include augmentation capex (for the reasons set out above). The SPA forecast capital replacement expenditure is characterised

45 The test, as promulgated by the ACCC, is to assess augmentation expenditure. A prudency test is applied to other (non-augmentation) capex undertaken in the current regulatory period.

46 VENCorp Revenue Rest, an Independent Review for the AER, PB, July 2007.

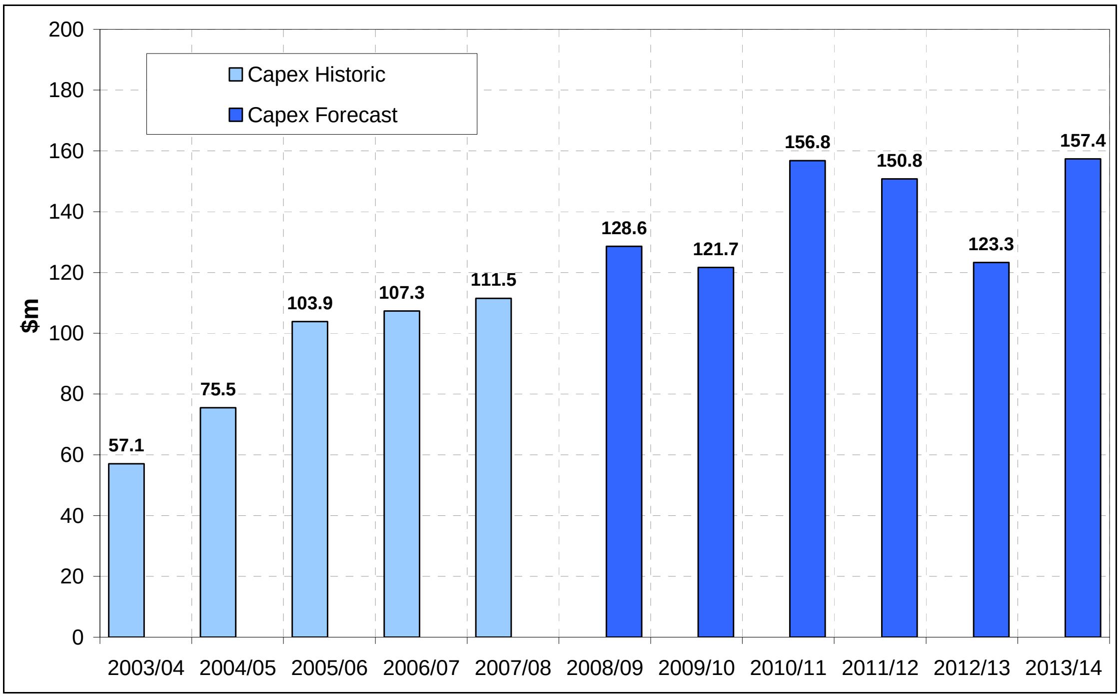
In terms of ex-ante (forecast) capex, almost half of the total forecast expenditure is associated with major substation refurbishment works; around one-fifth of the total on compliance capex[47], and the remainder on the planned replacement of other assets — such as current transformers (CT) and power transformers. A similar proportion (48%) of the SPA's proposed ex-post (historic) capex is associated with substation replacement, 14% was associated with compliance, and the remaining 38% on the replacement of assets other than entire substations.

It can be seen that the mix of capex (station replacement, compliance and other asset replacement) is similar across the ex-post and ex-ante expenditure proposals. The projects underpinning the SPA proposals are discussed further in Sections 4 and 5 (respectively) of this report.

The capex overview presented in this section includes the full 5 years ex-post expenditure plus the forecast capex associated with the ex-ante 6-year period. A review of the full 11-year period serves to highlight the longer term expenditure trends.

Figure 3-1 gives the historic and forecast total capex as proposed by SPA. The forecast (ex-ante) capex for 2008/09 to 2013/14 is approximately 53% higher than the actual expenditure of the previous 5-year period. The average annual capital spend for 2003/04 to 2007/08 was \$91m[48] compared with a forecast annual expenditure of \$140m for the next regulatory period.

Figure 3-1 – SPA actual and forecast capital expenditure (real 07/08)



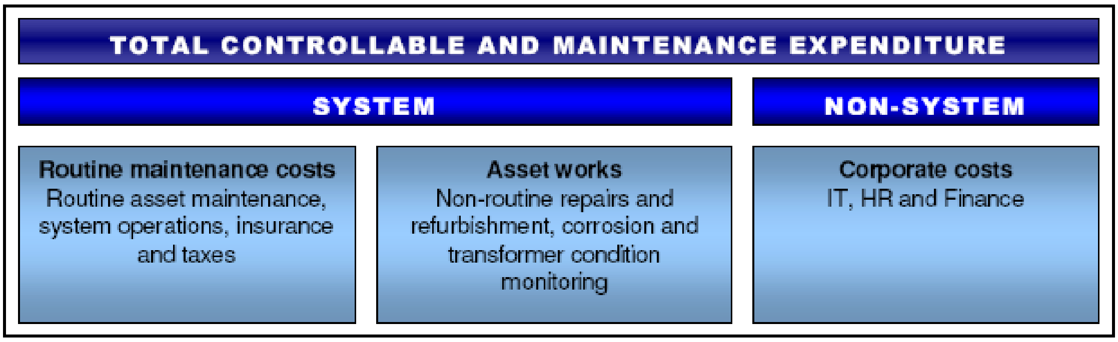
3.1.2 Opex overview

The SPA opex comprises routine maintenance and operations (system recurrent costs), corporate support (non-system recurrent costs such as finance, IT and HR) and non-recurrent costs associated with specific transmission system issues. Figure 3-2 shows the main system and non-system expenditure categories which form part of SPA's total controllable operating costs and maintenance expenditure.

47 This is the capex required to comply with safety, environmental and other mandatory business requirements.

48 Real 2007/08.

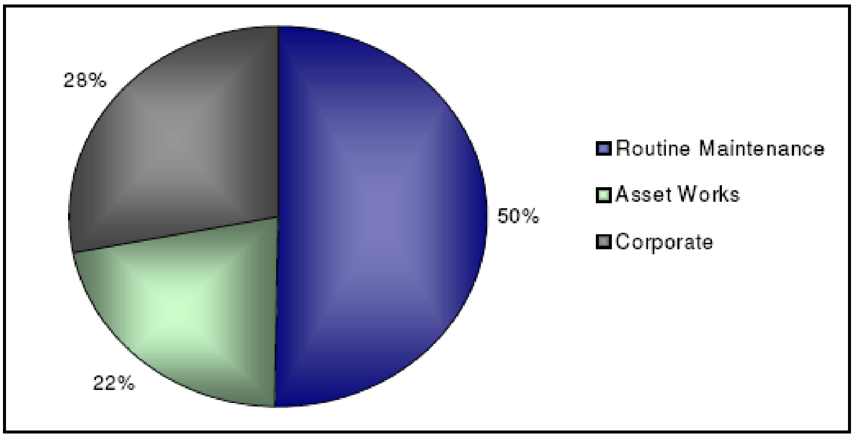
Figure 3-2 – SPA's main opex cost categories



Source: SP AusNet Transmission Revenue Proposal 2008/09 – 2013/14

Figure 3-3 is provided to illustrate the approximate contribution of each of the main cost categories to the total forecast capex. It can be seen that routine, recurrent, and maintenance costs account for half of the total (proposed) opex as proposed by SPA.

Figure 3-3 – Breakdown of the SPA proposed forecast (ex-ante) opex



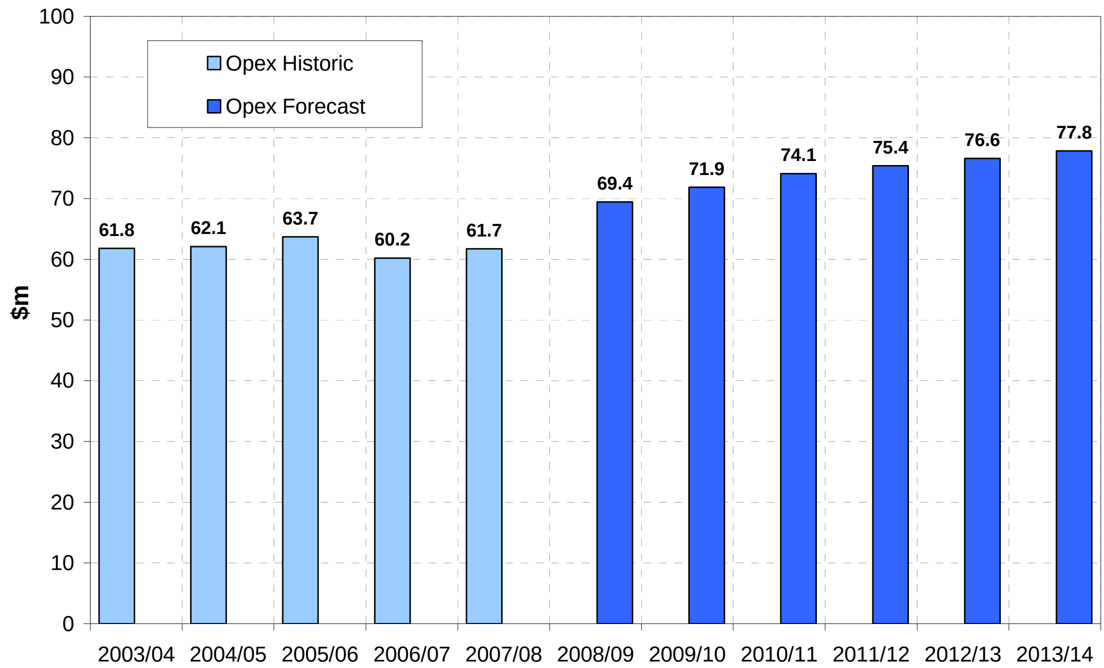
Source: SP AusNet Transmission Revenue Proposal 2008/09 – 2013/14

Figure 3-4 shows the actual (ex-post) and forecast (ex-ante) opex, as proposed by SPA. The SPA forecast opex for the period 2008/09 to 2013/14 is approximately 18% higher than the actual opex for the previous 5-year period. The average annual (actual) opex for the 5-year (ex-post) period 2003/04 to 2007/08 is $62.9m[49]. This compares to a proposed (ex-ante) annual expenditure of $74.2m for the next regulatory period.

The opex presented in these charts is for SPA only and does not include the opex associated with VENCorp. Furthermore, the high-level summary excludes the costs of self-insurance, availability rebate, glide path, debt-rising costs, equity-rising costs, and easement land tax.

49 Real 2007/08.

Figure 3-4 – SPA actual and forecast operating expenditure (real 07/08)



3.2 HIGH-LEVEL BENCHMARKING

In this section we undertake some high-level comparative analysis with other TNSPs in Australia. The separation of the network asset owner (SPA) from the investment decision-maker (VENCorp) is unique within the NEM. In other Australian states the transmission business has responsibility for planning and augmentation, as well as for the replacement, refurbishment and maintenance of ageing assets[50]. These arrangements have implications when attempting to compare, or benchmark, between Australian TNSPs.

We recognise the difficulties in attempting to accurately compare TNSP performance and also that these challenges are exacerbated by the unique arrangements in Victoria. Furthermore, we recognise that simply aggregating the individual measures for SPA and VENCorp in an attempt to make them more comparable with other TNSPs may be more appropriate in some cases than in others[51]. For this reason, we have chosen (where appropriate) to present separate data points for SPA and VENCorp – as well as a combined SPA/VENCorp measure. To provide for some additional focus on SPA's primary role, for some key benchmarks we have looked only at replacement capex in an attempt to more accurately reflect the SPA transmission business.

It is important to note that the benchmarking included in this report is not intended to represented a comprehensive study but instead aims to provide a high-level 'sanity check' on the SPA and VENCorp proposals.

Overview of benchmarking

In an attempt to place the SPA and VENCorp submission into context, we have undertaken some basic comparative analysis of the present (allowed) and proposed expenditure levels for both opex and capex. The limitations associated with this type of high-level benchmarking are fully recognised — particularly the difficulties in capturing, and reflecting, a transmission network's unique geographic, environmental and/or demographic characteristics.

50 The Victorian transmission arrangements, and the role of VENCorp, are described further in Section 1.3.1 of this report.

51 For example, the simple summation of SPA and VENCorp may overstate corporate costs.

In particular, as electricity transmission is essentially a transport activity, geographical distance has a significant influence. Other than this, network expenditure is shaped by major cost drivers such as size and design of the network (generation, demand, energy, voltage levels adopted, etc.), the level of reliability and security provided (planning criteria and network configuration), the environmental and regulatory conditions within which it operates and a businesses appetite for risk. Seven of Australia's TNSPs are included in this analysis.

An overview of scale and business conditions of the TNSP's is provided in Table 3-1.

Table 3-1 – Overview of Australian TNSPs included in comparative analysis

TNSP	RAB ($m)	Network length (km)	Number of sub-stations	Peak load (MW)	Energy transmitted (GWh)
Powerlink	3,264	12,013	98	8,295	47,734
TransGrid	3,428	12,480	82	13,292	72,383
SPA/VENCorp	2,223	6,553	44	8,730	50,267
Western Power (WP)	1,474	6,682	155	3,059	14,300
ElectraNet	1,051	5,611	76	2,938	12,856
Energy Australia	582	1,040	19	5,460	31,669
Transend	734	3,580	54	2,111	10,945

3.2.1 Sources of information

RAB values from the 2005/06 TNSP regulatory report have been used. Network length, number of substations, peak load and volume of energy transmitted for National Electricity Market TNSPs have been sourced from Transmission Network Service Providers Electricity Regulatory Report for 2005/06 (April 2007, AER).

Network length, number of substations, peak load and volume of energy-sent-out for Western Power have been sourced from 2006 Western Power transmission and distribution annual asset management report.

3.2.2 Capex benchmarking

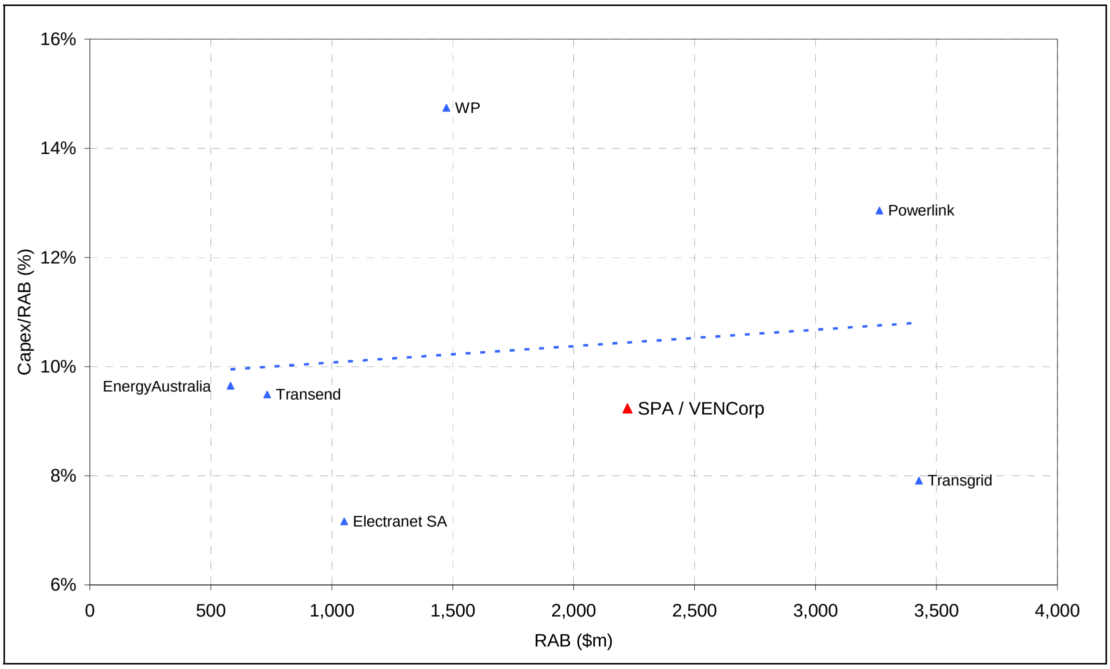
In order to account for differences in size and business conditions, PB has plotted the capital costs of TNSPs against the key cost drivers such as size (expressed by value of RAB, length of network, number of substations, MW of peak load and GWh of energy sent out) and load density (expressed by peak load per km of network and peak load per substation).

Capital expenditure shown is the average annual capital expenditure during the most recent regulatory period in each jurisdiction and is expressed in 2007/08 dollars. Values are sourced from publicly available regulatory determinations. Other than for SPA/VENCorp all expenditures are as allowed in the final determination. SPA/VENCorp benchmarking uses the aggregated capital expenditures (replacement and augmentation) as proposed by each business[52]. Indicative linear trend lines (that generally show poor correlation between data points and present no statistical basis for assessment) are shown in each chart.

52 It should be noted that the capex benchmarking compares the historical/current efficiency of the TNSPs in the sample group with the *future* efficiency of SPA (in the event that the capex and opex proposals

Figure 3-5 shows annual average capex for each business as a proportion of RAB value, plotted against RAB value. The measure for the combined SPA/VENCorp transmission business is reasonably low within this benchmark group — around 9.2% for a RAB value of $2,223m.

Figure 3-5 – Average annual capital expenditure as a proportion of RAB value



Source: PB analysis

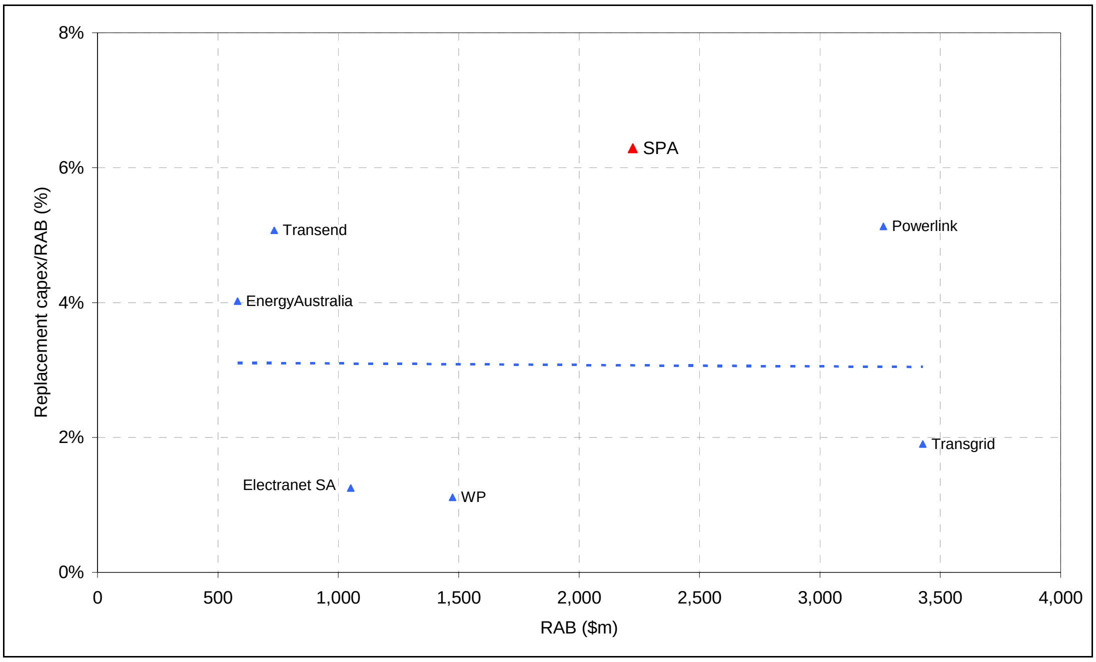
In Figure 3-6, we only plot the annual average replacement capex for each business as a proportion of RAB value, plotted against RAB value. Given that VENCorp has no replacement capex, it is excluded from this analysis. The measure for SPA is well above the other points within the benchmark group — around 6.3% for a RAB value of $2,223m. This result indicates that SPA's capex attributable to replacement is relatively high given the RAB value, and that it is likely to be smoothed when combined with VENCorp's relatively low augmentation expenditure. SPA advises some reasons for its high replacement capex are:

- the advanced age and condition of assets relative to other businesses
- the high costs associated with primarily brownfield station and asset redevelopment plans
- the relatively high costs of materials and labour over the outlook period
- increased compliance and security requirements.

All four points are likely to differentiate SPA from the other businesses, however the first two more so than the latter two since they are more common drivers across all businesses.

were to be accepted). The analysis does not, therefore, provide a comparison of SPA's historical efficiency with that of the other TNSPs.

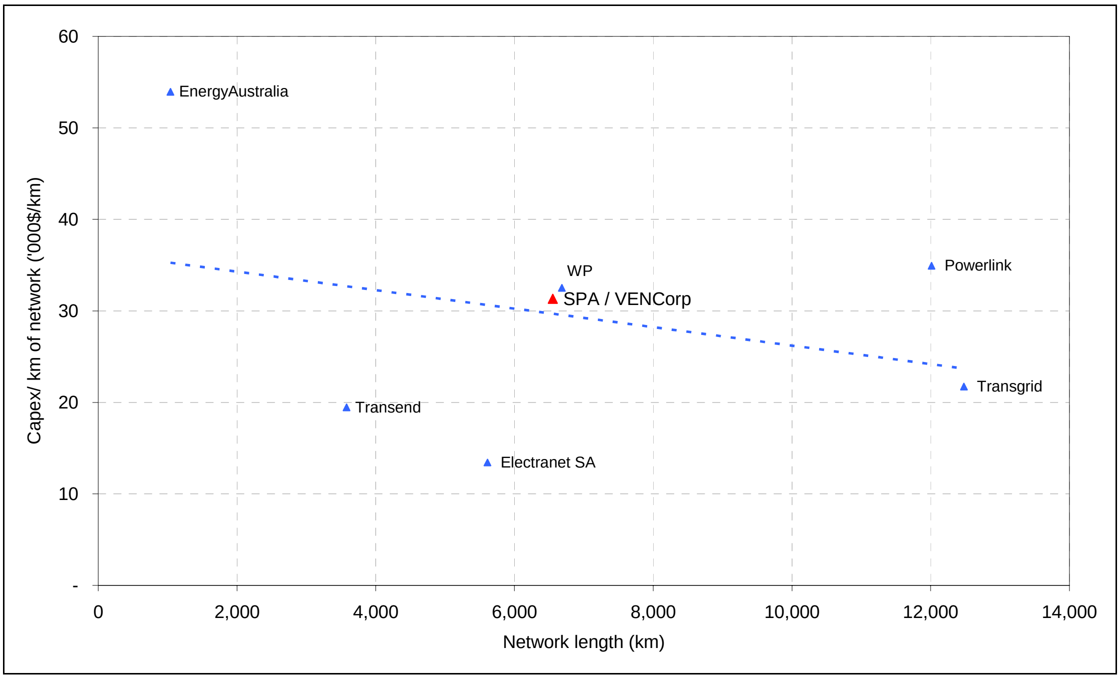
Figure 3-6 – Replacement capital expenditure as a proportion of RAB value



Source: PB analysis

Figure 3-7 shows capex per kilometre length of circuit (line) as a function of network length (km of line). The proposed capex for the combined SPA/VENCorp transmission business is seen to be close to that of the other benchmark businesses.

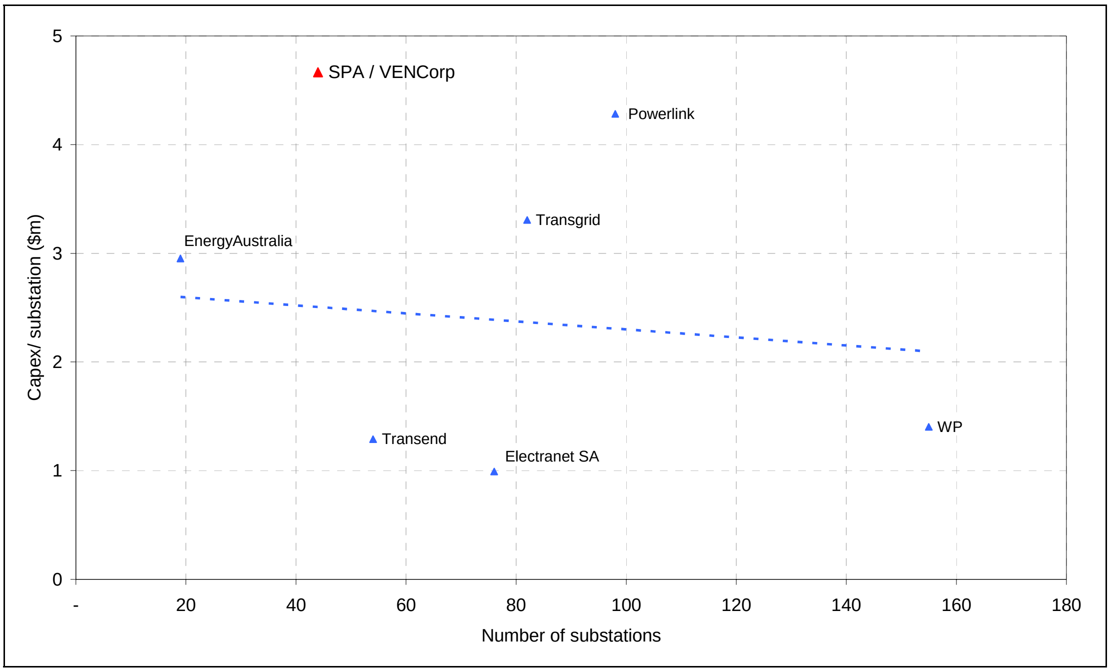
Figure 3-7 – Capital expenditure as a function of network length



Source: PB analysis

Figure 3-8 shows capex per substation as a function of number of substations. The proposed capex for the combined SPA/VENCorp transmission business is seen to be well above average, based on only 44 substations. This reflects the comparatively low number of high capital value substations which is a feature of the Victorian electricity transmission network. Jurisdictions having a lower network and load density (average peak load per substation), such as Tasmania, Western Australia and South Australia, are seen to have a lower capex per substation ratio. This result is also reflective of the significant station redevelopment programme outlined by SPA.

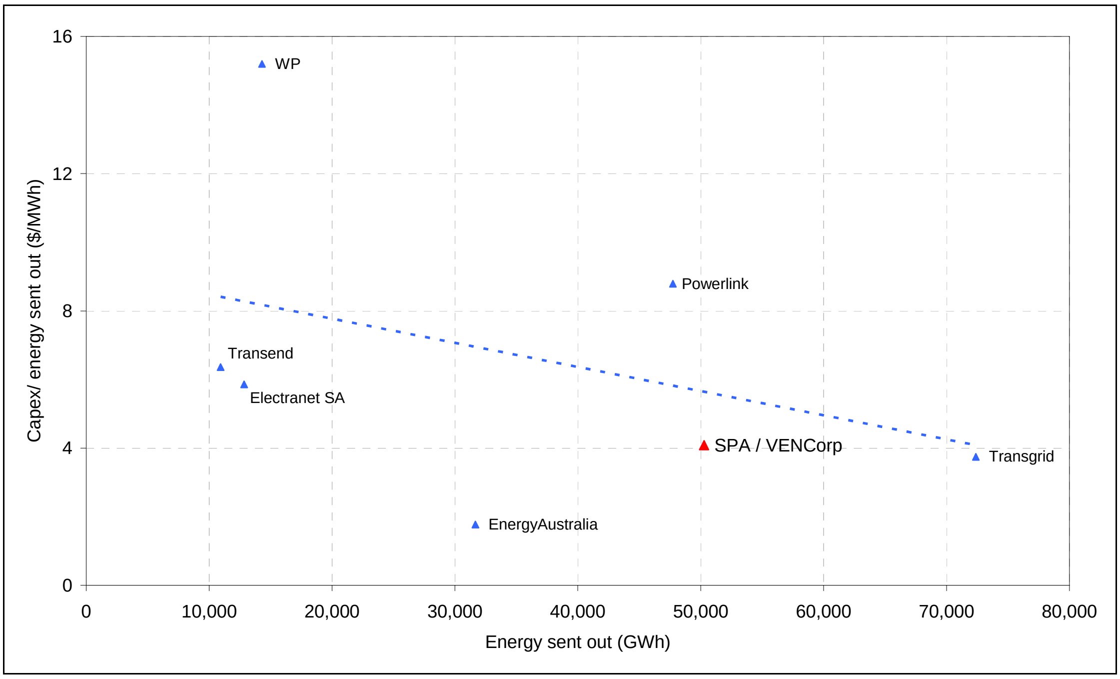
Figure 3-8 – Capital expenditure as a function of number of substations



Source: PB analysis

Figure 3-9 shows capex per GWh of transmitted energy (as a function of transmitted energy). The proposed capex for the combined SPA/VENCorp transmission business is shown to be relatively low.

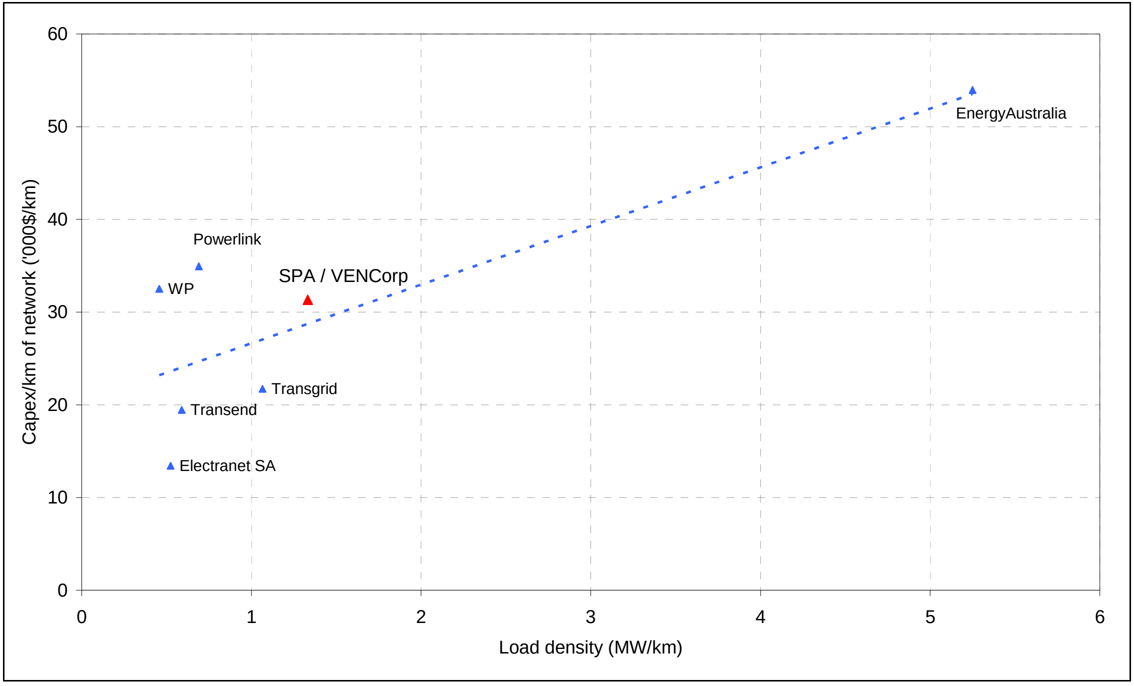
Figure 3-9 – Capital expenditure per GWh of transmitted energy



Source: PB analysis

Figure 3-10 shows capex per substation as a function of load density (expressed in MW of peak load per substation). The proposed capex for the combined SPA/VENCorp transmission business is seen similar to the other businesses. This, again, reflects the comparatively low number of high capital value substations which is a feature of the Victorian electricity transmission network. The outlying EnergyAustralia point indicates quite strongly how its centralised transmission network is not representative of the primary TNSP's in Australia.

Figure 3-10 – Capex per substation as a function of load density (MW/substation)



Source: PB analysis

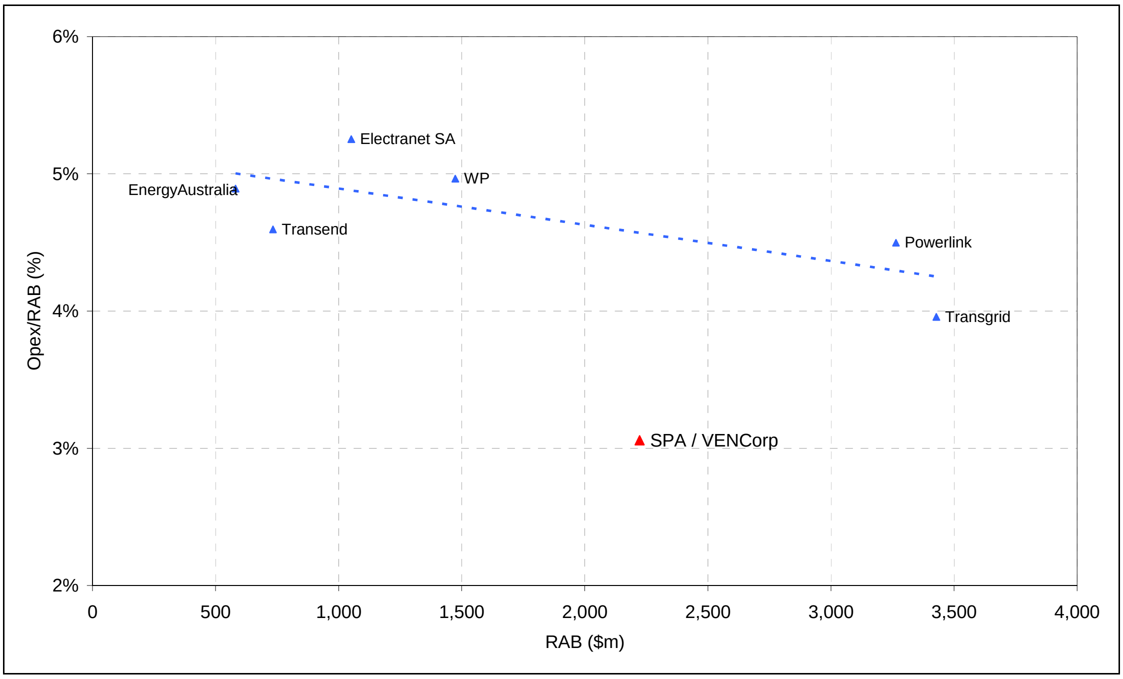
3.2.3 Opex benchmarking

In order to consider differences in both business size and business conditions, we have plotted the combined SPA/VENCorp TNSP opex against the key cost drivers such as size (expressed by RAB value, length of network, number of substations, MW of peak load and GWh of energy transmitted) and load density (expressed in peak load per km of network and peak load per substation).

The opex figures used in the benchmarking are the average annual operating expenditure during most recent regulatory period in each jurisdiction and are expressed in 2007/08 dollars. Values have been sourced from publicly available regulatory determinations. Other than for the combined SPA/VENCorp transmission business, all expenditures are as per the most recent regulatory determination. For the combined SPA/VENCorp transmission business, the proposed (ex-ante) opex for each business has been summated and used in the analysis.

Figure 3-11 shows opex as a proportion of RAB value plotted against RAB value for each of the sample transmission companies. As might be expected, the indicative trend is for opex (as a proportion of RAB value) to decrease as the asset base increases. This is likely to reflect the fixed costs of operations and maintenance, and hence the economies of scale available to the larger businesses. As shown on Figure 3-11, the proposed operating expenditures for the combined SPA/VENCorp transmission business per dollar of RAB value are the lowest in the benchmark sample group. These data points and characteristics are noted in the context that opex for contestable assets in Victoria are not represented as they lie outside the regulatory framework. Given the low value of these contestable assets though, this omission is not expected to make a material impact.

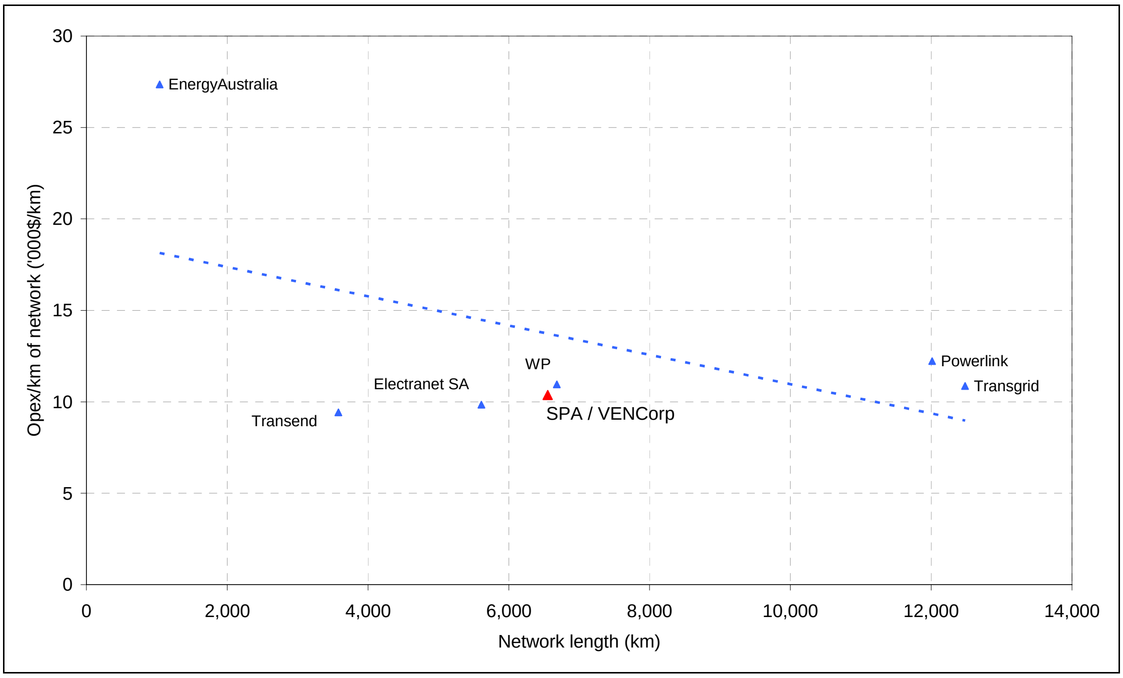
Figure 3-11 – Operating expenditure as a proportion of RAB value



Source: PB analysis

Figure 3-12 shows opex per kilometre length of circuit (line) as a function of network length (km of line). This, again, reflects the fixed costs of operations and maintenance, and hence the economies of scale available to the larger businesses. The proposed opex for the combined SPA/VENCorp transmission business is relatively low compared to the other businesses.

Figure 3-12 – Operating expenditure as a function of network length

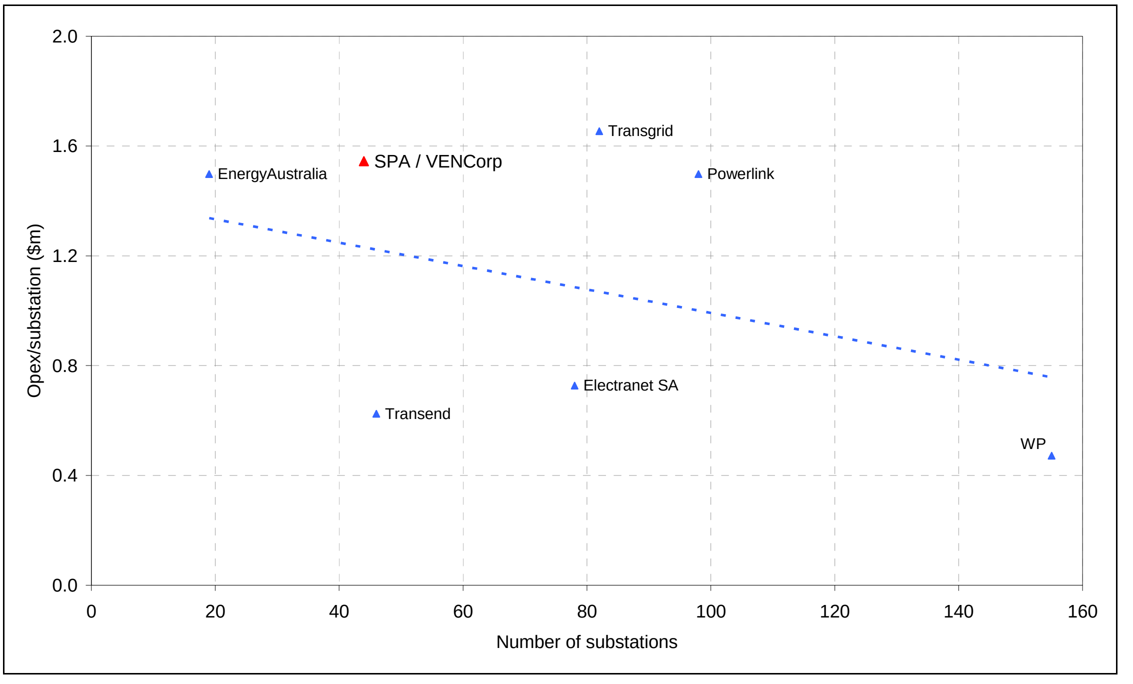


Source: PB analysis

Figure 3-13 shows opex per transmission substation as a function of number of transmission substations. The proposed opex for the combined SPA/VENCorp transmission business is seen to be above average for the sample group of companies. This again reflects the comparatively small number of large substations in the Victoria transmission system. Western

Power (WA), Transend (TAS) and ElectraNet (SA) are seen to have comparatively low operating costs per substation, which partly reflects the comparatively small service area per substation and the comparatively small substation size (and hence the lower operations and maintenance liability per substation).

Figure 3-13 – Operating expenditure as a function of number of substations



3.2.4 Conclusion

When combined, the expenditure levels proposed by both SPA and VENCorp, in the main, compare reasonably favourably with TNSPs expenditure in other jurisdictions. The exception to this are the comparisons which involve substation numbers where the relatively few (44 by number), comparatively large, substations in Victoria, lead to the 'capex per substation' measures being high.

Also, PB notes that the combined benchmarks are likely to be heavily influenced by VENCorp's relatively low augmentation capex, as evidenced on the benchmark of SPA's replacement (only) capex as a proportion of RAB. The individual replacement capex of SPA is found to be materially higher than that for other referenced TNSP's, irrespective of the value of its RAB. This is likely to be reflective of SPA's current (and forecast) replacement 'position' compared with that of other businesses historic positions.

The combined SPA/VENCorp operating expenditures benchmark well against other TNSPs, with the Victorian transmission business showing below average costs in all benchmark categories — again, with the exception of those comparisons involving substation numbers.

These conclusions are made in the context of the comments made in the introduction to Section 3.2 which recognises the limitations of this relatively simplistic comparative analysis – specifically, the complexities introduced by the unique transmission arrangements in Victoria.

3.3 HIGH-LEVEL REPLACEMENT CAPEX ESTIMATES

PB has adopted a multi-pronged approach to assessing the prudency and efficiency of SPA's capex expenditure. An element of this approach involves consideration of the total capex expenditure in light of the age profile of SPA's asset base. To achieve this, PB has modelled the scenario where SPA replaces all assets older than the average economic life of the asset base as a whole. That is, we answer the question of what the capex requirement would be if all assets of an age greater than the average economic life of the asset base at the end of the next regulatory period were replaced over the next regulatory period. This is of course a broad brush, high-level estimate, and it is not intended to be a substitute for detailed assessment. However it is PB's view that this estimate does provide an indication of the reasonable range replacement capex, and as part of other measures and assessments does serve to inform the overall capex review process.

Table 3-2 is an extract from SPA's Post-tax Revenue Model spreadsheet. This data shows that SPA has assumed an economic life of 60 years for transmission lines, 40 years for reactive power equipment, 45 years for other primary assets, and 15 years for secondary systems. Based on the proportion of each asset type in the asset base, we estimate the average economic life of the asset base as a whole, when weighted by un-depreciated replacement cost, to be approximately 51 years[53]. This is based on the un-depreciated replacement cost of SPA's network fixed assets (excluding land and easements) being estimated at approximately $3.7bn. While this estimate of the average economic life of the asset base may seem high, it needs to be noted that approximately 58% of the asset base comprises transmission lines with a 60-year life. Hence the overall life is skewed to the high side.

Table 3-2 – Opening regulated asset base for 2008–09 ($m nominal)

Category title	Opening asset value ($m)	Assets under construction (number)	Remaining life (years)	Economic life (Standard life) years
Secondary	187	8.2	10.5	15
Switchgear	355	9.0	28.0	45
Transformers	160	1.7	19.3	45
Reactive	92	0.0	23.0	40
Towers and conductor	1,022	0.6	29.4	60
Establishment	86	1.6	33.0	45
Communications	27	0.9	1.0	15

Source: SP AusNet Post Tax Revenue Model Lodged 280207 (spreadsheet). SPA, 2007.

Figure 3-14 shows the age profile of SPA's network assets. Based on the approach outlined above, and the estimated 51-year average economic life, PB has assumed a prudent asset replacement approach would be to ensure that sufficient funds are allocated to permit the replacement of all assets installed prior to 1964 by the end of the next regulatory period (51 years prior to the end of the next regulatory period). Analysis of the age profile shown in Figure 3-14 indicates that approximately 14% of the current asset base would need to be replaced under this model. Hence under this model a conservative estimate of the total replacement cost would be $518m (14% of $3.7b) over the next regulatory period. However, this estimate is likely to be low due to the following factors[54]:

- this figure is based on historic costs
- replacement required the dismantling of existing infrastructure, and working around existing live assets

53 This estimate of average economic life has been determined using replacement cost as the basis for the calculation, and uses only those asset categories that are relevant to the network.

54 It is acknowledged that incremental changes in standards such as compliance to the NER, security, OH&S, and environmental standards will also have a bearing on these estimates. It is PB's view that these incremental costs are not practically estimated, and are not material to this analysis.

- it is often not efficient to replace an existing asset with a modern equivalent asset of the same rating due to demand growth and network changes (e.g. higher fault levels, changes in design standards or requirements).

To account for this, PB has applied an asset replacement premium (brownfield factor[55]) and an augmentation premium. While PB has not undertaken an in-depth analysis of the values of these premiums appropriate to SPA, based on PB's industry knowledge and experience, suitable values would be:

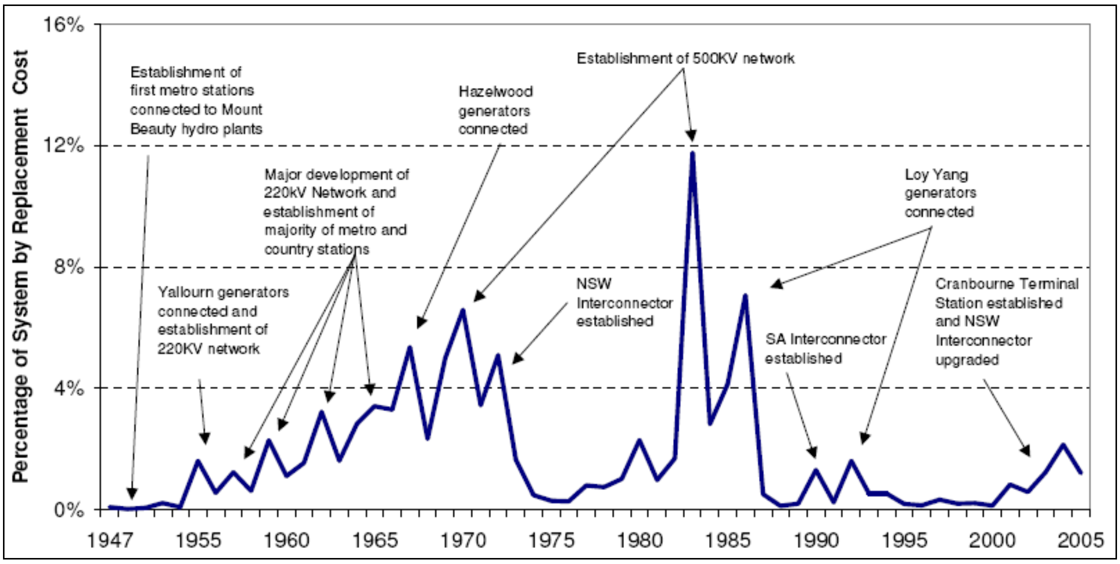
- asset replacement premium (brownfield factor): 40% high estimate, 30% expected estimate, and 20% low estimate.
- augmentation premium: 20% high estimate, 15% expected estimate, and 5% low estimate (all approximates).

Based on these premium estimates (assuming both were applied) then a reasonable replacement capex range would be approximately:

- $830m high-end estimate
- $750m expected estimate
- $650m low-end estimate.

It must be stressed that these are high-level estimates of SPA's network fixed asset replacement costs over the next regulatory period based on the replacement model outlined above. As such these estimates need to be understood in this context when being used to inform the overall capex review.

Figure 3-14 – SPA network assets age profile



Source: Page 20, SPA Electricity Transmission Revenue Proposal 2008/09 – 2013/14, SPA March 2007.

Conclusions

This high-level approach is based on the scenario where SPA replaces all assets older than the average economic life of the asset base as a whole. Based on this approach, PB would expect that the ex-anti capex proposal would be in the range of $650m to $830m, and probably about $750m. Against this expectation, SPA has proposed a total network ex-anti capex of $795.3m. While SPA's proposed figure is within the expected range, it falls slightly

55 Note that SPA has (in the past) used a similar approach, and refer to this as a brownfield factor. SPA has used values from around 20% to about 38%.

above the middle of the upper end of these estimates. If SPA's asset management approach was purely based on asset age, this result could reasonably be expected. However, SPA maintains that their asset management is based on equipment condition, and not age. On this basis it would be expected to observe that the proposed ex-anti capex would fall on the lower side of the expected range[56]. That is, condition-based replacement should give savings over aged-based replacement. Based on this analysis, this would not seem to be the case. Consequently, PB is of the view that the proposed ex-anti capex expenditure of $795.3m is higher than would otherwise be anticipated given SPA's stated approach to asset management, and their relatively sophisticated approach to asset risk modelling.

3.4 UNIT COST BENCHMARKING

In planning a project, the cost of the project needs to be established. The preferred source of costs would be a fixed quote from the work group or contractor completing the work, but this is a time-consuming process and the information required to construct a detailed quote may not be available at the early stages of a project.

A common process for establishing the cost of a project is to build up an estimate from individual elements and to reach a total cost for the project, commonly known as a building block approach. A reasonable source of these building block costs would be historic projects of a similar nature.

Depending on the stage of the project, the accuracy of the estimate of project costs will vary. At the inception of a project, it is common for the estimation of project costs to have a variance of up to ±25%. As the project progresses and the detail are refined, the accuracy of cost estimation will improve, typically to ±5%. Finally work assignment packages or contracts will be released and a price agreed.

PB has examined individual costs that SPA has used in their planning process, and compared these to the costs from completed projects. PB has also examined these costs against publicly available information and PB's own internal database of costs.

3.4.1 Selecting items to be benchmarked

SPA has supplied details and costs on a broad range of projects. PB has selected 70 different elements from these projects for benchmarking. These elements were selected against three main criteria.

The first criterion reflects the current replacement strategy for current transformers (CTs). Some types of CTs have failed in the same manner and SPA intends to replace 73 CTs[57] at a total cost of $23.4m. Owing to the large number of CTs that SPA intends to replace, the cost of each unit is significant.

The second selection criterion relates to the substation rebuilds and therein the large number of transformer replacements. Transformers are expensive items of equipment and require approximately 12 to 18 month notice to the manufacturer prior to delivery on site. As a single item, transformers are one of the most expensive items to procure.

The final selection criterion was based on items where PB had access to multiple benchmarks either publicly and in its own database. This selection enabled PB to develop a general perception of the unit costs used by SPA.

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56 PB acknowledges that actual asset condition can deteriorate faster than an age-based assessment would otherwise indicate. While there is some evidence of this in SPA's asset base (e.g. type failures in CTs only 20 years old), PB does not believe that this is a significant factor for SPA, and hence a condition-based replacement methodology is expected to produce advantages over an age-based replacement regime.

57 For clarity, PB recognises that the figure of 73 CTs relates to 73 sets of 1 phase CTs at differing voltages.

3.4.2 Availability of suitable benchmarks

When benchmarking equipment costs, it is important to recognise that the market for transmission equipment has few suppliers and also few customers. Additionally, the cost of purchasing single units can be high when compared to purchasing multiple units of equipment. This means that the availability of benchmarks in the public domain to which SPA's costs can be compared is limited. There are often similar items, but at differing voltages or capacities.

In establishing benchmark costs, PB has taken into account and adjusted for:

- inflation and monetary exchange rates
- voltage
- capacity
- design differences.

In addition to information provided as part of recent and current regulatory determinations, PB utilised two publicly available sources of information and has also included PB's own database of unit costs. The publicly available sources are:

- NZ Commerce Commission, 2004, Handbook for Optimised Deprival Valuation of System Fixed Assets of Electricity Lines Businesses
- CitiPower — Melbourne CBD Enhancement: Regulatory Test Analysis written by NERA dated 5 April 2007.

3.4.3 Accuracy of the price benchmarks

SPA provided its estimated costs for the major items of transmission equipment required to complete its forecast works program. As these costs were forecast for a range of projects at various stages of implementation, they contained some uncertainty when compared to actual costs incurred in the past. PB considers that when comparing SPA's forecast costs with the publicly available information and the information from its own database of costs, there will be some element of error. PB is of the view that costs within 20% of the benchmark should be considered to be reasonable.

Another element in differences between benchmarks and forecast costs can relate to the location of the project. For instance, the costs associated with building a new substation on vacant land (known as a greenfield build), can be significantly cheaper than retrofitting an existing substation (a brownfield build). The additional cost is usually associated with the need to plan around maintaining existing assets in service and managing the associated electrical hazard during the building process. A detailed estimation of this additional cost was conducted for SPA by SKM.[58] Taking the average of the identified factors increases costs by 8%. Therefore, where PB identified that works required the in situ replacement of equipment, it applied a factor of 8% to the benchmarked costs.

SPA also provided the incurred cost of equipment purchased for recent projects. While PB used this information to assist in its understanding of the changes in costs, it did not include SPA's historic costs in the cost benchmarks.

58 SP AusNet Revenue Proposal; Appendix C; SKM report, escalation factors affecting capital expenditure forecasts.

3.4.4 Current transformer benchmark

PB selected two CT types for benchmarking. The first selection was made from CTs associated with the CT replacement program. Table 3-3 shows that a majority of the CTs are related to the 220 kV network. As the benchmarks available to PB included both 220 kV and 275 kV CTs, PB averaged the costs proposed by SPA for these types of CT.

Table 3-3 – Current transformer replacement program; number and cost of replacement ($m real 2007/08)

Description	Number to be replaced	Total replacement cost ($)	Average price per unit ($)
500 kV CT	30	5,652,000	188,000
330 kV CT	33	3,209,000	97,000
275 kV CT	12	1,167,000	97,000
220 kV CT	144	13,317,000	92,000

Source: SP AusNet, CT replacement program

The second selection was for a 66 kV, 4000A CT as used by SPA in its capex projects.

The results of the comparisons are shown in Table 3-4.

Table 3-4 – Benchmark costs for current transformer ($m real 2007/08)

Description	SPA ($/average)	PB benchmark ($/average)	Variance (%)
220 kV CT, single phase, 4000A	93,750	95,400	-1.77
66 kV, live tank, 4000A	56,000	67,000	-19.6

Source: SP AusNet; PB benchmark database

The table shows that the costs established by SPA for 220 kV CTs matches closely to the benchmark. For the 66 kV CT, the cost is about 20% below the benchmark. PB considers this reasonable.

3.4.5 Transformers

Over the next regulatory period, SPA has identified the need to replace two 3-phase power transformers[59] and 57 single-phase power transformers[59] with modern equivalent units at a total cost of $138m[60] ($ real 2007/08 — 'as commissioned' cost).

PB has benchmarked the transformers as shown in Table 3-5.

59 SP AusNet Revenue Proposal, appendix E, Asset Management Strategy

60 SP AusNet templates – cost information lodged 280207.xls, forecast capex by asset class - AC

Table 3-5 – Benchmark cost for transformers ($m real 2007/08)

Description	SPA ($/average)	PB benchmark ($/average)	Variance (%)
40 MVA 66/22 kV	900,000	1,066,000	-18.4
55 MVA 220/66 kV	1,400,000	1,633,000	-16.6
55 MVA 220/22 kV	1,586,000	1,751,530	-10.4
200 MVA 220/66 kV	4,224,000	3,841,000	9.0
150 MVA 220/11 kV	3,800,000	3,894,000	2.5
150 MVA 220/66 kV (inc installation)	4,224,000	3,841,000	9.0
750 MVA 330/220 kV	12,650,000	10,244,000	19.1

Source: SP AusNet; PB benchmark database

The market price of non-ferrous metals has, in general, increased significantly over the last three years. Specifically the price of copper, a constituent component of power transformers, increased in price significantly and has maintained the high price for about 2 years. This is represented in Figure 3-15.

PB expects that the current high price for copper will ease over the 2007/08-13/14 period. However, the higher prices could be expected to lead to transformer costs higher than the benchmarks, particularly for the higher capacity transformers which contain more copper than the lower capacity transformers. PB notes that the costs for the 750 MVA transformer category (as supplied by SPA) are based on current procurement prices[61].

The benchmarks show that SPA's forecast costs of transformers are within ±20% of the benchmarks, which is reasonable.

Figure 3-15 – Copper index from the London Metal Exchange from 2000 to 2007[62]

Source: London Metal Exchange

61 SP AusNet; preliminary project costs, RTS redevelopment study.

62 Prices shown relate to grade A copper on the 15-month futures cash buyer contract.

3.4.6 Other items

To evaluate SPA's general approach to the procurement of equipment, PB selected a range of transmission equipment for which it had multiple benchmarks available. The results of the comparisons are shown in Table 3-6.

Table 3-6 – Benchmark costs of transmission equipment ($m real 2007/08)

Description	SPA ($/average)	PB benchmark ($/average)	Variance (%)
Transmission equipment			
220 kV 3 x 1-phase CVT	58,800	66,900	-13.8
220 kV CB; dead tank, 3150A, 50kA	1,290,000	1,275,000	1.2
220 kV disconnector, 3150A with 1 x earth switch	61,800	56,200	-9.1
Reactive support			
22 kV, 10 MVAr capacitor bank	150,000	171,900	-14.6
Substation construction element			
New control room giving 200 mm^2 of floor space	975,000	300,000	69.2
Switchyard element			
220 kV switch bay with 1 & ½ CB arrangement	4,200,000	2,896,000	31.4

Source: SP AusNet; PB benchmark database; NZ ODV 2004

The table identifies two items where the costs differ greater than ±20% from the benchmark. These are:

- new control room +69.2%
- 220 kV switch-bay with 1 & ½ CB arrangement +31.4%

The first item is the cost of providing new control rooms at existing sites. PB examined the cost associated with building a control room which are approximately 70% higher than expected. The information provided by SPA included a specification for a control room.[63] We compared the specification against PB's database and we found that the designs were similar. Therefore, PB concludes that the costs proposed by SPA are higher than could be reasonably expected for this item. PB notes, however, that the control-room building cost is small and will not materially alter the aggregate forecast capex requirement.

The second item was the 220 kV switch bay installation, with a one-and-a-half circuit-breaker arrangement. PB has examined the project information supplied[64] and compared the specification of the proposed circuit breakers against the circuit-breaker types in the publicly available information and the PB database. PB has found that the SPA proposed circuit breakers use a different technology to those included in the benchmark and therefore that the benchmark was not an equivalent for this item. The items that SPA are proposing to install are of a type known as gas-insulated switchgear (GIS) and the three circuit breakers included in the benchmark are not of this type. Table 3-7 shows the PB benchmark adjusted for this technology difference.

63 SP AusNet project engineering 12/05; appendix A – Control Room Design Requirements

64 SP AusNet; RTS rebuild Project planning estimate; appendix 1 – cost estimate

Table 3-7 – 220 kV GIS switch-bay benchmarking

Description	SPA ($/average)	PB benchmark ($/average)	Variance (%)
220 kV switch bay with 1 & ½ CB (GIS)	4,200,000	3,678,000	12.4

Source: SP AusNet; PB benchmark database; NZ ODV 2004

Given that the proposed costs are 12.5% of the adjusted benchmark, PB is of the opinion that the SPA unit cost is reasonable.

3.4.7 Conclusion

PB analysis of the equipments costs provided by SPA included benchmarking of items covering 78% of the forecast capital expenditure. PB found that the following items were lower or about the same as the benchmarks established by PB:

- capacitor VTs (CVTs)
- disconnectors
- small power transformers
- capacitor banks
- circuit breakers
- switch bays
- current transformers
- medium-sized power transformers.

PB found that the unit costs for large power transformers were at the high end of the expected range, but not unreasonable when compared to the benchmark.

Finally PB found that control-room building costs where higher than the benchmark by more than 20%. Although this item is higher than the benchmark, PB notes that the control-room building cost is relatively small. As such, adjustments to these items will not materially alter the aggregate forecast capex requirement.

4. REVIEW OF HISTORIC AND 'WORK IN PROGRESS' CAPEX PROJECTS

This section addresses the detailed review of a suite of nine historic and work-in-progress network projects that have been selected in consultation the AER (see Section 4.1 for details). These detailed reviews consider the prudency of the expenditure having regard to Appendix B of the Statement of Regulatory Principles (SRP).

In particular, to ensure that the investment process was consistent with good industry practice, these reviews involve a systematic examination of the critical decisions made when selecting and delivering investments. Specifically:

- was a justifiable need for the investment demonstrated
- was the proposed alternative the most efficient investment to meet the demonstrated need (assuming the investment need is recognised)
- was the proposed alternative developed, and if not, whether any differences reflect decisions that are consistent with good industry practice.

An analysis of these matters is presented for each detailed project review, along with consideration of the project's strategic alignment, timing and cost. Summary reviews are first presented in the main body of this report, while the details of each review are addressed in appendixes. Each of the summary reviews consists of:

- summary/overview — a brief outline of the project and its development
- costs — presents a summary of the project costs as submitted by SP AusNet (SPA) along with PB cost recommendations
- conclusion summary — a brief summary of the main views formed by PB.

The review details contained in the referenced appendices consists of the following sections:

- summary/overview — a brief outline of the project and its development (repeated in the appendix for completeness only)
- drivers (need or justification) — a summary of the documented needs as presented in the supplied project documentation
- strategic alignment and policy support — a brief consideration of any documented alignment of the project with SPA's asset management strategy, overarching policies, or plans
- alternatives — a summary of the options considered to meet the identified need as presented in the project documentation supplied
- timing — presents an overview of the project's timing
- PB analysis — presents a brief discussion of the views formed by PB in assessing the supplied project documentation. The focus in particular is on the capex prudency assessment
- costs — presents a summary of the project costs as submitted by SPA along with PB cost recommendations (repeated in the appendix for completeness only)
- conclusion — a brief summary of the main views formed by PB (repeated in the appendix for completeness only).

The following section presents an overview of the projects selected for review. Following this the detailed project review summaries are presented.

4.1 SELECTION OF PROJECTS FOR DETAILED REVIEWS

In conjunction with the AER, PB selected nine network capex projects in the ex-post period for detailed review. Table 4-1 presents the list of selected projects, and gives a brief outline of the reason for selection.

Table 4-1 – Selected historic and work-in-progress network capex projects

Project group	Project description	Reason for selection
STN5	MTS Redevelopment	Largest overall project (materiality). Involves a 'brown field' terminal station rebuild which is the focus of the largest portion of the forecast capex, and has a WIP component. Completion is anticipated in early 08/09.
STN4	BTS Redevelopment Project	Second largest project (materiality). Completed in late 06/07.
OPGW1	Installation of OPGW in the Metro Area	Large project with no WIP component. Completed in 05/06.
STN12	Refurbishment of RCTS	Large project with largest negative project cost variance (variance materiality). Completion is anticipated in October 2007.
EQP1	Tower Signage	Safety-related project with no WIP component. Completed in 04/05.
TCT3	220 & 66 kV CT Replacements, Stage 2	Scheduled to commence in 2007/08 with anticipated completion late in the year. A further stage of this program is scheduled for 2008–2014.
REACT1	Replacement of 66 kV Shunt Reactors at HOTS, KGTS & RCTS	Third largest non-WIP project related to reactive power. Completed in September 2004.
Tinsulator	Replacement of 16 mm Pin Insulators, Stage 2	Insulator replacement project, which is also a significant forecast capex project. Anticipated completion is in 07/08.
STN16	Refurbishment of BETS	Small overall project with a WIP component. Anticipated completion is in 06/07.

Source: PB analysis

4.2 MALVERN TERMINAL STATION (MTS) REDEVELOPMENT

The Malvern Terminal Station (MTS) redevelopment is part of the terminal station group of projects, and is referred to as STN5. While the 2002 cost proposal for MTS was $27.1m, SPA has proposed that the forecast 'as commissioned' cost is expected to be $38.58m (nominal) across the current regulatory period as shown in Table 4-2.

Table 4-2 – Capex for redevelopment of Malvern Terminal Station (inc. FDC)

Expenditure $m (nominal)	2003 stub period	03/04	04/05	05/06	06/07	07/08	March 08 WIP	Total[65]
SPA proposal	—	—	0.05	—	10.79	23.32	4.42	38.58

Source: SPA Proposal, Information Templates

This project ranks as the largest overall (ex-post) expenditure item and accounts for 9.3% of the SPA network-related capex in the current period. SPA anticipates completion of the project in early 08/09.

The following information is an extract of the full detailed project review that is presented in Appendix B.

4.2.1 Project overview

MTS is an urban 220 kV terminal station supplying the area bounded by Surry Hills in the north, Ormond in the south, Elwood in the west, and Oakleigh in the east. The station was established in the early 1950s by the former State Electricity Commission of Victoria (SECV) to supply the then rapidly growing south eastern suburbs of Melbourne. MTS provides both 66 kV and 22 kV supplies to the Alinta electricity distribution network, which in turn supplies approximately 69,000 customers in the area. The peak demands in 2002 were 147 MVA in winter and 170 MVA in summer (estimated)[66].

The station is supplied radially via a double-circuit 220 kV line from Rowville Terminal Station (ROTS). The original configuration involved 220 kV and 66 kV switchyards as well as a 22 kV indoor switchboard. These switchyards were fitted with three banks of 220/66 kV and three banks of 220/22 kV transformers. All original transformers are 55 MVA single-phase units. Other major MTS assets include a range of bulk oil switchgear, voltage transformers, associated cabling, protection and control equipment, and a number of buildings housing various items of in-service and redundant equipment. Most assets are understood to be original equipment installed at the time the station was being developed during the 1950s.

During 2002, SPA engaged Sinclair Knight Mertz (SKM) to evaluate the various asset management options for MTS. This investigation considered the condition, performance, and risks of the MTS assets, and identified a range of management options. The SKM report concluded (in part) that:

> *The general age and state of the MTS assets now dictates that specific action be taken by SP PowerNet to ensure the future reliability of the facility[67].*

65 The total column is shown only for consistency with the information submitted in SPA's Proposal Information Templates. PB recognises that this simple sum of the individual annual expenditure amounts may not be appropriate given that all historical cost information is expressed in nominal dollars.

66 Assets Management Study Malvern Terminal Station; SKM, October 2002, Page 11.

67 Ibid Page 5.

In drawing this conclusion, SKM also noted that:

> *Much of the major primary plant… is some 40 years of age. Some items of equipment are older, and some has suffered degradation in performance.*

The SKM report considered a number of options (see Section 2.3.4), and recommended that:

> *A planned brownfield asset replacement project which encompasses 220, 66, and 22 kV switchyards is the recommended course of action for MTS.*

At the time of their report, SKM estimated the capital cost of this option at $27.97m

SPA accepted the SKM recommendations, and undertook consultation with VENCorp, Alinta and Citipower, regarding their future requirements for the station[68]. Following this consultation process, SPA engaged Beca Carter Hollings & Ferner ('Beca')[69] to consider the practicality of a brownfield redevelopment at MTS, and to consider the feasibility of station layout options to ensure that long-term augmentation requirements would not be compromised by a 'like-for-like' station redevelopment. Beca investigated a number of station layout options and costs, and recommended a reconfiguration that supported the use of air-insulated switchgear (AIS)[70] for the majority of the redevelopment. The recommended option supported staged site development, and provides for the proposed future (timing unknown) diversion of Rowville to Richmond circuits into MTS[71]. Beca also recommended that a three transformer arrangement be adopted, as this was determined to be the lowest overall cost option.

In 2005 SPA concluded, (based on the SKM and Beca reports) that it was possible to reconfigure the station, enhance network security through improved 220 kV switching, and provide for future site augmentation for an equivalent cost to a 'like-for-like' replacement. Hence SPA considered the MTS redevelopment to be a modern equivalent replacement[72].

In May 2005, the SPA Board approved the MTS rebuild project, incorporating the redevelopment of the 220 kV, 66 kV, and 22 kV switchyards, replacement of secondary equipment, replacement of the 220/66 kV and 220/22 kV transformers, and the establishment of a new control building and 22 kV switchroom.

4.2.2 Costs

While the 2002 cost proposal for MTS was some $27.1m, SPA has proposed that the forecast 'as commissioned' cost is expected to be $38.57m. Subsequent changes to the scope of the MTS project — resulting from specific site constraints, compliance issues, and consultation outcomes — account for this cost variation. It is PB's view that such scope changes are not unexpected, particularly in a brownfield redevelopment where the original cost estimates were

68 In VENCorp's Electricity Revenue Cap Proposal (page 30; VENCorp Electricity Revenue Cap Proposal, 1 July 2008 to 30 June 2014) the proposed 220 kV Malvern to Heatherton connection is anticipated in 2011/12.

69 Feasibility study Malvern Terminal Station Rebuild Project; Beca Carter Hollings & Ferner, July 2004.

70 Options considered both air insulated and gas insulated switchgear. In general, air-insulated switchgear has a lower overall capital and life-cycle cost, but requires considerably more space.

71 Rearrangement of the site as part of these works was based on a least-cost analysis performed by Beca, and assumed that the customer-driven augmentations identified with VENCorp, Alinta and Citipower would occur over a 3- to 15-year planning horizon. Note that the more extensive augmentations were envisaged by Beca to be in 2008.

72 The final site layout provides for two extra 220 kV switchbays, and reduces the number of transformers to two 220/66 kV, and two 220/22 kV transformers of increased capacity. This arrangement provides for the future expansion of the station.

based on early design investigations[73]. PB is of the view that these scope differences are consistent with prudent asset management and good industry practice.

In the light of favourable cost benchmarking analysis[74], and given the complex nature of the MTS redevelopment project, the project scope, the voltages and types of equipment involved, as well as the associated site, compliance, and consultation issues, it is PB's view that the SPA submitted total site redevelopment cost is reasonable. Moreover, PB's is also of the view that the additional costs associated with the scope changes are reasonable.

Moreover, given the anticipated completion in 'early 2008/09', it is PB's view that the proposed timing of the project cash flow, as presented by SPA is reasonable for a project of this nature.

Table 4-3 sets out PB's recommendation on the prudency and efficiency of the submitted expenditure associated with the redevelopment of the Malvern Terminal Station.

Table 4-3 – PB recommendation for Malvern Terminal Station (inc. FDC)

Expenditure $m (nominal)	2003 stub period	03/04	04/05	05/06	06/07	07/08	March 08 WIP	Total
Submitted	—	—	0.05	—	10.79	23.32	4.42	38.57
Proposed variation	—	—	—	—	—	—	—	—
PB recommendation	—	—	0.05	—	10.79	23.32	4.42	38.57

Source: SPA Electricity Transmission Revenue Proposal 2008/09 – 2013/14, and PB analysis.

4.2.3 Conclusion summary

The MTS redevelopment project is SPA's largest single ex-post capex project. PB has reviewed the project information provided by SPA and has formed the following views.

- a justifiable *need* was identified, based on the equipment condition and that the general capability of the MTS facility was reaching the end of its useful life
- the project documentation demonstrates the strategic alignment of the MTS project with SPA's asset management strategy, overarching policies and plans
- that the range of alternatives identified were reasonably comprehensive and represented practical solutions to address the identified need
- that analysis of the alternatives, and the selection of the preferred alternative (AIS brownfield redevelopment), was reasonable and prudent, with the preferred alternative being shown to be the least-cost alternative that met the identified need while addressing stakeholder augmentation requirements
- that the options analysis appears to have been based on thorough and sound engineering assessment of the equipment within MTS
- that it was reasonable to assume that the optimal project timing was within the current regulatory period
- that the original implementation timing of late 2006 was reasonable given the condition of the equipment as recognised in the independent SKM report

73 SPI PowerNet Board Paper; SPI PowerNet – Redevelopment of Malvern Terminal Station - For Approval; SPA, 13 May 05.

74 Reference to benchmarking section.

- that while the scope of the project 'as implemented' was significantly different to that originally envisaged, the differences represent decisions that are consistent with prudent asset management and good industry practice
- that the proposed timing of the project capex as presented by SPA is reasonable for a project of this type
- that the forecast 'as commissioned' cost of $38.57m is reasonable in light of the scope changes which are not unexpected given the complex nature of the project[75].

4.3 BRUNSWICK TERMINAL STATION (BTS) REDEVELOPMENT

Brunswick Terminal Station (BTS) redevelopment is part of the terminal station group of projects, and is referred to as STN4. While the 2002 cost proposal for MTS was some $18.1m, SPA has proposed that the forecast 'as commissioned' cost is expected to be $22.08m (nominal) across the current regulatory period as shown in Table 4-4.

Table 4-4 – Capex for redevelopment of Brunswick Terminal Station (inc. FDC)

Expenditure $m (nominal)	2003 stub period	03/04	04/05	05/06	06/07	07/08	March 08 WIP	Total
SPA proposal	—	0.00	0.00	11.24	10.48	0.36	0.00	22.08

Source: SPA Proposal, Information Templates

This project ranks as the second largest overall (ex-post) expenditure item and accounts for 5.3% of the SPA network-related capex in the current period. While the original project timing involved completion in 04/05, the project was actually completed in late 06/07, due to delays associated with the 2006 Commonwealth Games and the need for additional (unanticipated work).

The following information is an extract of the full detailed project review that is presented in Appendix C.

4.3.1 Summary overview

BTS is an urban 220 kV terminal station supplying the inner Melbourne suburbs of the Brunswick area. The station is one of the oldest, with the majority of the major assets being between 48 and 60 year old. BTS provides 22 kV supplies to AGL and CitiPower distribution networks. The station also provides contingency support to Richmond Terminal Station that supplies the Melbourne CBD. The peak demand at BTS was recorded as 91.7 MVA in March 2002[76].

BTS is supplied from two 220 kV lines originating at Thomastown Terminal Station (TTS). The original configuration involves a 220 kV switchyard and a 22 kV indoor switchboard, with three 220/22 kV 55 MVA transformers. Other major BTS assets include 220 kV bulk oil switchgear, associated cabling, protection and control equipment, and a number of buildings housing various items of in-service and redundant equipment. Redundant facilities include construction offices, machine hall, and the remnants of a previous 66 kV yard which occupies a large portion of the site. Many of the assets are understood to be original equipment installed at the time the station was developed in the early 1940s. However, some transformer refurbishment

75 Note that SPA reported to its Board that the scope changes did not alter the relative merits of the alternatives considered (page 4, SPI Powernet Board Report, SPI Powernet – Redevelopment of Malvern Terminal Station; 13 May 2005).

76 Page 4; Brunswick Terminal Station Asset Replacement Study Final F; SKM, Feb 2003.

work was undertaken in the sixties and seventies, and some busbar upgrade work has also been carried out.

SPA undertook internal investigations into options for the management of BTS assets, and engaged SKM to provide and independent evaluation of the various options. SKM was also engaged to give consideration to station reliability, capital and operating costs, as well as customer benefits. In 2003, SKM delivered a report that recommended wholesale refurbishment of the BTS facility on the existing site (i.e. brownfield refurbishment), as the least-cost option[77]. In making this recommendation SKM noted that VENCorp, ALG, and CitiPower had advised that no significant changes to system configuration or terminal station capacity are required at BTS in the foreseeable future.

At the time of their report, SKM estimated the capital cost of this option at $17.51m.

The views expressed in the SKM report were accepted by SPA in the Authority to Proceed Approval Request dated 14 December 2002.

In March 2003, the SPA Board approved the BTS refurbishment project, incorporating the replacement of all major equipment at the site. This included 220 kV and 22 kV switchgear, 220/22 kV transformers, all associated protection, control and metering systems, as well as upgrading of bunding and drainage.

While the original project timing involved completion in 04/05, the project was actually completed almost two years later in late 06/07.

4.3.2 Costs

While the 2002 cost proposal for BTS was some $18.1m, SPA has proposed that the forecast 'as commissioned' cost is expected to be $22.08m. PB notes that there were subsequent changes to the BTS project scope that resulted from design issues, and site constraints. It is PB's view that scope changes are not unexpected, particularly on a brownfield redevelopment where the original cost estimates were based on early design investigations, and give SPA's limited experience with this type of project. Hence PB is of the view that these variations were reasonably required, and that the variation costs appear reasonable.

Given the complex nature of the BTS redevelopment project, the voltages and types of equipment involved, and the associated site, compliance, and consultation issues, it is PB's view the SPA submitted total site redevelopment cost is reasonable. Moreover, given completion in 06/07, it is PB's view that the proposed timing of the project cash flow as presented by SPA (see Table 4-5 below) is reasonable for a project of this type.

Table 4-5 sets out PB's recommendation regarding the project value to be rolled into the RAB.

Table 4-5 – Recommended project value to be rolled into the RAB (inc. FDC)

Expenditure $m (nominal)	2003 stub period	03/04	04/05	05/06	06/07	07/08	March 08 WIP	Total
Submitted	—	0.00	0.00	11.24	10.48	0.36	0.00	22.08
Proposed variation	—	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PB recommendation	—	0.00	0.00	11.24	10.48	0.36	0.00	22.08

Source: PB analysis

77 Brunswick Terminal Station Asset Replacement Study Final F; SKM, Feb 2003.

4.3.3 Conclusion summary

The BTS redevelopment project is SPA's second single ex-post capex project. PB has reviewed the project information provided by SPA and has formed the following views:

- that for such a major and complex (i.e. high risk) project, the standard of project documentation is relatively poor. SPA should be encouraged to ensure that decisions that underpin major project costs (and variations) are well documented and supported by appropriate record keeping practices
- that given the age of the equipment, the assertion that the BTS assets are in a deteriorating state does not seem unreasonable, and that on this basis a justifiable need was identified
- with regards to the relationship between the BTS refurbishment project and the applicable SPA strategies, PB is of the view that the project documentation supplied gives little consideration (arguably none) to this relationship (see above for comments on project documentation quality)
- the project documentation does not adequately demonstrate the strategic alignment of the BTS project with SPA's asset management strategy, overarching policies and plans
- that the range of alternatives identified was reasonably comprehensive, and represented practical solutions to addressing the need identified
- that analysis of the alternatives, as presented in the SKM report, was prudent
- that the extent of the cost–benefit documentation was not appropriate for a project of this scale and complexity (i.e. high risk)
- that the preferred alternative recommend in the SKM report was the most efficient alternative of those identified to meet the stated need
- that the analysis and documentation of project variations was inadequate
- that the project variations as documented were reasonably required, and that the costs presented for these variations appear reasonable
- that the optimal project timing was reasonably within the current regulatory period, and that completion in late 06/07 was reasonably optimal given the events intervening in the original project timing
- that while there were a number of significant project variations, on the balance of the available information, it is likely that (on the whole) the decisions taken were consistent with prudent asset management practices
- that the forecast 'as commissioned' cost of $22.08m is reasonable in light of the nature of the project and the scope changes.

4.4 INSTALLATION OF OPGW IN THE METRO AREA

Installation of optical fibre ground wire (OPGW) in the metro area (referred to as OPGW1) is project that forms part of a larger OPGW installation program. While the 2002 cost proposal for OPGW1 was some $2.75m, SPA has proposed that the 'as commissioned' cost is $2.92m (nominal) across the current regulatory period as shown in Table 4-6. The OPGW1 project does not have a large ex-post capex value, accounting for only 9.3% of the SPA network-related capex in the current period; however, it is part of a larger capex program totalling $29.9m. The OPGW1 project was completed in 05/06.

Table 4-6 – Capex for the OPGW1 project (inc. FDC)

Expenditure $m (nominal)	2003 stub period	03/04	04/05	05/06	06/07	07/08	March 08 WIP	Total
SPA proposal	—	2.28	0.72	(0.08)	0.00	0.00	0.00	2.92

Source: SPA Proposal, Information Templates

The following information is an extract of the full detailed project review that is presented in Appendix D.

4.4.1 Summary/overview

OPGW1 is a project to replace overhead ground wires with optical fibre ground wire (OPGW). Specifically the project involved the purchase, installation, and commissioning of OPGW on eight (8) metropolitan transmission lines and the relocation of one (1) associated radio link[78].

The OPGW replacement reduces SPA's dependence on pole mounted communications cables in Melbourne area, and was planned to occur when the existing corroded ground wires were replaced between 2003 and 2019. However, the proposed program was brought forward following a third party incident that damaged a fibre optic communications cable in May 2002.

The SPA communications network is a critical network element, and is dependent on pole mounted fibre optic cables. This network consists of two loops, an East loop and West loop configured, and for redundancy reasons the protection and control signals are carried on both cables. The overall length of the Melbourne metropolitan pole mounted communications network is approximately 200km.

In May 2002 the OPGW1 project was approved by an SPA director as originally proposed with an estimated capital cost of $2.75m. This cost was revised in May 2003 to $3.14m.

4.4.2 Costs

While the 2002 cost proposal for the OPGW1 project was some $2.75m, SPA has proposed that the 'as commissioned' cost is $2.92m. PB understands that subsequent implementation issues account for this cost variation. It is PB's view that such implementation issues are not unexpected, particularly on an urban based project of this type.

Given the nature of the OPGW1 project, the equipment involved, and the associated route issues, it is PB's view the SPA submitted total project cost is reasonable. Table 4-7 sets out PB's recommendation regarding the project value to be rolled into the RAB.

Table 4-7 – Recommended project value to be rolled into the RAB (inclusive of FDC)

Expenditure $m (nominal)	2003 stub period	03/04	04/05	05/06	06/07	07/08	March 08 WIP	Total
Submitted	—	2.28	0.72	(0.08)	0.00	0.00	0.00	2.92
Proposed variation	—	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PB recommendation	—	2.28	0.72	(0.08)	0.00	0.00	0.00	2.92

Source: PB analysis

78 Page 1; A to P Approval Request OPGW in Melbourne Metropolitan Area; SPA, 14 May 2002.

4.4.3 Conclusion summary

The OPGW1 project, while having only a small capex value, forms part of a larger program that involves the installation of OPGW across the SPA transmission network. PB has reviewed the project information provided by SPA and has formed the following views:

- that a justifiable need was identified given the critical role of this communications network in the operation of the transmission system, and the requirements of the NER and the Victorian System Code;
- that the project documentation demonstrates the strategic alignment of the OPGW1 project with the relevant SPA's policy;
- that the range of alternatives identified were reasonably comprehensive and represented practical solutions to addressing the need identified;
- that the documented treatment of the alternatives, and the related analysis, was lacking, however it is likely that that the preferred alternative (install OPGW and radio) was a reasonable and prudent selection;
- that while the documented analysis was lacking, preferred alternative was shown to be least cost of the costed alternatives, and that the preferred alternative was likely to have been the most efficient alternative of those considered to meet the identified;
- that the project timing was reasonable the criticality of the asset and the NER and Victorian System Code compliance issues;
- that while the project cost varied from that originally proposed, differences are adequately documented, and represent decisions that are consistent with prudent asset management and good industry practice; and
- that the 'as commissioned' cost of $2.92m is reasonable in light of the nature of the project, the equipment involved, and the associated route issues.

4.5 REFURBISHMENT OF REDCLIFFS TERMINAL STATION (RCTS)

Redcliffs Terminal Station (RCTS) redevelopment is part of the terminal station group of projects, and is referred to as STN12. While the 2002 cost proposal for OPGW1 was some $10.6m, SPA has proposed that the 'as commissioned' cost is $14.97m (nominal) across the current regulatory period as shown in Table 4-8.

Table 4-8 – Capex for redevelopment of Redcliffs Terminal Station (inc. FDC)

Expenditure $m (nominal)	2003 stub period	03/04	04/05	05/06	06/07	07/08	March 08 WIP	Total
SPA proposal	—	0.00	0.00	0.00	8.62	6.35	0.00	14.97

Source: SPA Proposal, Information Templates

This project ranks as the fifth largest overall (ex-post) expenditure item and accounts for 3.6% of the SPA's network-related capex in the current period. SPA anticipates completion of the project in October 2007[79].

The following information is an extract of the full detailed project review that is presented in Appendix E.

79 Page 3; Project Approval Committee Authority to Proceed REVISION> $250,000 – Transmission, RCTS Refurbishment (X432); SPA, 24 Apr 2007.

4.5.1 Summary/overview

RCTS is a rural 220 kV terminal station located in the far north-west corner of Victoria. The station was established in the early to mid-1960s and provides both 66 kV and 22 kV supplies to the Redcliffs/Mildura area via the Powercor distribution network. RCTS is also an interconnection point for the South Australian and NSW interconnectors.

The station is supplied by single-circuit 220 kV overhead line from Kerang Terminal Station (KTS) and Horsham Terminal Station (HOTS). The original configuration involved 220 kV, 66 kV, and 22 kV switchyards. The existing transformers consist of two 70 MVA and one 35 MVA 220/66/22 kV three-phase transformers. Other major RCTS assets include a range of air blast, minimum oil, and SF6 circuit breakers, current and voltage transformers, associated cabling, protection and control equipment, a control building and a compressor building. Many of the major assets at RCTS are understood to be original equipment installed at the time the station was developed during the early to mid-1960s.

In 2001 RCTS was augmented to include an additional bay to accommodate the Murray-Link interconnector. It should be noted that the Murray-Link bay and its associated equipment were not part of the RCTS redevelopment project, and are excluded from this analysis.

During 2004, SPA undertook an evaluation of the various asset management options for RCTS. This investigation considered the condition, performance, and risks of the RCTS assets, and identified a range of management options. The Redcliffs Terminal Station (RCTS) Redevelopment Study report concluded that the redevelopment of RCTS be undertaken as a ‘brownfield replacement’ with the 220 kV and 66 kV switchyard works being consolidated into a single project, and with the associated upgrade of the secondary systems. At the time of this report, the estimated capital cost of this recommendation was $11.60m.

In November 2004 the SPA Board approved the RCTS redevelopment project, incorporating the replacement of plant and equipment in the 220 kV and 66 kV switchyards, replacement of the 220/66 kV transformer and 66 kV protection, associated upgrades of the station control and information system (SCIMS), and refurbishment / extension of the existing control room.

4.5.2 Costs

While the 2002 cost proposal for RCTS was some $10.6m, SPA has proposed that the forecast ‘as commissioned’ cost is expected to be $14.97m. SPA have submitted that this cost increase is attributable to higher than expected material and installation costs, as well as additional unanticipated works due to site difficulties with the Murray-Link installation[80]. SPA further note that and independent report by SKM found that the site related costs were 30% too low in the original cost forecast. While PB has not sited the SKM report, PB is of the view that the remote location of the site is likely to involve significant additional costs. Additionally, it is PB’s view that such a brownfield redevelopment, where the original cost estimates were based on early design investigations, is likely to incur additional unforeseen costs. The revised AtoP presents details of this cost increase, and SPA’s considerations as to the appropriateness of the selected alternative in light of the additional costs.

Given the complex nature of the RCTS redevelopment project, the voltages and types of equipment involved, and the associated site location and conditions, it is PB’s view that the SPA submitted total site redevelopment cost is reasonable.

Table 4-9 sets out PB’s recommendation regarding the project value to be rolled into the RAB.

80 Page 9; Response to Clause 6A.11.1 Information Request; SPA, 31/03/07.

Table 4-9 – Recommended project value to be rolled into the RAB (inc. FDC)

Expenditure $m (nominal)	2003 stub period	03/04	04/05	05/06	06/07	07/08	March 08 WIP	Total
Submitted	—	0.00	0.00	0.00	8.62	6.35	0.00	14.97
Proposed variation	—	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PB recommendation	—	0.00	0.00	0.00	8.62	6.35	0.00	14.97

Source: PB analysis

4.5.3 Conclusion summary

The RCTS redevelopment project is SPA's fifth largest overall project undertaken in the current regulatory period, and is part of the broader terminal station redevelopment program. PB has reviewed the project information provided by SPA and has formed the following views:

- that a justifiable need was identified in that the equipment condition and general capability of the RCTS facility was reaching the end of its useful life
- that the RCTS report presented a thorough engineering analysis of the equipment within RCTS, and that this analysis was sound and reasonable
- that the project documentation demonstrates the strategic alignment of the RCTS project with SPA's asset management strategy, overarching policies and plans
- that the range of alternatives identified were reasonably comprehensive and represented practical solutions to addressing the need identified
- that analysis of the alternatives, and the selection of the preferred alternative (brownfield redevelopment), was reasonable and prudent, with the preferred alternative being the least-cost alternatives that met the identified need
- that the optimal project timing was reasonably likely to be within the current regulatory period, and that the planned commissioning date of 2006/07 represents reasonable optimal timing;
- that SPA's implementation of the RCTS project was not consistent with prudent asset management and good industry practice as it lacked rigor in original scoping, costing and project management
- had SPA been rigorous at the project outset, that the original project scope would have reflected the as implemented project
- that the forecast 'as commissioned' cost expectation of $14.97m is reasonable given the scope changes which are not unexpected for a project of this complex nature.

4.6 TOWER SIGNAGE

The Tower Signage project involves fitting of nameplates to each circuit on each tower. The project forms part of a larger program of works to improve tower safety and is referred to as EQP1. The EQP1 project involves the expenditure of $3.69m (nominal) across the current regulatory period as shown in Table 4-10.

Table 4-10 – Capex for tower signage project (inc. FDC)

Expenditure $m (nominal)	2003 stub period	03/04	04/05	05/06	06/07	07/08	March 08 WIP	Total
SPA proposal	—	3.50	0.19	0.00	0.00	0.00	0.00	3.69

Source: SPA Proposal, Information Templates

This project is relatively small ex-post expenditure item and accounts for 0.89% of the SPA network-related capex in the current period. It is understood that work commenced in 2003/04 and was completed in 2004/05.

The following information is an extract of the full detailed project review that is presented in Appendix F.

4.6.1 Summary/overview

In June 2001 an SPA employee was fatally injured while undertaking line work on a transmission tower. The subsequent investigations recommend (in part) the clear identification and designation of each line on each tower. SPA determined that fitting nameplates to each circuit on each tower would achieve the recommended outcome[81].

SPA has approximately 13,100 towers, with each supporting slightly greater than two circuits per tower on average. However some towers support up to four separate circuits. This project involved placing nameplates on each circuit of each of the towers to improve safety for work crews by reducing the possibility of incorrect circuit identification. This project forms part of a larger program of works to improve tower safety, and to improve crew safety through enhanced work practices.

SPA prepared an A to P Approval Request in August 2002 seeking approval for an estimated $4.11m to erect the proposed signage. The A to P Approval Request was approved by an SPA director on 7 October 2002. It is understood that work commenced in 2003/04 and was completed in 2004/05.

4.6.2 Costs

There was no 2002 cost proposal for the tower signage project as the need for the work was not realised until some months after the June 2002 fatality. In the SPA tower signage A to P, the estimated cost of this work is $4.11m, and SPA has proposed that the as complete cost is $3.69m. While fitting the signage to the towers is not a skilled task, it does require climbing of the tower to fit signs to the circuits, and this does require specialist skills. Given the large number of towers to be fitted with nameplates, the need to climb each tower to erect the signage, and the geographically dispersed nature of the towers, PB is of the view that the SPA submitted cost is reasonable. Table 4-11 sets out PB's recommendation regarding the project value to be rolled into the RAB.

81 A to P Approval Request, Safety Signage on Towers; SPA, 8 August 2002.

Table 4-11 – Recommended project value to be rolled into the RAB (inc. FDC)

Expenditure $m (nominal)	2003 stub period	03/04	04/05	05/06	06/07	07/08	March 08 WIP	Total
Submitted	—	3.50	0.19	0.00	0.00	0.00	0.00	3.69
Proposed variation	—	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PB recommendation	—	3.50	0.19	0.00	0.00	0.00	0.00	3.69

Source: PB analysis

4.6.3 Conclusion summary

The tower signage project is part of an initiative to improve tower safety, and is an element of a larger program of tower safety works. PB has reviewed the project information provided by SPA and has formed the following views:

- that a justifiable need was identified in that the tower and circuit signage in place at the time of the fatality was a recognised safety issue
- the project documentation demonstrates the strategic alignment of the tower signage project with OH&S policies and regulations
- that the range of alternatives identified were practical solutions to address the identified need
- that since no costing was presented in the selection of the preferred alternative, PB is not able to conclude that the selected alternative was the least-cost alternative to meet the identified need
- that analysis of the alternatives, and the selection of the preferred alternative (erect tower signage), was reasonable and prudent give that unambiguous circuit identification is a vital safety issue
- that the project timing was appropriate given that once SPA was aware of this issue that it had duty to promptly address this safety issue
- that the project was implemented as envisaged, and that the project implementation was consistent with prudent asset management and good industry practice
- that the as complete cost of $3.69m is reasonable in light of the large number of towers involved, the need to climb each tower, and the geographically dispersed nature of the towers.

4.7 220 AND 66 KV CT REPLACEMENTS STAGE 2

The 220 and 66 kV CT replacement project (stage 2) is part of a larger program of works targeting the replacement of current transformers (CTs) with a perceived high risk of failure. This project, referred to as TCT3, is scheduled to commence in 2007/08 with an anticipated completion late in the year. A further stage of this program, scheduled for 2008–2014, is addressed in Section 5.4 of this report.

The TCT3 project involves the expenditure of $3.88m (nominal) across the current regulatory period as shown in Table 4-12. This project is relatively small ex-post expenditure item and 0.93% of the SPA network-related capex in the current period.

Table 4-12 – Capex for 220 and 66 kV CT replacements stage 2 project (inc. FDC)

Expenditure $m (nominal)	2003 stub period	03/04	04/05	05/06	06/07	07/08	March 08 WIP	Total
SPA proposal	—	0.00	0.00	0.00	0.00	2.61	1.27	3.88

Source: SPA Proposal, Information Templates

The following information is an extract of the full detailed project review that is presented in Appendix J.

4.7.1 Summary/overview[82, 83, 84]

In 2002, a 500 kV CT at Moorabool suffered explosive failure. Following a second explosive failure in late 2005, SPA undertook a complete review of CT condition. In addition, there have been several other catastrophic failures involving 66 kV and 220 kV CTs. As a consequence of these failures SPA developed a CT risk assessment model to rank failure risk, and predict when CT replacement should be planned. Based on this assessment, SPA developed a program to replace high risk CTs. The TCT3 project targets the replacement of those perceived high risk CTs that are not part of SPA's terminal station rebuild program.

Stage 1 of the CT replacement program was the '500 kV CTs for replacements and spares' project which purchased 17 single-phase 500 kV CTs. The project currently under review is the second stage of this program, and involves the replacement of four sets of 66 kV CTs, and 18 sets of 220 kV CT that have a high risk of failure. It involves works at 10 terminal stations, as well as the purchase of six sets of 220 kV CTs, and one set of 330 kV CTs for spares.

In February 2007, the stage 2 CT replacement project was approved by two SPA directors as recommended by the SPA Project Approval Committee. The estimated capital cost of this project is $6.90m, and the project is scheduled to commence in 2007/08 with an anticipated completion late in the year.

4.7.2 Costs

The capital cost of this project was estimated at $5.92m in January 2007. This estimate covers the replacement (supply and installation) of four sets of 66 kV CTs, and 18 sets of 220 kV CT. It involves the purchase of six sets of 220 kV CTs, and one set of 330 kV CTs for spares. The submitted final figure for this project was $3.88m. Given the voltages and types of equipment involved, it is PB's view the SPA submitted total forecast cost estimate is reasonable. Table 4-13 sets out PB's recommendation regarding the project value to be rolled into the RAB.

82 Project Approval Committee Authority to Proceed >$250,000 – Transmission, 220 kV & 66 kV CT Replacements at Various Locations: Stage 2; SPA, 29 January 2007.

83 CT Replacement Program; SPA, 16 March 2007.

84 Replacement Program For Current Transformers Capital Works Project Description; SPA, 12/01/07.

Table 4-13 – Recommended project value to be rolled into the RAB (inc. FDC)

Expenditure $m (nominal)	2003 stub period	03/04	04/05	05/06	06/07	07/08	March 08 WIP	Total
Submitted	—	0.00	0.00	0.00	0.00	2.61	1.27	3.88
Proposed variation	—	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PB recommendation	—	0.00	0.00	0.00	0.00	2.61	1.27	3.88

Source: PB analysis

4.7.3 Conclusion summary

The 220 and 66 kV CT replacement project (stage 2) is part of a larger program of works targeting the replacement of current transformers (CTs) with a perceived high risk of failure. PB has reviewed the project information provided by SPA and has formed the following views:

- that a justifiable need was identified given the identified equipment condition and failure history, as well as the related OH&S and environmental risks associated with explosive failure, and the system reliability implications of this equipment
- that the project documentation presents a sound and reasonable engineering analysis notwithstanding the lack of collaborating data (e.g. summary of test findings, independent review)
- the project documentation demonstrates the strategic alignment of the TCT3 project with SPA's asset management strategy, overarching policies and plans
- that the range of alternatives identified were reasonably comprehensive and represented practical solutions to addressing the need identified
- that analysis of the alternatives, and the selection of the preferred alternative (replace with new CTs), was reasonable and prudent, with the preferred alternative being the least-cost alternatives that met the identified need
- that the implementation timing of this project was reasonable given the nature of the failures being experienced, the assessed condition of the equipment, as well as the attendant OH&S, environmental, and systems risks
- as the project is yet to be implemented, that it is not possible assess the project's implementation at this stage
- that the forecast capital cost estimate of $3.88m is reasonable given the voltages and the type of equipment involved.

4.8 REPLACEMENT OF 66 KV SHUNT REACTORS AT HOTS, KGTS, & RCTS

The replacement of shunt reactors project addresses ageing and faulty equipment in three (3) regional terminal stations. This project is identified as REACT1, and involves the expenditure of $3.14m (nominal) across the current regulatory period as shown in Table 4-14.

Table 4-14 – Capex for 66 kV shunt reactors project (inc. FDC)

Expenditure $m (nominal)	2003 stub period	03/04	04/05	05/06	06/07	07/08	March 08 WIP	Total
SPA proposal	—	0.00	3.14	(0.00)	0.00	0.00	0.00	3.14

Source: SPA Proposal, Information Templates

This project is relatively small ex-post expenditure item and represents 0.75% of the SPA network-related capex in the current period. The REACT1 project was completed in September 2004.

The following information is an extract of the full detailed project review that is presented in Appendix H.

4.8.1 Summary/overview

The shunt reactors (used for reactive voltage control) at Kerang, Horsham and Redcliffs Terminal Stations were supplied by Hawker Siddeley Brush (HSB) in 1972/74. Early in their operation a number of serious defects, which were caused by a high level of vibration, became apparent. Two units were repaired; however, in 1996 the vibration suddenly increased, resulting in internal faults and insulation contamination.

These shunt reactors play an important part in voltage control of the 220 kV outer grids, and have become unreliable due to the impacts of an inherent mechanical design weakness. This project involves the purchase and installation of three new 15 MVA shunt reactors, one in each of the terminal stations.

In February 2003 an SPA director approved the REACT1 project at an estimated cost of $3,89m. The project was completed in September 2004 at a total cost of $3.14m[85].

4.8.2 Costs

The original cost estimate for the REACT1 project was some $3.89m, while the as implemented total cost is understood to be $3.14m[86]. Given the voltages and type of equipment involved, PB's is of the view that the proposed cost of this project is reasonable. Table 4-15 sets out PB's recommendation regarding the project value to be rolled into the RAB.

Table 4-15 – Recommended project value to be rolled into the RAB (inc. of FDC)

Expenditure $m (nominal)	2003 stub period	03/04	04/05	05/06	06/07	07/08	March 08 WIP	Total
Submitted	—	0.00	3.14	(0.00)	0.00	0.00	0.00	3.14
Proposed variation	—	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PB recommendation	—	0.00	3.14	(0.00)	0.00	0.00	0.00	3.14

Source: PB analysis

4.8.3 Conclusion summary

The REACT1 project addresses ageing and faulty reactive support equipment in three regional terminal stations. PB has reviewed the project information provided by SPA and has formed the following views:

- that a justifiable need was identified in that SPA has identified that the condition of the reactors was such that the insulation contamination cannot be rectified and the units are at an increased risk of failure

85 A to P Approval Request, Replacement of 15 MVAR 67.5 kV Shunt Reactors at HOTS, KGTS and RCTS; SPA, 11 December 2002.

86 Hist Capex – Network sheet; SPA Templates - Cost information lodged 280207 (spreadsheet).

- that the SPA assessment of the equipment condition limited and lacked collaborating data (e.g. summary of test findings, independent review, etc) fundamental to a sound engineering analysis of equipment condition
- that the project documentation lacks explicit strategic alignment with the applicable SPA strategies, overarching policies and plans
- that the range of alternatives identified were reasonably comprehensive and represented practical solutions to addressing the need identified
- that analysis of the alternatives, and the selection of the preferred alternative (replace three reactors), was reasonable and prudent
- that while the preferred alternative was not shown to be least-cost solution, the arguments for dismissing the other alternatives were reasonable, and that the preferred alternative was the most efficient alternative of those considered to meet the identified need
- that given the age of the equipment, its history, assessed condition, and the nature of the equipment design, the timing of this project was probably reasonable
- that, based on the project documentation supplied, the implemented project is in accordance with the original proposal, and project implementation is consistent with prudent asset management and good industry practice
- that the 'as commissioned' cost of $3.14m is reasonable given the voltages and type of equipment involved.

4.9 REPLACEMENT OF 16 MM PIN INSULATORS STAGE 2

The Replacement of 16 mm Pin Insulators (Stage 2) project addresses ageing transmission line insulators, and is part of a broader program of capital works targeted at these assets. This project involves the expenditure of $2.07m (nominal) across the current regulatory period as shown in Table 4-16.

Table 4-16 – Capex for 16 mm pin insulators stage 2 project (inc. FDC)

Expenditure $m (nominal)	2003 stub period	03/04	04/05	05/06	06/07	07/08	March 08 WIP	Total
SPA proposal	—	0.00	0.00	0.00	0.00	2.07	0.00	2.07[87]

Source: SPA Proposal, Information Templates

This project is small ex-post expenditure item and represents 0.04% of the SPA network-related capex in the current period. Later stages of the insulator replacement program (referred to as Tinsulator) also form a significant part of the proposed forecast capex (3.7% of proposed capex). The stage 2 project is anticipated for completion in 07/08.

The following information is an extract of the full detailed project review that is presented in Appendix I.

[87] It is understood from correspondence received from SPA on 18 June 2007 that the estimated cots of this project may change due to additional switching costs that were not originally identified. SPA had not advised the details of this at the time of finalising this report.

4.9.1 Summary/overview

SPA's transmission lines have a wide range of construction ages and contain an extensive population of insulators. The insulators (and associated fittings) on older lines are not reliably meeting their expected life due to defects and deterioration. There has been several in service insulator string failures in the past 20 years, most of which have occurred in the last 5 years.

The Tinsulator project targets aged 16 mm diameter pin insulators and associated line hardware in order to reduce the risk of in service failure. The project focuses on high-risk situations (e.g. major road crossings, critical lines) by combining equipment condition assessment (i.e. service life, degree of corrosion and wear) with the local consequences of failure.

In March 2007, SPA approved project X668 (a major portion of the Tinsulator project) which proposes the replacement of 1,839 high-risk insulator strings on approximately 400 towers. In addition, a range of associated hardware (e.g. suspension clamps, dampers, etc) is also to be replaced under this project. A related project (X651) in this program, was also submitted for approval in March 2007, and proposes to replace the insulator strings and associated hardware on 16 towers located on the 500 kV line at Portland[88].

4.9.2 Costs

SPA has proposed that the forecast cost of these projects (X668, X651) is expected to be $2.07m. Given the voltages, the geographically distributed nature of an insulator replacement program, and the types of insulators proposed (polymeric), it is PB's view the SPA-expected cost estimate is reasonable. Table 4-17 sets out PB's recommendation regarding the project value to be rolled into the RAB.

Table 4-17 – Recommended project value to be rolled into the RAB (inc. FDC)

Expenditure $m (nominal)	2003 stub period	03/04	04/05	05/06	06/07	07/08	March 08 WIP	Total
Submitted	—	0.00	0.00	0.00	0.00	2.07	0.00	2.07
Proposed variation	—	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PB recommendation	—	0.00	0.00	0.00	0.00	2.07	0.00	2.07

Source: PB analysis

4.9.3 Conclusion summary

The Tinsulator project addresses ageing transmission line insulators, and is part of a broader program targeted at these assets. Later stages of this replacement program also form a significant part of the proposed forecast capex. PB has reviewed the project information provided by SPA and has formed the following views:

- that a justifiable need was identified in that the assessed condition of a significant portion of the insulator population is poor (high risk) and that there is an increasing risk of line drops

88 Project Approval Committee Authority to Proceed >$250,000 – Transmission, Replacement of High-Risk 16mm diameter Pin Insulators and associated Hardware on Road Crossings on various lines (Project No. X668); SPA, 14 March 2007. Project Approval Committee Authority to Proceed >$250,000 – Transmission, HYTS-APD 500 kV Insulator & Fittings replacement (T609-T629) (Project No. X651); SPA, 14 March 2007.

- that SPA's assessment of the insulator condition represents a thorough engineering analysis of the insulator condition, and that this analysis was sound and reasonable
- that the project documentation lacks explicit strategic alignment with SPA's asset management strategy, overarching policies and plans
- that the range of alternatives identified were reasonably comprehensive and represented practical solutions to addressing the need identified
- that analysis of the alternatives, and the selection of the preferred alternative (replace high-risk insulators and associated hardware with polymeric insulators), was reasonable and prudent, with the preferred alternative being the least cost of the identified alternatives that met the stated need
- the timing of this project was probably reasonable given the condition of the insulators identified by the model, and the proposed risk profile
- that it is not possible to assess whether the implementation is consistent with prudent asset management and good industry practice, as the these projects (X668, X651) are yet to be implemented
- that the forecast cost of $2.07m is reasonable given the voltages involved, the geographically distributed nature of an insulator replacement program, and the types of insulators proposed (polymeric).

4.10 REFURBISHMENT OF BENDIGO TERMINAL STATION (BETS)

Bendigo Terminal Station (BETS) redevelopment is part of the terminal station group of projects, and is referred to as STN16. While the 2002 cost proposal for BETS was some $15.6m, SPA has proposed that the 'as commissioned' cost is $14.45m (nominal) across the current regulatory period as shown in Table 4-18.

Table 4-18 – Capex for Bendigo Terminal Station project (inc. FDC)

Expenditure $m (nominal)	2003 stub period	03/04	04/05	05/06	06/07	07/08	March 08 WIP	Total
SPA proposal	—	0.00	0.00	0.71	2.56	11.19	0.00	14.45

Source: SPA Proposal, Information Templates

This project ranks as the seventh largest overall (ex-post) expenditure item and accounts for 3.5% of the SPA network-related capex in the current period. SPA anticipates completion of the project in 07/08.

The following information is an extract of the full detailed project review that is presented in Appendix J.

4.10.1 Summary/overview

BETS is a regional 220 kV terminal station that supplies the northern and eastern parts of the 220 kV state grid. The station's operation can have a significant impact on the operation of the Murray-Link and Snowy inter-state connectors.

BETS station was established in the early to mid-1960s by the former SECV to provide support to the distribution network in the Bendigo area, and for much of this area is the only source of supply. BETS provides both 66 kV and 22 kV supplies to Powercor's distribution business, which in turn supplies approximately 66,000 customers in the Bendigo and surrounding areas.

The station is supplied from three double-circuit 220 kV lines from originating at Ballarat, Shepparton, and Kerang. The original configuration involved 220 kV, 66 kV, and 22 kV switchyards. The station has two banks of 220/66/22 kV single-phase transformers, and a 220/66/22 kV three-phase transformer. Other major BETS assets include a range of air blast, bulk oil, minimum oil and SF6 switchgear, voltage transformers, current transformers, capacitor banks, associated cabling, protection and control equipment. Most of the primary assets at BETS are understood to be original equipment installed at the time the station was being developed during the early to mid-1960s.

During 2004, SPA undertook investigations into the various asset management options for BETS. This investigation considered the condition, performance, and risks of the BETS assets, and identified a range of management options. The investigation also considered the specific requirements of VENCorp and Powercor with regard to the shared network and connection assets respectively. The resulting report[89] concluded that a consolidated single project involving the brownfield redevelopment of the 220 kV switchyard and 66 kV switchyards, along with the coordinated replacement of the associated secondary systems delivers the most cost-effective outcome.

At the time of this report, it was estimated the capital cost of this option was $15.1m.

In December 2004 the SPA Board approved the BETS redevelopment project, incorporating the redevelopment of the 220 kV switchyard and partial redevelopment of the 66 kV switchyard along with the replacement of associated secondary equipment, and the extension and refurbishment of the control building.

4.10.2 Costs

While the 2002 cost proposal for BETS was some $15.6m, SPA has proposed that the ‘as commissioned’ cost is $14.4m. Given the scope of the BETS redevelopment project, the voltages and types of equipment involved, as well as the associated site, compliance, and consultation issues, it is PB’s view the SPA submitted total site redevelopment cost is reasonable. Table 4-19 sets out PB’s recommendation regarding the project value to be rolled into the RAB.

Table 4-19 – Recommended project value to be rolled into the RAB (inc. of FDC)

Expenditure $m (nominal)	2003 stub period	03/04	04/05	05/06	06/07	07/08	March 08 WIP	Total
Submitted	—	0.00	0.00	0.71	2.56	11.19	0.00	14.45
Proposed variation	—	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PB recommendation	—	0.00	0.00	0.71	2.56	11.19	0.00	14.45

Source: PB analysis

4.10.3 Conclusion summary

The BETS redevelopment project is part of the terminal station group of projects, and while it is one of the smaller terminal station refurbishment projects, it is none the less a material expenditure at $14.45m. PB has reviewed the project information provided by SPA and has formed the views that:

89 Bendigo Terminal Station (BETS) Redevelopment Study; SPA, December 2004

- while there was a lack of documented information to substantiate the equipment condition, given the age of the equipment, the assertion that the BETS assets are in a deteriorating state does not seem unreasonable
- where the assets are accepted as being in poor condition, and given the role of the station, as well as the identified OH&S and environmental risks, that a justifiable need was identified
- the BETS Redevelopment Study report presented a reasonably thorough engineering analysis of the equipment, and that the analysis was sound and reasonable
- the BETS Redevelopment Study report required more information to substantiate the reported condition of the equipment
- project documentation demonstrates the strategic alignment of the BETS project with SPA's asset management strategy, overarching policies and plans
- the range of alternatives identified were reasonably comprehensive and represented practical solutions to addressing the need identified
- analysis of the alternatives, and the selection of the preferred alternative (brownfield redevelopment), was reasonable and prudent
- the preferred alternative was the most efficient alternative identified to meet the need, with the preferred alternative being shown to be the least cost of the alternatives considered
- it is difficult to conclude that project timing was reasonably optimal, and it may have been possible to defer the BETS project by as much as 2 years
- the scope of the project as implemented was in accordance with the original proposal, and that the project implementation (excluding the question of project timing) was consistent with prudent asset management and good industry practice
- the 'as commissioned' cost of $14.45m is reasonable in light of the project scope, the voltages and types of equipment involved, as well as the associated site, compliance, and consultation issues.

4.11 CONCLUSION

This section has presented detailed reviews of a selection of nine ex-post network projects. These detailed reviews form part of a broader multi-pronged approach to assessing the prudency and efficiency of SPA's ex-post capex expenditure. This approach consists of:

- a review of SPA's governance systems, processes, policy and practice
- benchmarking and comparative analysis ('top-down')
  - impact of capex on the average age of the asset base
  - analysis at total expenditure level with other TNSPs
  - a review of unit costs (obtained from detailed project reviews)
- a detailed examination of a selection of projects ('bottom-up')
- PB's direct experience of other network businesses (including TNSP reviews).

Consequently, the views formed by PB in considering the prudency and efficiency of SPA's ex-post capex expenditure are informed by this broader context. Accordingly, while the detailed ex-post reviews form an essential element of this approach, they must be considered within this overall framework.

In determining a recommendation on the prudency and efficiency of the overall (ex-post) capex proposed by SPA, PB has given due consideration to a range of factors assessed as part of this review, including:

- our review of the governance, approvals processes and systems set in place by the SPA Board, which (consistent with the standards expected of a publicly listed company) indicate well-established and documented process leading to the approval of capex and opex, and at a high level generally good electricity industry practices associated with its asset management functions
- PB's independent benchmarking found that SPA benchmarks well (about average, or above average) on almost all benchmarks assessed in this review. This finding is consistent with SPA's own review conducted by Jervis Consulting in 2006[90]
- High-level benchmarks across a range of measures show that SPA's capex is at or below that of the average of other Australian TNSPs
- depreciation-based benchmarking indicates that the weighted average age of SPA's network across various asset categories is generally being held stable
- SPA is progressively implementing a condition-based asset management framework based upon asset risk models that are, in PB's opinion, technical sound and approaching best practice[91].

Within this context the main findings of the detailed ex-post project reviews can be summarised:

- in all cases examined, a justifiable need was identified
- while some of the project documentation does demonstrate strategic alignment with SPA's asset management strategy, overarching policies and plans, there is considerable inconsistency across the projects examined
- in all cases examined, the range of alternatives identified were reasonably comprehensive and represented practical solutions to address the identified need
- generally the analysis of the alternatives, and the selection of the preferred alternative, was reasonable and prudent, with the preferred alternative being shown to be the least cost of the alternatives assessed that met the identified need
- in some cases the extent of the documentation in relation to equipment condition, alternative analysis, cost–benefit analysis, and project variations was not considered appropriate for the project
- in almost all cases examined the project implementation timing was reasonable. However, in some cases it was difficult to determine that timing was optimal due to the quality of the documentation (particularly the cost–benefit and equipment condition information). This was particularly the case for the Bendigo Terminal Station (BETS) redevelopment project
- in a number of the projects significant variations occurred during implementation, and while the standard of documentation was inconsistent, on the whole, given the nature of the projects (e.g. brownfield developments), the fact that many estimates were based on preliminary design information, and other factors (e.g. latent site conditions), these variations are not unexpected or inconsistent with prudent asset management and good industry practice
- in almost all cases examined it was clear that the project implementation was consistent with prudent asset management and good industry practice
- that the 'as commissioned' costs proposed by SPA are reasonable given the nature of the projects (e.g. brownfield developments, project scope, etc), the equipment and voltages involved, and the issues encountered during implementation (e.g. community requirements, latent site conditions, etc).

[90] Report on Asset Risk Management Survey conducted for SP AusNet July/August 2006. Jervis Consulting in 2006.

[91] In arriving at this opinion, PB acknowledges that it has not conducted a detailed review of each of SPA's asset risk models, and that it understands that these models are under ongoing development.

Overall, while the detailed reviews did identify a number of issues, these related essentially to the quality of the documentation, as opposed to the underlying issues or analysis being presented. That is, in a number of cases the conclusions drawn in the documentation were not well supported by the documented evidence (as supplied). For example, equipment condition was asserted to be poor and reasonably beyond repair or refurbishment; however, in a number of cases little corroborating evidence was presented (e.g. BETS project). Consequently, while it was difficult in some cases to find that SPA had demonstrated prudency and efficiency, from an external technical perspective, and in the broader context of this assessment (refer above), it is PB's view that on the balance of the available information that it is likely that SPA has (in general) been prudent and efficient in regards to the management of its ex-post capex.

Variation against 2002 determination

During the current regulatory period, SPA overspent its capex allocation with respect to the amount approved in the 2002 regulatory determination. This overspend is expected to be approximately 9.2%[92]. The majority of the overspend is associated with items and events which were unanticipated at the time of the 2002 determination and which led to scope changes and additional works (for example, change in OHS compliance requirements associated with tower access).

4.12 PB RECOMMENDATION (WIP AND HISTORIC CAPEX)

PB has considered the prudency and efficiency of SPA's ex-post capex through a multi-pronged top-down and bottom-up approach. Based on the information provided by SPA, and PB's investigations and assessments, it is PB's view that SPA's ex-post network capex expenditure over the period 2002/3 to 2007/08 was, in general, timely, reasonable and efficient.

PB has considered the values proposed by SPA for inclusion in the RAB, and recommends the values as shown in Table 4-20. Table 4-21 summarises this information showing the results for the detailed projects reviews.

Table 4-20 – Final recommendation for values to be included in SPA's RAB (by project)

Project	Submitted	Proposed variation	PB recommendation
MTS Redevelopment	38.57	—	38.57
BTS Redevelopment Project	22.08	—	22.08
Installation of OPGW in the Metro Area	2.92	—	2.92
Refurbishment of RCTS	14.97	—	14.97
Tower Signage	3.69	—	3.69
220 & 66 kV CT Replacements, Stage 2	3.88	—	3.88
Replacement of 66 kV Shunt Reactors at HOTS, KGTS & RCTS	3.14	—	3.14
Replacement of 16 mm Pin Insulators, Stage 2	2.07	—	2.07
Refurbishment of BETS	14.45	—	14.45
Reviewed total	**105.77**		**105.77**
Balance of proposed RAB	**310.47**	—	**310.47**
TOTAL	**416.25**	—	**416.25**

Source: PB analysis

92 in net terms.

Table 4-21 – Final recommendation for values to be included in SPA's RAB

Expenditure $m (nominal)	2003 stub period	03/04	04/05	05/06	06/07	07/08	March 08 WIP	Total [93]
Proposed total	24.4	38.6	58.4	76.5	93.3	103.3	21.9	416.2
Recommended total	24.4	38.6	58.4	76.5	93.3	103.3	21.9	416.2
Adjustments total	—	—	—	—	—	—	—	—
Adjustments total %	—	—	—	—	—	—	—	—

Source: PB analysis

93 The total column is shown only for consistency with the information submitted in SPA's Proposal Information Templates. PB recognises that this simple sum of the individual annual expenditure amounts may not be appropriate given that all historical cost information is expressed in nominal dollars.

5. REVIEW OF FORECAST (EX-ANTE) CAPEX PROJECTS

In this section, PB provides a high-level overview of SP AusNet's (SPA) proposed forecast capex allowance; we review a selection of network-related projects captured within the forecast allowance; we consider and evaluate the need, timing, scope and costs associated with these projects; and we then make recommendations on the appropriateness of their inclusion in the ex-ante forecast allowance. PB also extends its analysis and recommendations from the detailed projects reviews through to the remaining program, as appropriate.

5.1 SUMMARY

SPA has identified six main drivers influencing its expenditure levels over the next 20 years. These include:

- asset condition, performance and failure risks
- increased asset utilisation and deterioration
- increasing fault levels
- operational reliability and reliability performance
- compliance with legislation, rules and regulations
- technological changes.

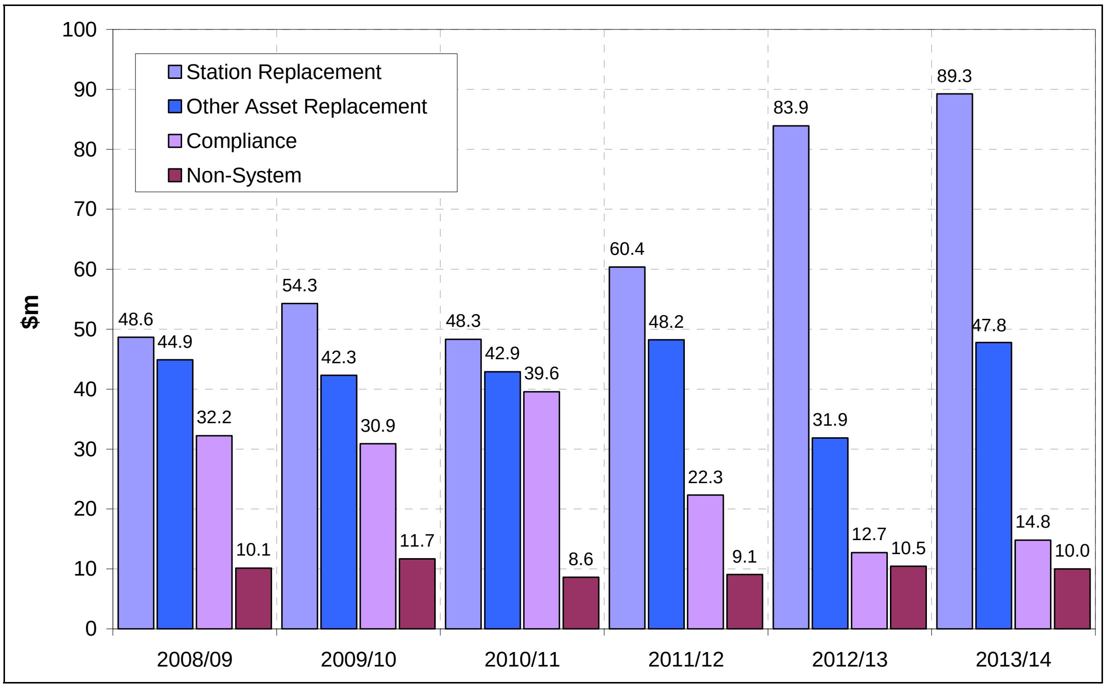
SPA is forecasting a total capital expenditure amount of $854m (real 07/08, 'as spent') over the 6-year period 2008/09 to 2013/14, which is around $143m per annum. This includes a replacement program categorised into either 'station based' or 'other asset type' replacements, a compliance program, or non-system expenditure, as shown in Table 5-1 and Figure 5-2. This is an increase of around 55% (real) per annum compared to the previous 5-year period, and a noticeable increase is occurring in the station replacement category.

Table 5-1 – SPA's forecast capex proposal categorised by project type

Expenditure $m ('as spent', real 07/08)	08/09	09/10	10/11	11/12	12/13	13/14	Total
Station replacement	48.6	54.3	48.3	60.4	83.9	89.3	384.8
Other asset replacement	44.9	42.3	42.9	48.2	31.9	47.8	258.0
Compliance	32.2	30.9	39.6	22.3	12.7	14.8	152.6
Non-system	10.1	11.7	8.6	9.1	10.5	10.0	60.0
TOTAL	135.9	139.2	139.4	140.0	139.0	161.8	855.3

Source: SPA Proposal, Information Templates

Figure 5-1 – SPA's forecast capex proposal categorised by project type



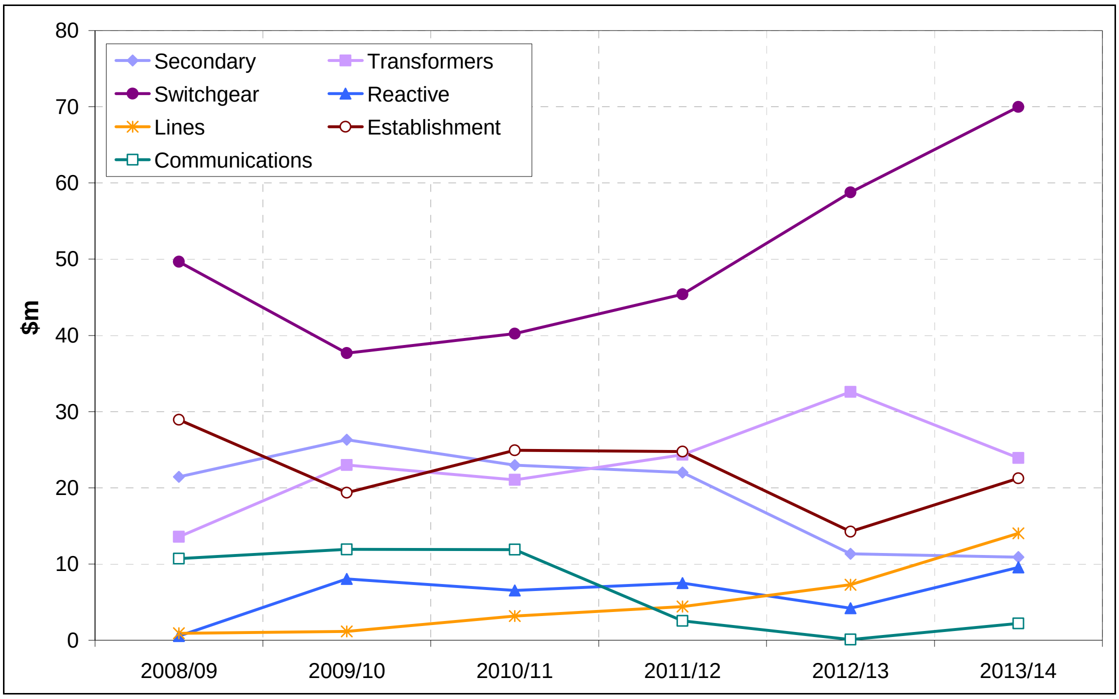
A further observation from Figure 5-1 is that the vast majority of capex is related to the network, with only 7% of the total spent expected to be related to non-system aspects. Non-system capex is discussed further in Section 6 of this report.

At a high level, the methodology adopted by SPA to prepare its replacement capex work program forecast has included:

- ongoing development of its quantified and dynamic risk-based models, informed through the used of periodic and on-line condition monitoring
- consideration of the condition-based ranking of assets through the five detailed risk models (CBs, CTs, transformers, lines and protections systems), which consider both probability of failures and consequences
- sorting and presentation of the risk-ranked data based on locations, asset (fleet) types and risk levels, with particular attention to relative changes in risks over time
- detailed technical assessments based on triggers identified through the risk models taking into consideration additional factors that are not covered by the risk models. These factors include:
  - interdependencies on work programmed at stations
  - the consequences of failure
  - construction logistics and outage impacts
  - health and safety risks
  - environmental issues
  - operating and maintenance costs and expectations
- economic evaluations to identify the most favourable and least-cost projects and programs
- interaction and refinement of project requirements with the augmentation needs of VENCorp and connected parties
- project and program prioritisation and optimisation to ensure that maximum efficiencies are gained across the entire work schedule.

The forecast capex can also be described in terms of asset classes, including categories of secondary plant, switchgear, transformers and lines, etc,. This breakdown is shown in Figure Figure 5-2, which highlights that expenditure is associated with switchgear, establishment, transformers and secondary plant. Noticeably there is very little expenditure on lines, and this is consistent with SPA's advice that the replacement program is focused on the redevelopment of metropolitan terminal stations.

Figure 5-2 – SPA's forecast capex proposal categorised by asset class



Source: PB analysis

The forecast program includes major rebuilding of six Melbourne metropolitan terminal stations including Brooklyn, Keilor, Richmond, Ringwood, Thomastown and the commencement of West Melbourne, plus major rebuilding of four regional stations at Glenrowan, Geelong and two at Hazelwood.

The other asset replacement program includes 30 separate projects covering various asset classes including large expenditure amounts for matters such as control and monitoring equipment, transformers, and bulk oil circuit breakers, down to minor expenditure amounts for the likes of AC and DC supplies, station air conditioners and energy metering.

The compliance program includes projects related to matters concerning occupational health and safety, security measures and environmental obligations. It includes projects like the installation of fall restraints on towers, replacement of post type CTs that are prone to fail explosively, upgrading of oil containment facilities, noise mitigation, station security and access controls.

5.2 SELECTION OF PROJECTS FOR DETAILED REVIEW

The role of detailed project reviews is to test the investment framework and the internal procedures within SPA from a bottom-up perspective. The importance of the detailed reviews is to understand each step throughout the decision-making process using practical examples rather than generalised references and substantiate that a consistent approach has been adopted across the various project categories.

In accordance with Table 4.3[94] within the supporting templates of SPA's Electricity Transmission Revenue Proposal, there are 56 separate projects or programs of work proposed over the 6-year 2008/09 to 2013/14 regulatory period.

These 56 projects have been categorised in accordance with Table 5-2.

Table 5-2 – Summary of the ex-ante (network) projects proposed by SPA

Project category	Number of projects	Total expenditure $m(real 07/08)	Total expenditure %	Key driver for expenditure
Compliance	16	154.0	19.4	Compliance
Other asset replacements	2	51.3	6.5	Compliance
Other asset replacements	12	50.9	6.4	Operational performance
Other asset replacements	16	154.7	19.5	Asset failure risk
Station replacements	10	384.4	48.3	Asset failure risk
TOTAL	56	795.3	100	

Source: PB using Information Template submission Table 4.3

PB, in conjunction with the AER, has selected six forecast (ex-ante) projects for detailed review. The selection process for the forecast projects has been coordinated with that for the historic projects and has captured the materiality of the cost, the defined project categories and drivers, the asset categories, the project location and affected parties, and the timing of the expenditure.

The six projects selected are summarised in Table 5-3

Table 5-3 – Selection of ex-ante projects for detailed review

Project category	Project description	Key driver for expenditure	Total expenditure $m (real 07/08)
Compliance	Replacement of post type CTs	Compliance	24.5
Other asset replacements	Replacement of station and control centre SCADA	Compliance	43.9
Other asset replacements	Response capability for undefined works	Operational performance	5.5
Other asset replacements	Transformer replacement	Asset failure risk	28.8
Station replacements	Redevelopment of RTS	Asset failure risk	89.7
Station replacements	Refurbishment of HWPS	Asset failure risk	36.6
TOTAL			229.0

Source: PB analysis

94 Information Templates, Table 4.3 - FORECAST CAPEX - NETWORK - (As Spent) by project

The selection of forecast capex projects for detailed review includes all project categories and drivers, and covers 11% of the program by the number of projects (56 in total) and 29% of the program by the value of projects ($795m).

The following sections contain a summary of the detailed project reviews. The main body of these reviews are contained in the appendixes referenced with the review summaries. Each summary review consists of a project overview, costs and a conclusion.

The review details contained in the referenced appendices consists of the following sections:

- project overview — a brief outline of the project and its development (repeated in the appendix for completeness only)
- drivers (need or justification) — a summary of the documented needs as presented in the supplied project documentation
- strategic alignment and policy support — a brief consideration of any documented alignment of the project with SPA's asset management strategy, overarching policies, or plans
- alternatives — a summary of the options considered to meet the identified need as presented in the project documentation supplied
- timings — presents an overview of the project's timing
- PB analysis — presents a brief discussion of the views formed by PB in assessing the supplied project documentation, focusing in particular on the capex prudency assessment
- costs — presents a summary of the project costs as submitted by SPA along with PB cost recommendations (repeated in the appendix for completeness only)
- conclusion — a brief summary of the main views formed by PB (repeated in the appendix for completeness only).

5.3 REFURBISHMENT OF HAZELWOOD POWER STATION SWITCHYARD (HWPS)

The Hazelwood power station switchyard (HWPS) refurbishment project involves the staged expenditure of $36.6m ('as spent', real 07/08) across the 2008/09 to 2013/14 regulatory period as shown in Table 5-4.

Table 5-4 – Proposed capex for refurbishment of HWPS

Expenditure $m ('as spent', real 07/08)	08/09	09/10	10/11	11/12	12/13	13/14	Total
SPA proposal	8.2	4.1	8.8	3.5	5.8	6.2	36.6

Source: SPA Proposal, Information Templates

This project ranks as the seventh largest (ex-ante) expenditure item and accounts for 4.6% of SPA's total proposed network-related capex.

The following information is an extract of the full detailed project review that is presented in Appendix K.

5.3.1 Project overview

Hazelwood power station switchyard is a 220 kV switchyard established in the mid-1960s and it contains 33 circuit breakers and six bus-bars, within 21 separate bays. The key role of the facility is the entry connection for generation from the neighbouring power station.

The project scope involves the replacement of 24 bulk oil type circuit breakers and associated bay equipment, including disconnect and earthing switches and secondary equipment, and the establishment of a new control building. Other than through the use of modern equivalent assets as part of the replacement program, there is no augmentation element captured in this project.

5.3.2 Costs

The detailed and itemised cost estimate presented for the *targeted brownfield replacement* option appears, to PB, reasonable and thorough. This is on the basis that the estimate was established using SPA's detailed Expert Estimator system and the costs were clearly categorised into management, design, site establishment, procurement and installation of electrical plant, civil works, protection, control and AC and DC supplies components.

The estimate also includes reasonable amounts for dismantling and removing existing equipment, a 5% contingency capturing latent conditions, and a weighted 4.7% adjustment for real capex costs escalations[95]. Costs have also been sub-categorised into labour, material, plant, and subcontracted costs. PB observes that the levels of expenditure are reasonable, where internal labour accounted for at least 30% of the total cost, and this consistent with our previous experience, including recent TNSP regulatory determinations.

The technical specification of the replacement circuit breakers[96] appears efficient and prudent, given the incremental costs of these units compared with the specification of the bulk oil plant being replaced, and the advice stipulated by VENCorp to cater for future augmentation provisions. The average cost to remove the existing plant and replace each circuit breaker equates to around $1.5m per unit.

The scope of work for both options evaluated by SPA includes installation of bus-side remote-operated isolators (ROIs) for each new CB. This is an outcome of the decision by SPA to use SF_6 (gas-insulated) circuit breakers, and a policy directive by VENCorp. This appears to be an efficient outcome given the compliance obligations; however, for transparency purposes PB would have been preferred to see SPA's consideration of other technologies that may have precluded the need for the bus-side ROIs.

Use of plant side ROIs (as opposed to bus-side ROIs), and the replacement of a number of post insulators, surge arrestors, current transformers and capacitor voltage transformers, appears to be beyond the scope of work to address the specified CB failure need identified by SPA. While there may be technical, risk based, and economic benefits of extending the scope and costs to include these items, PB has not reviewed any such analysis. On this basis, and on the understanding that this work does not address the primary identified need, PB is of the view that the expenditure associated with these aspects of the refurbishment is not efficient and should be excluded from the ex-ante allowance. PB recommends an adjustment of $4.0m[97] be made to the $35.7m (real 2006/07) estimate to account for this.

The development of a dedicated SPA control room (as opposed to sharing of the existing relay room with the power station owner) to house the protection, monitoring, and control equipment

95 It also included a 1% adjustment to allow for outage costs.

96 50kA fault rating, 3,150A load rating.

97 Estimated based on procurement and installation (only) of 20 ROI's, 40 CVTs, 5 surge arrestors, and 100 post insulators.

for the switchyard, appears reasonable given the extent of the work proposed in the targeted replacement option and the additional redundancy benefits.

The scope of work for each option also appears to be fundamentally based on a ‘like-for-like’ replacement (using conventional outdoor equipment), whereby the need to maintain the original functionality of the switchgear is preserved (i.e. all lines which are currently single switched remain single switched, etc). The logistical issues at the site introduce cost penalties associated with new overhead line entries and the need to move some connections between bays. However, PB believes that these additional costs are comparatively small and should not lead to large-scale inefficiencies.

PB understands that the cost for Stage 1 of the deferred expenditure option has been estimated using a preliminary planning assessment as opposed to the detailed Expert Estimator process. In most cases these costs are generalised and transparent, and typically reflect a reasonable and prudent amount based on the defined scope of works, typical labour rates, and estimates of the duration of work involved. However, one of the cost estimates is considerably higher than PB would have expected[98] — that of the critical work associated with the removal, refurbishment, and re-installation of the bushings on the circuit breakers — we recognise that this may be reflective of the intensity of the work requirements and therefore do not propose any adjustments.

5.3.3 Conclusion

The proposed redevelopment of HWPS ranks as the seventh largest (ex-ante) expenditure item and accounts for 4.6% of SPA’s total proposed network-related capex.

After PB’s detailed review of project documentation and the risk model application undertaken by SPA, we have formed the following views:

- the refurbishment of HWPS is driven by a clear need, the risk of failure of the bushings of multiple and ageing bulk oil circuit breakers, as evidenced by three major failures of the same CBs since 1992
- the project delivers strategic benefits by reducing the number of bulk oil CBs within the network and removing 24 of the top 25 risk-ranked CBs from this asset category
- SPA considered a wide range of alternatives during its assessment; however, the technical feasibility of a key option was found to be limited once a more detailed review was undertaken, as dictated by simplistic economic assessment
- Notwithstanding an escalation error captured in the economic analysis, SPA has selected the most technical and economically reasonable option for inclusion in it forecast capex allowance
- the staged timing of the development and expenditure is reasonable given the complexity of the yard and the clear need to mitigate the risk of asset failure
- SPA has not demonstrated a justified need for expenditure associated with the replacement of a number of isolators, post insulators, surge arrestors and capacitive voltage transformers at HWPS. On this basis, PB believes a more efficient project scope is appropriate and, on this basis, has recommended a capex reduction of $4m.

Given these findings, PB recommends a slight reduction in the expenditure allowance for the HWPS redevelopment over the 2008/09 to 2013/14 regulatory period. This outcome should have minimal impact on the overall risk profile faced by SPA, and the recommended expenditure is shown in Table 5-5.

98 More than 100 person-days per unit.

Table 5-5 – HWPS refurbishment project review

Expenditure $m ('as spent', real 07/08)	08/09	09/10	10/11	11/12	12/13	13/14	Total
SPA proposal[99]	4.9	11.7	8.6	3.4	5.6	1.5	35.7
Proposed variation	—	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(4.0)
PB recommendation	4.9	10.9	7.8	2.6	4.8	0.7	31.7

Source: SPA Proposal and PB analysis

5.4 REPLACEMENT OF POST-TYPE CURRENT TRANSFORMERS

The replacement of post-type current transformers (CTs) proposed by SPA is a compliance-based program of works targeted at the progressive replacement of CTs at various sites. It involves the staged expenditure of $24.5m ('as spent', real 07/08) across the 2008/09 to 2013/14 regulatory period as shown in Table 5-5.

Table 5-6 – Proposed capex for the CT replacement program

Expenditure $m ('as spent', real 07/08)	08/09	09/10	10/11	11/12	12/13	13/14	Total
SPA proposal	4.8	6.1	5.2	4.2	2.7	1.4	24.5

Source: SPA Proposal, Information Templates

This program ranks as the thirteenth largest (ex-ante) expenditure item and accounts for 3.1% of SPA's total proposed network-related capex.

The following information is an extract of the full detailed project review that is presented in Appendix L.

5.4.1 Project overview

This capex is an extension of around $10m of CT replacement-related works initiated during the current regulatory period, and is in addition to the selective replacement of CTs as part of specific station refurbishment works.

The project scope includes the replacement of 73 sets of independent[100] single-phase CTs (and associated voltage transformers) at 14 different sites, across four different voltage levels (at 220 kV or above) and across nine different manufacturers. Except for the use of modern equivalents as part of the replacement program, there is no augmentation captured in this project.

5.4.2 Costs

The costs of the proposed CT replacement program have been established by SPA through the use of unit cost estimates. The average replacement cost for CTs at the different voltage levels used by SPA for the 2008/09 to 2013/14 regulatory period is shown in Table 5-6.

99 As amended by SPA.

100 Excludes the consideration of the 1,100 toroidol CTs built into transformers or switchgear.

Table 5-7 – Average CT replacement costs

Voltage level	220 kV	275 kV	330 kV	500 kV
Replacement cost (per three phase set) ($k, real 07/08)	275	290	290	565

Source: PB analysis

These cost estimates include allowances for higher proportions of project management and site establishment costs in recognition of the smaller scope of the replacements, plus significant brownfield-related costs to allow removal of existing plant and increased design and management costs. The cost of any necessary CVTs has been spread across the 220 kV CTs to represent and overall average.

5.4.3 Conclusion

The proposed replacement of 73 sets of oil-insulated post-type CTs ranks as the thirteenth largest (ex-ante) expenditure item and accounts for 3.1% of SPA's total proposed network-related capex.

After PB's detailed review of project documentation and the risk model application undertaken by SPA, we have formed the following views:

- the replacement of post-type CTs is driven by a clear need, their explosive nature and risk of failure presents an unacceptable risk for SPA, as evidenced by seven major failures since 1985
- the project delivers strategic benefits by reducing the number of post-type oil insulated CTs within the network and reduces the relative asset-risk level by around 30% in 2013
- the range of alternatives considered by SPA are reasonable, comprehensive and technical feasible
- the planned replacement by asset class approach is pragmatic given that the CTs being replaced are typically matched with other plant that is in reasonable working condition and does not require imminent replacement
- the timing of CT replacement expenditure appears more aggressive than that driven purely by the outputs of SPA's detailed asset risk model and has captured a large proportion of units with a life expectancy of greater than or equal to 7 years. In PB's view, SPA has not established a justifiable need for all aspects of the proposed replacements. On this basis PB has recommended a revised expenditure profile that reflects what it considers to be a reasonable and prudent capex allowance
- while the costs of individual CT replacements appears efficient, given historical experience and the need to include some capacitive voltage transformers, PB considers the project scope and cost proposed by SPA is inefficient on the basis that allowance was made for some expensive 500 kV CT units but that these have been interchanged with 220 kV units based on the latest information. PB has adjusted the cost of the allowance to accommodate this change.

Given these findings, PB recommends a deferral in the timing of investment for some CTs, reflected in a reduction in the expenditure allowance for the post-type CT replacement over the 2008/09 to 2013/14 regulatory period. This outcome should have only a small impact on the overall risk profile faced by SPA, and the associated expenditure is shown in Table 5-8.

Table 5-8 – CT replacements project review

Expenditure $m ('as spent', real 07/08)	08/09	09/10	10/11	11/12	12/13	13/14	Total
SPA proposal	4.8	6.1	5.2	4.2	2.7	1.4	24.5
Proposed variation	(2.0)	(3.6)	(2.8)	(2.5)	(1.0)	—	(12.0)
PB recommendation	2.8	2.5	2.4	1.7	1.7	1.4	12.5

Source: SPA Proposal and PB analysis

5.5 RESPONSE CAPABILITY FOR UNDEFINED WORKS

The response capability for undefined works is an expenditure allowance aimed to improve SPA's operational performance. It involves the once-off expenditure of $5.5m ('as spent', real 07/08) in 2008/09 as shown in Table 5-8.

Table 5-9 – Proposed capex for the response capability for undefined works

Expenditure $m ('as spent', real 07/08)	08/09	09/10	10/11	11/12	12/13	13/14	Total
SPA proposal	5.5	—	—	—	—	—	5.5

Source: SPA Proposal, Information Templates

This allowance ranks as the 34th largest (ex-ante) expenditure item and accounts for 0.7% of SPA's total proposed network-related capex.

The following information is an extract of the full detailed project review that is presented in Appendix M.

5.5.1 Project overview

This project effectively makes an allowance for unforeseen minor works activity and expenditure in network-related areas of protection, control, communications, primary equipment, civil works, structures, buildings and grounds. The scope of works cannot be described in any specific terms, but will be related to events associated with key assets.

5.5.2 Costs

SPA advised that it believes the proposed allowance is a highly conservative figure based on previous experience. It arrived at the figure through analysis of its historical expenditure, where there were around 47 projects per annum previously unforeseen across the 2002/03 to 2007/08 regulatory period. It expects there will be around 10 each year in the coming period and has used the historical average cost to develop its forecast.

PB acknowledges the historical experience but also notes that the previous forecast was formed under an ex-post regulatory regime — suggesting there was less onus on SPA to maximise the accuracy of its forecast.

5.5.3 Conclusion

The proposed allowance for SPA's response capability for undefined works ranks as the 34th largest (ex-ante) expenditure item and accounts for 0.7% of SPA's total proposed network-related capex.

In the context of the efficiency incentive-based ex-ante regulatory regime underpinning SPA's allowance, and given the rigorous and systemic approach adopted by SPA in preparing its forecast using a bottom-up approach (inclusive of estimating contingencies), PB cannot support the proposed allowance given its asymmetrical nature. We consider there will be sufficient discretion within the overall replacement program to ensure minimal changes in risk should relatively minor and unforeseen events require network based capex.

PB recommends no unforeseen minor works allowance be included in SPA's forecast capex, and the impacts of this recommendation are presented in Table 5-10.

Table 5-10 – Response capability for undefined works project review

Expenditure $m ('as spent', real 07/08)	08/09	09/10	10/11	11/12	12/13	13/14	Total
SPA proposal[1]	0.92	0.92	0.92	0.92	0.92	0.90	5.5
Proposed variation	(0.92)	(0.92)	(0.92)	(0.92)	(0.92)	(0.90)	(5.5)
PB recommendation	—	—	—	—	—	—	—

Source: PB analysis

5.6 TRANSFORMER REPLACEMENTS

This expenditure is associated with the replacement of transformers at a number of different terminal stations to minimise the risk and consequences of asset failure. It involves the staged expenditure of $28.8m ('as spent', real 07/08) across the 2008/09 to 2013/14 regulatory period as shown in Table 5-11.

Table 5-11 – Proposed capex for the transformer replacement program

Expenditure $m ('as spent', real 07/08)	08/09	09/10	10/11	11/12	12/13	13/14	Total
SPA proposal	3.5	5.4	2.0	5.5	7.9	4.5	28.8

Source: SPA Proposal, Information Templates

This program ranks as the eleventh largest (ex-ante) expenditure item and accounts for 3.6% of SPA's total proposed network-related capex.

The following information is an extract of the full detailed project review that is presented in Appendix N.

5.6.1 Project overview

Power transformers are critical elements of the transmission system allowing connected party's access to and from the network, and allowing for efficient transmission of power at high voltage levels. Failure of a transformer at a critical time, particularly at customer-connected terminal stations, may result in the disconnection of generation or local loss of supply to customers. Furthermore, depending on the nature of the failure and the availability of spares, the restoration time after transformer failures may be significant — extending to months given their specialist design and application.

SPA has developed a quantitative risk model specially looking at the reliability, availability safety, environmental, and business risks associated with major failures of more than 200 power transformers. It considers the probability of failure of a unit based on a condition assessment of its tap changers, bushings, insulating oils and cores and windings through the use of over 200 separate measurable parameters. The model also considers the consequences of failure including environmental and collateral damage and unplanned procurement, amongst other things. SPA has also developed a condition based model, for which the output is a relative ‘condition score’ (ranging from 0–69) based on individual condition monitoring and testing, where 0 reflects a brand new unit and 69 reflects a condition consistent with the oldest unit in SPA’s network.

This project scope allows for the replacement of five transformers (comprised of 12 separate units). Three of these are at specific locations (Dederang, Bendigo and Yallourn), while two of these address a fleet of transformers across a number of metropolitan stations. This expenditure has been coordinated with a separate refurbishment program, station-specific transformer replacements and the procurement of a spare 220/22 kV unit. Three of the five transformer replacements include an aspect of augmentation, while the remaining two replacements provide for improved cyclic ratings compared with the existing units.

5.6.2 Costs

The cost of the transformer replacement program has been established through the use of unit prices based on SPA’s previous experience given the specific nature of these types of projects.

The specification for each transformer is slightly different with units ranging from 150 MVA to 340 MVA, and voltage levels from 330 kV to 11 kV. Replacement units will be of three-phase design, extending the design standardisation principles adopted by SPA and maximising the benefit of strategic spares.

In two of the five cases considered (Ballarat and Yallourn), SPA appears to have unilaterally taken the opportunity to include an augmentation component – however this appears to be driven by the adoption of standard transformer sizes. In the case of the Dederang transformer replacement, SPA advises that the augmentation component has been discussed with VENCorp on a number of occasions and that it has been mutually accepted between the parties to replace the existing unit with a transformer to match the capacity of the existing units. In the other two transformer replacement cases, SPA is proposing improvements in the applicable cyclic ratings of the transformers, which is likely to lead to increased transfer capability.

The existing Dederang and Bendigo transformers comprise single-phase banks and additional costs have been allowed to cater for new, appropriate rack structures, foundations and oil-containment devices.

Cost estimates range from \$3.8m to \$9.7m and these appear reasonable for the capacity and type of installed transformer (without any switchgear) when compared to our benchmark costs.

5.6.3 Conclusion

The proposed replacement of five transformers ranks as the eleventh largest (ex-ante) expenditure item and accounts for 3.6% of SPA’s total proposed network-related capex.

After PB's detailed review of project documentation and the risk model application undertaken by SPA, we have formed the following views:

- the replacement of one 150 MVA fleet transformer and the Bendigo unit within this project is not driven by a clear demonstrated need and therefore does not appear to be prudent. SPA does not appear to discuss the consequences of failure in the context of the various spare units available, nor the units released for service from other station rebuilds
- the project aims to deliver strategic benefits by targeting single phase units and reducing the relative risk levels compared with that in 2008. SPA provides some high level discussion on the integration of various projects to capture economies of scale to provide a better overall outcome, however such analysis is not carried through to provide economic support for the replacement of transformers that are reasonably well ranked in the asset risk model
- in the majority of cases SPA's consideration of alternatives during its assessment is reasonable; however PB believes that the use of spares and further discussion on any merits of deferred expenditure or refurbishments is warranted. In the case of the Yallourn transformer, while a immediate need for replacement is apparent the ongoing need is not apparent given the low load supplied by the unit; alternative options are likely to be more prudent and efficient
- given the discretionary nature of the timing of the transformer replacement expenditure, PB considers that alternative prudent and efficient options involving the deferral of transformer replacements are appropriate and reasonable from a relative risk perspective. This is based on the minimised consequences of failures given spares availability and the original intent to integrate some degree of transformer capacity augmentation
- with respect to the Dederang replacement, PB considers a clear need has not been established purely based on asset condition and risk alone, but that through a combined augmentation/replacement project with VENCorp, the project is likely to be prudent and efficient and therefore should proceed
- PB considers the replacement of one of the large fleet of 150 MVA transformers is a reasonable, prudent and efficient outcome given the number of these units and the strategic nature of the sites they supply
- the proposed scope of work in each replacement case appears reasonable and efficient with reference to unit cost benchmarking outcomes.

Given these findings, PB recommends a reduction in the expenditure allowance for the targeted transformer replacements over the 2008/09 to 2013/14 regulatory period. This outcome should have minimal impact on the relative risk levels faced by SPA and the recommended expenditure is shown in Table 5-12.

Table 5-12 – Transformer replacement project review

Expenditure $m ('as spent', real 07/08)	08/09	09/10	10/11	11/12	12/13	13/14	Total
SPA proposal[1]	3.5	5.4	2.0	5.5	7.9	4.5	28.8
Proposed variation	(3.5)	(0.9)	2.5	(5.5)	(2.9)	(4.5)	(19.3)
PB recommendation	—	—	4.5[1]	—	5.0[2]	—	9.5

Note 1: allowance for a 150 MVA unit

Note 1: allowance for 50% of the Dederang unit

Source: PB analysis

5.7 REDEVELOPMENT OF RICHMOND TERMINAL STATION

The Richmond Terminal Station (RTS) redevelopment involves the staged expenditure of $89.7m ('as spent', real 07/08) predominantly in the last 2 years of the 2008/09 to 2013/14 regulatory period as shown in Table 5-13.

Table 5-13 – Proposed capex for the redevelopment of RTS

Expenditure $m ('as spent', real 07/08)	08/09	09/10	10/11	11/12	12/13	13/14	Total
SPA proposal	—	—	—	7.2	44.8	37.7	89.7

Source: SPA Proposal, Information Templates

This project ranks as the largest (ex-ante) expenditure item and accounts for 11.3% of SPA's total proposed network-related capex.

The following information is an extract of the full detailed project review that is presented in Appendix O.

5.7.1 Project overview

Richmond Terminal Station (RTS) was originally established in the 1930s on the banks of the Yarra River as a key station supporting the growing load of Melbourne and the surrounding areas. In 1964, a major redevelopment occurred where the original 132 kV switchyard was replaced with one operating at 220 kV, and the 22 kV outgoing switchyard was supplemented with a new 66 kV switchyard.

At present the site contains four 220/66 kV transformers, two 220/22 kV transformers, an open ring 220 kV switch yard with six circuit breakers, 22 66 kV circuit breakers and 23 22 kV circuit breakers. It is interconnected at 220 kV via three circuits, two overheads to Rowville and one cable to Brunswick and is forecast to supply approximately 620 MW[101] (6.4% of the entire state demand) under peak demand conditions over the 2007/08 summer period.

The project scope is still under review, but for the purposes of its revenue proposal, SPA has included redevelopment and reconfiguration of the 220 kV switchyard with indoor gas-insulated switchgear (GIS), replacement of three of the four 220/66 kV transformers, and the redevelopment of the 66 kV switchyard with conventional outdoor air-insulated switchgear (AIS). The project includes some aspects of augmentation, particularly upgraded individual transformer capacity; however, it is proposed one of the existing transformers will be released for use elsewhere. SPA is currently working with Citipower and VENCorp to determine the final 220 kV switching arrangement.

5.7.2 Costs

SPA has developed a preliminary cost estimate for the redevelopment of RTS based on unit prices and previous experience with similar plant.

The cost for the design, procurement, testing and installation of the four bay, indoor GIS 220 kV switchyard, inclusive of 12 circuit breakers and associated switchgear, plus short sections of 220 kV cable, is estimated as $40.2m. This includes a weighted allowance of 5% and 10% as a contingency and brownfield allowance, respectively and a further 11% for a building to enclose the plant.

101 Peak summer demand forecast (50% PoE) for 2007/08, VENCorp APR 2006, Pages 139 and 146.

The costs for the three sound enclosed 220/66 kV 225 MVA transformers is $20.6m and the 66 kV outdoor switchyard including 20 feeder bays and fault limiting reactors is $23m. Establishment, site works and infrastructure costs including remedial works and the relocation of communication facilities requires and additional $9.2m. The entire project estimate has been determined to be $93m and this includes an allowance of over 6% for unforeseen contingencies and a 10% premium to allow for the brownfield aspects of the work.

These costs compare favourably with those presented by Citipower for the BTS redevelopment (5 x 220 kV GIS at $3m each, 2 x 225 MVA transformers $6m each, 12 x 66 kV GIS CBs $750k each). On this basis PB considers the costs proposed by SPA are efficient given the defined scope of works.

5.7.3 Conclusion

The proposed redevelopment of RTS ranks as the largest (ex-ante) expenditure item and accounts for 11.3% of SPA's total proposed network-related capex.

After PB's detailed review of project documentation and the risk model application undertaken by SPA, we have formed the following views:

- the redevelopment of certain aspects of RTS are driven by a clear need, in particular the condition and configuration of the 220 kV switchyard which supplies a considerable amount of load supporting the Melbourne central business district (greater than 620 MW[102]), and which has remained primarily unchanged since its completion in 1964
- the proposed project delivers strategic benefits with respect to reduced asset failure risk and captures economies of scale by replacing the entire 220 kV switchyard with an environment impact friendly greenfield indoor GIS development
- PB believes that the timing of the replacement of the 220/66 kV transformers and the 66 kV switchyard is not prudent and has not been clearly demonstrated by SPA. Each of these developments should be considered in further detail as the outcomes of SPA's refurbishment program and Citipower augmentation needs (as affected by the Brunswick and Malvern developments) become clear. PB recommends both these aspects of the project be deferred beyond the end of regulatory period
- SPA has undertaken a rigorous review of multiple feasible and practical development alternatives, and decided upon a technically superior option. While PB considers aspects of the overall development option are reasonable, the selection process should be facilitated with a detailed economical assessment
- While the overall unit costs for assets appear reasonable and consistent (compared with benchmark costs and given the allowance for brownfield development) the efficiency of the project scope has not been demonstrated and PB recommends a reduction in the number of proposed 220 kV circuit breakers from twelve to eight – reducing the cost of the 220 kV development by around $4m.

Given these findings, PB recommends a reduction in the expenditure allowance for the RTS redevelopment over the 2008/09 to 2013/14 regulatory period. This outcome should have minimal impact on the overall risk profile faced by SPA, and the recommended expenditure is shown in Table 5-14.

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[102] Peak summer 50% PoE demand forecast for 2007/08, VENCorp APR 2006, Pages 139 and 146.

Table 5-14 – RTS redevelopment project review

Expenditure $m ('as spent', real 07/08)	08/09	09/10	10/11	11/12	12/13	13/14	Total
SPA proposal[103]	—	—	—	7.2	44.8	37.7	89.7
Proposed variation	—	—	—	(7.2)	(24.5)	(20.0)	(51.7)
PB recommendation	—	—	—	—	20.3	17.7	38.0

Source: PB analysis

5.8 REPLACEMENT OF STATION AND CONTROL CENTRE SCADA

The replacement of station and control centre Supervisory Control and Data Acquisition (SCADA) equipment is a compliance-based program of works targeted at the progressive replacement of equipment used to monitor and control SPA's transmission assets. The expenditure proposed amounts to $43.9m ('as spent', real 07/08) and is staggered across each year of the 2008/09 to 2013/14 regulatory period as shown in Table 5-15.

Table 5-15 – Proposed capex for the replacement of station and control centre SCADA equipment

Expenditure $m ('as spent', real 07/08)	08/09	09/10	10/11	11/12	12/13	13/14	Total
SPA proposal	12.4	7.9	6.5	5.4	7.5	4.2	43.9

Source: SPA Proposal, Information Templates

This program ranks as the third largest (ex-ante) expenditure item and accounts for 5.5% of SPA's total proposed network-related capex.

The following information is an extract of the full detailed project review that is presented in Appendix P.

5.8.1 Project overview

The control and monitoring system, widely referred to as SCADA, includes a central Master Station that systematically polls 100 remote terminal units (RTUs) installed at 53 separate locations for relevant measures such as voltages, currents and plant status/condition and then interprets and displays this data to operational personnel in the control centres. The system interfaces with NEMMCO as the market operator and VENCorp as the planning body. The functionality of the system is integral to the real-time operation of the network and there are significant legal and consequential implications associated with failure of the system to the extent that its design warrants duplicated, fully redundant systems across different sites.

The scope of work has been categorised into six separate elements, including:

- control centre — end-of-life replacement
- control centre — upgrade of the Master Station
- control centre — system improvements and enhancements
- substations — end-of-life replacement

103 Cost based on 220 kV switchyard replacement only and reduction in number of CBs from 12 to 8.

- substations — general upgrades
- substations — system improvements and enhancements.

5.8.2 Costs

The cost proposed by SPA for the control centre and station-based upgrade of the SCADA system has been determined primarily through previous experience. Effectively the program work costs are based on prior Authority to Proceed approvals, experience with similar works, and unit type costs for major works covering aspects such as the Master Station upgrade, replacing legacy RTUs with SCIMS platforms (small, medium and large types), integrating communications alarms and battery charger outputs into RTUs and SCIMS. SPA has not presented any supporting evidence associated with its historic costs.

The scope of work has been categorised and costs estimated based on six separate elements:

- control centre — end-of-life replacement, $6,085
- control centre — upgrade of the Master Station, $8,473
- control centre — system improvements and enhancements, $4,674
- substations — end-of-life replacement, $14,396
- substations — general upgrades, $5,602
- substations — system improvements and enhancements, $3,591

These costs can be summarised to reflect that over $19m is forecast on the control centre SCADA, $23m on substation SCADA, $20m on end-of-life replacements, $14m on upgrades, and $8m on enhancements.

SPA has not presented any further breakdown of the project costs and, except at the high level outlined above, PB has not undertaken a detailed review of the make up of the cost estimates.

5.8.3 Conclusion

The proposed replacement of control centre and station-based SCADA ranks as the third largest (ex-ante) expenditure item and accounts for 5.5% of SPA's total proposed network-related capex.

After PB's detailed review of project documentation, we have formed the following views:

- the proposed expenditure on monitoring and control (SCADA) infrastructure is supported by a general and ongoing need to ensure the critical systems affecting the reliability of the interconnected Victorian transmission network remain secure and available
- SPA has proposed a reasonable proportion (19%) of the overall expenditure to deliver enhancements and improvements that have not been economically substantiated
- the project delivers strategic benefits such as the wide-scale introduction of modern SCIMS functionality, while ensuring compliance with a number of operational and regulatory requirements
- practical and reasonable alternatives were considered, with SPA adopting past experience as a key indicator of the way forward in selecting the incremental upgrade approach
- the recurring nature of the replacements and upgrade supports the staged timing of expenditure as proposed by SPA

- without undertaking a detailed review of the sub-components of the scope of work and costs for this project, PB has been unable to categorically verify the efficiency of the proposed capex allowance.

Given these findings, PB recommends a slight reduction in the expenditure allowance for the SCADA replacement project over the 2008/09 to 2013/14 regulatory period. This outcome should have no impact on the overall risk profile faced by SPA, and the recommended expenditure is shown in Table 5-16.

Table 5-16 – Replacement of SCADA systems project review

Expenditure $m ('as spent', real 07/08)	08/09	09/10	10/11	11/12	12/13	13/14	Total
SPA proposal[1]	12.4	7.9	6.5	5.4	7.5	4.2	43.9
Proposed variation	(1.3)	(1.3)	(1.4)	(1.4)	(1.4)	(1.4)	(8.2)
PB recommendation	11.1	6.6	5.1	4.0	6.1	2.8	35.7

Source: PB analysis

5.9 CONCLUSION FROM DETAILED REVIEWS

PB has undertaken a detailed review of six projects within SPA's forecast ex-ante allowance. The projects have covered all project categories and all asset types and comprise 29% of the proposed capex allowance of $795m.

PB's general observations from this detailed review include:

- in four of the six projects investigated[104], the forecast capex is underpinned by a detailed and rigorous risk-based approach to asset management, where individual assets are ranked relative to one another according to their condition and the consequences of their failure through quantitative risk models for key asset classes
- in these four cases, the projects aim to maintain or reduce SPA's relative risk levels compared with those in 2003 and 2008
- there is considerable evidence that SPA uses its detailed risk models as a preliminary and systematic tool to inform its general views, but that its also uses good electricity industry practice and engineering judgement to capture a number of aspects within its projects not specifically addressed through the risk models — namely, compliance matters, operational improvements, and economical efficiencies (such as not revisiting sites frequently to undertake piecemeal works)
- SPA has presented reasonable and appropriate arguments to support the approach that run to failure is a less efficient and practical outcome compared to targeted and planned replacements. This is based on tangible experiences after previous explosive failures where significant health and safety risks are presented and where significant premiums are incurred to repair and replace assets in emergency timeframes
- the risk model inputs are based on contemporary and systematic condition monitoring programs (such as oil and dissolved gas analysis, and dielectric tests) that enable the model outputs to reflect the dynamic and changing characteristics of critical plant. This fosters an environment that strongly encourages continual improvement
- the outcome of a number of assessments results in SPA proposing to capture economies of scale by undertaking wide-scale redevelopment at sites where there

104 HWPS and RTS redevelopments, and the CT and transformer replacement programs

are numerous assets requiring attention at approximately the same time; SPA has not explicitly presented the economic basis for these options, but the principle is sound and should result in prudent and efficient capex

- in two of the projects investigated[105], the forecast allowance has been primarily informed through SPA's historical experience, and expectations that the underpinning drivers will continue into the next regulatory period
- the specification of plant (other than transformers) for replacement purposes appears reasonable and makes sensible allowance for incremental capacity upgrades consistent with the use of modern-day equivalents
- the specification of transformers for replacement purposes appears to incorporate a moderate amount of augmentation. While this has been coordinated with plans presented by VENCorp and connected parties, and in some cases aligned with the strategic increase in capacity from 150 MVA to 225 MVA at metropolitan sites with high load growth, additional economic justification seems warranted
- as a general finding, PB has identified that the expenditure proposed by SPA has a good technical and risk-based foundation; however, the timing of the expenditure appears to be aggressive and there appear to be a number opportunities to prioritise tasks and defer some expenditure. This needs to be considered in light of the 'wall of wire', and the trough in expenditure between 1974 and 1979
- PB has recommended the deferral of some expenditure on the basis that SPA can make better use of the assets it releases as part of the progressive redevelopment and this mitigates the consequences of asset failures. The availability of additional (refurbished) spares should allow SPA to take fewer risks with plant that it identifies as deteriorating rapidly; and it is noted that SPA proposes to release a good condition transformer at RTS with discussion on its intended application
- there does not appear to be any capex allowance that is more suited to re-classification into contingent project provisions.

PB's project targeted observations from this detailed review include:

- at HWPS, the replacement of circuit breakers is driven by a clear need, underpinned by asset failure risks and as evidenced by historic events. However, SPA has not demonstrated and clear basis or economic justification for the replacement of a number of other assets within the yard and PB has made a minor adjustment to the capex allowance to reflect, what it believes to be, a more efficient scope of works
- at RTS, PB concurs that the 220 kV switchyard warrants redevelopment given its critical role in supplying the Melbourne CBD, the condition of the assets and the technically inferior configuration of the yard. The timing, and therefore prudency of work to replace and augment the 220/66 kV transformers should be re-evaluated and coordinated with Citipower given the potential augmentation needs, the refurbishments planned by SPA and the availability of spare units to mitigate the consequences of failure, as should works concerning the 66 kV switchyard
- concerning the targeted CT replacements, we observed that SPA relied upon the dynamic output of the asset risk model to establish a program of CT replacements across numerous sites and at various voltage levels. This allowance was established based on a life expectancy threshold of 10 years. PB considers the outcome of this approach is not prudent and efficient and has recommended a alternative approach which results in a reduction in capex with moderate increase in relative risk
- in some cases, the need to replace a number of specific transformers outside the significant station redevelopment program does not appear to be substantiated and does not explicitly and appropriately consider the application of the various spares available to SPA to mitigate the risk of operational failures. In particular, the

[105] The replacement of station and control centre SCADA, and the undefined works allowance.

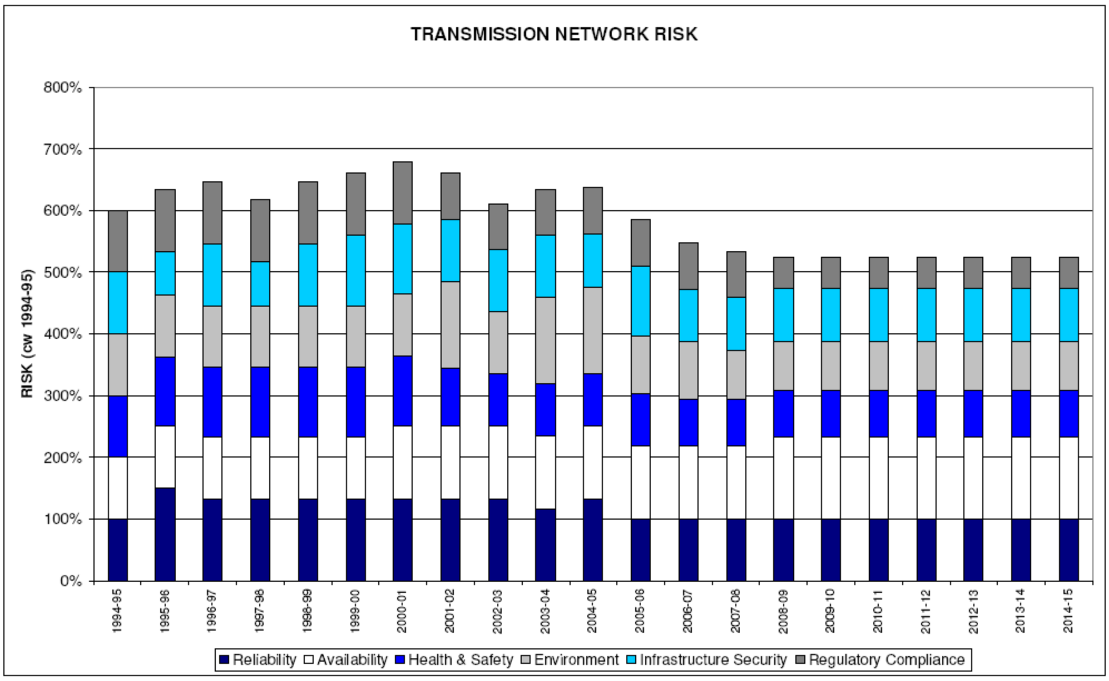
augmentation component of the Dederang transformer replacement should be coordinated with works proposed by VENCorp as this may have a material impact on import capability into Victoria

- the works to replace and upgrade critical components of the control and monitoring system (SCADA) at both the control centres and various terminal stations is consistent with historical practice and prudent and reasonable given the integral role of these systems in the real time operation of the network. However, some aspects associated with enhancements and augmentations to the system warrant further justification
- the small and non-specific allowance proposed by SPA to allow it to respond to unforeseen issues over the 2008/09 to 2013/14 regulatory period appears inconsistent with the efficiency based ex-ante regulatory regime and does not mitigate any material risk given the discretionary nature and timing of much of the forecast allowance.

5.10 APPLICATION OF DETAILED RISK MODELS

As discussed in Section 2.2 SPA has developed five quantitative risk models that are either continuously or regularly updated to reflect the existing status of its network. The models use the condition informed view of an assets probability of failure coupled with the potential network-related consequences to determine risk profiles at three levels — an individual asset risk (which also extends to asset categories), a program risk (which covers reliability, availability, health and safety, environment, infrastructure security and code compliance), and an overall network risk (which captures all multiple asset types and programs). Figure 5-3 represents SPA’s relative transmission network risk over the 20-year period 1994/95 to 2014/15.

Figure 5-3 – SPA transmission network program relative risks over time



Source: SPA Proposal

Figure 5-3 shows that:

- reliability-based risk, measured in number of interruptions (minutes unsupplied), has increased in the first 10 years but is expected to be maintained constant and consistent over the later 10 years compared with the 1994/95 reference

- availability risk, driven by planned and forced outages and increasing financial consequences of such outages, diminished over the first 10 years but is expected to increase by around 38% to 2014/15
- health and safety risk, associated with the likelihood of individual incidents, has progressively reduced and is targeted to reduce by around 30% given the ongoing replacement programs for line insulators and oil-insulated CTs, etc
- environmental risks, influenced by factors such as noise levels, use of SF6 insulation gas and bulk oil, has increased since 1994/5, but is expected to gradual reduce by around 20% compared with the reference level primarily through a reduction in the volume of oil-insulating material
- infrastructure security risk, measured by security-related events, and the heightened need for preventative measures given the risk of terrorism, has varied cyclically over time, but is expected to reduce by around 10% towards 2014/15
- regulatory compliance risk, dictated by the re-structuring of the Victorian electricity industry and emergence of the NEM, has continuously reduced as experience has matured and the environment has stabilised. The relative risk level will be around 50% that in 1994/95.

Overall the SPA transmission network risk is expected to decrease by 75% in 600% (or by 12.5%) and this is summarised in Table 5-17.

Table 5-17 – SPA transmission network program risks

Program risk	1994/95 level	2014/15 level	Improvement
Reliability	100%	100%	—
Availability	100%	138%	(38%)
Health and safety	100%	75%	25%
Environment	100%	75%	25%
Infrastructure security	100%	87%	13%
Regulatory compliance	100%	50%	50%
TOTAL	600%	525%	75%

Source: PB analysis

SPA detailed risk model outputs are discussed in the following sections based on each asset category.

5.10.1 Circuit breaker asset failure risk

SPA's circuit breaker fleet is one of the oldest when compared with international transmission network asset owners[106] and its performance is measured by failure rates.

Each circuit breaker has a detailed condition assessment undertaken, which looks at matters such as condition, health and safety, environment, fault levels and support costs. A condition weighting is then assigned and a condition ranking and probability of failure determined based on the thresholds in Figure 5-4.

106 ITOMS 2005 Report – International Transmission Operations & maintenance Study – Revision 6, May 2006.

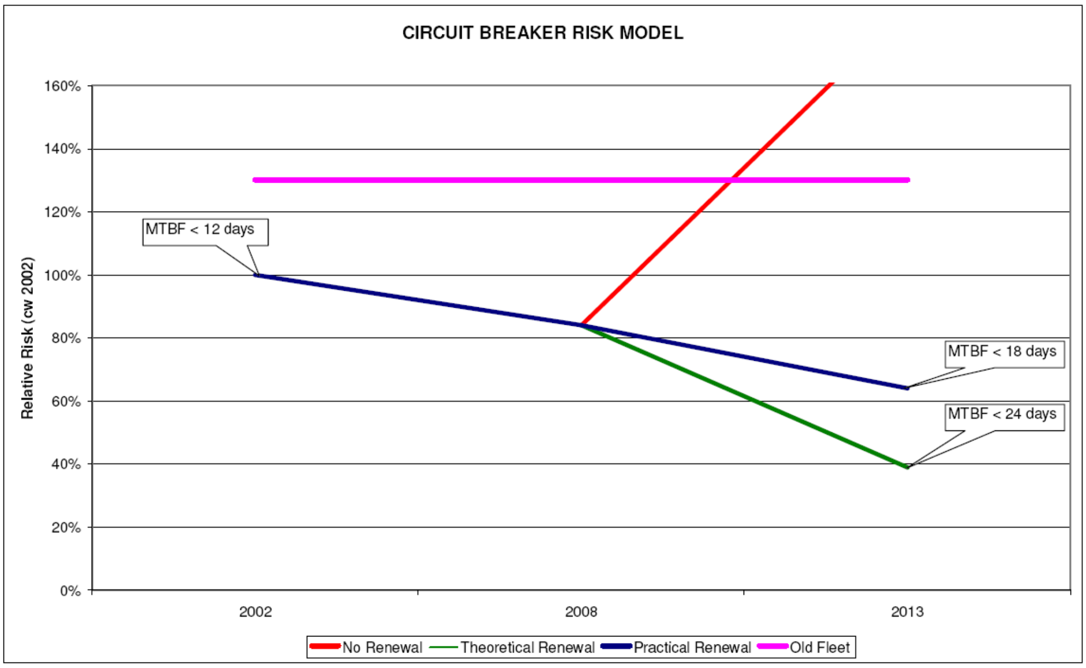
Figure 5-4 – Circuit breaker condition rankings

	Ranking levels				
Weighted Risk Score	0.00000	0.003422159	0.010266477	0.020532953	0.034221589
Probability	0.02580	0.03354	0.0516	0.0774	0.11352
MTBF	38.75969	29.81514609	19.37984496	12.91989664	8.809020437
Assigned Ranking	Low	Med/Low	Medium	High	Very High
Normalised Age	1	25	35	45	55

Source: SPA Proposal

The overall asset failure risk[107] is shown in Figure 5-5, and is based on a population of 1,017 units. The relative level of risk is seen to decrease materially from 100% as a reference level in 2002 to approximately 85% in 2008 and subsequently 65% in 2013, based on SPA's proposed level of expenditure.

Figure 5-5 – Circuit breaker asset failure risk



Source: SPA submission, VERSION 1 CIRCUIT BREAKER - RISK MODEL.pdf, March 2007

Table 5-18 summarises the detailed application of SPA's circuit breaker asset failure risk model.

107 Asset failure risk only accounts for the condition and probability of failure, without any consideration to the consequences of failure.

Table 5-18 – Application of circuit breaker asset failure risk (at 2013)

Program risk (in 2013)	MTBF[1] (years)	Station refurb.	CB bay replace.	Asset works program[2]	Next period	OK	TOTAL
Very High	8.8	117	22	—	7	—	146
High	12.9	6	—	7	13	—	26
Medium	19.4	60	14	10	62	19	165
Medium/Low	29.8	25	—	—	33	119	177
Low	38.8	2	—	6	1	494	503
TOTAL	—	210	36	23	116	632	1017

Note 1: Mean Time Before Failure reference level

Note 2: These CBs are not to be replaced, but shall have additional work performed as part of a high level program

Source: PB analysis

The key observations from Table 5-18 include:

- 246 (24%) of circuit breakers in the risk model are forecast to be replaced over the 2007/08 to 2013/14 regulatory period[108]
- there are 20 circuit breakers rated in the High or Very High risk categories (as of 2013) that are scheduled for replacement in the subsequent regulatory period — this represents SPA's acceptance that the asset risk models do not completely dictate investment programs at any cost
- there are 145 circuit breakers scheduled for replacement that are categorised with a risk of High or Very High, and 139 of these are in the Very High risk category which represents circuit breakers with a MTBF of less than 8.8 years (as of 2013)
- there are 99 circuit breakers scheduled for replacement that are categorised with a risk of Medium or Medium/Low — this represents SPA intentions of advancing the replacement of circuit breakers due to other technical aspects not captured in the risk models, through compliance needs, or simply to capture economic efficiencies. Specifically a large number of these circuit breakers (>60[109]) are scheduled for replacement to pre-empt the large volume (>200 units) of 66 kV bulk oil circuit breakers that will require replacement over the next 15 years — as at 2009, the newest of these will be 40 years of age
- there are two circuit breakers targeted for replacement from the low risk category, which represents circuit breakers with a MTBF of greater than 38 years (as of 2013). These are 2 x 66 kV capacitor bank CBs at Thomastown and PB has reviewed documentation submitted by SPA and identified no clear need for the CBs to be replaced. The issue appears to be clearly associated with high maintenance and low availability due to failure of individual capacitors within the bank and the resulting unbalances. However, given the CBs are relatively inexpensive (66 kV), PB considers no capex adjustment is necessary given the small scale.

108 These are comprised of 14, 116, 100 and 16 circuit breakers at voltage levels of 500 kV, 220 kV, 66 kV and 22 kV, respectively.

109 Located at Morwell, Keilor, Horsham, Geelong, Brooklyn, Richmond, and Ringwood.

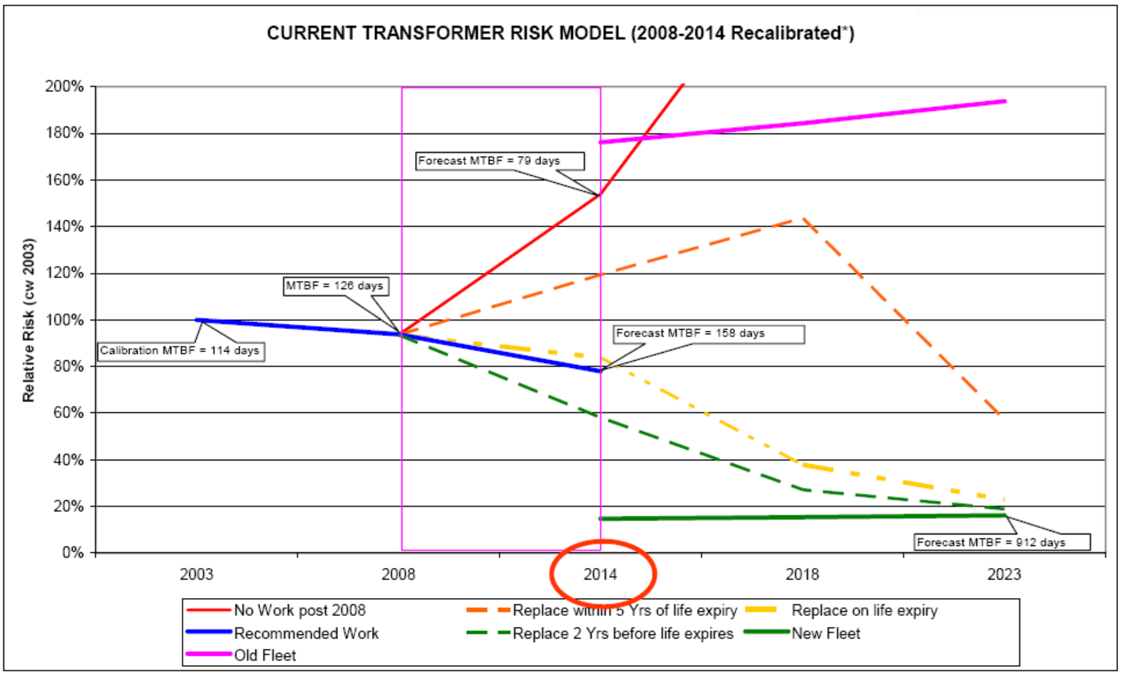
5.10.2 Current transformer asset failure risk

SPA has experienced several explosive failures of oil-insulated post-type CTs, as discussed in Section 5.4.

The risk model is informed through the regular and routine oil sampling and subsequent dissolved gas analysis. The risk model uses these inputs to determine the estimated remaining life (life expectancy) for each current transformer, with SPA using a threshold of 10 years as the basis for asset replacement, unless the work can be integrated with other station works.

The asset failure risk[110] is shown in Figure 5-6, and is based on a population of 1,120 units[111]. The relative level of risk is seen to decrease materially from 100% as a reference level in 2003 to approximately 90% in 2008 and subsequently 75% in 2013, based on SPA's proposed level of expenditure, which includes replacement of over 580 single phase CTs.

Figure 5-6 – Current transformer asset failure risk



Source: SPA submission, UPDATED CURRENT TRANSFORMER RISK MODEL.ppt, 16 March 2007

Table 5-19 summarises the detailed application of a subset (350 units) of SPA's current transformer asset failure risk model.

110 Asset failure risk accounts for the condition and probability of failure and a generic consequence of failure independent of voltage level and location.

111 This comprises about 60% of the entire CT fleet of over 1850 units – which excludes toroidal units mounted within transformer and switchgear bushings.

Table 5-19 – Application of current transformer asset failure risk

	Life expectancy of units to be replaced (years, as of 2008)					
Program risk	**0-4**	**5-9**	**10-14**	**15-19**	**20>**	**TOTAL**
Geelong	9	7	14	1	1	32
Brooklyn	—	17	16	—	—	33
Glenrowan	—	9	14	3	1	27
Horsham	—	4	8	—	—	12
Hazelwood	2	6	7	8	1	24
Keilor	8	13	35	6	2	64
Richmond	—	7	5	—	—	12
Program	20	23	25	5	—	73
(Not replaced)	—	(11)	(30)	(16)	(16)	(73)
TOTAL	39	97	154	39	21	350

Source: PB analysis

The key observations from Table 5-19 include:

- of the 350 current transformers presented[112], 277 (79%) are forecast to be replaced over the 2007/08 to 2013/14 regulatory period
- the majority of replacements (58%) are occurring at only a few locations, indicating SPA is capturing efficiencies of doing multiple replacements at fewer sites
- the majority of CTs (55%) scheduled for replacement have a life expectancy of greater than 10 years.

5.10.3 Transmission line insulator asset failure risk

SPA owns transmission lines comprising over 6,500 km of circuit length, with over 13,000 individual structure and towers. Predominantly, the plant is 220 kV transmission and the tower, conductors and insulators have an average age slightly greater than national and international contemporaries.

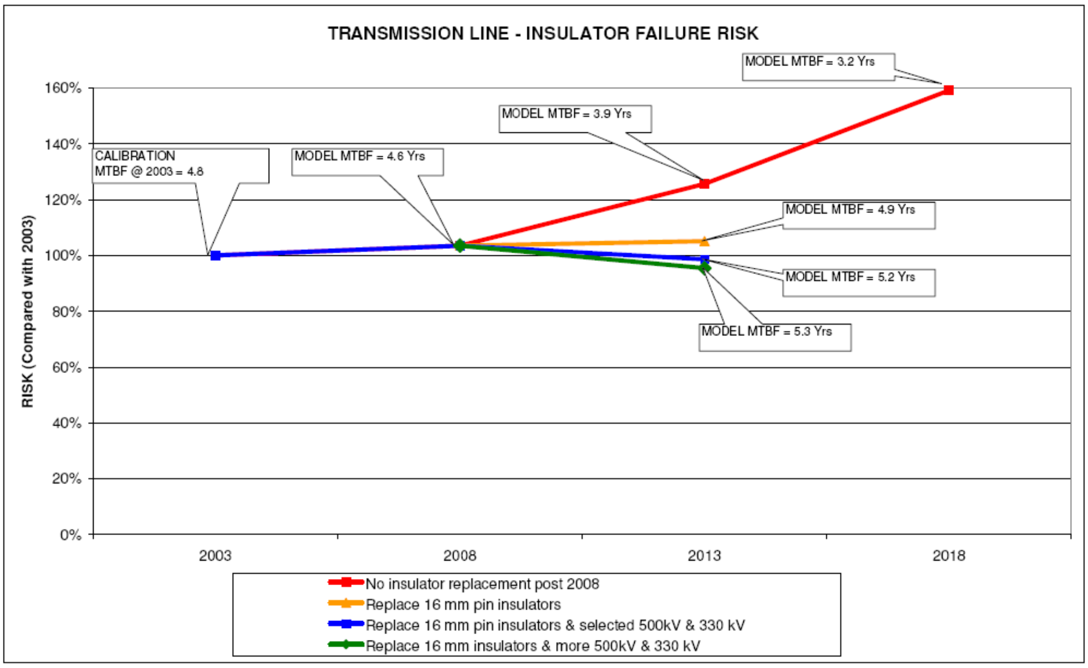
Between 2001 and 2004, every tower in northern and western Victoria was subjected to a detailed climbing inspection, and in 2006 this process was refined so that only 9% of towers in eastern Victoria were assessed. The condition of the tower foundations, the steelwork, the insulators, the conductors and the earth wires were each considered separately and systematically. SPA's asset failure risk model draws on each of these aspects; however, the line insulators are the critical components and dominate the resultant risk profiles.

Asset condition scores are then used to determine a typical, short or long life probability of failure versus age curve for each asset. A score of less than or equal to 4.1 dictates a long life, greater than 4.1 a typical life, and greater than 5.1 a short life.

[112] This is only a subset of the entire CT risk model output

The overall asset failure risk[113] is shown in Figure 5-7, and is based on a population of 13,265 units. The relative level of risk is seen to increase marginally from 100% as a reference level in 2002 to approximately 105% in 2008 and then subsequently decrease to around 98% in 2013, based on SPA's proposed level of expenditure.

Figure 5-7 – Transmission line – insulator asset failure risk

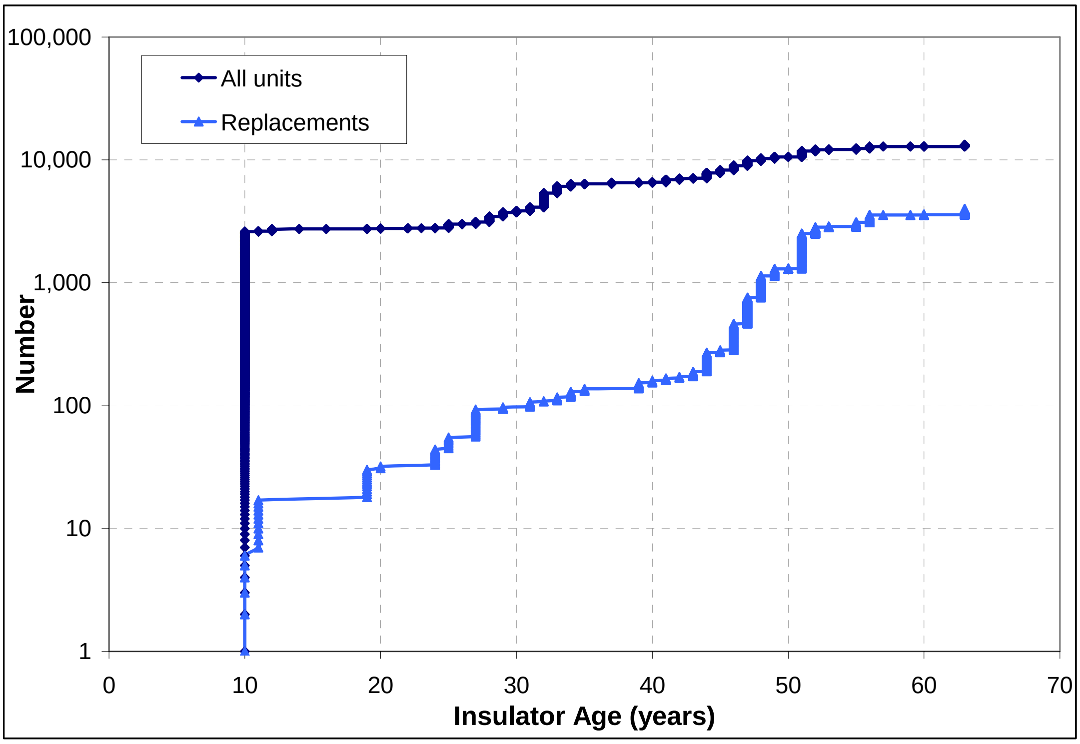


Source: SPA submission, VERSION 1 TRANSMISSION LINE RISK MODEL.ppt, March 2007

Figure 5-8 summarises the detailed application of SPA's circuit breaker asset failure risk model.

113 Asset failure risk accounts for the condition and probability of failure, and the consequences of failure, such as specific availability incentives, bush fire risks or proximity to public thoroughfares.

Figure 5-8 – Transmission line insulator risk model application



Source: PB analysis

The key observations from Figure 5-8 include:

- 3,986 (30%) of line insulators in the risk model are forecast to be replaced over the 2007/08 to 2013/14 regulatory period
- the vast majority of these (>96%) are more than 40 years old [114]
- there are 17 units (0.4%) with an age of 11 years or less that are being replaced
- there are 424 units (11%) with an age of 50 years or more being replaced.

SPA is progressing the staged replacement of 16 mm pin diameter insulator strings, plus a selection of 330 kV and 500 kV insulators. The use of the risk model has provided only preliminary insight into investment decision since some fatigue based failures have not yet been integrated.

5.10.4 Power transformer asset failure risk

SPA's fleet of transformers is relatively old when compared with international transmission network asset owners[115]. There are a significant proportion of units with an age (as of 2006) greater than 36 years — approximately 65% of main tie transformers and 75% of connection transformers.

SPA's power transformer condition model separately assesses the condition of the oil, tap changer's, the core and winding's, bushings, the tank itself, plus the wiring and cooling system based on monitoring and testing programs. From the detailed condition assessment model, an overall relative condition weighting is assigned, and a relative ranking (a 'condition score') is assigned to each unit ranging from 0 (representative of a brand new unit) to 68 (representative

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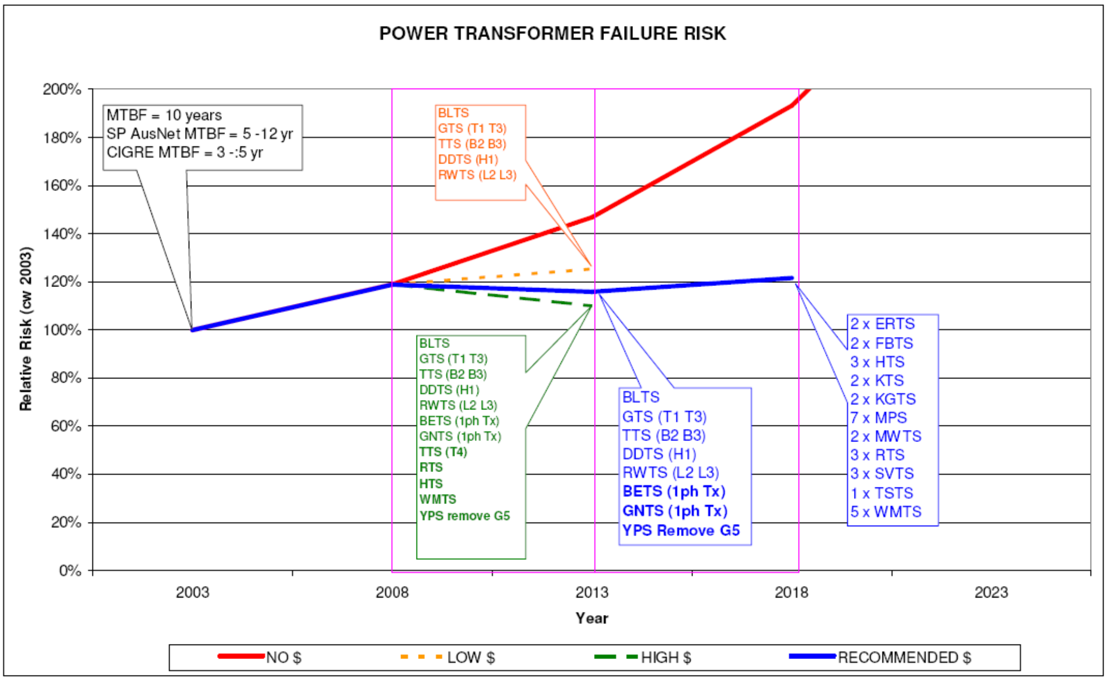
114 As of 2013.

115 ITOMS 2005 Report – International Transmission Operations & maintenance Study – Revision 6, May 2006.

of the oldest and most deteriorated unit in Victoria). The condition score is used to identify transformer tanks for further investigation and potential remedial action, including increased condition monitoring, refurbishment and possible replacement. SPA has adopted a condition score trigger level of '40', against which all transformers with higher relative ranking are subject to further investigation. This trigger level has been informed by historical experience where operational units of a similar ranking have failed in service.

SPA has also developed a transformer risk model that extends information in the condition model to include matters such as the probability of failure and consequences of failure. The risk model also captures the entire fleet of transformers. The overall asset failure risk[116] is shown in Figure 5-9, and is based on a population of 217 units. The relative level of risk is seen to increase from 100% as a reference level in 2003 to approximately 120% in 2008, and subsequently reduce marginally to 115% in 2013, based on SPA's proposed level of expenditure.

Figure 5-9 – Power transformer asset failure risk

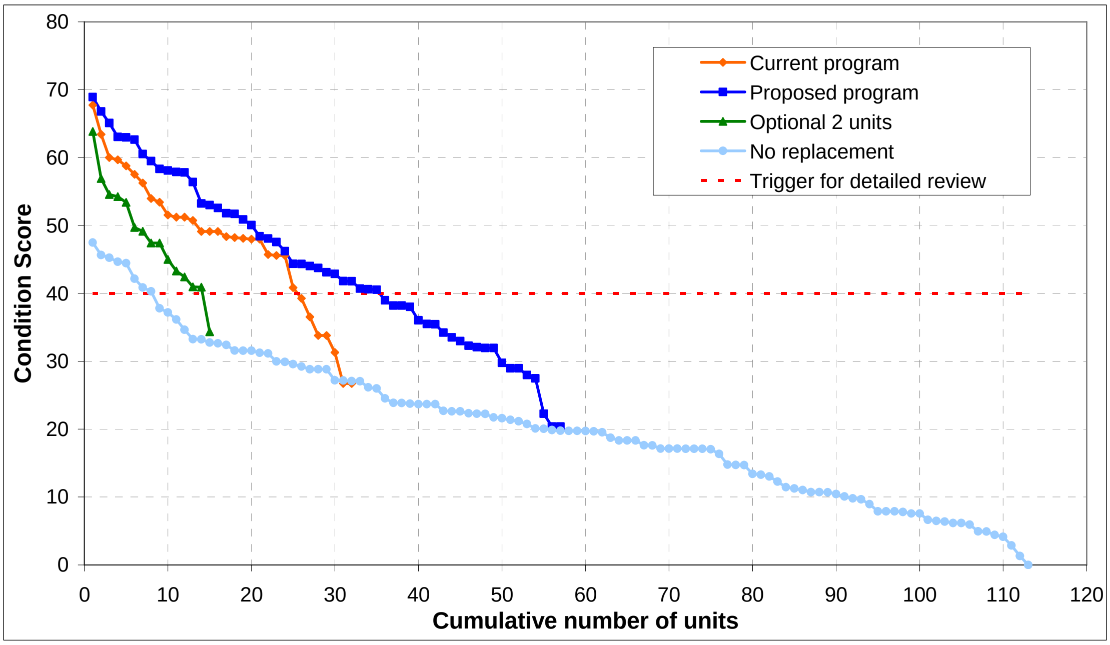


Source: SPA submission, VERSION 1 POWER TRANSFORMER RISK MODEL.ppt, March 2007

Figure 5-10 summarises the output of SPA's power transformer condition model for transformer tank main windings.

116 Asset failure risk accounts for the condition and probability of failure, and with due consideration to the availability incentive rebates, health & safety issues, environmental damage, additional business costs associated with unplanned procurement and replacement, and the collateral damage associated with the consequences of failure.

Figure 5-10 – Power transformer condition model application



Source: PB analysis

The key observations from Figure 5-10 include:

- 32 (15%) of the power transformers in the condition model have been replaced over the current 2002/03 to 2007/08 (5.25 year) regulatory period. Their scores range from 68 to 27, with an average score of 48, and 78% of these are above the trigger level for detailed review of 40
- 57 (26%) of the power transformers in the condition model are proposed to be replaced over the next 2007/08 to 2013/14 (6-year) regulatory period. Their scores range from 69 to 20, with an average score of 44, and 61% of these are above the trigger level for detailed review of 40
- a number of the units ranked less than 30 are single-phase units that operate in parallel with higher ranked units, and for the purposes of asset management are considered as the same asset
- SPA has proposed for two units of a fleet of critical transformers to be replaced. The actual units to be replaced are optional across a group of 15. Their scores range from 64 to 34, with an average score of 48, and 93% of these are above the trigger level for detailed review of 40
- 113[117] (52%) of the power transformers in the condition model are not proposed to be replaced. Their scores range from 47 to 0, with an average score of 21, and 93% of these are below the trigger level for detailed review of 40
- the proposed program is materially larger than the current program and this appears to capture more units that are rated below 45
- of the 57 units proposed for replacement, there will be 34 (60%) that have a transformer condition score less than the highest ranked unit not being replaced.

117 Excluding the 13 remaining units in the optional category.

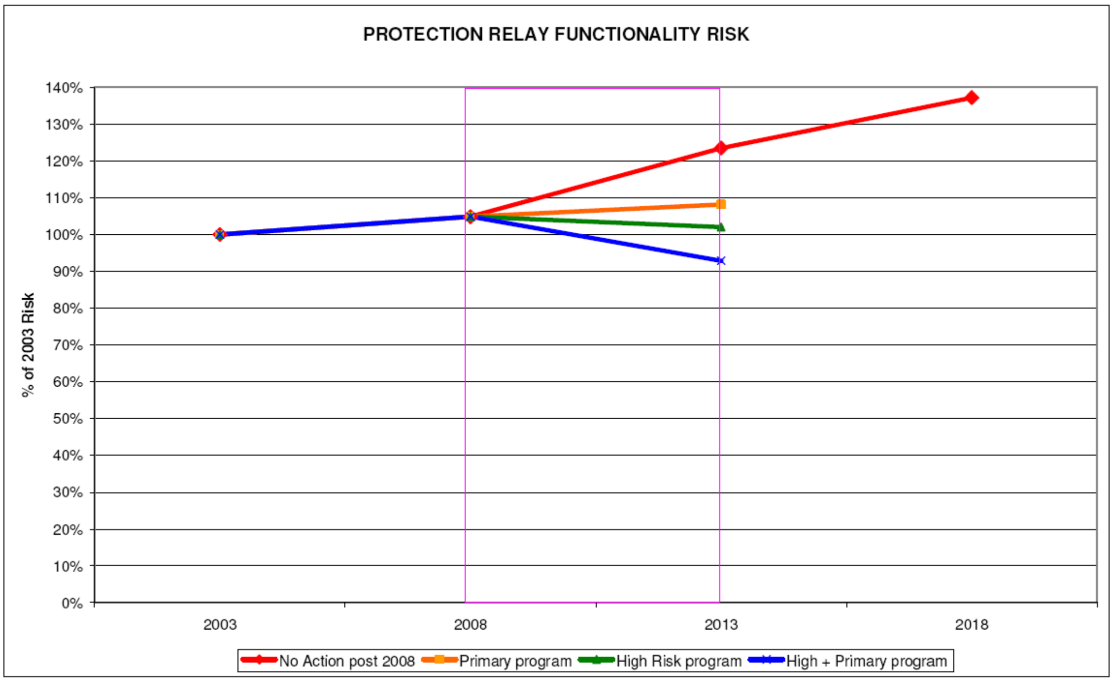
5.10.5 Protection relay asset failure risk

The protection relay asset failure model quantifies the functionality risk of devices fundamental to the protection of transmission lines, transformers, buses and reactive plant. The model allows the relative reduction in functionality compared with an equivalent electronic digital relay. Indirectly this approach represents the risk of incurring unnecessary operating costs to ensure protection devices operate correctly, remain calibrated, and meet the increasing (speed and availability) demands of modern integrated networks.

Each of six types of protection relays (including electromechanical and integrated microprocessor is assigned a condition score and associated probability of failure.

The overall asset failure risk[118] is shown in Figure 5-11, and is based on a population of 2,308 units. The relative level of risk is seen to increase marginally materially from 100% as a reference level in 2002 to approximately 105% in 2008 and subsequently reduce down to 93% in 2013, based on SPA's proposed level of expenditure.

Figure 5-11 – Protection relay asset failure risk

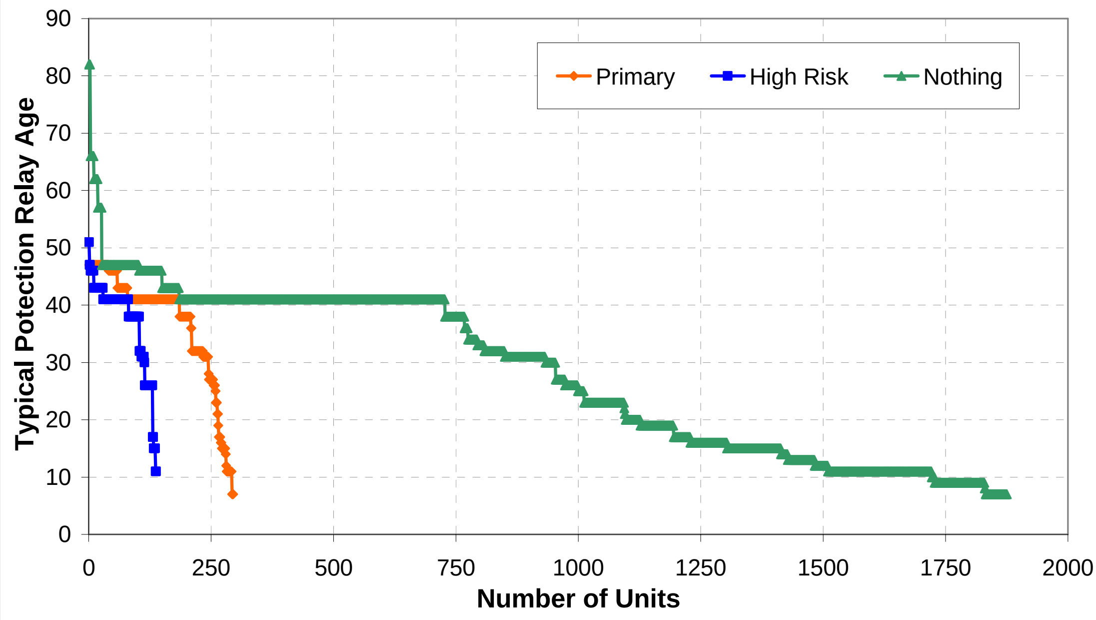


Source: SPA Proposal, Appendix E, Page 27 of 87

Figure 5-12 summarises the detailed application of SPA's protection relay asset failure risk model.

118 Asset failure risk only accounts for the condition and probability of failure, with consideration of generic consequences of failure.

Figure 5-12 – Protection relay risk model application



Source: PB analysis

The key observations from Figure 5-13 include:

- 295 (13%) of the protection relays in the risk model are proposed to be replaced over the next 2007/08 to 2013/14 regulatory period as part of other primary works. Their typical ages (as of 2013) range from 47 to 7, with an average age of 37
- 138 (6%) of the protection relays in the risk model are proposed to be replaced over the next 2007/08 to 2013/14 regulatory period due to their high risk. Their typical ages (as of 2013) range from 51 to 11, with an average age of 37
- the vast majority of the protection relays, 1,875 (81%) in the risk model are not proposed to be replaced. Their typical ages (as of 2013) range from 82 down to 7 years, with an average age of 28.

5.10.6 Conclusions

SPA is proposing to reduce its overall relative asset failure risk level compared to those existing in 2003 and in 2008. This is to be achieved through a wide-scale asset replacement program because the risk of asset failures and consequences would considerably increase otherwise.

On an asset category basis, SPA has advised that is seeking to:

- stabilise asset failure risks associated with transmission line insulators, power transformers and protection relays
- significantly reduce the current transformer risk due to a considerable decline in the Mean Time Between Failure (MTBF) over recent years and the catastrophic nature of these failures
- significantly reduce the circuit breaker risk due to the high volume of units moving into the high and very high categories through the 2008/09 to 2013/14 period.

The time-based high-level asset risks are summarised in Table 5-20, where it can be seen the overall asset failure risk increases slightly from the reference level of 500% in 2003 to 505% in 2008, and then reduces to 446% in 2013.

Table 5-20 – SPA asset failure risks over time

Asset failure risk	2003 level	2008 level	2013 level – with capex	2013 level – no capex	Reduction (03-13)
Circuit breakers	100%	85%	65%	180%	35%
Current transformers[1]	100%	90%	75%	140%	25%
Transmission line insulators	100%	105%	98%	138%	2%
Power transformers	100%	120%	115%	146%	(15%)
Protection relays	100%	105%	93%	124%	7%
TOTAL	500%	505%	446%	728%	54%

Note 1, using original CT risk model output based on 2008-2013 timeframes for consistency

Source: PB analysis

PB considers the ongoing development of quantified risk models provides a contemporary framework for SPA to analyse its asset replacement based business decisions and provides for a tangible mechanism through which preventative and reactive risk strategies and measures can be promulgated.

Consistent with its strategic intentions, from Table 5-19, SPA appears to be particularly aggressive with respect to its replacement of circuit breakers and current transformers; however, the relative risk of the transformer assets is still higher than that experienced in 2003. This outcome is in spite of the recent replacement of 34 tanks (16%) and the proposed replacement of an additional 59 tanks (27%) out of a population of 217.

PB also highlights the material reduction in relative risk (of 282%) in 2013 on the basis of SPA's propose capex over the 2008/09 to 2013/14 regulatory period, and that this ensures a reduction in overall risk of around 50% compared to that in 2003 or 2008.

5.11 PB RECOMMENDATIONS (FORECAST CAPEX)

In this section PB provides an overall recommendation on SPA's $795m network-related forecast capex.

5.11.1 Detailed project reviews

Specific findings, generally referred to as 'positive', 'neutral' and 'negative' from our detailed project and asset model reviews are summarised in Table 5-21. It should be noted that these classifications are the associated findings are representative only and aim to capture key aspects of our detailed reviews. They should not be considered interpedently of, or in lieu of, the detailed reviews and discussions.

Table 5-21 – Summary of findings from detailed project reviews

Project	Positive	Neutral	Negative
HWPS	- Reduction in risk posed by critical bulk oil 220 kV CBs - Coordination with connected parties - Recognition of costs associated with asset failure and O&M and brownfield works	- Poor selection and assessment of non-practical alternatives - High brownfield factor and costs for removal	- 5% real cost escalation - Slight scope extension beyond specified needs - High contingency
CT program	- Systematic application of risk models - Bulk order and site cost efficiencies - Replace before fail is economic	- Prioritisation criteria not clear - Dynamic nature of risk model outputs	- Aggressive replacement threshold - Unsupported outcome (500 kV units at LYPS)
Response capability		- Non-prescriptive scope	- Unsymmetrical under ex-ante efficiency regime
RTS	- Efficient costs and use of modern technology - Reduction in risk posed by critical 220 kV CBs and CTs - Recognition of environmental risks - Use of independent technical expert advice	- Thorough alternatives assessment - Coordination with connected parties - Limited description of use of released plant in good condition - Use of larger transformers at incremental costs	- Aggressive timing for transformers and 66 kV switchyard - High contingency - Scope (number of 220 kV CBs unsupported - No economical assessment
SCADA	- Logical, consistent approach to critical assets	- Limited evidence of historical costs	- Unjustified inclusion of enhancements and upgrades
Transformers	- Strategic coordination of some multiple projects	- Augmentation coordination	- Lack of clear need and not supported by risk models - Lack of discussion of consequences of failure, as affected by spares holdings

Table 5-22 summarises the outcomes of our detailed project reviews.

Table 5-22 – Recommended capex of project under detailed review

Expenditure $m ('as spent', real 07/08)	08/09	09/10	10/11	11/12	12/13	13/14	Total
Proposed HWPS refurbishment	4.9	11.7	8.6	3.4	5.6	1.5	35.7
less amount for inefficient scope	—	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(4.0)
Proposed CT replacements	4.8	6.1	5.2	4.2	2.7	1.4	24.5
less amount for part deferral	(2.0)	(3.6)	(2.8)	(2.5)	(1.0)	—	(11.9)
Proposed minor works	0.92	0.92	0.92	0.92	0.92	0.90	5.5
less amount to remove allowance	(0.92)	(0.92)	(0.92)	(0.92)	(0.92)	(0.90)	(5.5)
Proposed transformer replacements	3.5	5.4	2.0	5.5	7.9	4.5	28.8
less amount for limited need and other alternatives	(3.5)	(5.4)	2.5	(5.5)	(2.9)	(4.5)	(19.3)
Proposed RTS redevelopment	—	—	—	7.2	44.8	37.7	89.7
less amount for deferral of transformers-66 kV switchyard	—	—	—	(7.2)	(24.5)	(20.0)	(51.7)
Proposed SCADA replacement	12.4	7.9	6.5	5.4	7.5	4.2	43.9
less amount for enhancement and augmentation	(1.3)	(1.3)	(1.4)	(1.4)	(1.4)	(1.4)	(8.2)
Proposed capex — total	26.5	32.0	23.2	26.6	69.4	50.2	228.0
Recommended capex — total	18.8	20.0	19.8	8.3	37.9	22.6	127.4
Change in capex	(7.7)	(12.0)	(13.4)	(18.3)	(31.5)	(27.6)	(100.6)
Change in capex — %	29%	38%	15%	69%	45%	55%	44%

Source: PB analysis

On a project by project basis, PB has made significant and material recommendations to reduce SPA's capex allowance. This is primarily driven by the deferral of intensive capex works at RTS, and works to replace power and current transformers.

5.11.2 High-level review of asset risk models

PB has undertaken a high-level review of SPA's application of its quantitative asset risk models. Our general findings are summarised in Table 5-23 and once again the classifications used and the description of findings are representative only and aim to capture key aspects of our detailed reviews. They should not be considered interpedently of, or in lieu of, the detailed reviews and discussions.

Table 5-23 – Summary of findings from detailed asset risk model reviews

Risk Model	Positive	Neutral	Negative
CB risk model	Majority of High, Very High risk CBs replaced	Moderate number of CBs replaced in lower risk categories	Aggressive reduction in relative risk
CT risk model	Evidence of strong continuous improvement framework	Moderate number of CTs replaced with long life expectancy	Aggressive reduction in relative risk
Transformer risk model	Majority of highly ranked transformers to be replaced	Ranking on average lower than current replacements	Large number of units targeted for replacement under the assessment threshold
Lines risk model	Stable reduction in risk	Good balance between old and new for replacements	
Protection relay risk model	Moderate reduction in relative risk	Modernisation of technology	

Source: PB analysis

PB has not drawn any further recommendations from the-high-level review of SPA's application of its risk models.

5.11.3 Extension of findings to balance of forecast capex

PB's review of detailed projects has captured 11% of the program by the number of projects (56 in total) and 29% of the program by the value of network-related projects ($795m).

Prior to determining a recommendation on the prudency and efficiency of the overall (ex-ante) forecast capex program proposed by SPA, PB has given due consideration to a number of factors assessed as part of our review. These include the following general findings:

- based on an assessment of high-level inter-business benchmarks across a range of measures, it is evident that the combined SPA/VENCorp proposed capex is at or below that of the average when compared with other Australian TNSPs, but that SPA's replacement capex alone is relatively high
- based on a top-down intra-business depreciation-based assessment, SPA's forecast capex aligns quite strongly with the expected level of depreciation over the 2008/09 to 2013/14 regulatory period, indicating that the weighted average age of the network across various asset categories will be held stable
- the processes used to estimate project costs are reasonable and the unit costs that form the basis of SPA's project estimates are generally efficient and with PB's benchmarks
- all of the expenditure associated with our detailed and high-level review of SPA's ex-post (historic) capex over the period 2002/3 to 2007/08 was found to be timely, reasonable and efficient
- the service standards proposed by SPA are consistent with past practice and will ensure key performance measures associated with service delivery will be maintained
- the processes and outcomes of SPA's operation and maintenance cost forecasts were generally found to be reasonable and efficient and required only minor downward adjustment

- our review of the governance, approvals processes and systems set in place by the SPA Board, which (consistent with the standards expected of a publicly listed company) indicate well-established and documented process leading to the approval of capex and opex, and at a high level ensure good electricity industry practices are captured within its asset management functions.

In considering the specific mechanisms through which PB has recommended adjustments to SPA's project-related capex proposals, we consider these in turn and discuss the appropriateness of extrapolating the findings across the balance of the capex program:

- post-type CTs, use of aggressive replacement threshold: PB considers it is not prudent or efficient to propose replacement of some units with a life expectancy at or beyond 10 years over the 6-year regulatory period. This principle cannot extend directly to any other project, given the specific use of a life expectancy measure; however, it is noted that the transformer ranking threshold adopted by SPA (position 40) is similar in nature and that a number of units around and below this threshold are targeted for replacement. This matter is addressed as part of the RTS and transformer replacements projects
- post-type CTs, unsupported scope of work through inclusion of costs for expensive 500 kV CT replacements: PB considered inclusion of these costs is inefficient given the updated the life expectancy of these units. This factor is attributable to the dynamic nature of the risk models (as influenced by real time condition monitoring). PB considers it is inappropriate to extend this principle to other programs as it is expected other models are less dynamic than the CT model and it is more likely that asset condition will deteriorate rather than improve in most circumstances
- replacement of SCADA, unsupported enhancements that have no demonstrable need: PB considers this reduction is a once off given the nature of the project and cannot be extrapolated to other work programs
- response capability or undefined works, removal of allowance on the basis that it is asymmetric and inconsistent with the efficient based ex-ante allowance provisions: PB considers this is a once-off adjustment that cannot be reflected to any other projects or allowances given the non prescriptive nature of works
- transformer replacements, lack of clear need unsupported by risk models: PB recommended adjustments to specific projects proposed by SPA. Given the nature of these recommendations, it is possible that similar outcomes exist are apparent in other projects; however, without an exhaustive detailed review of all projects, recommendations for additional adjustments are not substantiated
- transformer replacements, coordination of augmentation needs: PB consider the opportunities to capture augmentation opportunities is greatest with transformers given the incremental costs of procuring higher capacity units and that it is unlikely SPA has supported other projects using impending augmentation needs outside the already identified station redevelopments
- RTS redevelopment, aggressive timing of transformer replacements, and 66 kV switchyard developments: PB's consideration of this outcome is focused on the timing of works and the limited economical assessment supporting the entire work scope within the 2013/14 regulatory period. We consider a clear risk-based need has not been outlined and the timing is not prudent. Given this finding, it is possible to extend the principle to other station rebuilds (which account for 48% of the entire network) capex, in particular Glenrowan and Brooklyn. However, without detailed review of the risks and benefits associated with other rebuild projects, PB believes that a clear recommendation would be difficult to sufficiently substantiate
- RTS redevelopment, inefficient scope: SPA has proposed a very robust 12-circuit-breaker design to replace the existing 6-circuit-breaker configuration. While some augmentation is appropriate, PB considered that sufficient benefits were not established to support the 12-circuit-breaker approach and recommended a minor reduction in capex to maximise efficiency. It is possible that an inefficient configuration has been proposed for some of the other station rebuild projects.

However without a detailed review of each design, firm conclusions about the efficiency (or lack thereof) of the other rebuild projects can not be drawn

- HWPS rebuild, inefficient scope: SPA has extended the scope of redevelopment to include the replacement of post-insulators, CVTs, surge arrestors and isolators. While acknowledging that these items are not captured in detailed asset failure risk models, and whilst recognising that undertaking work at the same time at a station may capture economies of scale, PB considers a demonstrable need or economic basis was not presented by SPA for this extra work. It is possible that scope creep of this nature has been proposed for other projects. However without a detailed review of each design, firm conclusions about the efficiency, or lack thereof, of the other projects can not be inferred
- HWPS rebuild, use of 5% real capex escalators, SPA acknowledged that this was an inappropriate adjustment to include in its economic assessment and, given the materiality of the error, provided assurances and evidence[119] that this error was not captured in other economical assessments. PB is satisfied it has not been and has made no recommendations affecting other project allowances to account for this.

Given these findings, and in the context that SPA's capex forecast has benchmarked reasonably well in the other areas of our assessment, we conclude that any high-level adjustments to the balance of the capex forecast would be unsubstantiated. The recommended capex after our detailed review is presented in Table 5-23.

Table 5-24 – Recommended total network capex after detailed reviews

Expenditure $m ('as spent', real 07/08)	08/09	09/10	10/11	11/12	12/13	13/14	Total
Reviewed capex — projects	26.5	32.0	23.2	26.6	69.4	50.2	228.0
Recommended capex — projects	18.8	20.0	19.8	8.3	37.9	22.6	127.4
Balance of capex	99.2	95.5	107.6	104.3	59.1	101.6	567.3
High-level adjustment to balance of capex	—	—	—	—	—	—	—
Proposed total capex	125.8	127.5	130.8	131.0	128.5	151.8	795.3
Recommended total capex	118.0	115.5	127.4	112.6	97.0	124.2	694.7
Change in capex	7.7	12.0	3.4	18.3	31.5	27.6	100.6
Change in capex — %	6%	9%	3%	14%	25%	18%	13%

Source: PB analysis

119 SPA provided its economical assessments for 13 other projects. PB systematically reviewed these to ensure that no real capex escalation was included. While PB identified no escalations were applied, we have noted that 5% financing charges were included in capital cost estimates which is inappropriate in a discounted cash flow analysis. Given this is likely to have been applied to all projects and was a 'once of adjustment', PB considers any inappropriate inclusion of financing charges is not likely to have altered the outcomes of the economic assessment unless the alternatives considered had very similar present values.

5.11.4 Use of estimating contingencies

SPA has used three methods for forecasting the capital costs of its projects:

- unit cost estimates that are based on high-level unit prices and with limited information regarding site specific requirements. This system has been used for all projects outside of the station rebuilds
- preliminary planning estimates that consider site-specific requirements coupled with the high-level unit costs to form a more accurate estimate than based on unit costs alone. This process has been used in the case of the Richmond redevelopment
- an Expert Estimator system that allows detailed, highly categorised cost estimates to be prepared based on a specific and detailed scope given a thorough understanding of site requirements. This system has been used for nine of the ten station rebuild projects.

Generally, the accuracy of cost estimating processes increases as the estimate progresses through the three stages — typically from ±25% to ±10%.

Through our detailed assessment, SPA has advised that contingency provisions have been included in all of the station redevelopment projects (48% of forecast network capex). The contingencies range in magnitude from 4.9% (Hazelwood) to 9.6% (Thomastown), with an average of 7.4%. This accounts for over $24m in the forecast allowance.

PB considers it is inappropriate for contingencies to be included in the forecast capex allowance on the basis that:

- SPA's costs without the contingency represent efficient construction costs based on our independent benchmarks and view of labour and material escalators
- the contingency is applied to another generalised factor for 'brownfield' development (which is as high as 10%) and acts to double count for some unknowns as well as labour and material escalators
- application of a contingency reduces the onus on SPA to accurately forecast its costs and reduces the focus on efficiency
- the risk is asymmetric and will be transferred to end use consumers who have no capability to influence the outcome. Effectively the cost included for contingencies may not be realised, resulting in a windfall gain to SPA.

PB recommends the contingency allowance be removed in accordance with Table 5-25.

Table 5-25 – Recommended total network capex after removal of contingency

Expenditure $m ('as spent', real 07/08)	08/09	09/10	10/11	11/12	12/13	13/14	Total
Recommended total capex	118.0	115.5	127.4	112.6	97.0	124.2	694.7
Less contingency allowance[1]	(2.3)	(2.6)	(2.3)	(2.9)	(4.1)	(4.3)	(18.6)
Adjusted total capex	115.7	112.8	125.0	109.7	92.9	119.9	676.1

Note 1: total allowance based on identified amounts in station rebuild, excluding Richmond, and allocated based on proportion of annual capex for the station rebuilds.

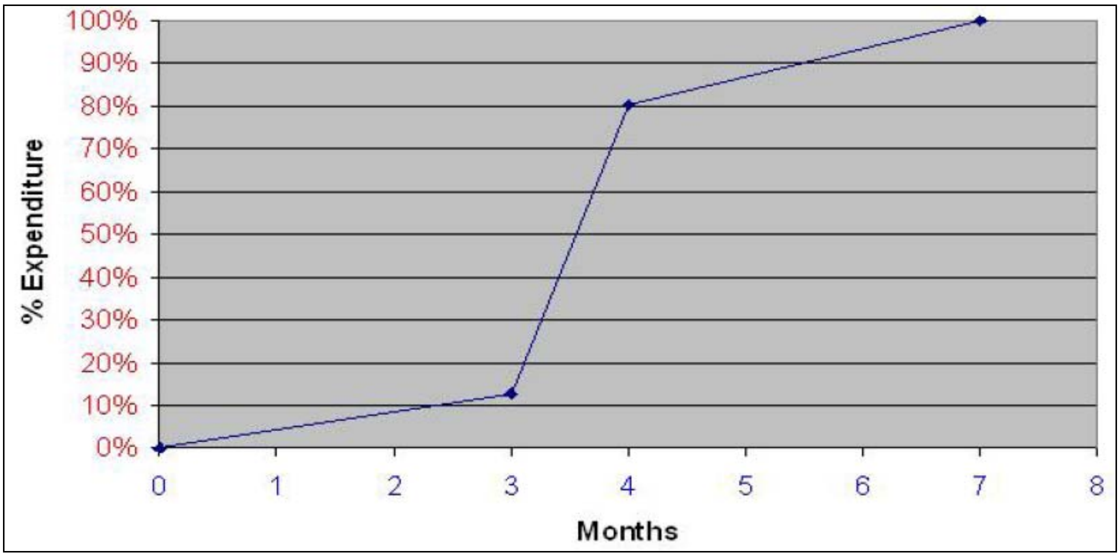
Source: PB analysis

5.11.5 Use of S-curves to establish 'as spent' profiles

Examination of the capex spend profile proposed by SPA is an important element in assessing the overall capex efficiency, as it impacts on both the timing of the revenue required to fund the proposed capex, as well as the assessment of project (program) implementation efficiency. SPA has advised that it has used over 27 different S-curves to convert its 'as commissioned' expenditure to 'as spent'.

Specifically, SPA advises that it has relied upon historical profiles taken from completed projects in determining the timing of the proposed ex-ante capex (the spend profile)[120]. The paper also presents a number of typical S-curves for a number of project types, as shown in Figure 5-13, Figure 5-14 and Figure 5-15.

Figure 5-13 – S-curve for purchase and install replacement 220 kV CTs



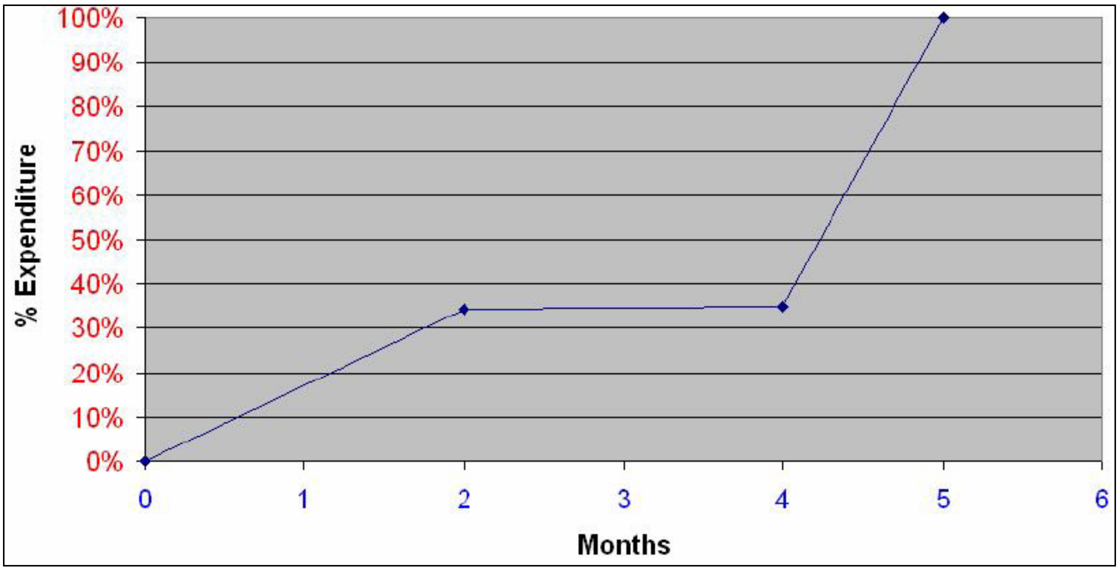
Source: Page 5. Escalation of Project Costs. SPA 12/04/07

Figure 5-13 relates the replacement of 220 kV CTs, and proposes that such projects typically require 7 months to complete. This overall timeframe does not seem unreasonable given the supply lead time of CTs[121]; however, the 3-month installation timeframe does seem slightly higher than would have been anticipated from PB's experience, given that design and job scheduling can occur during the equipment lead time. Nonetheless, PB is of the view that this expenditure profile is reasonable.

120 Page 4, Escalation of Project Costs. SPA 12/04/07.

121 As typical lead times of 220 kV CTs can be in the order of 9 to 18 months, PB assumes that SPA has a standing contract for the supply of this equipment.

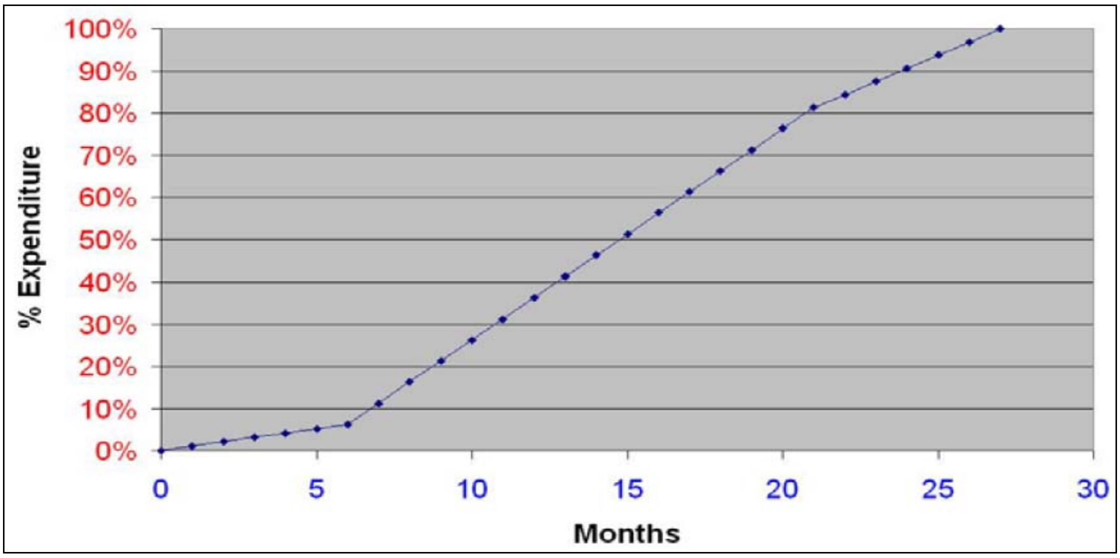
Figure 5-14 – S-curve for insulator strings on high load towers



Source: Page 5. Escalation Of Project Costs. SPA 12/04/07

Figure 5-14 relates the installation of insulator strings, and suggests that such projects typically require 5 months to complete. While PB would have expected a 3 to 4 month overall timeframe under a best practice design, procurement, and construction process, a 5-month profile is not unreasonable given supply lead times and work scheduling requirements.

Figure 5-15 – S-curve for station rebuild > $25m

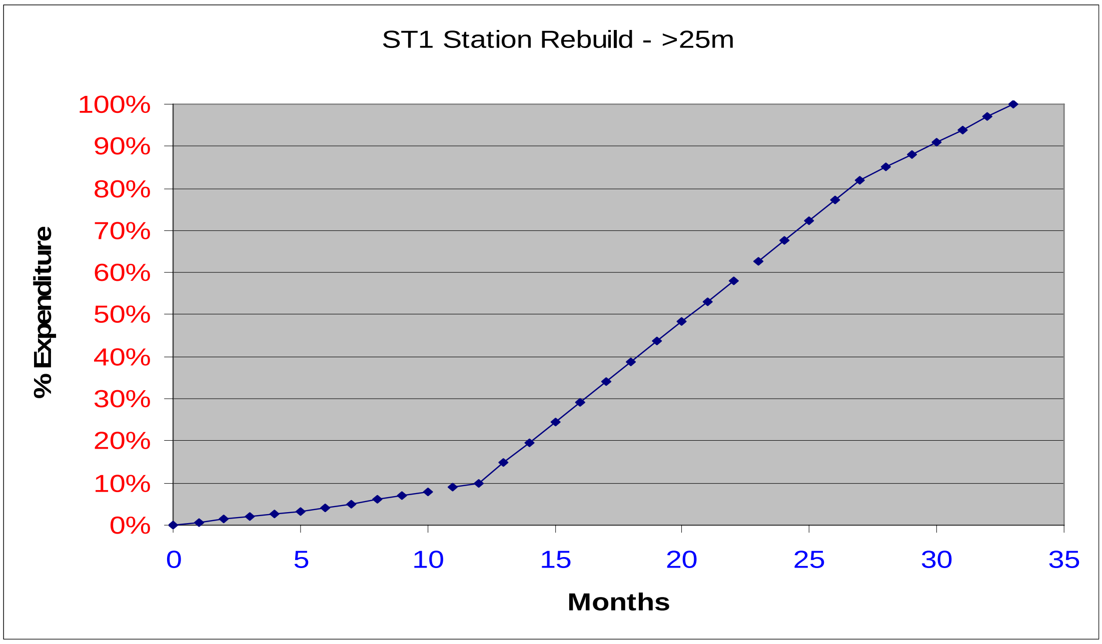


Source: Page 6. Escalation Of Project Costs. SPA 12/04/07

Figure 5-15 relates the rebuild to terminal stations for large projects (over $25m) and proposes that such projects take approximately 27 months to complete. SPA has also supplied[122] a second version of this S-curve, as shown in. This updated version (curve 2) suggests a 33-month implementation timeframe. Direct comparison of Figure 5-16 and Figure 5-15 shows that this timing difference implies an additional 27% (37%–10%) of the project expenditure will have been incurred (theoretically) at the 12-month point. While at 24 months this additional expenditure would account for an additional 22% (90%–68%). Essentially the use of the originally documented curve advances the project cash flow by around 20%–25% in simple terms.

122 Email 19/06/2007 from SPA to PB.

Figure 5-16 – Version 2 of S-curve for station rebuild > $25m



Source: RTS — PB Response to Email 15-06-07 V1 (spreadsheet). SPA, June 2007.

PB is of the view that a 24 to 36 month implementation timeframe for a station rebuild project is not unreasonable, subject to the complexity of the rebuild. However, given that SPA's station rebuild program is a significant part of the ex-ante capex (48%), PB undertook to reassess this S-curve from SPA's ex-post station rebuild project data.

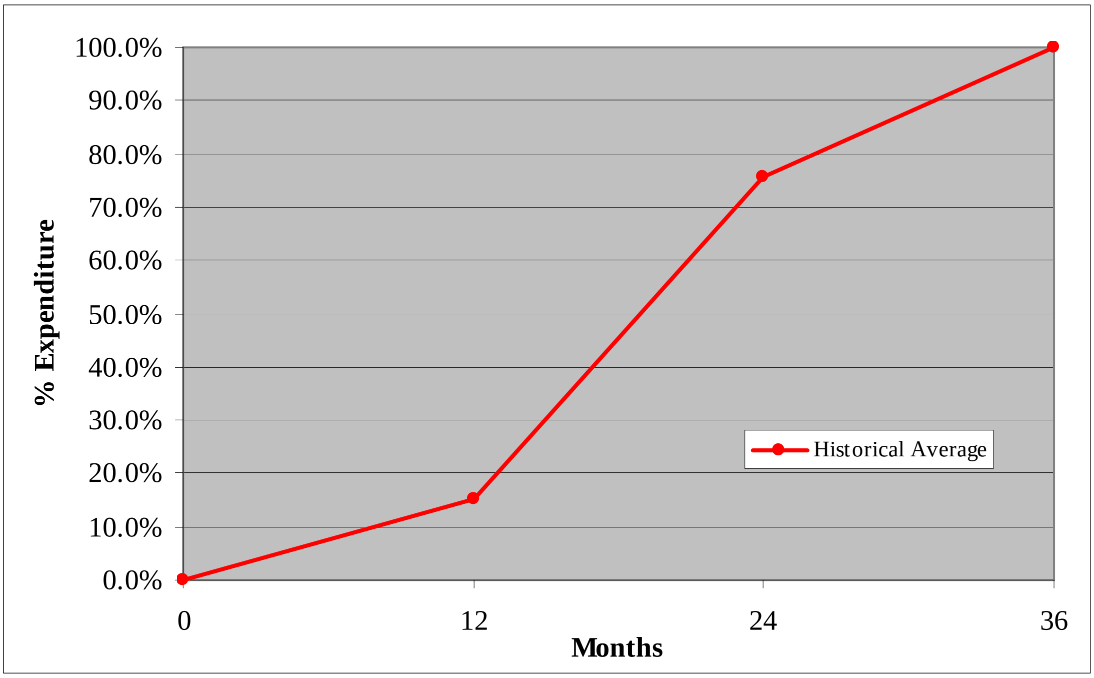
Figure 5-17 shows the S-curve PB derived from analysis of the SPA submitted station rebuild data[123]. This analysis was based on a 36-month implementation timeframe as the supplied data was annualised. The analysis shows that at the 12 month and 24 month points the cumulative project expenditure would be approximately 16% and 75% respectively.

As the curves presented in Figure 5-15, Figure 5-16 and Figure 5-17 represent different implementation timeframes, PB rescaled each of these curves so a direct comparison could be made. Based on ex-post data, approximately 70% of station rebuild projects have an implementation timeframe of around 24 months, while 30% span approximately 36 months[124]. Based on this observation, and for the purposes of this analysis, PB has assumed an average implementation timeframe of 28 months for station rebuild projects. A 28-month implantation timeframe is reasonable for such a project, and particularly in light of the brownfield nature of this work, which would tend to complicate the work program and extend the implementation period.

123 Note that adjustments were made to the data to remove the effects of significant outliers.

124 These figures are based on annualised ex-post station rebuild data supplied by SPA in their SPA Templates - Cost information lodged 280207 spreadsheet.

Figure 5-17 – Station rebuild S-curve derived from SPA ex-post data

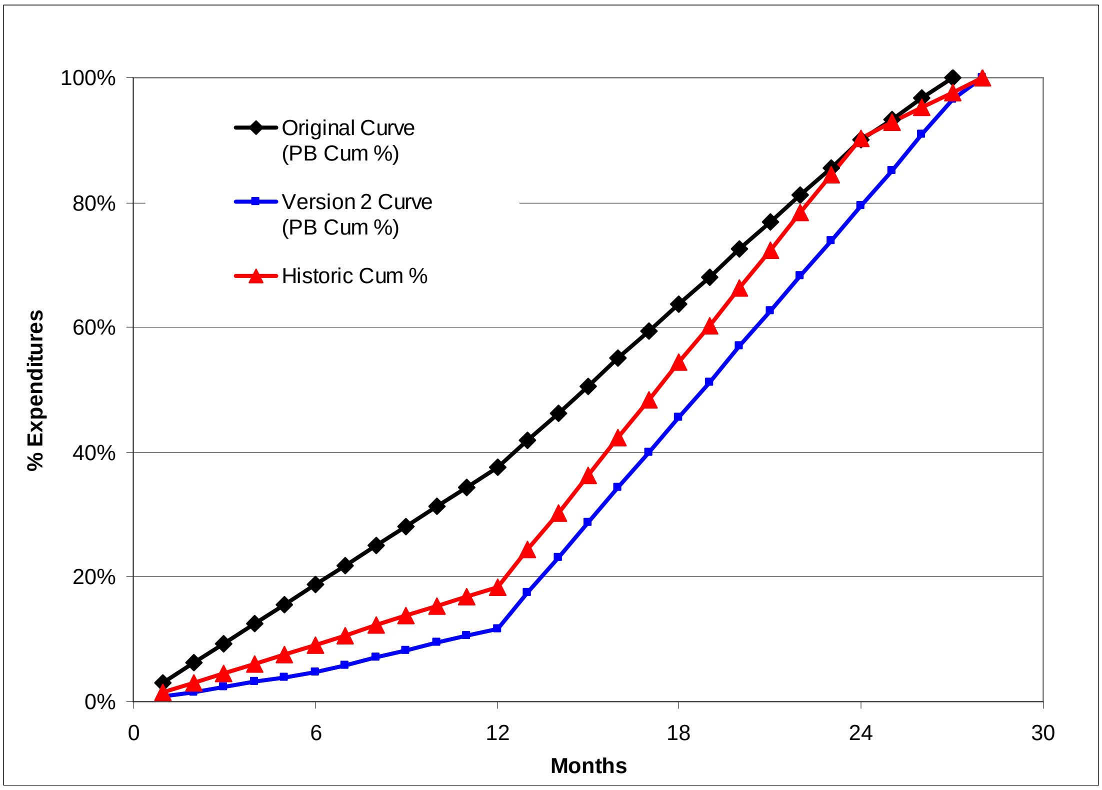


Source: PB analysis.

Figure 5-18 shows a comparison of the three S-curves each rescaled to a 28-month implementation timeframe. It is clear from this comparison that SPA's original S-curve (Figure 5-15) overstates the cumulative project expenditure at the 12- month point by approximately 20% (38%–18%) in comparison to the results of the PB analysis, and by 26% (38%–12%) in comparison to the version 2 curve submitted by SPA (Figure 5-16)[125].

125 Note that these values are adjusted values produces from scaling the S-curves to a 28-month duration.

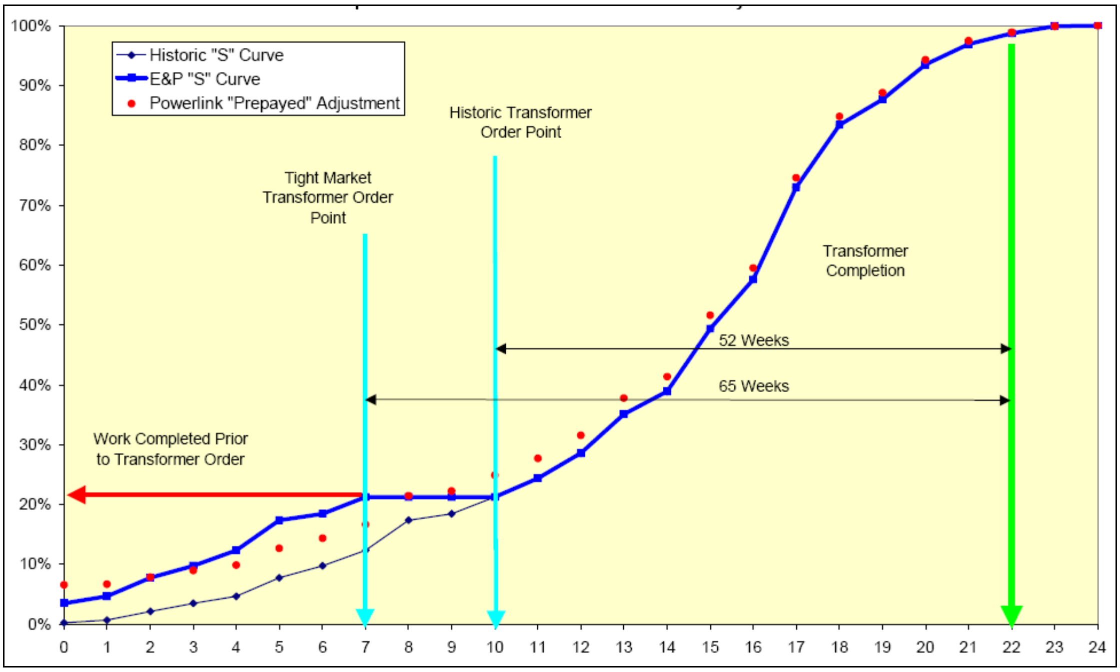
Figure 5-18 – Comparison of ex-post analysis with SPA station rebuild S-curves



Source: PB analysis.

As a further comparative measure, we can contrast the substation implementation S-curve recently proposed by Powerlink as shown in Figure 5-19, with the original S-curve proposed by SPA (Figure 5-15). Again, comparing the cumulative expenditure at the 12-month point as a simple point of comparison, it can be seen that Powerlink proposed approximately 29%, while the SPA original S-curve proposes approximately 37%. Clearly SPA's figures are overstated in comparison to those suggested by Powerlink. Moreover, this apparent overstatement is more pronounced when the difference in implementation timing between SPA's 27-month curve and Powerlink's 24-month period is considered (a longer implementation period would generally reduce the early cumulative expenditure values). A further factor adding to the apparent overstatement is the difference in the nature of Powerlink's predominantly greenfield developments, compared to SPA's predominantly brownfield developments. Generally, greenfield developments can be implemented considerably quicker than brownfield developments where the work is slowed due to site access issues.

Figure 5-19 – Powerlink substation implementation S-curve



Source: Page 6. Appendix D, Adjustment of Historic 'S' Curves to Reflect Tight Market Conditions — Powerlink Revenue Cap 2007-08 To 2011-12 AER Draft Decision, Adjustment Of Historic 'S' Curves To Reflect Tight Market Conditions; Evens & Peck, January 2007

Conclusions

PB is of the view that the S-curves presented by SPA for the replacement of its 220 kV CTs (Figure 5-13), and for the installation of insulator strings (Figure 5-14) are reasonable.

However, for a key project category (major station rebuilds, which makes up over 48% of the forecast network capex) SPA has provided conflicting information regarding the S-curve it has used to transpose 'as commissioned' expenditure to 'as spent'. Potentially SPA has overstated the time at which expenditure is likely to occur.

Notwithstanding this ambiguity, we have some evidence (the RTS expenditure profile) that SPA has used an S-curve (the second version, Figure 5-16) that benchmarks well against publicly available material and our internal references. On this basis, we do not propose to adjust SPA's 'as spent' expenditure profiles. Prior to the AER accepting SPA's expenditure profiles, we recommend that SPA provides further assurances on the actual S-curves it has adopted and applied and how it arrived at these curves.

5.11.6 Use of materials and labour escalators for capex

In this section we review SPA's application of escalation factors in its forecast of capex. Our analysis includes consideration of both labour and material escalators and is an extension from recommendations made in Section 7 of this report.

Approach adopted by SPA

SPA has applied escalators as once of adjustments to its 2005/06 costs to generate its 2006/07 cost estimating database based on internal staff expertise, given experience with purchasing, design, and installation of works with many projects over recent years — as detailed in Table 5-26. SPA's basis for the rate adopted is also included in the table.

Table 5-26 – Escalation of project components

Component	Equipment (Materials) (C)	Basis	Design and installation (Labour) (D)	Basis
Primary	3.0%	Primary equipment is mainly steel and aluminium which is showing increasing costs	5.0%	Primary equipment installation required highly trained technicians capable of working safely in live switchyards
Secondary	0.0%	Secondary equipment is not increasing in price. It is computer based and prices are static	6.0%	The design, installation and testing requires specialized technicians who can command high prices for their work
Communications	0.0%	Similar comments to secondary	6.0%	Similar comments to secondary
Lines	0.5%	Components mainly silicon composites with steel fittings so modest increases are expected	4.0%	The costs associated with OH&S rules for work at heights will increase the costs of installation
Transformers	10.0%	The amount of copper and steel causes significant increases in the costs	5.0%	The installation work is carried out by similar staff to those who do the Primary work
Infrastructure	2.0%	Components comprise a wide range of manufactured materials and this is expected to increase in price	4.0%	Staff training required for work in live switchyard. OH&S rules will cause increased costs
Establishment	2.0%	Similar to Infrastructure	4.0%	Similar to Infrastructure

Source: SPA

SPA advises that the adjusted 2006/07 expenditure reflects the increase in costs observed towards the end of the current regulatory control period.

SPA has used the percentage allocations between labour and material for various project categories detailed in order to calculate the appropriate weighted escalator to apply to each category of the forecast capex costs over the next regulatory period.

Table 5-27 – Materials component for projects

Category	Equipment (Materials) (A)	Design and installation (Labour) (B)	Comments
Establishment	20%	80%	Predominantly installation works such as oil and water containment, foundations, roads, buildings, etc that are labour intensive and relatively small materials component
Secondary	25%	75%	Design, installation and commissioning work carried out by highly trained technicians. Materials are not expensive
Lines	30%	70%	Components used are not expensive but getting them into place in widely spread locations requires mobile plant and work at heights, which dominates the costs
Switchgear	40%	60%	Switchgear is more expensive but the design and installation requires foundations and work in live switchyards and this increases the costs
Reactive	45%	55%	Reactive plant is similar to switchgear but slightly more expensive and may require specialised work to commission
Transformers	70%	30%	Transformers are dominated by the purchase but the transport and foundation costs are significant

Source: SPA

To calculate the appropriate effective weighting escalator for each category, SPA has used the following formula and the data in Table 5-26 and Table 5-27.

Effective Weighted Escalation = [A*(1+C) + B*(1+D)]

The effective weighted escalation factors used by SPA determined by this equation for each category and its overall impact of increasing the forecast allowance by $37.1m (4.9%[126]) are shown in Table 5-28

Table 5-28 – SPA applied escalation by category

Category	Proposed capex $m	Proposed escalator	Reference capex $m
Secondary	115.0	4.5%	110.0
Switchgear	301.7	4.2%	289.6
Transformers	138.4	8.5%	127.6
Reactive	36.4	7.3%	33.9
Lines	31.0	2.9%[1]	30.1
Establishment	133.5	3.6%	128.8
Communications	39.4	3.2%[2]	38.2
TOTAL	795.3	4.9%	758.2

Note 1, SPA advises this effective escalation was 3.0%; however, PB considers the correct value is 2.9%

Note 2, PB has assumed the communications escalator based on a material/labour split of 20%/80% and a material/labour escalator of 0%/4% given no specific advice on these by SPA.

Source: PB analysis

126 Page 56 of SPA's Proposal indicates the average increase was 4.7%

After its once of adjustments have been made, SPA has proposed to maintain costs in real terms for the duration of the forthcoming regulatory period (i.e. SPA has adjusted the outcome if its expenditure profiles established in real 2006/07 dollars by 2.6% to determine its ex-ante allowance based on real 2007/08 dollars).

PB analysis of once off adjustment

SPA substantiates its labour and material adjustments with reference to the SKM report[127], where it claims that its approach (a weighted 4.7% increase) is slightly more conservative than the increases observed in the SKM report.

The SKM report indicated weighted cost increases in substations exceeding CPI by 5.0% and transformer costs exceeding CPI by 6.2% across the 2002 to 2006 period, as shown in Table 5-29.

Table 5-29 – SKM accumulative cost increases for the period 2002-2006

Item	2002	2003	2004	2005	2006
Substation (excluding power transformers	1.0	1.011	1.058	1.095	1.171
Power transformers	1.0	0.982	1.000	1.048	1.183
CPI actual	1.0	1.027	1.052	1.078	1.121

Source: SKM report, page 2

Importantly, it is observed the final year increases between 2005 and 2006 show that substation costs have outstripped CPI by 3.3% and transformer costs have outstripped CPI by 9.2%.

These figures support SPA's proposed once-off escalators, however we note that SPA's substation costs are a bit more aggressive (3.6%, 4.2% and 4.5% for establishment, switchgear and secondary, compared with SKM's substation value of 3.3%), while the transformer costs are lower (8.5% compared with SKM's value of 9.2%).

PB considers the SKM report is a well presented and contains considerable and detailed material. It is well referenced and robust review of observed and forecast factors affecting capex forecasts and the findings and conclusions drawn are consistent with PB experience and expectations. In PB's opinion the report can be used as valid, up-to-date reference.

Independently, PB has reviewed the material and installation costs used by SPA to forecast capex. We have benchmarked the plant and material costs against both publicly available information and our own internal database of building block costs. The results of this benchmarking exercise indicate that SPA's 2006/07 adjusted costs are generally supported as efficient by our measures.

PB has observed that base metal prices peaked during 2006 and have remained relatively high during the first half of 2007. These high base metal costs are now being reflected in higher manufactured electrical equipment costs such as power transformers. In addition to the higher base metal costs, there is presently a high worldwide demand for electrical power equipment. This is due to the electrification of rural areas during the growth periods in the decades after the second world war. Many of these assets are now nearing the end of their service lives and are also subject to capacity constraints due to the increasing reliance on electricity in rural industries. Hence, significant numbers of distribution and transmission businesses have large replacement and refurbishment programs pending. These projects

127 A copy of the SKM report, Escalation Factors Affecting Capital Expenditure Forecasts, is provided as Appendix C to the SPA revenue proposal.

usually involve the replacement of assets such as power transformers and the demand for such assets is currently very high.

In conclusion, PB considers the once-off adjustment — informed by reasonable allocations of project work into materials and labour and capturing recent increases in materials and labour costs — is a prudent and efficient outcome.

PB analysis of future escalations

For the forthcoming regulatory control period, SPA has maintained its material costs in real terms. Again, this is more conservative compared with the SKM report, which estimates substation costs will track above CPI over the period 2006 to 2013 by 1.1%.

PB has consistently recommended that the labour escalators used in opex and capex should be the same. This position is based on the premise that the staff engaged in both the opex and capex aspects of the business are basically governed by the same types of enterprise agreements (EBAs), are subject to the same market forces in relation to supply and demand, and generally belong to the same union.

The BIS Shrapnel report recommends the use of a real labour escalator of 2.8% for opex works, but SPA has applied a labour escalator of 2.83%, the reasons for which SPA advises were detailed in an earlier BIS Shrapnel report. As part of our review, we have recommended the use of a labour escalator for opex of 2.11% (real) and the reasons for this recommendation are detailed in Section 7.5.1 of this report.

Whilst it can be observed that around 60% of SPA's entire forecast network capex is associated with labour (and therefore that labour escalators play a more critical role than materials escalators) in the outlook — PB considers the real increase in labour over the outlook period will be tempered by reductions in material costs, particularly towards the end o the next regulatory period. This is supported by the detailed information in SKM's report.

On this basis, we concur that SPA's approach of maintaining costs in real terms is likely to be slightly conservative, and recommend no changes to SPA's forecast capex associated with future labour or materials escalations.

5.11.7 Recommended forecast capex allowance

As an outcome of our detailed project reviews, and one adjustment to remove contingencies, PB's recommendation on an efficient and reasonable forecast capex for network investment is $676m, a reduction of 15% from the original proposal, as shown in Table 5-30.

Table 5-30 – Final recommendation for SPA's total network capex

Expenditure $m ('as spent', real 07/08)	08/09	09/10	10/11	11/12	12/13	13/14	Total
Proposed total capex[1]	125.8	127.5	130.8	131.0	128.5	151.8	795.3
Recommended total capex	115.7	112.8	125.0	109.7	92.9	119.9	676.1
Adjusted to total capex	10.1	14.7	5.8	21.3	35.6	31.9	119.2
Adjusted to total capex %	8%	12%	4%	16%	28%	21%	15%

Note 1, excluding the minor adjustments proposed by SPA as part of our review for two projects.
Source: PB analysis

The breakdown of the PB recommendations, by detailed project review, is provided in Table 5-31.

Table 5-31 – Forecast (ex-ante) capex

Expenditure $m ('as spent', real 07/08)	SPA submitted	Proposed variation	PB recommendation
HWPS refurbishment	35.7	(4.0)	31.7
CT replacements	24.4	(11.9)	12.5
Response capability for minor works	5.5	(5.5)	—
Transformer replacements	28.8	(19.3)	9.5
RTS redevelopment	89.7	(51.7)	38.0
SCADA replacement	43.9	(8.2)	35.7
Total of reviewed projects	228.0	(100.6)	127.4
Balance of forecast capex	548.7	—	548.7
Removal of contingency	18.6	(18.6)	—
TOTAL	795.3	(119.2)	676.1

Source: PB analysis

6. NON-NETWORK CAPEX

SP AusNet's (SPA) non-system[128] capital expenditure forecast provides for investment costs to be incurred in addressing the needs of the business not directly related to the development and augmentation of the electricity transmission network. An example of capex that falls within this category is the cost of vehicles, and computers and other IT equipment.

This section of the report will examine the historic non-system capex that SPA has requested to be included into the Regulatory Asset Base (RAB) for the period up until 01 April 2008 — its ex-post expenditure. It also reviews the ex-ante forecast expenditure that SPA has identified in its revenue proposal and provides an independent view on the reasonableness of this forecast. Both the ex-post and ex-ante expenditure proposals form a part of the SPA Electricity Transmission Revenue Proposal.

6.1 OVERVIEW

As part of our review, PB has examined the non-system capex over the period 2003/04 to 2013/14. This assessment has included a review of the underlying business drivers supporting the forecast; comparative (benchmark) assessments of the expenditure proposed by SPA with that of other (relevant) transmission network service providers in Australia; and detailed bottom-up project reviews. In particular, the detailed reviews have enabled PB to understand the implications of non-system cost drivers, and informed us of how SPA applies its policies and procedures.

6.1.1 Expenditure summary

SPA has proposed a total of $72.1m (real 2007/08, inclusive of FDC)[129] to be rolled-into the opening RAB on 01 April 2008 to account for its historic non-system expenditure between 01 January 2003 and 31 March 2008.

SPA has also forecast its non-system capex for the period 01 April 2008 to 31 March 2014 is expected to be $59.9m ('as spent', real 2007/08)[130].

SPA's non-system capital expenditure comprises two major categories:

- Information Technology (IT) — this includes expenditure on IT-related items that are not directly related to the development, or augmentation, of the transmission network
- Support the Business — this provides for expenditure required for SPA to undertake business activities to support the development of its transmission network.

Table 6-1 shows the categorised ex-post non-system capex that SPA has incurred[131] up to the end of the current regulatory period.

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128 Commonly also referred to as 'non-network' capex.

129 SPA Templates — Cost Information lodged 280207.xls; worksheet — historic capex — non-network — $67.7m ($ nominal).

130 ibid; worksheet — forecast capex — non-network AS.

131 2007/08 numbers are based on a forecast and all historic (ex-post) submission expenditure has been converted from nominal expenditure of the year to real 2007/08 dollars for the purposes of comparison with the ex-ante proposals. The adjustments have been made using actual CPI data — as confirmed with AER.

Table 6-1 – Ex-post non-system capex (1 January 2003 to 31 March 2008)

Expenditure $m (real 2007/08)	03 [132]	03/04	04/05	05/06	06/07	07/08	Total
Business IT	4.50	6.89	5.59	9.77	5.83	7.67	40.25
Support the Business	1.83	6.22	5.22	12.69	5.33	0.59	31.88
Total	6.33	13.11	10.81	22.46	11.16	8.26	72.13

Source: SPA Templates – Cost Information lodged 280207.xls

Table 6-2 shows the categorised ex-ante non-system capital expenditure forecast by SPA over the 2008/09 to 2013/14 regulatory period.

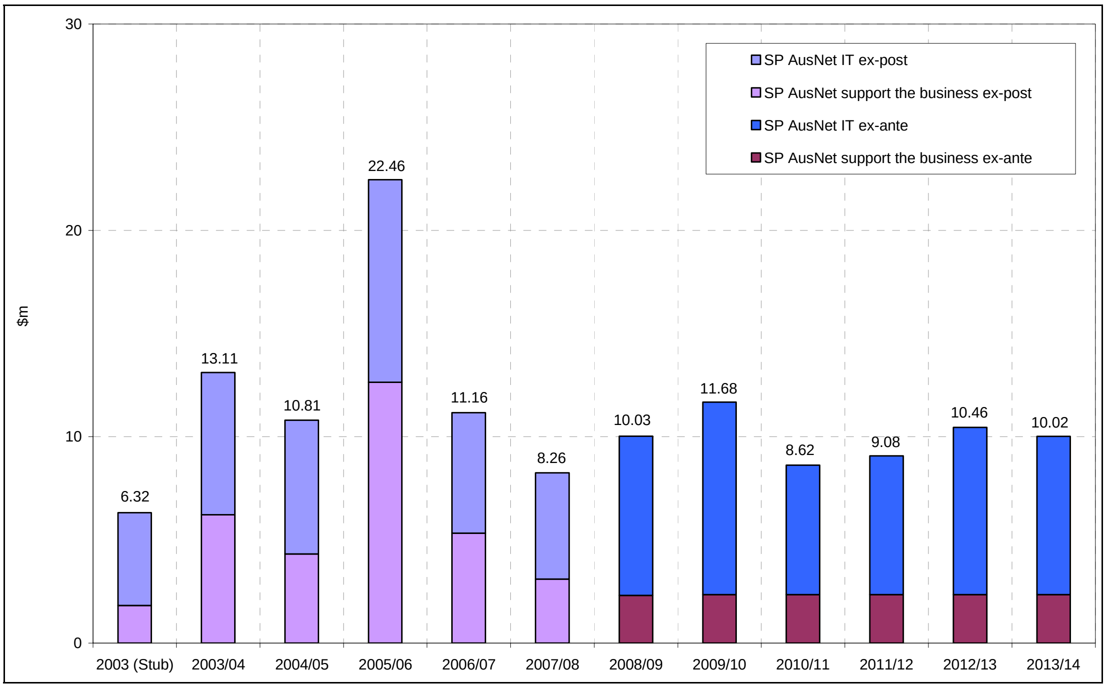
Table 6-2 – Ex-ante non-system capex (1 April 2008 to 31 March 2014)

Expenditure $m (real 2007/08)	08/09	09/10	10/11	11/12	12/13	13/14	Total
Business IT	7.71	9.33	6.27	6.73	8.11	7.67	45.82
Support the Business	2.32	2.35	2.35	2.35	2.35	2.35	14.07
Total	10.03	11.68	8.62	9.08	10.46	10.02	59.89

Source: SPA Templates – cost information lodged 280207.xls

Figure 6-1 shows the categorised trend of non-system capex outlined by SPA.

Figure 6-1 – Ex-post and ex-ante non-system capex proposals ($ real 2007/08)



Source: SPA Templates – Cost Information lodged 280207.xls

132 Year '03' is for the 'stub' period 01 Jan 03 to 31 Mar 03

The key observations from Figure 6-1 include:

- a considerable increase on non-system capex in 2005/06, driven by particularly high support the business capex
- an even and relatively low support the business forecast.

6.1.2 Support the Business capex

The expenditure on the Support the Business category is a comprised of four sub-categories, including:

- inventory (movements)
- premises
- vehicles
- other.

Each of these sub-categories is discussed below.

Inventory

To assist in the secure operation of the transmission system, SPA has identified a need for certain items of equipment to be made available at short notice. The items include, but are not limited to, expensive items that can take a long time to be manufactured or be delivered to site. SPA procures items that are held in store under two policies:

- strategic spares policy
- property, plant and equipment policy.

These policies are discussed in more detail in Section 6.3.3 of this report.

The concept of 'spares holdings' is supported through a (SPA) company-wide strategic spares policy. This policy sets out the general principles which underpin the rationale for the holding of spares across the entire transmission business — including the sharing of spares (and their costs) with other transmission businesses[133].

The strategic spares policy prescribes that SPA reviews its strategic spares holdings on an annual basis to ensure that the correct equipment is being retained. Asset-condition assessments are also considered as part of this review in order to identify any equipment deterioration that may require additional spares to be held.

PB understands that an inventory value was included in the regulatory asset base on 1 January 2003 as part of the ACCC decision[134] and since that date the change in the inventory holdings is reflected in the inventory cost category and considered for appropriate inclusion in the RAB.

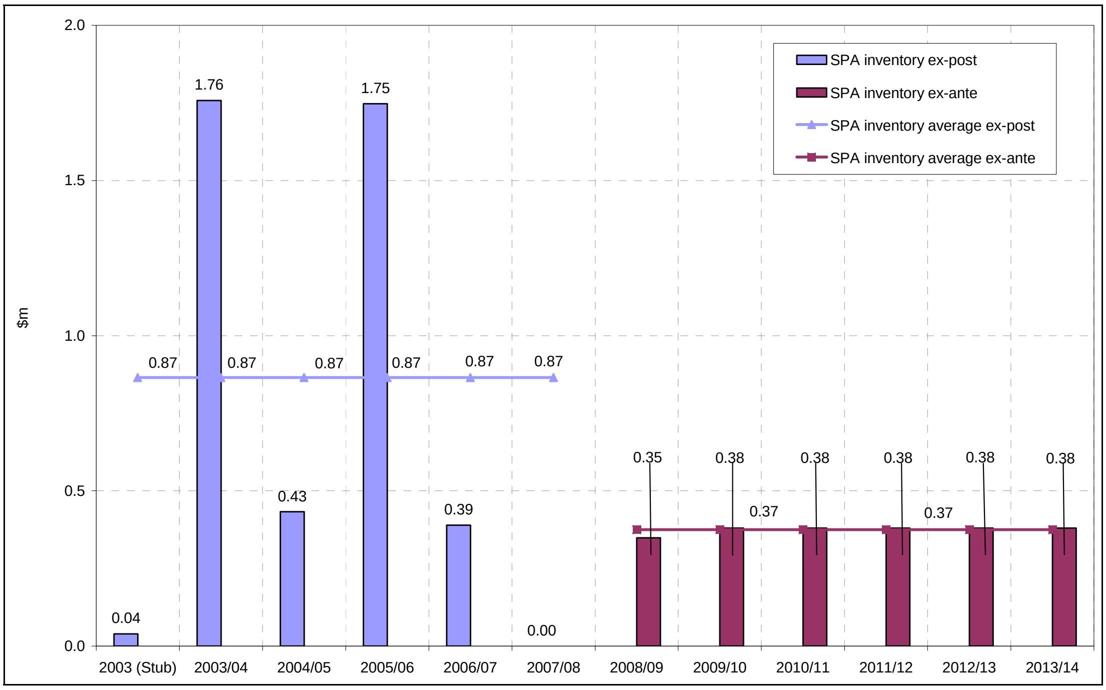
Given that the defined inventory value is a reflection of the change in (or movement of) inventory from year to year, the inventory value may be negative or positive, suggesting a year-on-year reduction or increase in total store holdings.

133 The assets held by transmission businesses may be suitable for use on other transmission networks in Australia and vice versa. The transmission businesses in Australia have agreements in place to 'share' assets where practicable.

134 Decision; Victorian Transmission Network Revenue caps 2003-2008; Date 11 December 2002; File no: C2001/1093; Page 37; Table 3.2

Figure 6-2 shows the ex-post and ex-ante inventory values as proposed by SPA. Figure 6-2 also shows the average inventory value over the ex-post[135] and ex-ante periods.

Figure 6-2 – Ex-post and ex-ante inventory values ($m real 2007/08)



Source: SP AusNet: SPA Templates – cost information lodged 280207.xls

From the current regulatory period (2003/04 to 2007/08) to the next regulatory period (2008/09 to 2013/14) SPA estimates that its average yearly expenditure on inventory will reduce by 57%.

Premises

SPA owns and operates premises throughout Victoria. These premises include a large number of operational substations and also a number of offices and other operational sites. As these premises are owned and operated by SPA, there is a requirement for maintenance to be carried out.

As with all assets that SPA owns or controls, the justification for expenditure is controlled via the AtoP process. An example has been viewed by PB in relation to premises with the consolidation form three offices to one single office[136].

The drivers identified in SPA's documented Authority to Proceed[136] were identified primarily through the sudden increase in the staff numbers as an acquisition of a complementary business had occurred. Maintaining a large workforce across three physical offices was deemed to be inefficient.

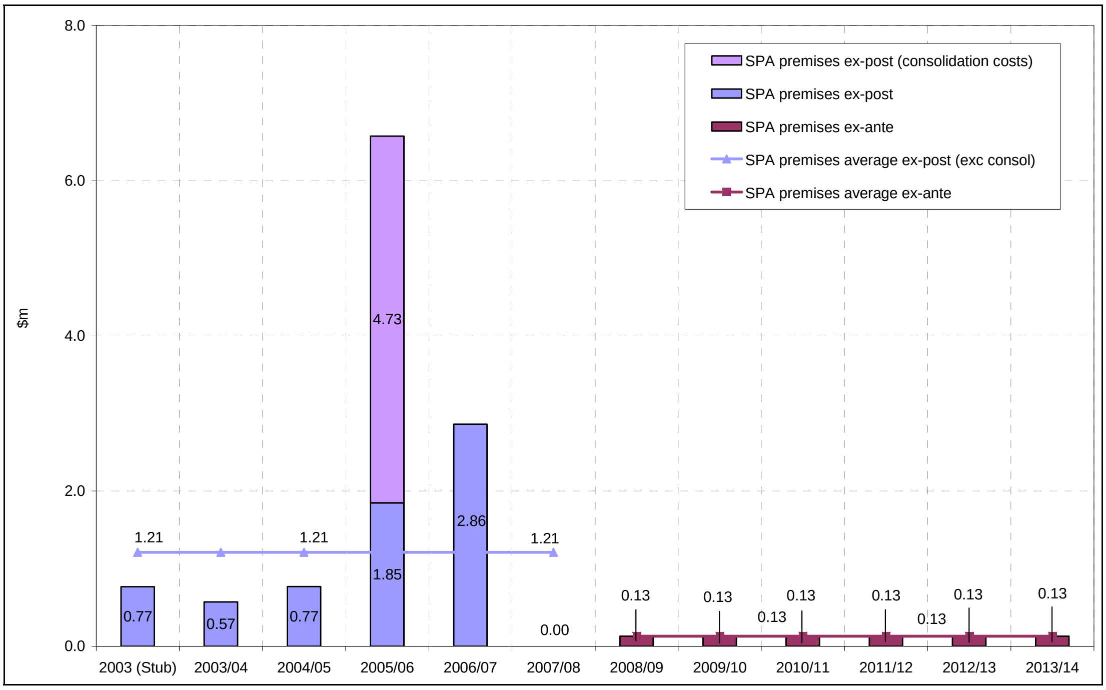
Figure 6-3 displays the ex-post expenditure on the refurbishment of premises. The average expenditure shown over the period from 2003/04 to 2007/08 excludes the one-off expenditure ($4.73m ($real 2007/08)) that was incurred in the 2005/06 period when SPA consolidated the three Melbourne locations into the single location at Freshwater Place.

135 The calculation of the average value for the ex-post period excludes the 2003 (stub) value as this value does not cover a full year.

136 Head office relocation to FWP (G500).

The consolidation costs have been excluded from the averaging[137] as this was identified as a large single event, occurring shortly after SPA's acquisition process[138], which would otherwise distort the historic figures.

Figure 6-3 – Ex-post and ex-ante expenditure for 'premises' ($m real 2007/08)



Source: SP AusNet: SPA Templates – cost information lodged 280207.xls.

From the current regulatory period (2003/04 to 2007/08) to the next regulatory period (2008/09 to 2013/14) SPA estimates that its average yearly expenditure on premises will reduce by 89%.

Vehicles

In order to undertake the required maintenance on the transmission system, SPA project and field staff are required to travel widely, and to geographically diverse sites. In order to carry out this maintenance work effectively SPA procures suitable vehicles.

At the start of the current regulatory period, SPA advises there were a total of 105 cars and trucks on the SPA list of vehicles. This fleet of mixed vehicle types has been maintained at a similar level (moderately lower at 97) over the period 2003/04 to 2007/08.

The allocation of vehicles within SPA is controlled by an 'eligible employee criteria'[139] which allocates vehicles depending on the role the employee undertakes within the business.

The criteria include, but are not limited to;

- primary role being operational with high field presence
- role involving availability duty or response to asset operational issues

137 The 2003 (stub) value has been excluded from the average value as it does not cover a complete year.

138 In July 2004 Singapore Power, an electricity transmission business, acquired an electricity distribution and gas distribution business from TXU Corp. This was followed in June 2005 of the launch of the SPA brand for the three businesses. SPA identified $4.73m in costs related to the consolidation of the electricity transmission business.

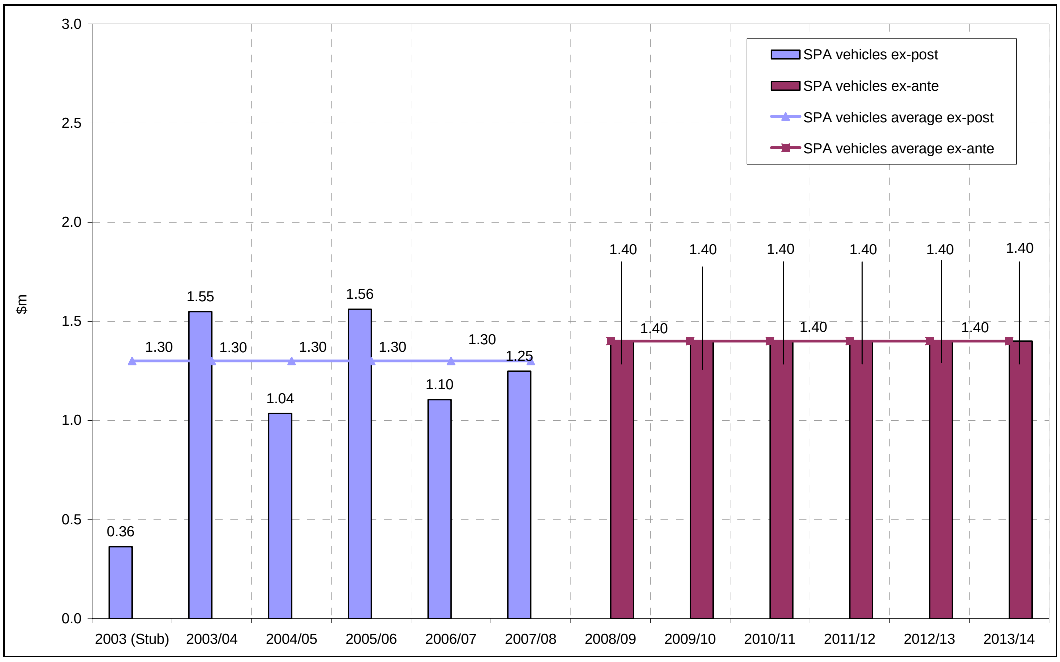
139 As per email from SPA to PB dated 21 May 2007.

- roles involving specialist tools and equipment to complete tasks
- on-call staff to respond to plant failure.

Ultimately the decision to provide an employee with a vehicle rests with the SPA's general management and the eligibility of each employee is routinely reviewed.

Figure 6-4 shows the expenditure that SPA has incurred on vehicles in the current regulatory period, together with the expenditure forecast in the next regulatory period.

Figure 6-4 – Ex-post and ex-ante expenditure for 'vehicles' ($m real 2007/08)[140]



Source: SP AusNet: SPA Templates – cost information lodged 280207.xls

From the current regulatory period (2003/04 to 2007/08) to the next regulatory period (2008/09 to 2013/14) SPA estimates that its average yearly expenditure on vehicles will increase by 8%.

Other

As part of its ongoing operation, SPA procures a number of one-off items which are grouped under a single category labelled as 'Other'. This expenditure category includes, among other things, the following items:

- specialist tools and equipment
- documentation standardisation
- office equipment (printers, cameras etc).

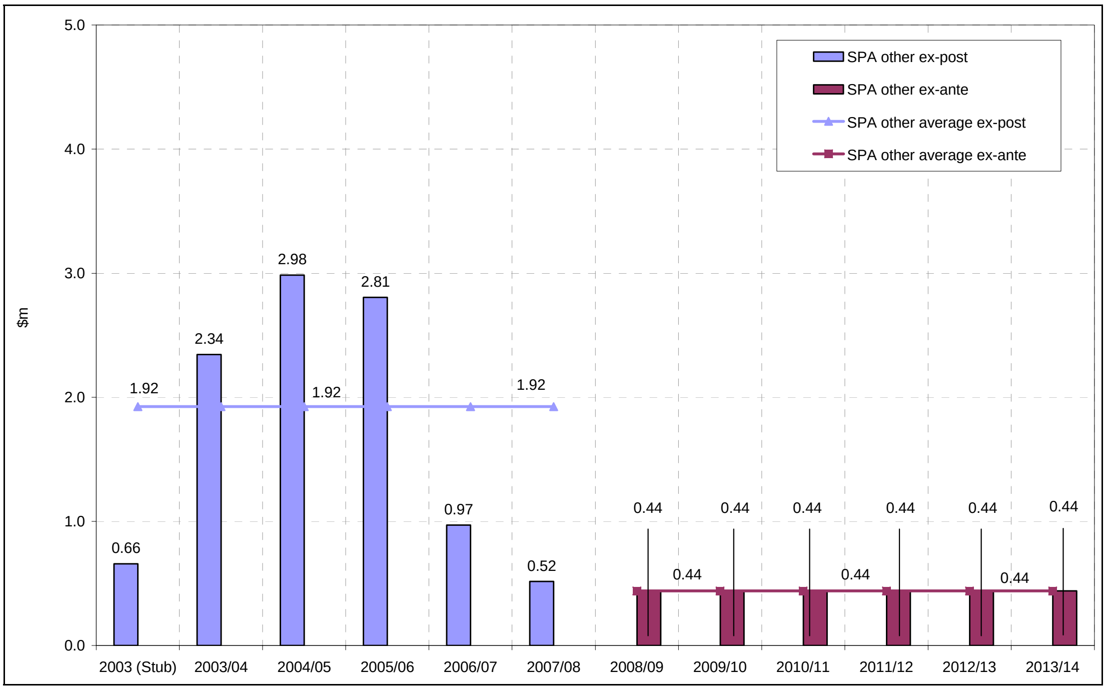
Figure 6-5 shows the expenditure on 'Other' items over the current regulatory period and also the expenditure forecast for the next regulatory period. Period averages are also provided[141].

There is no common driver for expenditures under the 'Other' section. Each item that is procured and allocated to this category uses the internal approval process to justify the procurement.

140 The 2003 (stub) value has been excluded from the average as it does not cover a full year.

141 The 2003 (stub) value has been excluded from the average as it does not cover a full year.

Figure 6-5 – Ex-post and ex-ante expenditure in the 'Other' category ($m real 2007/08)



Source: SP AusNet: SPA Templates – cost information lodged 280207.xls

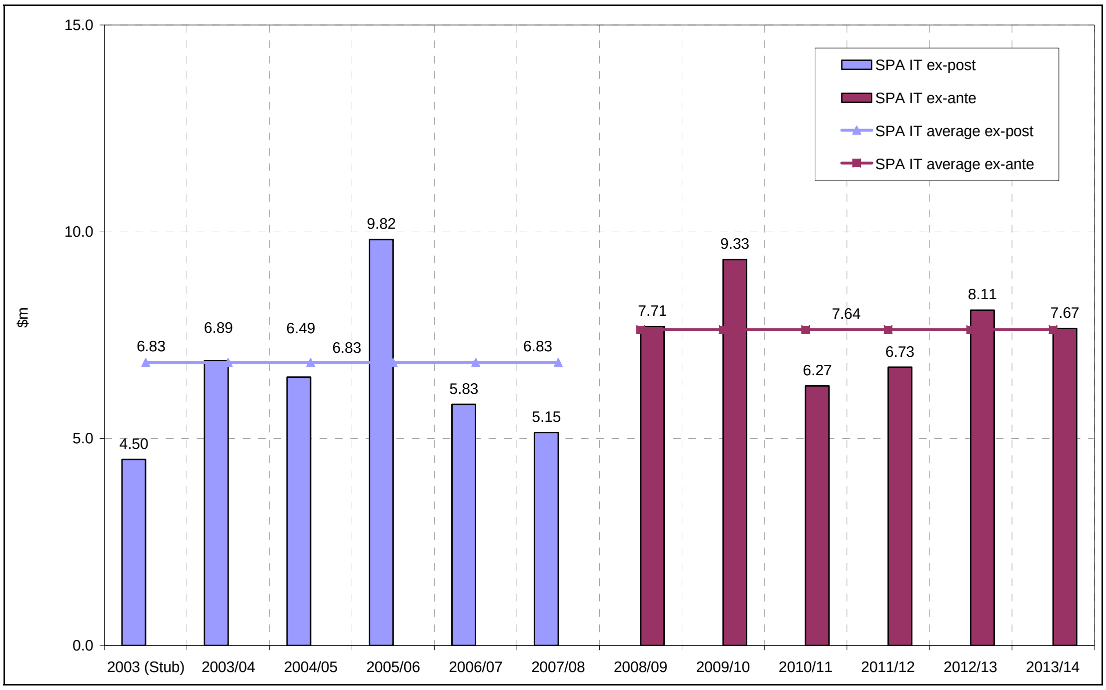
From the current regulatory period (2003/04 to 2007/08) to the next regulatory period (2008/09 to 2013/14) SPA estimates that its average yearly expenditure on 'Other' will decrease by 77%.

6.1.3 Information Technology

The transmission business is dependent on Information Technology (IT) for general business operation, Figure 6-6 shows the ex-post and ex-ante expenditure that SPA has requested in its proposal[142].

142 The 2003 (stub) value has been excluded from the average as it does not cover a full year.

Figure 6-6 – Ex-post and ex-ante expenditure for IT ($m real 2007/08)[143]



Source: SP AusNet: SPA Templates – cost information lodged 280207.xls

From the current regulatory period (2003/04 to 2007/08) to the next regulatory period (2008/09 to 2013/14) SPA estimates that its average yearly expenditure on IT will increase by 12%.

At the time of the last regulatory reset[144], SPA forecast a 'business-as-usual' approach to its IT-related capex. The largest IT investment identified at the time was a major upgrade to the Network Switching Centre.

SPA advises that the acquisition of a gas and electricity distribution businesses in July 2004 led to a significant increase in the size of the company, and provided opportunities for efficient investment in a number of significant IT projects. These projects aimed to deliver efficiency and productivity gains through economies of scale which may not have been possible before the acquisition. Major IT projects were commissioned on this basis under a 'whole of business development' initiative.

As part of this review, SPA has presented its documented Transmission Business Systems Strategy[145]. This strategy describes the establishment of a holistic approach to IT for the whole of the SPA integrated business. SPA has identified the share of these (total) whole of business costs attributable to its transmission business.

It is also noted that the company-wide strategy does not automatically guarantee procurement of the equipment. The need for justification of the project to the electricity transmission business is still required. This is conducted through the AtoP procurement policy.

143 The 2003 (stub) value has been excluded from the average as it does not cover a full year.

144 Decision; Victorian Transmission Network Revenue caps 2003-2008; Date 11 December 2002; File no: C2001/1093; Page 57.

145 Transmission Business Systems Strategy V1_0

6.2 BENCHMARKING

PB has compared the forecast non-system capex proposed by SPA with other Australian transmission businesses.

6.2.1 Background

In order to develop an independent view on the prudency of the historic and proposed SPA non-system expenditure, PB has benchmarked the SPA proposal against other transmission businesses in Australia. Our analysis has been undertaken using publicly available information for five other transmission businesses, including:

- Powerlink in Queensland
- Transgrid in New South Wales
- EnergyAustralia in New South Wales
- Transend in Tasmania
- ElectraNet SA in South Australia.

6.2.2 PB analysis

PB has benchmarked SPA's total non-system capex and each of the sub-categories — 'Support the Business' and IT.

Furthermore, in order to capture the unique Victorian TNSP arrangements, we have included two subsequent benchmarks based on VENCorp and the independent planner and SPA/VENCorp combined to represent the combined role of a TNSP in other jurisdictions.

6.2.3 Overall non-system

The five Australia transmission businesses identified above have all been subject to regulatory price reviews in the last 5 years. The results of which have been published[146]. The regulatory decision information used in our analysis is based upon regulatory periods which commenced between 2002 and 2005.

PB has extracted and reviewed the regulatory determinations for five of the businesses and to ensure a common baseline for reference, all non-system capex has been adjusted to 2007/08 equivalent dollars and annual average figures have been used. PB considers this approach facilitates more meaningful comparisons as it better reflects long-term trends in business expenditure. The SPA data has also been average over the review period in question.

To aid in our benchmarking analysis, we have extracted and compared data using company employee numbers available in annual reports[147]. SPA provided direct advice on the number of full-time equivalent employees that work within its regulated transmission business.

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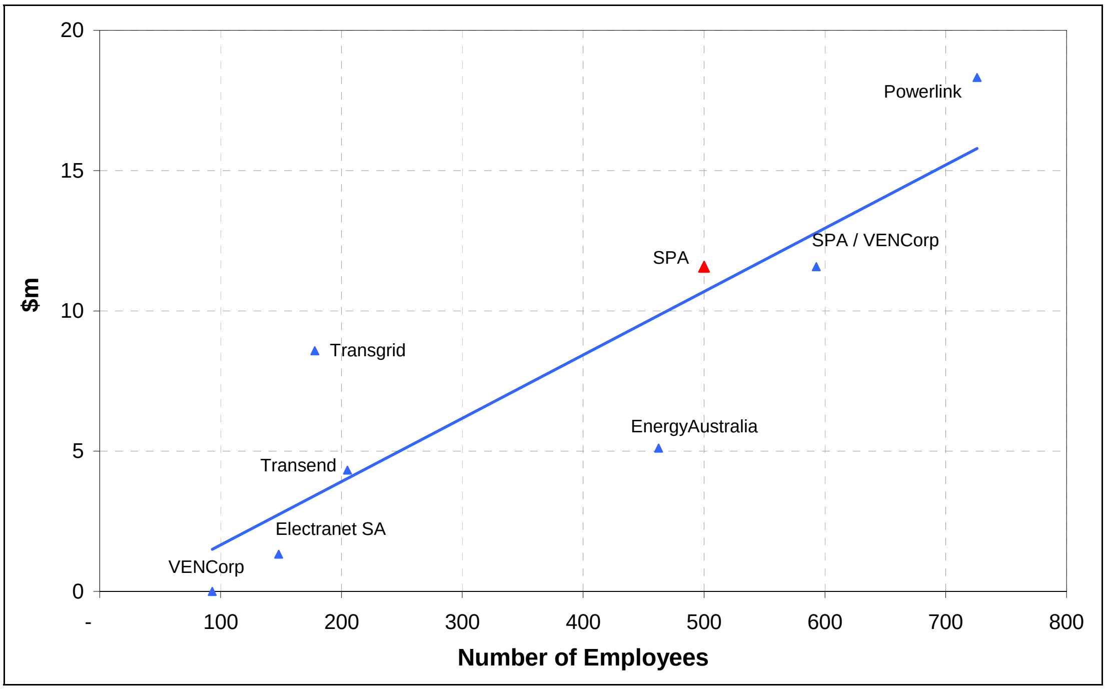
146 ACCC or AER websites.

147 In the case of EnergyAustralia (EA) we have derived suitable employee numbers by discounting the employee's allocated to retail and corporate functions as reported in a response to a question in NSW parliament from September 2003 (http://www.parliament.nsw.gov.au/prod/la/qala.nsf/ad22cc96ba50555dca57051007aa5c8/ca25708400173f67ca25704a00090cfa!OpenDocument).

PB subsequently scaled the employee numbers as reported in EA's Annual Report of 2005/06 based on the percentage of EA's RAB that is allocated to its transmission business (12%) as reported to the AEMC at (http://www.aemc.gov.au/electricity.php?r=20070323.132438). Consequently PB's estimated number of EA employees in its transmission business is 462.

Figure 6-7 represents the annual expenditure on non-system capex as identified in various regulatory decisions and using the total number of employees in each transmission business as a base.

Figure 6-7 – Non-system capex (average per year) as a function of employee numbers ($m real 2007/08)



Source: PB analysis; regulatory decisions

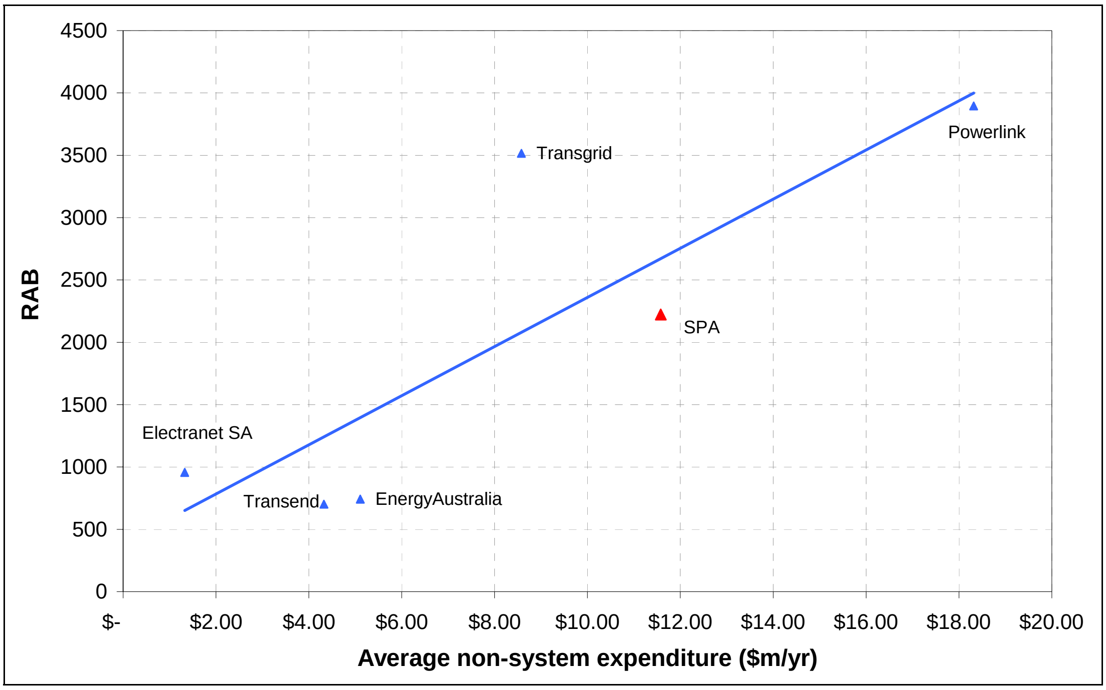
Figure 6-7 shows that SPA is expending an average of $23,200 per employee per year on non-system capex. As the expenditure on IT is the dominant cost in non-system, this implies that ‘number of employees’ is a more appropriate reflection of the cost driver rather than ‘size of the network’ or the serviced area of the business. From the information attained via the regulatory decisions, the average for the transmission industry is $21,700 per employee. SPA is seen to be slightly higher than the industry average by 6.5%. From this analysis PB observes that the average SPA expenditure is moderately higher (for both ex-post and ex-ante periods), but we conclude that these costs are not unreasonable.

PB also compared the non-system expenditure against three established transmission industry quantities:

- size (value) of the regulatory asset base at the last review
- average annual opex
- average annual capex.

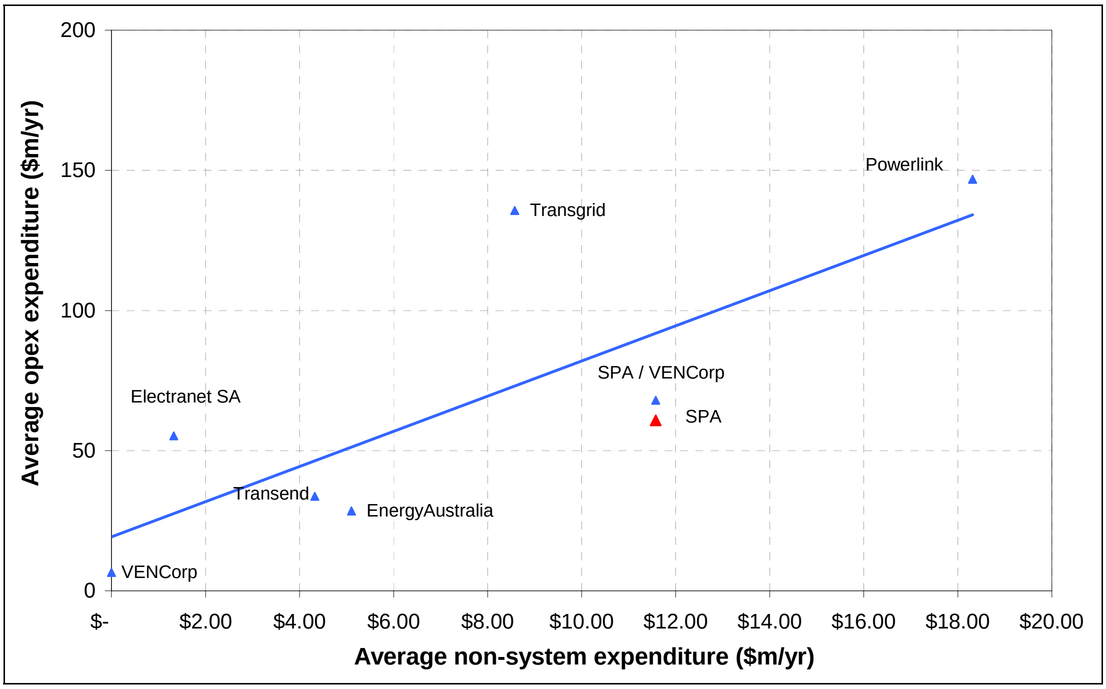
The results are shown in Figure 6-8, Figure 6-9 and Figure 6-10

Figure 6-8 – Average annual non-system capex as a function of RAB ($m real 2007/08)



Source: PB analysis; regulatory decisions

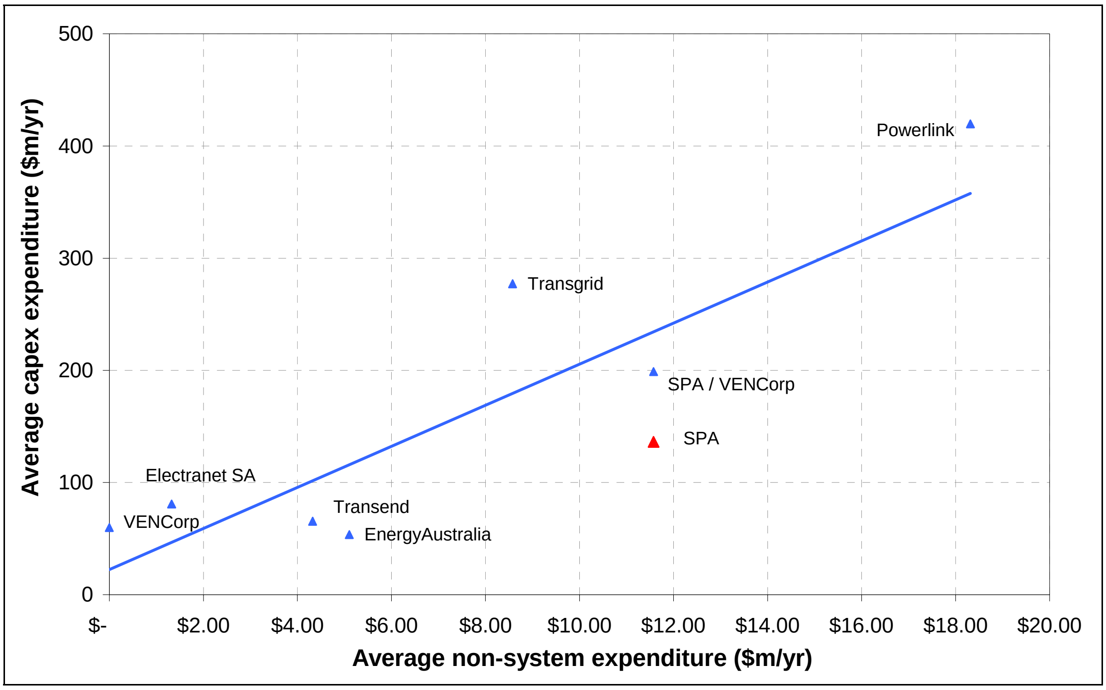
Figure 6-9 – Annual non-system capex as a function of opex[148] ($m real 2007/08)



Source: PB analysis; regulatory decisions

148 Annual values for non-system capex and opex.

Figure 6-10 – Average non-system capex as a function of total capex ($m real 2007/08)



Source: PB analysis; regulatory decisions

From the three figures above, SPA are below the average linear trend of the transmission businesses. PB also reviewed the combined expenditure of SPA and VENCorp to establish how the Victorian transmission business compares to equivalent businesses.

PB draws from this analysis that in all cases SPA appears to be below the industry trend for non-system expenditure when compared to other transmission businesses and when the combined businesses of SPA and VENCorp are examined, the figures are still below the industry trend

6.2.4 Support the business and IT capex

In the context of benchmarking, PB has undertaken a more detailed review of the individual categories of 'Support the Business' and the IT capex against information collected from the most recent ex-ante review of Powerlink in Queensland.

PB has examined the individual non-system categories as a function of the total RAB as stated by SPA in 2007/08 and Powerlink in 2006/07 and adjusted for CPI. We would expect that economies of scale would be captured for businesses that own or manage larger transmission networks (a function of the RAB). This efficiency would then be reflected in the number of staff needed to manage the network, and ultimately in the support to the staff (a function of non-system).

The first stage was to establish the percentage of expenditure that each business expended on Non-system, Business IT and Support the Business. This is shown in Table 6-3.

Table 6-3 – SPA and Powerlink Non-System capex as a percentage of the RAB value

Relative expenditure (%)	Non-system	IT	Support the Business
SPA	0.52	0.33	0.19
Powerlink	0.47	0.21	0.26

Source: PB Analysis; SP AusNet Revenue proposal

From this analysis, SPA appears to be expending less than Powerlink on Support the Business and when comparing Business IT SPA appears to be expending more than Powerlink. As non-system is the summation of Business IT and Non-system, the higher expense in this section is driven by Business IT.

PB concludes that although there are differences, the comparative expenditure of the two businesses is close and does not highlight an area of concern.

6.3 DETAILED EXPENDITURE REVIEWS

PB has reviewed three areas of expenditure in detail. This review has focused on IT, inventory and vehicles. We looked specifically at the historic (ex-post) expenditure associated with Business IT and Inventory and the forecast (ex-ante) expenditure proposed for vehicles.

Where possible (and appropriate) we have used the outcome of the ex-post detailed reviews to inform our recommendations on SPA's ex-ante proposals; and vice versa.

6.3.1 Summary and selection

In selecting the areas of expenditure for detailed review, PB has considered a number of factors (such as materiality and timing), and in general the areas were chosen to provide as wide coverage as possible across the entire non-system expenditure program.

PB has examined the expenditure associated with each specific item and has reviewed the proportion of the total allowance it comprises. The largest single expenditure in the non-system capital expenditure relates to Business IT. PB has therefore selected the ex-post Business IT to review in detail.

The second expenditure item, ex-post inventory, was selected on the basis that spares holdings represent a large proportion of procurements made by SPA. The final expenditure item chosen for review related to recurring vehicle acquisitions, and selected the ex-ante vehicles expenditure to review.

Table 6-4 shows the value of each of these expenditure items and the percentage of the SPA non-system regulatory expenditure proposed that they represent.

Table 6-4 – Expenditure associated with the three items selected for detailed review

Expenditure $m (real 2007/08)	Proposed expenditure reviewed		Total non-system expenditure		% of total non-system expenditure
	ex-post	ex-ante	ex-post	ex-ante	
Business IT	40.25		72.13	—	55.80
Inventory	4.37		72.13	—	6.05
Vehicles		8.40	—	59.89	14.03

Source: SP AusNet Proposal; PB analysis

6.3.2 Business IT (ex-post)

Business IT is the largest ex-post and ex-ante expenditure category within the total SPA non-system capex.

Overview

SPA has requested $40.24m[149] ($ real 2007/08) of ex-post expenditure to be rolled into the RAB as of 01 April 2008. This accounts for 56% of the total proposed non-system capital expenditure.

Company policy

SPA has developed a Transmission Business System Strategy[150] that covers a rolling 5-year period to record the large-scale Business IT expenditure it has proposed, and outlining the overall business strategy.

SPA's Business IT program comprises the following integrated sub-programs:

- asset management automation
- network management automation
- corporate services automation
- accessibility and mobility automation
- reporting and data integration
- desktop PC and peripheral support
- IT infrastructure services.

The SPA Business Systems Strategy is reviewed and updated annually. Each project objective is reviewed to ensure that it aligns with the strategic objective of the business.

Each separate project is prepared, assessed and approved through a defined business case. Typically, business cases include the identification of alternative options (including a 'do nothing' option), followed by a cost–benefit analysis. Projects are then approved in accordance with the SPA 'Authority to Proceed' approval process.

PB analysis

SPA's Business IT program incorporates over 200 separate procurements of differing sizes and scales. In a detailed listing[151] of IT projects presented to PB, SPA IT projects range in value from $340 (printer) to $3.8m for the SPA energy management system upgrade.

To assist in the PB analysis SPA divided the IT projects into four categories:

- desktop
- infrastructure
- projects
- other.

Business IT expenditure covers a large number of separate and not necessarily related projects and PB examined the policies that have been introduced to control expenditure of

149 SPA application is for $37.9m nominal or $40.24m (real 2007/08).

150 SP AusNet; Transmission Business System Strategy; V1.0

151 SP AusNet; Ex-post IT project financial details.xls.

these IT projects. We started by conducting a systematic sense check of the list of all the projects in the IT section to gain a high-level understanding of the scope and types of projects included in this category.

On receiving the information from SPA[152], it was noted that there were minor errors in the allocation of projects under the IT section. Three projects listed under the IT heading should have been allocated to either 'other' or 'vehicles' categories. The removal of these three items reduced the overall IT component by 4%, as itemised in Table 6-5[153].

Table 6-5 – Incorrectly classified expenditure affecting IT ($m real 2007/08)

Incorrectly classified expenditure $m (real 2007/08)	Total ($)
From 'Other' to Business IT	0.94
From Business IT to tools	1.34
From Business IT to vehicles	1.18
Reduction in Business IT	1.57

Source: SP AusNet; Ex-post IT project financial details.xls

Following the high-level check of the projects listed within the IT program, PB examined a number of specific SPA expenditure items. Under SPA policy, procurement should be justified with an individual business case. PB has examined the business case for a selection of the larger SPA procurements. Specifically, we have examined the SPA procurement guidelines relating to the following items:

- multiple procurement of laptops and computers
- energy management system upgrade
- HR learning and performance project.

Replacement of desktop fleet

The SPA replacement strategy for desktop IT equipment is documented in a business review document. The document was provided to PB as part of its review[154]. The document sets out the processes that SPA has introduced to ensure that replacement of computer hardware is both appropriate and timely.

The document identifies two options: the 'do nothing' option and the option which is based on the replacement of computer equipment that has reached the end of its life. The document also identifies the relative merits of replacement of computers and peripheral equipment.

The total cost of the project is $2.57m, of which $1.03m has been allocated to the transmission business; this is to cover 502 electronic notebooks, 180 laptops and approximately 20 printers.[155]

The majority of the project expenditure is associated with the purchase of laptops and notebooks (682 in total). The average cost of a laptop/notebook is $3,768 per unit. Of this, 40% is allocated to the transmission business.

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152 SP AusNet; revised non network template.xls

153 These items were incorrectly classified rather than an error in the value, therefore they have been re-allocated to the correct category without having a net effect on the overall non-system capex.

154 SP AusNet; Replacement of desktop hardware fleet (IT069).doc

155 Ibid.

From PB's review SPA had identified a need and, through the required Authority to Proceed process, identified an appropriate solution that reduced the cost of procurement to SPA by using their ability to purchase multiple items at a lower until cost.

During the review of the project, PB became aware of a component within IT listed as 'other' and includes items of varying value including laptop and computer purchases. This is distinct from the itemised list within non-system capex of 'other'. SPA purchased 26 computers directly under business cases for a total of $226,813[156]. This equates to $8,723 per unit, compared to the more efficient $3,768 per unit when procured in bulk under the general policy, a 57% reduction in the price per unit. When considering the allocation of cost to the transmission business of 40%, this leads to a total reduction in total purchase cost of $52,000.

PB concludes that, although the direct procurement of the 26 laptops was justified under the Authority to Proceed process, there is an opportunity for SPA to reduce computer-related costs as SPA has recognised that by procuring a significant quantity of laptops and notebooks they are able to secure a lower price. However, as the calculated reduction is comparatively small, PB is not recommending any reduction in the ex-post non-system capex, as proposed by SPA.

Energy management system (EMS) upgrade

SPA control and monitor the transmission system via a Supervisory, Control and Data Acquisition (SCADA) system. The SCADA system also provides interfaces to the National Electricity Market Management Company (NEMMCO). The project was an upgrade of the software and the hardware components of this SCADA system to minimise the risk of failure and to ensure that the system was fully supported.

PB has reviewed two documents relating to the SPA SCADA system. The first document was an approval request for the purchase of the software ($2.2m) [157]. The second document was an approval request for the purchase of the hardware ($1.67m)[158].

Each document justifies the need for the upgrade on the basis of ensuring that the system is supported and the risk of failure is reduced to an acceptably low level.

After reviewing both documents, each document was presented as a stand-alone business case justification. From the details in the software project of $2.2m, it was dependent on approval and implementation of the hardware upgrade. This dependency was identified in the document relating to the software. In PB's view this suggests that SPA are correctly identifying projects that have a co-dependency, and are takings steps to ensure that the SPA Board is aware of this prior to approval.

During the review, PB became aware of the ex-ante *network* capex item of $43.9m associated with upgrades and replacements to the SCADA EMS system. On reconciling the two projects, PB believes that this project should form part of the *network* capex proposals (as opposed to the *non-network* capex). However, PB notes that the two programs of work are separated in time by more than six years. Furthermore, we were unable to identify any amount of SCADA EMS (non-network) expenditure that aligned with the ex-ante project forecast.

Although this EMS upgrade scheme might be classed as a network augmentation, PB notes that:

- the treatment of *non-system* IT capex and *network* IT capex is the same
- the proposed ex-ante capex and the ex-post capex relate to different projects

156 SP AusNet; IT other projects.xls.

157 、 SP AusNet; approval request; energy management system strategic direction – software ($m, real 2001)

158 SP AusNet; approval request; energy management system strategic direction – hardware (presented in $m, real 2001).

- through its review of the ex-ante IT, PB has not identified any duplication of projects relating to SCADA.

PB recommends that no changes are made to the non-system capital expenditure relating to this scheme.

HR learning and performance project

This project is intended to be a company-wide initiative delivering benefits to all company employees in both the regulated transmission areas and the distribution and gas businesses. A general need has been identified in the approval request document[159]. The approval request document clearly identifies the scope of the works and includes an economic assessment of alternative options[160].

From analysis of the actual expenditure against the total project cost, it is possible to ascertain that 37% of the total budget has currently been allocated to the transmission business. This amount is also supported by the ex-post review document[161] that identifies both the total cost and also the proportion of the total cost allocated to the transmission business.

Although it is possible to determine that the costs have been allocated on the basis of a ratio of approximately 60:40 (distribution to transmission), PB has not been able to explicitly identify how this allocation is determined and controlled.

Conclusion

The ex-post IT expenditure proposed for inclusion in the RAB comprises a large number of projects of differing scopes and various values. In an initial check of the projects three errors we identified that overstated the value of IT by $1.58m ($ real 2007/08) — approximately 5% of the total IT allocation. Table 6-6 displays the errors and the corrections to the yearly totals.

Table 6-6 – Business IT capex (ex-post) from 01 Jan 2003 to 31 Mar 2008

Expenditure $m (real 2007/08)	03 (stub)	03/04	04/05	05/06	06/07	07/08	Total
Proposed Business IT	4.50	6.89	5.59	9.77	5.83	7.67	40.25
Identified error	0.00	0.00	0.90	0.04	0.0	(2.52)	(1.58)
Revised Business IT	4.50	6.89	6.49	9.81	5.83	5.15	38.67

Source: Decision; Victorian Transmission Network Revenue Caps 2003 – 2008; File ref: C2001.1093; p57

PB subsequently reviewed aspects of the non-system IT capex in detail. From our review, we were able to identify that SPA was following its processes and procedures as documented. This was evidenced through the Energy Management System Upgrade project — that was appropriately split into three separate stages. Each stage was approved separately, and PB found that each stage of the project referenced the initial document that identified the total cost.

We also identified, that SPA has developed strategies for managing large multiple acquisitions that reduce the overall cost to the business. This is highlighted with the notebook/laptop replacement program. However, PB found that SPA has purchased laptops and computers

159 SP AusNet; Authority to Proceed; HR Learning and Performance Management System; G622.

160 It is noted that an economic analysis for a project of this type, specifically the net benefits, are more difficult to quantify than a transmission augmentation. Nevertheless, SPA has included a ranking system for the three options to allow a NPV summary to be created.

161 SP AusNet; HR Learning and Management System(G622); V0.2

outside this strategy, and this ‘single acquisition approach’ appears to have resulted, in some instances, in the unit cost being more than twice that which might otherwise have been achieved.

PB checked to see how the costs between the transmission business and the other two businesses within SPA[162] were allocated. We found that as part of the IT projects examined there was a clear identification of the total cost and the partial cost to be allocated to transmission. However, we were not able to clearly establish the basis for the allocation of costs between transmission and the rest of the business. However, PB does not consider that the absence of this clarification warrants a reduction to the cost.

6.3.3 Inventory

Inventory has the largest volume of individual items of all the expenditure categories within the total SPA non-system capex. This section presents the results of PB’s (detailed) review of the proposed ex-post inventory capex. Towards the end of the section will also make recommendations on the proposed (ex-ante) capex – as a direct result of our findings from the ex-post review.

Overview

The inventory expenditure covers spares that SPA holds relating to the transmission equipment on the network. Each asset is assessed to establish what strategic spares are required to ensure that in the event of equipment failure, replacement or repairs can be done in a timely manner.

As the network ages, the equipment installed on the network can be superseded by modern equivalent technology. In these circumstances SPA has noted that equipment it uses is no longer manufactured, and consequently not supported by the original manufacturer. In this circumstance, SPA may decide to procure additional spares that will allow them to maintain their equipment for a longer period.

In 2002 the ACCC allowed a certain value of inventory to be rolled into SPA’s Regulatory Asset Base, as of 01 January 2003[163]. The value of inventory at this date was $11.47m ($real 2007/08)[164]. By summating the movement in the inventory over the regulatory period, the value at the end of the period is expected to be $16.24m (real 2007/08), as of 01 April 2008.

The inventory expenditure represented in SPA’s Revenue Proposal is the movement in the total value of the inventory and can be a negative as well as positive.

Company policy

SPA control spares parts under two policies:

- Strategic Spares Policy
- PN1 — Property, Plant and Equipment Policy.

The Strategic Spares Policy identifies how SPA classifies items as strategic spares. There are 17 criteria to which an item may be classed as a strategic spare. These include, but are not limited to items like:

- age, history and condition of plant

162 SP AusNet operates three businesses under the one brand, electricity transmission, electricity distribution and gas distribution.

163 Decision; Victorian Transmission Network Revenue caps 2003-2008; Date 11 December 2002; File no: C2001/1093; Page 37

164 Figure reported in SPA revenue Proposal and the ACCC determination was $10.1m (nominal 2003)

- criticality
- cost of the spare
- lead time to manufacture
- share options with other transmission businesses.

The policy identifies how the purchase of spares should be consistent with achieving the businesses performance objectives whilst ensuring efficient management of strategic spares.

The second document used by SPA establishes the accounting treatment of the items procured by SPA and is used to ensure that it is compliant with the accounting standard PN1 – property, plant and equipment. PN1 is based on the accounting standard AASB116 and prescribes the accounting treatment and the capitalisation for property, plant and equipment.

PB considers the Strategic Spares Policy to be well documented and contains a high level of detail that allows clear identification of what constitutes a strategic spare.

PB analysis

PB examined the inventory movement from a list of changes to the stores holdings in May 2006. In the single month 571 items of plant and equipment were added to the inventory listings, this amount is intended to be included into the RAB of the value of $4.38m (nominal 2006).

Based on the above analysis PB became aware that some of the items identified in the inventory listings were not consistent with the company policy, PN1 — Property, Plant and Equipment Policy, specifically the classification of a spare that is to be capitalised.

From SPA Strategic Spares Policy, a strategic spares is defined as:

> a spare which is a complete unit or item specifically held to replace a unit or item which either fails or is damaged during service such that replacement is required. Strategic spares will typically consist of complete assemblies or major sub-assemblies of the plant and equipment items. Strategic spares are not intended to be utilised for normal operational and maintenance requirements.

SPA policy[165] identifies a spare unit as:

> a spare unit or item which is for use for recurrent maintenance and fault repair and which has not been specially purchased/allocated for use as a strategic spare.

From SPA's capitalisation policy[166] on accounting principals:

> an individual asset, other than a depreciable spare, is recognised as plant, property and equipment if it has:
>
> (b) service potential of more than one year
>
> (c) purchase or construction cost is more than $500.

The above policies are consistent with each other and identify that 'normal stores items' should be written-off at the time of purchase, not rolled into the RAB and an appropriate allowance made in opex.

PB has received confirmation from SPA[167] that the 'normal line spares' are not being differentiated from strategic spares and have been included in the line item — 'inventory'.

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165 SP AusNet; Strategic Spares Policy

166 SP AusNet; PN1 – Property, plant and equipment

From discussions with SPA on the approach taken to 'spares', SPA has confirmed that all items are booked out of 'stores' at the time they are required and this reduces the total value of the inventory holdings. The stores item 'booking' is recorded against the work being undertaken. If the work undertaken is maintenance, then the value of the inventory item is allocated to opex. If the work is associated with a specific project, then the value of the inventory item is recorded against the project in question.

PB has been able to establish from SPA that approximately 10% of the inventory turns over in a single year. Working on the principle that strategic spares are not expected to be turned over on an annual basis, a base line of 10% is assumed to be related to 'normal line items'.

Conclusion

SPA classifies two types of spare parts, 'strategic spares' and 'normal line items'. From the analysis carried out by PB, both types of spares have been included in the 'inventory' category in the SPA Proposal, and therefore rolled into the RAB. From the accounting standard AASB116, 'normal line items' should not be capitalised and should be written off at the time of purchase and not capitalised. During the ex-post review it was apparent to PB that it would be difficult to clearly identify the precise value of inventory that should be written-down.

When evaluating the *ex-ante* inventory, PB was not able to clearly identify a value of 'normal stores items' that under financial rules should be written down and allocated to opex at the time of purchase. Through its review PB has, however, been able to identify that 10% of the SPA inventory is known to be turned-over annually.

Therefore, PB recommends that as part of its forecast for inventory, SPA modifies its internal accounting process to meet the accounting guidelines and reduces the forecast by 10% per year to reflect the value of the additional items that would be rolled over on an annual basis. PB recommends that the forecast opex is increased by an equivalent amount[168].

From communications with SPA and a detailed description of the forecast process,[169] SPA used a base year of 2007/08 to forecast the inventory. Therefore PB recommends that the base year estimation is reduced by 10% and this reduction is then reflected in the entire ex-ante proposal. This is set out in Table 6-7.

Table 6-7 – PB recommendation on SPA ex-ante inventory proposal ($m real 2007/08)

Expenditure ($m real 2007/08)	08/09	09/10	10/11	11/12	12/13	13/14	Total
Current ex-ante proposal	0.35	0.38	0.38	0.38	0.38	0.41	2.28
Proposed variation	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.24)
PB recommendation	0.31	0.34	0.34	0.34	0.34	0.37	2.04

Source: SP AusNet Proposal; PB Analysis

167 As per email from SP AusNet to PB dated 22 May 2007

168 The recommended adjustment to forecast opex is addressed in Section 7 of this report.

169 SP AusNet; Estimation of inventory forecast.doc; v1

6.3.4 Vehicles (ex-ante)

SPA procures vehicles on a regular basis and this section is the results of PB's review of the proposed ex-ante vehicles capex.

Overview

SPA utilises vehicles to carry out operational and maintenance functions. SPA stated that a replacement program for each vehicle aligns with the manufacturers warranty period of:

- replacement at end of warranty period (normally 3 years)
- replacement at 100,000 km.

SPA also has identified that certain vehicle manufacturers have introduced an extended warranty period of up to 5 years. SPA has stated that they do not have many vehicles from these specific manufacturers, but that they have purchased a moderate number of vehicles to establish the robustness and the possibility of moving towards these types of vehicle.

For the ex-ante period, SPA intends to maintain the number of vehicles at a consistent level compared with the ex-post period, with a target of approximately 110 vehicles.

As an outcome of our detailed review, PB identified that the cost of vehicles has been understated due to a categorisation error. In the ex-post period of 2006/07, the vehicle capex reported was $1.132m lower actually undertaken by SPA.

Company policy

Vehicles are required by SPA staff to undertake their role in an efficient manner. The allocation of vehicles is controlled by an 'eligible employee criteria'[170] which allocates vehicles depending on the role the employee undertakes within the business.

The criteria include, but are not limited to:

- primary role being operational with high field presence
- role involving availability duty or response to asset operational issues
- roles involving specialist tools and equipment to complete tasks
- on-call staff to respond to plant failure.

Ultimately the decision to provide an employee with a vehicle rest with the general management and the eligibility of each employee is constantly reviewed.

PB analysis

SPA provided two sets of documentation to substantiate its use of vehicles. The first set of documents included sales acknowledgement notices[171] of the vehicles that were sold in 2007. The second set of documents included an excel spreadsheet detailing all the vehicles currently belonging to SPA[172].

SPA provided 15 sales acknowledgment notices for vehicles that were sold between February 2007 and March 2007. Each document included the following information:

- make and model of the vehicle

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170 As per email from SPA to PB dated 21 May 2007.

171 SP AusNet; 'Vehicles info.pdf'.

172 SP AusNet; 'Vehicle current.xls'.

- registration number
- final odometer readings (kilometres travelled).

The second document was an excel spreadsheet that listed 101 vehicles, containing the following:

- description of the vehicle
- registration number
- latest odometer readings (kilometres travelled)
- date of purchase
- age.

Within the list of 101 vehicles, SPA identified 27 vehicles were associated with the regulated transmission business, and sales acknowledgement notices had been provided for 18 of these vehicles.

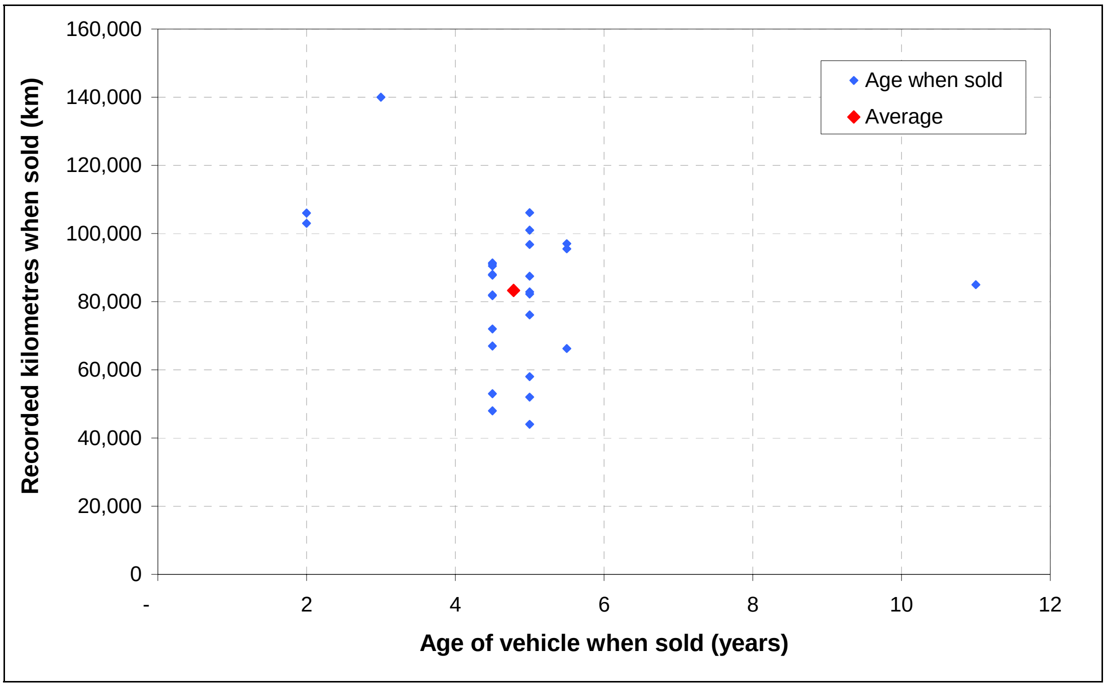
The data in the sales acknowledgment notices did not identify the age of the vehicle when it was purchased, but this detail was cross-referenced in the spreadsheet.

For the 18 vehicles where sales acknowledgment notices were provided, PB was able to identify the exact age of the vehicle at the time of sale and the recorded kilometres when the vehicle was sold.

Of the remaining nine vehicles, the registration numbers were numerically similar to vehicles where sales acknowledgement notices were provided. By inferring that the registration numbers were released at the same time we were able to deduce the age of the vehicle given the sales acknowledgement notices identifying the date it was sold.

Figure 6-11 displays the kilometres as recorded when the vehicles were retired from service, against age (either known or inferred).

Figure 6-11 – Age and recorded kilometres at time of sale, for vehicles used in the transmission business



Source: Custom Fleet Sales dockets & SP AusNet – Vehicle retirement accruals spreadsheet

PB has identified that the average age, against average kilometres, for the 36 vehicles is 5 years or 80,000 km; this is shown as the red data point on Figure 6-11.

Conclusion

SPA has set its ex-ante replacement forecast on vehicles using a period of 3 years. From the historical detail provided it appears the vehicles in the transmission business are typically replaced between 4 to 6 years, and on average every 5 years.

PB proposes that the ex-ante average replacement profile is amended to reflect a 5-year replacement cycle. This has the effect of reducing the forecast capex requirement by $3.42m over the 6-year regulatory period as shown in Table 6-8.

Table 6-8 – PB adjustments to the SPA ex-ante proposal for vehicles

Expenditure $m (real 2007/08)	08/09	09/10	10/11	11/12	12/13	13/14	Total
Submitted	1.40	1.40	1.40	1.40	1.40	1.40	8.40
Proposed variation	(0.57)	(0.57)	(0.57)	(0.57)	(0.57)	(0.57)	(3.42)
PB recommendation	0.83	0.83	0.83	0.83	0.83	0.83	4.98

Source: SP AusNet: SPA Templates – cost information lodged 280207.xls; PB Analysis

6.4 RECOMMENDATIONS

PB has reviewed in detail the two major categories of non-system capex and makes the following recommendations.

Using top-down benchmarking measures, PB found that the total non-system capex proposal made by SPA was in line with similar businesses. We reviewed the non-system expenditure against the number of staff, the RAB at the last review, average opex and average capex and determined that SPA was typically below the industry average. At a high level, PB is of the opinion that SPA's non-system capex is reasonable.

Following this high-level review we looked at each category of the non-system capex. The conclusion of each section is below

6.4.1 Support the Business

For Support the Business we were able to benchmark SPA against one other transmission business and found that SPA was expending an equal amount in Support the Business when using measures informed by staff numbers, size of the RAB. Given this outcome, PB is of the opinion that at a high-level SPA expenditure on Support the Business is reasonable.

To support this view we analysed each sub-category of support the business element in a more detailed bottom-up manner.

Inventory (movement)

SPA records the change in inventory and the difference is added to the capital base. This figure can be negative as well as positive.

PB found that SPA has included normal stores items that, under accounting practice, should be written down rather than capitalised. PB conducted an ex-post review of the inventory and from information supplied by SPA and identified approximately 10% of the inventory is turned over annually. During the ex-post review it has become apparent to PB that it would be difficult to clearly identify the precise value of Inventory that should be written-down. On this basis we recommend that no adjustments are made to the ex-post inventory value.

However, as the ex-ante Inventory value has been based on a base line year, we recommend that the proposed ex-ante inventory total is reduced by an equivalent value of 10%. PB also recommends that the forecast opex is increased by an equivalent amount.

Vehicles

SPA utilises vehicles as part of its regulated transmission business. SPA noted that vehicles are replaced on a 3-year basis or 100,00km. From our detailed analysis, PB noted that the average turn around of vehicles was every 5 years or 100,000km.

Therefore PB recommends that the ex-ante forecast is adjusted to the historic average.

Premises

PB has not reviewed this element of the SPA proposal in detail, but from the high-level analysis and benchmarking we have not identified any areas of concern.

Other

PB has not reviewed this element of the SPA proposal in detail, but during the review of the IT section, we became aware of a misallocation of costs. Two items were allocated to IT that should be classified under ‘Other’.

6.4.2 IT

PB conducted high-level benchmarking of SPA’s IT ex-post proposal against one other transmission business. From this benchmarking, we identified that SPA was expending a similar amount on IT per person as the other business.

We also carried out further analysis by benchmarking using measures informed by the value of the RAB, and opex and capex levels and identified overall SPA was expending an equivalent amount.

PB analysed the IT entry in detail and we became aware of three errors that overstated the IT by approximately 4%.

During the review of IT related capex, we noted that the process and procedures adopted were clear and well understood. In all cases the formal process of project approval was followed and in the case of inter-related projects, the various project approvals were correctly referenced.

We identified that some additional purchases did not build on SPA’s ability to bulk purchase equipment and items was purchased at a higher cost than the bulk strategic procurement.

Although the one-off purchases were justified through business cases, PB would recommend that SPA reviews how bulk purchases can be advantaged when additional equipment is needed.

Overall, apart from the three allocation errors identified, In PB’s opinion that SPA’s IT expenditure is reasonable.

Summating the above proposals, PB recommends that the values shown in Table 6-9 (ex-post) and Table 6-10 (ex-ante) are included into the SPA RAB at the end of the regulatory period.

Table 6-9 – Proposed ex-post non-system capital expenditure from 01 January 2003 through to 31 March 2008

Expenditure $m (real 2007/08)	03[173]	03/04	04/05	05/06	06/07	07/08	Total
Submitted							
Business IT	4.5	6.89	5.59	9.77	5.83	7.67	40.25
Support the Business	1.83	6.22	5.22	12.69	5.33	0.59	31.88
Total	6.33	13.11	10.81	22.46	11.16	8.26	72.13
Detailed breakdown of the costs							
Inventory	0.04	1.76	0.43	1.75	0.39	—	4.37
Business IT	4.50	6.89	5.59	9.77	5.83	7.67	40.25
Premises	0.77	0.57	0.77	6.58	2.86	—	11.55
Other	0.66	2.34	2.98	2.81	0.97	0.52	10.28
Vehicles	0.36	1.55	1.04	1.56	1.10	0.07	5.68
Total	6.33	13.11	10.81	22.47	11.15	0.59	72.13
Revisions identified due to errors							
Business IT	—	—	0.90	0.04	0.00	(2.52)	(1.58)
Other	—	—	(0.90)	(0.04)	—	—	(0.94)
Vehicles	—	—	—	—	—	1.18	1.18
Total	—	—	—	—	—	(1.34)	(1.34)
Overall affect on the non-system capex							
Business IT	4.50	6.89	6.49	9.81	5.83	5.15	38.67
Support the Business	1.83	6.22	4.32	12.66	5.33	1.77	32.13
Total	6.33	13.11	10.81	22.47	11.16	6.92	70.80

Source: PB analysis

PB recommends that SPA proposal is adjusted as per the values Table 6-10.

173 This data is for the period 01 January 2003 to 31 March 2003.

Table 6-10 – Proposed ex-ante non-system capital expenditure from 01 April 2008 through to 31 March 2014

Expenditure $m (real 2007/08)	08/09	09/10	10/11	11/12	12/13	13/14	Total
Submitted							
Business IT	7.71	9.33	6.27	6.73	8.11	7.67	45.82
Support the Business	2.32	2.35	2.35	2.35	2.35	2.35	14.07
Total	10.03	11.68	8.62	9.08	10.46	10.02	59.89
Detailed breakdown of the costs							
Inventory	0.35	0.38	0.38	0.38	0.38	0.38	2.25
Business IT	7.71	9.33	6.27	6.73	8.11	7.67	45.82
Premises	0.13	0.13	0.13	0.13	0.13	0.13	0.78
Other	0.44	0.44	0.44	0.44	0.44	0.44	2.64
Vehicles	1.40	1.40	1.40	1.40	1.40	1.40	8.40
Total	10.03	11.68	8.62	9.08	10.46	10.02	59.89
PB recommendations							
Change to inventory	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.24)
Change to vehicles	(0.57)	(0.57)	(0.57)	(0.57)	(0.57)	(0.57)	(3.42)
Total	(0.61)	(0.61)	(0.61)	(0.61)	(0.61)	(0.61)	(3.66)
Overall affect on the non-system capex							
Business IT	7.71	9.33	6.27	6.73	8.11	7.67	45.82
Support the Business	1.72	1.75	1.75	1.75	1.75	1.75	10.47
Total	9.43	11.08	8.02	8.48	9.86	9.42	56.29

Source: PB analysis

7. OPERATIONAL EXPENDITURE

The National Electricity Rules require SP AusNet (SPA) to present its opex requirements for the forthcoming regulatory control period in order to:

- meet the expected demand for prescribed transmission
- comply with all applicable regulatory obligations associated with the provision of prescribed transmission services
- maintain the quality, reliability and security of supply of prescribed transmission services
- maintain the reliability, safety and security of the transmission system through the supply of prescribed transmission services.

Schedule 6A.1.2 describes the type of accompanying information that SPA must provide in order to explain and justify its forecast opex. This information includes:

- an overview of historic and forecast opex
- a description of factors that will affect opex in the forthcoming regulatory control period
- a brief description of the forecasting methodology employed and the assumptions underpinning the opex forecast
- a detailed presentation of SPA forecast opex, for each of the following categories
  – routine maintenance
  – asset works
  – corporate costs
  – other costs.

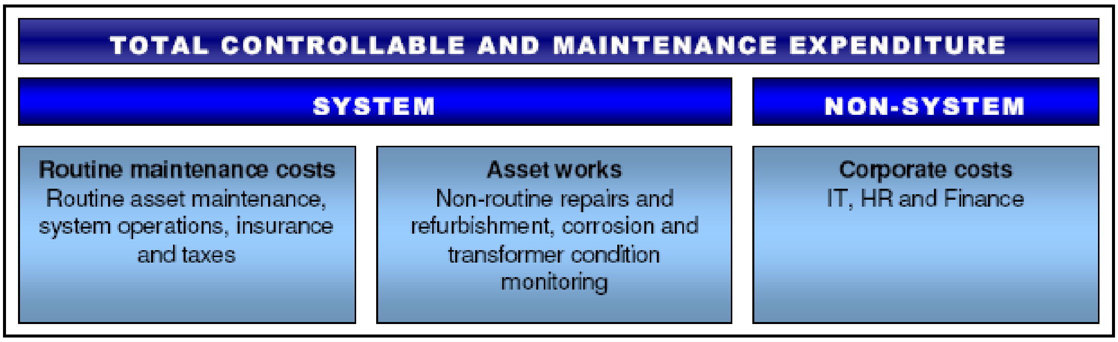
In this section we review the SPA proposals for a number of separate opex categories. Whilst many of the cost categories are independent, some categories are inter-dependent. Where PB makes recommendations on individual cost categories the suggested variations do not take account of any of these inter-dependencies[174]. However, PB's overall recommendations (Section 7.7) do take account of any inter-dependencies and the recommended adjustments have been calculated by modelling the effect of all the individual recommendations simultaneously.

7.1 MAINTENANCE POLICIES AND PROCESSES

SPA divides its total controllable and maintenance expenditures into two categories — system and non-system expenditures. System expenditures are further subdivided into routine maintenance costs and asset works. Non-system expenditures relate to management fees, IT, HR and finance costs. Figure 7-1 shoes these opex cost categories.

174 All other inputs and variables remain constant.

Figure 7-1 – SPA's main opex cost categories



Source: SP AusNet Transmission Revenue Proposal 2008/09 – 2013/14

Routine maintenance costs include routine asset inspection and maintenance costs, system operation and insurance and taxes. Asset works include non-routine repairs and refurbishment, corrosion rectification and transformer condition monitoring.

In addition to these three principal controllable cost categories, SPA has identified a fourth category (‘other costs’) for the purpose of developing its revenue proposal for the forthcoming regulatory period. This category includes debt and equity raising costs, rebates, self-insurance, easement tax and glide path. PB has only reviewed the self-insurance component of these ‘other costs’ as part of its review.

7.1.1 Maintenance processes

SPA carries out its maintenance and operation functions using a combination of internal staff and contractors. In the northern and western areas of Victoria, a contractor provides operation and maintenance services. This section of the network accounts for approximately half of the operation and maintenance effort while representing approximately two-thirds of the network.

This arrangement allows benchmarking to be carried out between the internal service provider and the external contractor to identify any efficiency opportunities and to facilitate the roll out of best practice work procedures across the entire business.

7.1.2 Relative efficiency

To compare the relative efficiency of internal staff and contractors, PB requested information regarding average times to complete circuit-breaker overhauls (Class 1) — for two classes of 220 kV circuit breakers and two classes of 66 kV breakers, over the last 10 years. The circuit breakers selected have relatively large fleet sizes and are located in areas where the maintenance is performed by both internal staff and external contractors. A Class 1 overhaul includes the maintenance of the operating mechanism, and auxiliaries and diagnostic testing which is used to determine whether the scope of the work at the overhaul will need to be increased.

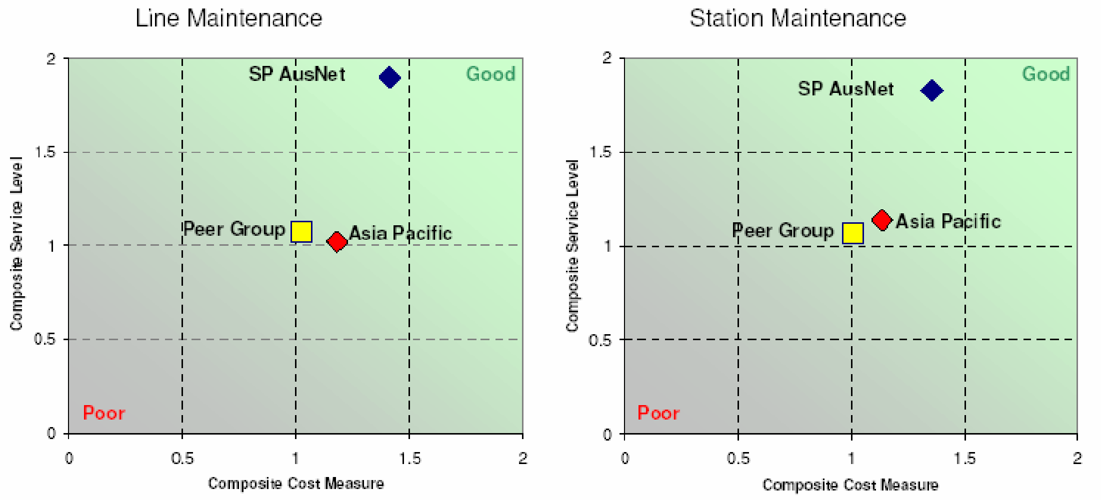
In all cases the time allocated to each overhaul by internal staff was slightly more, on average 7.5%, over the four maintenance processes reviewed. The percentage of additional time ranged from 4.9% to 11.9% and the processes ranged in size from approximately 18 person-hours to 93 person-hours, providing a good diversity in the sample of overhauls reviewed.

PB considers the time taken by SPA’s internal staff to be comparable to the time taken by contractors for these maintenance processes — especially when due consideration is given to the different charge out practices used by internal staff when compared to contract staff. In general, contractors only allocate actual time to the job in hand and cover the cost of unproductive time in overheads. Unproductive time includes time taken to restock truck stores, replenish vehicle fuel, complete timesheets and truck washing etc. Internal (SPA) staff usually book time taken for these ancillary tasks to the current job number and only time lost as a result of, for example, wet weather is booked to a specific job number. This unproductive time could quite easily account for the average 7.5% difference in the time taken for the maintenance procedures.

PB has formed the view that SPA maintenance processes and procedures are at, or are near to, the current industry efficiency threshold and this position is further supported by the ITOMS benchmarking study. The ITOMS charts comparing Composite Service Levels against Composite Cost Measures for Line Maintenance and Station Maintenance from the 2005 ITOMS Benchmarking Study are reproduced in Figure 7-2 and show SPA in the top right-hand quadrant which indicates high relative efficiency levels.

Figure 7-2 – ITOMS benchmarking

Figure 1.5: Benchmarking



Source: ITOMS 2005 Report

Source: ITOMS 2005 report, figure 1.5.

7.1.3 Operating costs methodology

SPA has forecast routine maintenance costs and non-system costs by applying escalation factors to selected base year expenditures. Taxes and all insurance costs have been estimated using a bottom-up approach.

The escalation factors have been calculated by applying labour escalators to the labour component of each line item and maintaining material costs constant in real terms. That is, material costs are assumed to increase in line with CPI. The SPA opex model calculates a weighted escalation factor for each line item by firstly determining the average labour component (percentage) for the most recent 3 years actual expenditures (where available) and then increasing this labour component by a labour escalator. For the 2006/07 financial year SPA has used 9 months (un-audited) actual data and 3 months forecast data.

SPA has adopted a *real* escalation rate for the next regulatory period of 2.83%, based on a report by BIS Shrapnel. Asset works have been individually estimated, using either a bottom-up approach or scaling of historical project costs by CPI to estimate current costs.

SPA proposes to roll into the RAB assets valued at $118.7m. The impact of this increase in system assets on forecast maintenance has been estimated using the SPA opex model. The model applies an escalation factor to the pre roll in maintenance forecasts, based on the proportion of regulated to unregulated assets in the asset base, both before and after the asset roll in.

7.2 TOTAL (HISTORIC) OPERATING EXPENDITURES

Table 7-1 compares actual annual opex against the forecast expenditures identified in the previous revenue cap determination. The table indicates a consistent under-expenditure against the revenue cap determination; this is particularly notable for the 2006/07 financial year. The SPA revenue proposal[175] implies that this consistent under expenditure is due to the quality of the asset management process employed to manage the assets, and also in 2006/07 the economies of scale and scope associated with the integration of a distribution business into the company.

PB has reviewed the asset management process used by SPA including the 'Maximo' system which is used to schedule maintenance operations and record asset-specific maintenance cycles, triggers and routine test results. As a result of this review, we have formed the opinion that SPA is currently employing up-to-date asset maintenance philosophies, processes and procedures in the maintenance of its assets. It is also apparent that SPA has effective risk management processes at the core of its asset management process.

Table 7-1 – Comparison of actual opex with that forecast for the current regulatory period

Expenditure $m (real, 2007/08)	2003^	2003/04	2004/05	2005/06	2006/07*	2007/08*
Decision (CPI adjusted)	20.6	69.3	70.3	69.7	70.3	71.2
Actual	17.8	61.8	62.1	63.7	60.2	61.7
Difference	**(2.8)**	**(7.5)**	**(8.3)**	**(6.0)**	**(10.0)**	**(9.4)**

Notes:

^ Stub period from 1 January to 31 March 2003.

** Actual to December 2006, forecast to 2007/08.*

** From 2003/04 to 2007/08 excludes easement tax, glide path for opex and capex, debt and equity raising costs and rebates, from 2007/08 to 2013/14 excludes easement tax, glide path for opex and capex, debt and equity raising costs and rebates, however, it includes SPA's claim for self-insurance.*

Source: SPA Proposal, Table 6.3.1.

Table 7-1 illustrates the economies of scale and scope achieved by the integration of the SPA transmission and distribution business from 2006/07, with significant under expenditures forecast for this year. PB has investigated the scope and timing of these savings in opex to ensure that all practical economies in operating expenditures, resulting from the integration of the distribution business, have been captured in the base year data used to forecast future operating expenditures. To this end we have examined the integration program used by the business and determined the quantity and extent of any outstanding issues that could result in additional opex savings.

As a result of this investigation PB has formed the opinion that the integration program is substantially complete and the saving reasonably expected to be achieved by the integration of the two businesses has been included in the base year expenditures used to forecast future opex.

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7.3 RECURRENT OPEX

In forecasting recurrent opex, such as routine maintenance and corporate costs, SPA has applied cost escalation factors to a base year. The base year used was 2006/07, based on actual expenditures for 9 months and forecasts for the remaining 3 months. The 3-month forecasts are based on historical spend patterns to replicate, as far as possible actual costs. PB notes that actual 2006/07 results will be available prior to the finalisation of this review and we would recommend that any substantive differences are incorporated into the forecast and recommended operational expenditures.

Other recurrent routine maintenance opex costs, such as insurance and taxes/leases, have been independently forecast for the next regulatory period.

In the view of PB, it is imperative that the base year expenditures exclude any one-off expenses and represent efficient expenditures for the asset base being operated and maintained. PB also believes that any efficiency gains achieved during the current regulatory period should be captured in the base year so that any benefits are shared between stakeholders during the following regulatory period.

In addition, we believe that the opex model used to forecast recurrent operating expenditures should accommodate any changes to the quantity, type and age of the assets under management and any proposed changes to compliance standards or service standards.

7.3.1 Routine maintenance

SPA has forecast base opex for recurrent expenditure in the next regulatory period equal to the 2006 actual recurrent expenditure, with the labour component escalated by 2.83% (real) per annum. Material and other costs have been kept constant in real terms. The base forecasts have been adjusted to compensate for the proposed roll in of unregulated assets. Table 7-2 shows SPA's historical and forecast routine maintenance expenditures.

Table 7-2 – Routine maintenance costs 2003/04 to 2013/14

Expenditure $m (real 2007/08)	02/03	03/04	04/05	05/06	06/07	07/08*	08/09*	09/10	10/11	11/12	12/13	13/14
Maintenance	4.6	19.7	19.2	17.8	17.4	17.7	18.1	18.4	18.8	19.2	19.6	19.9
System operation	0.9	3.9	3.9	3.5	2.5	2.6	2.7	2.7	2.8	2.9	2.9	3.0
OHS	0.3	1.0	0.9	0.9	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Support	1.0	3.1	3.8	6.1	4.7	4.8	4.9	5.1	5.2	5.3	5.4	5.5
Total	6.9	27.6	27.8	28.2	25.2	25.7	26.3	26.8	27.4	27.9	28.5	29.1
Benchmark	9.8	34.6	35.7	35.3	35.7	36.3	n/a	n/a	n/a	n/a	n/a	n/a
Difference	(2.9)	(7.0)	(7.9)	(7.1)	(10.5)	(10.6)	—	—	—	—	—	—

*Note: * Actual to December 2006, forecast to 2013/14.*

Source: SPA Proposal, Table 6.5.1

7.3.2 Corporate costs

Table 7.3 shows SPA's historical and forecast corporate opex costs. This shows the influence of a significant increase of management fees, HR and IT costs during 2005/06. SPA has indicated in its revenue proposal that these costs were associated with the introduction of a management company and the integration of the TXU distribution business, and they are not reflected in the 2006/07 base year and hence not included in any forecasts for the next regulatory period.

In addition, SPA has advised that costs associated with the separation of the TXU retail business from the distribution company have all been allocated to the distribution business. PB observes that the costs from 2006/07 onwards display a steady increase without any step changes.

Table 7-3 – Corporate opex costs 2003/04 to 2013/14

Expenditure $m (2007/08)	02/03	03/04	04/05	05/06	06/07	07/08*	08/09*	09/10	10/11	11/12	12/13	13/14
Finance	2.0	5.2	4.9	4.7	2.9	2.9	3.0	3.1	3.1	3.2	3.2	3.3
HR	0.4	1.5	1.7	2.2	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
IT	0.8	2.6	2.7	3.9	3.9	3.9	4.0	4.0	4.1	4.1	4.1	4.2
Other corporate	0.9	3.5	4.7	5.4	3.1	3.2	3.2	3.2	3.3	3.3	3.4	3.4
Management fees	0.0	1.6	1.5	3.1	7.4	7.6	7.8	8.0	8.3	8.5	8.7	9.0
Total	**4.1**	**14.4**	**15.5**	**19.3**	**18.0**	**18.3**	**18.7**	**19.0**	**19.4**	**19.8**	**20.2**	**20.6**
Benchmark	3.7	13.7	13.5	13.6	13.8	13.9	n/a	n/a	n/a	n/a	n/a	n/a
Difference	0.4	0.7	1.9	5.7	4.2	4.4	—	—	—	—	—	—

*Note: *Actual to December 2006, forecast to 2013/14*

Source: SPA Proposal, table 6.6.1

7.3.3 Management company costs

SPI Management Services is a wholly owned subsidiary of Singapore Power International Pte Ltd and has entered into a management services agreement with SPA Networks (Transmission) Ltd and SPA (Distribution) Ltd. The costs of the management services contract are allocated between the transmission and distribution businesses based on an assessment of management effort, which is determined by surveying manager's time spent on activities within the individual businesses. Prior to 1 April 2006, the split was 60% to distribution and 40% to transmission. The allocation between businesses is now 65%:35% (distribution to transmission).

The management services agreement is for a 10-year period and relates to the provision of the following services:

- employee management
- business management
- evaluation of business opportunities
- management of regulatory compliance and relations with regulators
- financial and management accounting, including treasury and tax services

- asset management strategy
- management of information technology
- management and coordination of maintenance and engineering services
- public and investor relations
- legal and company secretarial services
- general administration and company reporting.

The Management Company is reimbursed for providing these services through the payment of a management fee, which for operational expenses is included in ‘Recurrent Expenditures — Corporate costs’ line item. The Management Company also receives a performance fee, but this fee is not included in the regulated costs of the transmission business.

7.3.4 Business overheads

Prior to the commissioning of the new SPA financial system in December 2006, the transmission business used fully absorbed labour rates. Under this system, general business overheads are recovered within the hourly rate applicable to each staff type when charging out to individual jobs. Hence the labour rates generally provide for direct labour costs, direct on-costs (such as leave loading and allowances), on-costs associated with general business overheads, payroll tax and Workcover costs.

Since the introduction of the new financial system, labour is now charged at actual rates per job type and only includes direct labour costs and direct on-costs (such as Workcover and payroll tax). For capital works, an overhead capitalisation rate is calculated to capture an appropriate share of overheads including HR, Finance and Management Company fees etc. This rate is applied monthly to direct capital expenditure within the financial system, with an annual review conducted to reconcile the overheads charged to adjust for any over/under clearances.

The transmission business overheads, capitalised in the 2006/07 year and included in forecasts for the next regulatory period, are $1.96m. PB is advised that the actual capitalised overheads charged for the year ended 31 March 2007, including the 4 months under the new methodology, are $1.99m.

In relation to opex, labour is also charged at actual rates per job including applicable direct labour overheads but excluding general business overheads. The general business overheads for opex are now included as a separate line item in the accounts.

7.3.5 Allocation of costs

PB has carried out a detailed review of the allocation of costs to ensure the appropriate allocation of regulated and unregulated costs as well as the appropriate allocation of business overheads.

Direct costs, which include maintenance and operating costs, are allocated to the transmission business based on the asset type and the work being undertaken. The asset type combined with the work type identifies whether the project is associated with assets which are either regulated or unregulated. All costs in Maximo are coded with the job work type and equipment, and these codes are used to classify the work as either regulated or unregulated.

Indirect costs, which include support, infrastructure and corporate costs, are allocated using appropriate activity cost drivers. These activity cost drivers are asset based, or assigned to activities using timesheet data or survey. Surveys are mainly used for the allocation of management expenses.

Some items are directly coded into the accounts, for instance, the Management Company performance fee is directly coded into the unregulated accounts.

An opex model further allocates direct and indirect costs into system recurrent, system non-recurrent and non-system regulatory segments.

7.3.6 PB analysis (recurrent opex)

PB is generally satisfied with the methodology used by SPA to forecast recurrent opex for the next regulatory period. We believe the base year costs, where applicable, seem reasonable. However, these are subject to confirmation by audited results which are expected to be published prior to AER finalising its determination. On this basis we believe the recurrent routine maintenance base costs used in the SPA opex model for Maintenance, System Operation, Health & Safety and Support SR are reasonable and are therefore an acceptable basis for forecasting costs for the next regulatory period.

However, we have identified several issues in relation to the opex modelling used by SPA. These are as follows:

- the SPA allowance for the transmission business insurance premiums has not been adjusted to account for the unregulated assets covered by the policies
- the impact of the new North West Contract for the provision of maintenance and operation services in northern and western Victoria does not appear to have been factored into the base year results.

Each of these issues is discussed in detail below. The conclusions drawn from reviews of the SPA cost allocation methodology, allocation of overheads and the management company costs are also discussed in the following sub-sections. It should be noted that the recommended reductions do not represent the total recommended reductions in recurrent routine maintenance, since other recommendations — such as that relating to labour escalation — also impact PB's final recommended recurrent routine maintenance forecasts.

Insurance

In order to assess the reasonableness of the insurance premium allowance in the SPA opex model, PB requested that SPA provides its insurance broker's insurance premium forecasts for the next regulatory period, including the basis for the forecasts. Data provided is for the entire SPA business and the estimates included in the SPA opex model were found to be 60% of the total annual amounts (converted into 2007/08 dollars).

PB requested additional information from SPA in relation to these calculations to confirm the basis of the allocation between the transmission and distribution businesses and also to determine if there would be any unregulated assets covered by these insurance premiums in the next regulatory period.

SPA has advised that the allocation of the insurance premium to transmission is based on the actual insurance premiums paid for transmission and distribution in the 2006/07 year. This percentage split was carried forward to estimate the percentage of the total premiums applicable to the individual business.

We also reviewed the assumption and basis underlying the future insurance premiums advised by the insurance broker. PB has found that, in general, the broker has used current risk profiles, with the exception of property cover where the forecast premiums assume an improving risk profile. In regard to the risk associated with property insurance the broker notes that SPA currently has a good risk profile and there is an expectation that it will improve as there appears to be a management interest in preventing loss. This outlook is reflected in 5% premium reductions in years 2008 and 2010.

We have reviewed the information provided by SPA and believe that the allocation to the transmission business of 60% of the total insurance premium is reasonable.

SPA has advised that the allocation between regulated and unregulated assets during the current regulatory period is 92%:8%. The same allocation for the next regulatory period has been forecast to be 93.21%:6.79%. This is based on the assumption that the AER determines that it is appropriate to roll into the regulated asset base the full asset value recommended by SPA, namely $118.7m. If the roll-in amount changes then the percentage split between regulated and non-regulated assets will change and the impact of this recommendation will also have to be recalculated.

However it appears that the total transmission premium has been allocated to the regulated business, instead of just that proportion applicable to the regulated assets. PB recommends, therefore, that the insurance premiums in the SPA opex model be reduced by 6.79% to reflect the percentage of unregulated assets covered by these premiums in the next regulatory period. The annual reductions and total reduction for the 6-year period are displayed in Table 7-4.

Table 7-4 – Insurance premiums; impact of regulated/unregulated asset split

Expenditure $m (real)	08/09	09/10	10/11	11/12	12/13	13/14	Total
Submitted	2.908	3.176	3.354	3.491	3.514	3.514	19.957
Proposed variation	(0.197)	(0.216)	(0.228)	(0.237)	(0.239)	(0.239)	(1.356)
PB recommendation	2.711	2.960	3.126	3.254	3.275	3.275	18.601

Source: PB analysis

North west contract

The previous contract for the provision of operation and maintenance services in northern and western Victoria was held by Transfield and expired on 31 March 2007. A new contractor, Powercor, has been appointed and this new contract is based on a new contract model which encompasses a combination of fixed unit rates for scheduled (planned) works, a reimbursable 'target cost' for emergency (unplanned) works and a fixed cost associated with corporate overhead and support functions. We believe that the commencement of this new contract during this year has an impact on the adoption of the 2006/07 results as an efficient base year reference point for forecasting opex expenditures into the next regulatory period.

An open tender process resulted in two compliant tenders being received, one from Transfield and the other from Powercor. Transfield has held the contract for a considerable length of time, essentially since 1999. We believe that this would place the incumbent in an excellent position to understand the assets involved and hence able to forecast, with a good degree of accuracy, the amount of planned and unplanned work involved on an annual basis. Hence we regard the Transfield tender to be a reasonable proxy for the person-hours of effort factored into the opex model's base year, representing the effort required to provide routine maintenance and operation services to the assets covered by the contract; essentially two-thirds of the SPA asset base, accounting for approximately half the total maintenance and operation effort.

The two tenders appear reasonably similar with the lower costs associated with the Powercor tender resulting from lower support/overhead costs, slightly lower profit and a slightly lower allocation for unscheduled works.

This new contract commenced during the current regulatory period and therefore, in our view, has an impact on the adoption of 2006/07 as an efficient base year to forecast future operational expenditures. PB recommends that as this new maintenance and operation contract will result in efficiency gains being achieved during this current regulatory period, the impact of this contract should be factored into the forecast for operational expenditures.

PB notes that this new contract, in net present terms (over 5-years), is $1.82m (2006/07) lower than the Transfield tender. We believe that as Transfield held the tender for a considerable time prior to it being let to Powercor they would have an excellent understanding of the work and hence costs associated with continuing to provide these services. Accordingly, we have used their pricing as a proxy for baseline costs.

PB recognises that potential advantages of appointing the incumbent distribution business (Powercor) as the service provider — overlapping service areas, established depots resulting in reduced travelling times, and the ability to use existing staff for some of the TNSP work — and that this may account for a large proportion of the savings when compared to the continuation of the use of a contractor such as Transfield. These are the savings that we believe should be factored into opex model when predicting future operational expenditures from the 2006/07 base year.

PB has calculated the annual savings using a 5.66% (real) discount rate, a 5-year period and a NPV of $1.82m. The same annual saving has been assumed for the final years of the next regulatory period. Using this available data, PB has calculated the annual saving to be $0.428m (2006/07). This is equivalent to $0.439m (2007/08).

We recommended that this reduction in annual maintenance and operation spend be factored into the SPA opex model by reducing the proposed spend in the maintenance line item in the 'Routine Maintenance — Recurrent' section of the model for the year 2006/07 by $0.428m. We recommend that the escalation factors are left unchanged as the percentage impact of this decrease in the base year expenditure is not material when calculating the weighted escalator factor.

The impact of this reduction in the maintenance line item in the base 2006/07 year is a reduction of $2.807m over the next (6-year) regulatory period. This recommended reduction in maintenance reduces the total forecast operational expenditure for routine maintenance and corporate cost from $328.4m over the next 6-year regulatory period to $325.6m. Table 7-5 displays the annual and total effect of the reduction.

Table 7-5 – NW contract adjustment for routine maintenance costs

Expenditure $m (2007/08 real)	08/09	09/10	10/11	11/12	12/13	13/14	Total
Submitted	51.559	52.893	54.164	55.421	56.590	57.765	328.392
Proposed variation	(0.445)	(0.454)	(0.463)	(0.472)	(0.482)	(0.491)	((2.807))
PB recommendation	51.114	52.439	53.701	54.949	56.108	57.274	325.585

Source: PB analysis

In summary, PB recommends that the SPA real annual routine maintenance forecasts be reduced by $0.428m in the 2006/07 financial year to reflect the impact of the new North West Operation and Maintenance contract.

Management company costs

PB has reviewed the impact of the implementation of the Management Company and the allocation of management expenses to the transmission business. Based on the information provided, we have formed the opinion that the introduction of the Management Company has not resulted in any increased overheads. This is because the creation of SPI Management Services reallocated existing costs from SPA to SPI Management Services. The allocation of costs from SPI Management Services to the regulated entities re-allocates the appropriate part of those costs to the regulated entities.

Furthermore we are satisfied that the survey method used to apportion costs to the individual businesses results in a reasonable outcome, with appropriate costs being allocated to the transmission business.

Corporate costs

PB has reviewed the assertions made by SPA in relation to the exclusion of any merger costs in the 2006/07 base year and concluded that these assertions are correct. This opinion is based on comparing the total opex spend for routine maintenance and corporate costs for the 2004/05 and 2006/07 financial years in real 2007/08 dollars. This comparison shows that the total spend in 2004/05 was $43.3m and for 2006/07 was $43.2m, indicating that in fact the aberration in the 2005/06 financial year was due primarily to the formation of the Management Company resulting in the transfer of management costs from routine maintenance to corporate costs over the period reviewed.

Cost allocation

We have reviewed the information provided relating to the SPA opex cost model (called ‘Oros’) and the associated data flows and have formed the opinion that costs are appropriately allocated within the transmission business to the regulated accounts. The segregation of costs within the transmission segment of the business also appears appropriate.

7.4 NON-RECURRENT OPEX — CONTRACTOR COSTS

SPA has included an annual allowance in the next regulatory period for proposed asset works which are essentially maintenance works of a non-recurrent nature. The specific maintenance projects included in the Asset Works category have been separately identified, scoped and costed using a bottom-up approach. The total annual costs for asset works includes external contractors’ costs, internal SPA’s engineering and supervisory costs, plus SPA’s support costs (with the labour component escalated).

In most instances, the asset works projects included in the revenue proposal have been sourced from current maintenance programs and therefore represents a continuation of maintenance work projects already in hand. For example, the towers scheduled for painting in the next regulatory period have been identified as part of an overall tower painting program that is already in place; the works included in the next regulatory period represent a continuation of this program.

To determine annual forecast expenditures for these non-recurrent maintenance projects, SPA states that it has used a bottom-up approach to determine direct project costs, and a benchmarking approach to forecast ‘Internal SPA Costs’ and ‘Support Costs’. The Opex Model clearly indicates that a bottom-up approach is used to forecast external contractor project costs and that benchmarking is used to forecast ‘Support Costs’ from the base year. However a constant amount of $2.247m has been used for ‘Internal SPA Costs’ for each year of the next regulatory period. The SPA opex model applies labour escalation to the total of internal SPA costs and external contractor costs. .

SPA has included a total of $90.263m of asset works in its revenue proposal for the next regulatory period of which $67.94m (2007/08) is for external contractor costs. Table 7-6 shows the annual historical and forecast asset works costs from 2002/03 to 2013/14 (2007/08 dollars) included in the SPA proposal. The SPA proposed annual expenditure for the next regulatory period displays a 40% average increase over the current average annual expenditure.

Table 7-6 – Asset work costs 2003/04 to 2013/14

Expenditure $m (2007/08)	02/03	03/04	04/05	05/06	06/07*	07/08*	08/09	09/10	10/11	11/12	12/13	13/14
Corrosion/ Condition	4.8	11.9	11.6	8.1	8.4	9.0	12.2	13.2	14.1	14.1	14.1	14.1
Support	0.5	0.6	0.5	1.0	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Total	5.3	12.5	12.1	9.1	9.8	10.4	13.6	14.6	15.5	15.5	15.5	15.5
Benchmark	5.4	13.7	13.5	13.6	13.8	13.9	n/a	n/a	n/a	n/a	n/a	n/a
Difference	(0.1)	(1.2)	(1.4)	(4.5)	(4.0)	(3.5)	—	—	—	—	—	—

*Note: *Actual to December 2006, forecast to 2013/14*

Source: SPA Proposal, table 6.7.1

Table 7-7 displays the individual asset works projects included in the revenue proposal together with the associated external contractor costs. Table 7-8 details the compliance works included in the revenue proposal together with the associated external contractor costs.

Table 7-7 – Asset works program — 2007/08 to 2013/14

Asset Works program	Expenditure $m
Tower foundation corrosion	4.2
Tower ground-level corrosion	8.2
Tower painting	4.8
Tower bolt replacement	0.6
Replacement of tower steelwork	1.2
Replacement of transmission line hardware	1.8
SF6 circuit-breaker refurbishments	10.1
Gas-insulated switchgear refurbishment	5.2
Power cable repairs*	7.5
Power and instrument transformer repairs	2.3
Facilities maintenance	2.8
Condition monitoring	1.0
Miscellaneous works	6.5
Total expenditure ($2006/07)	**56.2**
Total expenditure ($2007/08)	**57.7**

Notes: The expenditure specified in SPA's Revenue Proposal is in ($2006/07), however, the expenditure in the PTRM to determine SPA's Maximum Allowable Revenue is specified in ($2007/08).

** The expenditure specified in SPA's Revenue Proposal for Power Cable Repairs is specified as $7m. This is a drafting mistake and should be $7.5m*

Source: SPA, Response to Clause 6A.11.1 Information Request 2008/09 – 2013/14, table 1.4.1(a)

Table 7-8 – Compliance programs (2007/08 to 2013/14)

Compliance program	Expenditure $m
Asbestos removal	2.7
Switchyard resurfacing	2.5
Lead contamination	0.5
Transformer leaks repairs and oil treatment	4.3
Total expenditure ($2006/07)	**10.0**
Total expenditure ($2007/08)	**10.3**

Note: The expenditure specified in SPA's Electricity Transmission Revenue Proposal 2008/09-2013/14 is in ($2006/07), however the expenditure in the PTRM to determine SPA's Maximum Allowable Revenue is specified in ($2007/08).

Source: SPA, Response to Clause 6A.11.1 Information Request 2008/09 – 2013/14, table 1.4.1 (b).

PB analysis

PB has carried out detailed reviews of six of the most significant maintenance projects included in the Asset Works category scheduled for the next regulatory period. Each of these projects has been reviewed for prudency and efficiency by identifying the need for the work, confirming the proposed timing of the works and analysing the efficiency of the project estimates. In addition, PB has also held detailed discussions with SPA during site visits regarding other asset works projects including the conditioning monitoring and asbestos removal projects.

Through PB's review of the individual maintenance project reports, it appears that several of the contractor expenditures associated with these projects are expressed in 2007/08 dollars[176];. PB therefore believes that some of the expenditures detailed in Table 7-7 and Table 7-8 may already be expressed in 2007/08 dollars and hence do not need to be escalated further as part of the SPA opex modelling.

PB notes, however, that in the opex model these contractor cost are again increased purportedly to escalate the costs to 2007/08 dollars. PB believes that this has resulted in incorrect annual amounts being included in the SPA opex model for the contractor cost component of asset works.

SPA has advised that the BTS-RTS Cable Repair, GIS Refurbishment, SF6 Circuit Breaker Refurbishment and Condition Monitoring Development costs that are in 2006/07 dollars and therefore require escalation to 2007/08 dollars. PB has made these adjustments in the SPA opex model to determine its recommended annual variations to SPA's forecast expenditures.

The additional total amount for contractor costs included in the SPA opex forecasts is $1.122m dollars over the six year regulatory period and the annual variations are detailed in Table 7-9.

176 Or that the wording in the project reports implies that the costs relate to the next regulatory period and hence are assumed to be in 2007/08 dollars.

Table 7-9 – Asset works contractor costs adjustment

Expenditure $m (2007/08 real)	08/09	09/10	10/11	11/12	12/13	13/14	Total
Submitted	9.868	10.876	11.799	11.799	11.799	11.799	67.940
Proposed variation	(0.138)	(0.146)	(0.185)	(0.208)	(0.216)	(0.229)	(1.122)
PB recommendation	9.730	10.730	11.614	11.591	11.583	11.570	66.818

Source: PB analysis

Our overall recommendation in relation to the contractor cost component of asset works is based on the outcome of the detailed review of six projects (55% of total asset works contractor costs) and reviews and discussions with SPA associated with two additional projects, condition monitoring and asbestos removal programs, representing a further 5.5% of the total asset works program. In addition, a desk-top review of the project documentation associated with a further five asset works projects has been undertaken to assess each project for prudency and efficiency. These five additional programs were: civil infrastructure (facilities maintenance) program, line hardware maintenance program, switchyard resurfacing program, tower steelwork replacement program and the tower bolt replacement program.

Our comments and recommendations regarding each of the six projects reviewed in detail, including our view on the deliverability of each project, are set out below.

7.4.1 SF6 circuit-breaker refurbishments

SPA's SF6 CBs have suffered from gas leaks caused by flange corrosion, hardening of seals, interrupter design problems and trapped metal particle problems. In fact, SF6 leaks are the most common cause of SF6 CB incidents, followed by hydraulic drive problems. When the current SF6 CBs were purchased it was known that half-life refurbishment would be required.

In addition to the technical problems associated with the loss of insulating medium in the switchgear, SF6 gas is considered a greenhouse gas largely because it has a very long life in the atmosphere (about 3,000 years) and hence leakages must be minimised. The half-life refurbishment program also includes the maintenance of the hydraulic operating mechanism.

Alternatives

The two options considered by SPA were: 1) do nothing; and 2) continue the SF6 CB refurbishment program. Option 1 was discounted due to the likely increase in the number of major and minor defects and the likely increase in the amount of corrosion and associated gas leaks.

Option 2 would result in asset management practices in accordance with accepted industry practices for the safe and reliable operation of SF6 CBs being implemented. In addition option 2 also addresses the project drivers identified in the project justification section of this report.

SPA project justification

This project is justified on the basis safety of issues (in the event of asset failure) in relation to staff, contractors and the general public, reduction of financial risk resulting from increased operating costs if the assets fail in service, rebate penalties associated with asset availability and potential civil actions resulting from personal injury. There are also issues in relation to compliance with Electrical Safety (Network Assets) Regulations, compliance with Occupational Health & Safety Act and recommended preventative maintenance requirements for maintenance of insurance cover.

Timing

The works scheduled for the next regulatory period form part of an overall SF6 maintenance program as detailed in Table 7-10. The timing of the individual CB refurbishments is dictated by the timing of the half life refurbishment and the fact that corrosion, particularly in the flanges is worse than anticipated resulting in more than expected SF6 leaks.

Table 7-10 – SF6 maintenance program

Period	03/04–07/08	08/09–13/14	14/15–18/19
Duration (years)	5	6	5
Siemens type 3AT5 CBs refurbished	5	14	4
MG type FA4 CBs refurbished	—	8	—
Dell type FL245 CBs refurbished	—	17	—

Source: SPA SF6 Circuit Breaker Refurbishment Project 2008 — 2014

PB analysis

SPA has estimated the total external contractor project costs to be $10.1m (2007/08) over the next regulatory period. The project consists of four individual SF6 CB refurbishment programs as detailed in Table 7-11.

Table 7-11 – SF6 CB refurbishment programs

CB equipment type	Voltage class	Main scope	Number	Cost $m
Siemens 3AT5	550 kV	Interrupters and hydraulics	14	6.1
MG FA4	550 kV	Hydraulics	8	2.1
Delle FL245	220 kV	Hydraulics	17	1.2
SF6 Capacitor Bank CBs	66 kV & 220 kV	Interrupters	4 @ 220 kV 15 @ 66 kV	0.7
Total				**10.1**

Source: SPA SF6 Circuit Breaker Refurbishment Project 2008 – 2014

PB has reviewed the initial information provided by SPA and the additional information requested by PB (SF6 Circuit Breaker Refurbishment Program Update) in relation to the current condition of the SF6 CB fleet. PB is of the view that sufficient evidence exists to justify both the need and timing of the proposed refurbishment program.

In relation to the estimate of external contractor costs for the program, PB requested the base data used to determine the bottom-up calculation of the major component of this project, the $6.1m refurbishment of the Siemens 3AT5 fleet.

Table 7-12 shows the actual contractor costs of refurbishing a breaker and these historical costs form the basis of determining the total external contractor estimate for the proposed works scheduled for the next regulatory period. PB has formed the view that this approach is reasonable as in many instances (including this one) spare parts are not commonly available. Many manufacturers no longer support previous models or products and spares have to be either manufactured to order by the original equipment supplier or sourced from a third-party supplier. In this instance an Australian manufacturer was sourced to provide spares for the hydraulic operating mechanism resulting in considerable time and cost savings.

Table 7-12 – Historical contractor costs of refurbishing a circuit breaker

Work description	Cost estimate (per CB) $	Cost estimate (Total) $
Technical support, Contract (Siemens)	121,436	—
Workshop labour, Contract (Siemens/Silcar)	92,778	—
Hydraulic contractor (Union Hydraulics)	54,881	—
Transport, plant hire, etc	41,705	—
Procurement (one overhaul kit)`	90,480	—
Procurement, material	40,406	—
Subtotal (per CB)	**441,686**	—
Cost for 14 CBs	—	6,183,604
Less the cost of one overhaul kit	—	90,480
Total		**6,093,124**

Source: SPA SF6 Circuit Breaker Refurbishment Project 2008 – 2014, table 1.4.1 (b)

Although the work is of a very specialised nature, SPA has already sourced suitably experienced and qualified contractors to assist them obtaining the necessary spare parts and also in performing these maintenance operations. Furthermore, SPA has the necessary technical expertise to carry out the work. PB is also of the view that the scale and scope of this project is such that SPA can deliver this project within the next regulatory period.

Conclusion

PB has formed the view that this project is both prudent and efficient and should be included in the proposed asset works program. We also believe that the project is deliverable within the next regulatory period.

7.4.2 Tower ground-level corrosion

This project involves the maintenance of steelwork, at ground level, of 2730 towers over the 6-year regulatory period. It includes excavation around each tower leg, inspection and assessment of the steelwork at natural ground level followed by sandblasting of scale material. Steel members with significant corrosion are either replaced or spliced. A corrosion proof coating is then applied.

Alternatives

Two options were considered by SPA: 1) do nothing; and 2) continue the ground-level maintenance program. The do nothing option would involve continuing the asset inspection and testing program, recording potential defects and taking limited actions to rectify the defects as they are identified.

Option 2 involves the pre-emptive ground-level excavation, inspection and assessment program which is based on tower age and location, sandblasting the scale materials from the corroded section of the tower at or near ground level, replacement and or splicing of significantly corroded members and the application of corrosion proof coating. Option 2 addresses the project drivers identified in the project justification section.

SPA project justification

This project is justified on the basis of safety issues (in the event of asset failure) in relation to staff, contractors and the general public, reduction of financial risk resulting from increased operating costs if the assets fail in service, rebate penalties associated with asset availability and potential civil actions resulting from personal injury. There are also issues in relation to compliance with Electrical Safety (Network Assets) Regulations, compliance with Occupational Health & Safety Act and recommended preventative maintenance requirements for maintenance of insurance cover.

The work program is particularly important in relation to potential tower failure due to the risks of injury to staff, contractors and the general public and damage to property, as well as the potential to start fires.

Timing

The work planned for tower ground-level corrosion program in the next regulatory period is part of a comprehensive program and involves 2,730 towers being treated as detailed in Table 7-13.

Table 7-13 – Tower ground-level corrosion program

Item	02/03–07/08	08/09–13/14	14/15–22/23
Duration (years)	6	6	9
Total towers treated	4160	2730	2700
Towers treated per year	693	455	300

Source: SPA Tower Ground Level Maintenance Project 2008 — 2014

PB analysis

The total forecast external contractor expenditure for the tower ground-level corrosion project for the next regulatory period is $8.2m (2007/08). This forecast was developed using a bottom-up approach and is based on the historical contractor expenditure for this type of work as shown in Table 7-14.

Table 7-14 – Tower ground-level corrosion program — historical contractor expenditure

Line	No. towers	Coating costs $	Other costs (excl PM) $	Total cost $	Rate per tower $	Rate Other $	Rate total $
KTS-BLTS-WMTS-ATS and MLTS-GTS	127	234,005	—	234,005	1,843	—	1,843
ERTS-ROTS-SVTS-HTS	62	133,845	—	133,845	2,159	—	2,159
HWPS-HWTS	26	75,500	—	75,500	2,904	—	2,904
MBTS-EPS	353	832,758	—	832,758	2,359	—	2,359
BATS-BETS-SHTS	345	810,928	—	810,928	2,351	—	2,351
YPS-ROTS various lines	480	911,037	—	911,037	1,898	—	1,898
Coating + Eng + Repairs	1393	2,998,073	264,000	3,262,073	2,152	190	2,342
Cost at 2008 allowing for 3% escalation per year = 9% (from 2005)							2,552
Allow additional $400 per tower							2,952
						Adopt	**3,000**

Source: SPA Tower Ground Level Maintenance Project 2008 — 2014

The total estimate was developed using the following formula:

Total External Contractor Cost = 6 years x 455 towers x $3,000 = $8,190,000

PB has reviewed the initial material provided by SPA and the additional information we requested (Tower Ground-level Corrosion Update) in relation to the current condition of the tower foundations proposed to be refurbished during the next regulatory period. In addition, supporting photographic evidence detailing the condition of a sample of the towers proposed to be refurbished was also provided. Based on the information provided, we have formed the opinion that sufficient evidence exists to justify the project proceeding and the proposed timing of the work.

In relation to the estimate of external contractor costs for the program, PB requested that additional information be provided detailing more current costs as the initial estimate was based on 2005 data and escalated to 2007/08 dollars using CPI. In response, SPA has provided external contractor cost/estimates for tower footing refurbishment projects currently being undertaken. This data is reproduced in Table 7-15. This includes actual costs (where available) and estimated costs where the actual costs are not available.

Table 7-15 – Historical external contractor costs for tower footing refurbishment projects

Description of work	Cost (Actual/Estimated) $	Comments
Orders for 160 towers	419,000	—
Variations to orders	23,000	Up to 20/4/07
Return visit coating cost	37,000	Estimated – 22 towers x $1,700/tower
Supply steelwork	6,000	Up to 20/4/07
Supply additional steelwork	15,000	Estimated
Site inspection	25,000	By independent contractor
Engineering	14,000	Up to 20/4/07
Additional engineering	20,000	Estimated
Repairs	44,000	Estimated — 22 towers x $2,000/tower
Total	**603,000**	
Hence the cost (external) per tower is $603,000/160 = $3,769		

Source: SPA Tower Ground Level Maintenance Project 2008– 2014.

PB notes that the current estimated average external contractor cost for the correction of corrosion of towers at ground level is $3,769 per tower and the escalated historical average costs are $2,552 per tower. SPA has used an average estimated cost for the next period of $3,000 per tower which is less than the average of the two cost sources. We have concluded, therefore, that the forecast estimates for this project appear reasonable.

Owing to the large number of towers scheduled for maintenance annually, PB would normally have had concerns regarding the ability of SPA to source suitably qualified contractors who could be relied upon to perform these maintenance operations successfully. However, reference to the towers maintained and or scheduled for maintenance during the current period (693 per year) has allowed us to form the view that the project as described is deliverable within the next regulatory period.

Conclusion

PB has formed the view that the project is prudent and external contractor costs appear reasonable. Furthermore, we believe the work is deliverable within the next regulatory period.

7.4.3 Power cable repair program

The Brunswick to Richmond (BTS – RTS) 220 kV cable was installed in 1992. The cable joints used during installation were of a unique design that does exist anywhere else in the world. The joints are oil filled with each joint having an oil accumulator and gas pressurised bladder. A monitoring system was installed during construction to monitor oil pressure and temperature at each joint.

The joints have been failing due to seal failure allowing moisture to ingress, breakdown of the epoxy insulator and breakdown of the insulating oil. Sheath resistance testing has identified moisture ingress at all joints. To date one joint has failed explosively, one joint has been replaced due to a zero earth sheath reading, and one further joint is scheduled for replacement due to an oil leak.

This project involves the replacement of six joints per annum over the 6-year regulatory period which results in all joints on the cable being replaced by the end of the next regulatory period.

Alternatives

Three options were considered for this project by SPA: 1) do nothing and replace the joints on failure; 2) replace joints where problems have been identified; and 3) replace all joints in a planned way.

Option 1 was discounted due to the number of joint failures experienced to date, given the short service life of the cable. In addition there are significant costs and major disruptions to the transmission system associated with random joint failures. There are also significant lead times associated with the purchase of replacement joints and unplanned outages incur outage rebates under SPA's network agreement with VENCorp for disrupting transmission services.

Option 2 was discounted as financial modelling has shown that the replacement of one joint in only cost effective if the other two joints within the joint bay do not require replacement within the next 17 years.

Option 3 was adopted as it is apparent that to achieve the expected service life of the 220 kV cable all the joints would require replacement with modern XLPE joints. Currently the cable service life and reliability is limited by the performance of the cable joints. This option addresses all the issues detailed in the project justification section.

SPA project justification

Routine annual sheath testing has identified moisture ingress in all joints. To date there have been two incipient faults and one catastrophic joint failure. The red phase joint at Bay 8 was replaced to remedy a zero sheath reading, the red phase joint in Bay 4 failed explosively and the white phase joint in Bay 9 is scheduled for replacement this year due to an oil leak. When a joint in a joint bay is replaced all three joints in the bay are replaced.

The catastrophic joint failure in Bay 4 caused a forced outage for emergency repairs that lasted for 7 weeks. In addition, the location of the cable in public roads makes it extremely difficult to gain access easily owing to traffic control, negotiation of access arrangements, and compliance with other conditions.

The joint coffin removed from Bay 8 showed that the gel coat had broken down and was falling off the fibreglass coffin. This gel coat provides the moisture barrier and its failure explains why moisture is entering the joints.

As stated earlier these joints are unique to this cable and there is no experience available on life expectancy available from other users or the original equipment manufacturers. Explosive joint failures historically take longer to repair and are more costly than planned pre-emptive joint replacements due to the collateral damage which requires rectification and the amount of damaged cable that has to be replaced either side of the joint.

Timing

At the commencement of the next regulatory there will be 36 of the original joints remaining in service and SPA proposes to replace six joints per annum over the 6-year regulatory period. By the end of the next regulatory period all joints on the cable are scheduled to have been replaced.

PB analysis

PB has reviewed the initial data provided in support of this project and because of the unusual nature of the work requested additional supporting data. It is most unusual for all joints in a 220 kV cable in service for only approximately 15 years to need replacement. The additional information requested was details of the forensic investigations carried out on all the joints previously removed from service, details of the sheath insulation readings, and a detailed breakdown of the external contractor cost estimates. This information has been provided and reviewed.

Details of the results of investigations on the nine joints already replaced are shown in Table 7-16. The results indicate a history of oil leaks and moisture ingress consistent with the breaking down of both oil seal and joint coffins. Each joint bay initially contains three joints, one for each phase of the three phase cable. The three phases are labelled either the red, white or blue phase.

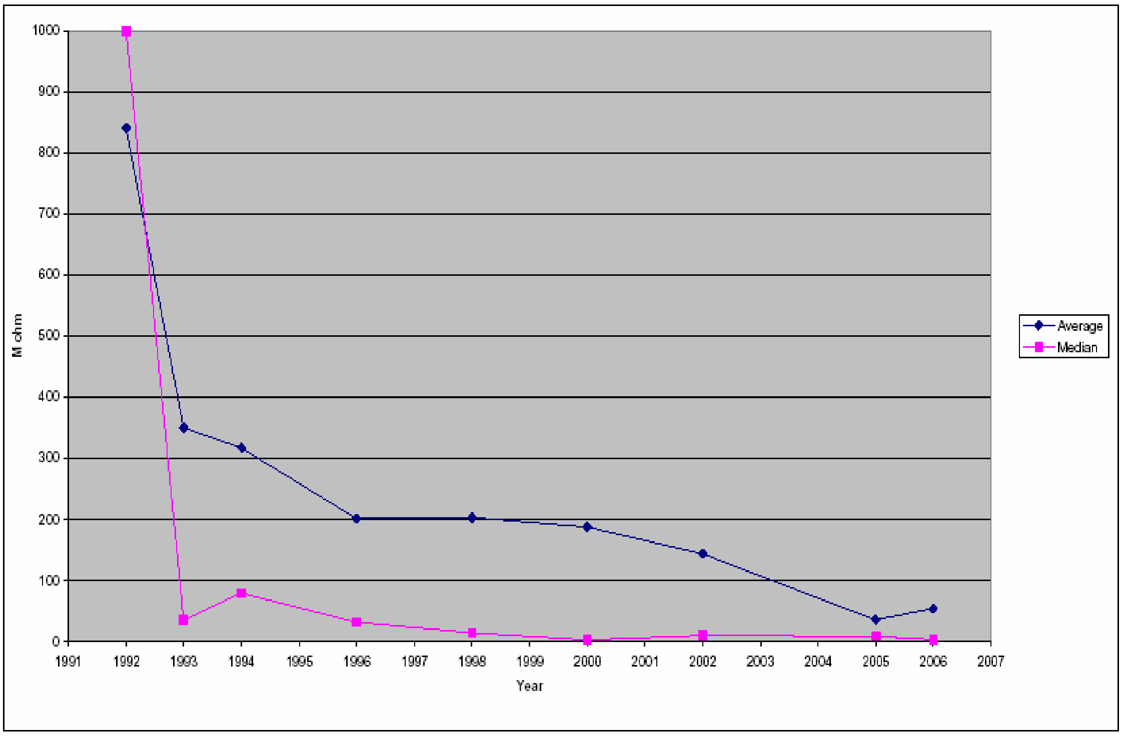
Table 7-16 – Results of 220 kV cable failure investigations

Joint bay	Phase	Problems found
JB4	Red	Catastrophic failure
JB4	White	Oil found under the cable jacket outside the joint
JB4	Blue	Suspected oil seal degradation
JB8	Red	Water found under the cable jacket outside the joint
JB8	White	Water found under the cable jacket outside the joint
JB8	Blue	Suspected oil seal degradation
JB9	Red	Suspected oil seal degradation
JB9	White	Oil leak and water found under the cable jacket outside the joint
JB9	Blue	Water found under the cable jacket outside the joint

Source: SPA Power cable Repair Project 2008— 2014

As part of its review, PB also requested records of the cable earth sheath readings. The results of this request are given in Figure 7-3. This data confirms the progressive ingress of moisture into the joints and is the most compelling evidence justifying the commencement of a comprehensive joint replacement program. PB notes that the median readings are not registering on the chart and should be in the hundreds of M ohms range.

Figure 7-3 – BTS-RTS 220 kV cable earth sheath insulation resistance readings



Source: SPA

In addition, PB has been supplied with external contractor cost estimating information, which detailed the cost for each joint bay including those already replaced. SPA has therefore provided historical external costs against which we have compared the forecast external cost estimates.

PB has noted that the external contractor estimates include an allowance of $0.4m for forensic investigation of the joints as they are removed during the replacement program, and in addition a variation of $0.1m in the project estimates provided compared to the costs included in the SPA proposal. We believe that if the decision to replace all the joints is made then it is of little value to keep investigating the failure modes of the original joints. We therefore recommend that this allowance, as well as the variation in the project estimate, be removed from the total external contractor estimates for this project. Table 7-17 details PB's recommended annual and total costs for the project.

Table 7-17 – Impact of removal of forensic costs and project estimate variation on power cable repair program

Expenditure $m (real)	08/09	09/10	10/11	11/12	12/13	13/14	Total
Submitted	1.3	1.3	1.3	1.3	1.3	1.0	7.5
Proposed variation	(0.0833)	(0.0833)	(0.0833)	(0.0833)	(0.0833)	(0.0833)	(0.5)
PB recommendation	1.217	1.217	1.217	1.217	1.217	0.917	7.0

Source: PB analysis

The project involves the replacement of six joints per annum over the next 6-year regulatory period. Although negotiations with the relevant authorities is required to gain access to the joint bays (which are located in public roadways) and that complex site access requirements such as traffic control and restoration works etc are required, PB is of the view that the project is deliverable within the next regulatory period. Experience gained during the repair of the joint that explosively failed indicates that the work associated with the replacement of all joints within a joint bay can be performed within a 2-month window.

Conclusion

The external contractor cost estimates were developed using a bottom-up approach and we have reviewed all the cost components and formed the view that they are reasonable with the exception of the allowance for forensic investigation. We believe that if the decision to replace all the joints is made then it is of little value to keep investigating the failure modes of the original joints. We therefore recommend that the external contractor cost estimate be reduced to $7.0m in total over the next 6-year regulatory period.

7.4.4 Tower painting program

Towers in areas of low pollution have a life expectancy of over 70 years. In some aggressive environments, however, significant deterioration occurs in less than 20 years. The project involves the painting of 20 towers and 10 bay rack structures over the next regulatory period, where significant corrosion has been identified.

The procedure consists of inspection and assessment of the structures, preparation for access by non-electrical workers, application of protection at ground level to prevent pollution of the environment and sand blasting of scale material followed by the application of paint to the members being maintained.

Alternatives

Two options were considered. Option 1 involves the continuation of the current inspection and testing cycles, recording defects and taking limited action to address potential defects.

Option 2 involves the inspection and assessment of the structures, preparation for access by non-electrical workers, application of protection at ground level to prevent pollution of the environment and sand blasting of scale material followed by the application of paint to the members being maintained.

Project justification

This project is justified on the basis of safety issues (in the event of asset failure) in relation to staff, contractors and the general public, reduction of financial risk resulting from increased operating costs if the assets fail in service, rebate penalties associated with asset availability and potential civil actions resulting from personal injury. There are also issues in relation to compliance with Electrical Safety (Network Assets) Regulations, compliance with Occupational Health & Safety Act and recommended preventative maintenance requirements for maintenance of insurance cover.

In addition, SPA states that Option 2 demonstrates asset management practices in accordance with accepted industry practice for the long-term safe operation and maintenance of the network. SPA also states that this option will facilitate the analysis of failure modes enabling the business to identify potential future issues and therefore plan mitigation measures to be implemented pre-emptively.

PB notes that maintaining the protective coatings on towers clearly extends their service lives, particularly in highly corrosive environments. It is simply more cost effective to maintain the coating on towers than to replace them approximately half-way through their potential service life. In addition it is well accepted that if maintenance is carried out at the first signs of corrosion, the remedial costs are lower than at a later time when the procedures are more complex and expensive.

Timing

The program proposed for the next regulatory period involves 20 towers and 10 bay rack structures where significant corrosion has already been identified. Table 7-18 indicates that this work comprises part of an overall structure painting program.

The high number of towers and steel poles located in the corrosive marine environment at Port Henry, and the corrosive industrial environments near the Alcoa smelter at Portland and in the Latrobe Valley are scheduled for maintenance during the regulatory period commencing in 2014.

Table 7-18 – Tower painting program

Period	03/04–07/08	08/09–13/14	14/15–18/19
Duration (years)	5	6	5
Total towers painted per period	39	20	100 + 321
Towers bay rack structures painted	0	10	0

Source: SPA Painting Project 2008-2014

PB analysis

As part of its review, PB requested additional information in relation to the overall tower painting program and the methodology used to estimate the cost per square metre to maintain the bay rack structures. SPA also provided comprehensive photographic evidence of the condition of the towers proposed to be repainted during the next regulatory period. In light of the information and data provided we have formed the opinion that the project is prudent and the timing reasonable.

The historical external contractor costs used as a basis to forecast current external costs appears reasonable as does the use of CPI to escalate costs to the current day external contractor costs of $426 per square metre, as the majority of the costs are direct labour.

In regard to the external contractor costs to maintain the bay rack structures SPA has provided the information shown in Table 7-19.

Table 7-19 – External contractor costs to maintain rack structures

Work description	Surface area m^2	Cost $ per m^2	Total cost $
Painting	2,140	426	911,640
Erect and remove scaffold	—	—	208,740
Erect and remove barriers	—	—	200,000
Total	**2,140**	**$617**	**1,320,380**

Source: SPA Painting Project 2008-2014

PB notes that the same external contractor rate for painting towers has been used for bay rack structures, which we believe to be reasonable, and all the additional costs relate to gaining access to rack structures while the terminal stations remain in service. The additional work to access the structures involves the erection of barriers to prevent workers contacting adjacent live equipment and the erection of scaffolding for personnel access to perform the maintenance operations. This work is time consuming due to the proximity of live apparatus and has to be carried out either by electrically qualified staff or under their direct supervision.

We have also reviewed the scale and scope of this project and consider that it will be possible for SPA to secure appropriate suitably qualified contractors to carry out the work and we believe the project is deliverable within the next regulatory period.

Conclusion

PB is of the opinion that the need for the project has been established and the timing is reasonable. The external contractor costs, which have been developed primarily from historical costs, also appear reasonable. We believe that this project is deliverable within the next regulatory period.

7.4.5 Tower foundation maintenance program

This program consists of four separate projects: foundation inspection, foundation repairs, sacrificial anode cathodic protection, and impressed current cathodic protection. The work associated with these projects includes the excavation of at least one leg of each tower, foundation inspection and assessment, sand blasting of scale material from corroded steel members, replacement of steel members displaying significant corrosion, application of protective coatings, re-instatement of concrete foundations showing significant degradation, and the installation of cathodic protection at specific locations.

The transmission tower foundation maintenance project will target some of those towers with foundation steelwork which is not completely encased in concrete. (Note that the tower foundation is considered to commence at 500 mm below the actual ground surface level and continue down). PB notes that there are approximately 4,000 such towers out of a total population of 12,739 towers.

Experience with past inspection and maintenance has enabled SPA to target specific locations where tower foundation corrosion is prevalent. Accordingly, the project for 2008– 2014 is anticipated to involve a significant number of towers that will require a range of activities to be undertaken to maintain the tower foundations and provide ongoing protection to the steel below ground level.

Alternatives

SPA considered two options. Option 1 was the do nothing option which involves maintaining the routine asset inspection and testing cycles above ground level and recording defects identified, followed by limited action to remedy defects identified.

Option 2 involves maintaining the current tower foundation maintenance program which involves the excavation of at least one leg of each tower, foundation inspection and assessment, sand blasting of scale material from corroded steel members, replacement of steel members displaying significant corrosion, application of protective coatings, re-instatement of concrete foundations showing significant degradation, and the installation of cathodic protection.

Project justification

This project is justified on the basis of safety issues (in the event of asset failure) in relation to staff, contractors and the general public, reduction of financial risk resulting from increased operating costs if the assets fail in service, rebate penalties associated with asset availability and potential civil actions resulting from personal injury. There are also issues in relation to compliance with Electrical Safety (Network Assets) Regulations, compliance with Occupational Health & Safety Act and recommended preventative maintenance requirements for maintenance of insurance cover.

In addition, SPA states that Option 2 demonstrates asset management practices in accordance with accepted industry practice for the long-term safe operation and maintenance of the network. In effect Option 2 ensures the towers now approaching 50 years of age, and those installed in aggressive environments, will reach their designed service life of 70 years in a cost effective manner.

Timing

During the next regulatory period it is proposed to excavate the footings of 21 towers whose footings are not totally encased in concrete and are located in close proximity to terminal stations. These proposed works form part of an overall program which is detailed in Table 7-20.

Table 7-20 – Tower foundation maintenance program

Item	03/04–07/08	08/09–13/14	14/15–18/19	Comments
Duration (years)	5	6	5	—
Number of towers in or near terminal stations	23	21	20	69% of total towers in/near terminal stations

Source: SPA Tower Foundations Maintenance Project 2008-2014

Work in the current regulatory period on 23 towers has indicated that three towers required new foundations to be constructed and another required local repairs to be carried out. The remaining 19 towers had foundations in acceptable condition.

SPA also plans to commence a cathodic protection program during the next regulatory period. Table 7-21 indicates the extent of the proposed program. SPA also intends to install one impressed current cathodic scheme during the next regulatory period.

Table 7-21 – Tower foundation cathodic protection program

Item	08/09–13/14	14/15–18/19	19/20–23/24	24/25–28/29	29/30–33/34
Duration (years)	6	5	5	5	5
Towers with CP installed per period	250	500	750	1,000	1,500
Towers per year with CP installed	42	100	150	200	300
Cumulative % of towers (4,000) with CP installed	6	19	38	63	100

Source: SPA Tower Foundations Maintenance Project 2008–2014

PB analysis

PB has reviewed the initial information provided by SPA and has also requested additional information in relation to the extent of the existing and proposed programs.

The total external contractor cost estimated by SPA for the program is detailed in Table 7-22.

Table 7-22 – External contractor costs for tower foundation program

Work description	Estimated cost $
Foundation investigation	500,000
Foundation repairs	1,480,372
Sacrificial anode cathodic protection	2,150,000
Impressed current cathodic protection	30,000
Total	**4,160,372**

Source: SPA Tower Foundations Maintenance Project 2008–2014

The external contractor costs for two components of the project, foundation investigation and sacrificial anode protection, were estimated using a bottom-up approach based on historical cost escalated to current costs in line with CPI. The external contractor costs for foundation repairs were estimated using a combination of historical costs where available and cost estimates prepared by engineering consultancy Connell Wagner in 2004. The last project, impressed current cathodic protection was estimated using a bottom-up approach.

Table 7-23 shows the historical costs in relation to foundation investigation on which the forecast external contractor costs have been based.

Table 7-23 – Historical external contractor costs for tower foundation investigations

Project	Description	Actual costs $
W302,W303, W305	Ground-level electrical testing for corrosion	42,761
W326	Ground-level electrical testing for corrosion	108,538
V416 (2004)	Tower foundation excavation along lines	166,367
V417 (2005)	Tower foundation excavation in TS	113, 413
V579 (2005)	Tower foundation excavation in TS and lines	267,566
Total		**698,645**

Source: SPA Tower Foundations Maintenance Project 2008-2014

Projects W302, W303, W305 and W326 included electrical testing of a large number of towers, whereas projects V416, V417 and V579 were for excavations of a total of 25 towers. Hence the average external cost per tower for excavations of foundations was $547,346 / 25 = $21,893 per tower. Escalation at 3% per year for 3 years brings this external cost to 1.09 x $21,893 = $23,863 per tower.

For the next regulatory period it is planned to carry out foundation excavations of a further 21 towers at a total external contractor cost of $23,863 x 21 = $500,000 (approx).

In relation to the tower foundation cost estimates SPA has based its estimates on the historical data shown in Table 7-24.

Table 7-24 – Historical external contractor costs for tower foundation repairs

Project	Work description	Actual costs $
V488	Repair foundations on one tower at HOTS (April 2005)	141,051
V524	Repair foundations on one tower at GTS (October 2005)	138,630
V5C8	Repair foundations on one tower at SVTS (June 2006)	159,689
Total		**439,370**

Source: SPA Tower Foundations Maintenance Project 2008-2014

The estimated external contractor cost for repairing the foundations of an additional three towers during the next regulatory period is therefore $439,370 escalated by 6% to $465,732.

SPA has based the external contractor cost estimates for the work proposed on the 66 kV towers on the Wagner Connell construction estimates, escalating these estimates to current dollars and then adding the additional costs associated with geotechnical investigations, engineering input, access and site costs. The total estimated external contractor cost for foundation repairs during the next regulatory period is $1,014,640 + $465,732 = $1,480,372.

SPA has also provided additional information in relation to the sacrificial anode cathodic protection project as follows:

> *The current age of SPA's direct buried steel foundations is approximately 40 to 60 years. To date a small number of tower foundations have had cathodic protection installed. Foundation investigations by SPA have shown that foundations, in localised aggressive soils, are showing signs of galvanising failure and that a directed program of CP installation should be commenced in the 2008/9 to 2013/14 period to address these areas.*
>
> *The CP program, in the longer term, will be driven by evidence based investigation programs, but is expected to expand to mitigate the anticipated risk of foundation failure as the original galvanising on this large tower population fails. SPA anticipates that the last stage of this program (2029/30 to 2033/34 period) will be to protect towers which have had steelwork buried for approximately 60 to 80 years. The CP program will continue beyond this initial installation program through monitoring and replenishment of sacrificial anodes, as the need arises.*

PB notes that it is now common practice for TNSPs to use cathodic protection to provide protection against corrosion of tower foundations; for example, Powerlink is using this form of tower foundation protection in Queensland.

Conclusion

The original information and data provided, as well as additional information and photographs of the tower footings already exposed, has been reviewed. Based on this information, we have formed the view that the proposed works are justified and the timing of the project reasonable. We also believe that the external contractor cost estimates are reasonable as they are based primarily on historical data and in the case of the proposed work on the 66 kV towers, an independent external engineering consultancy.

7.4.6 Miscellaneous works

PB requested SPA to provide details of the works included under the heading of ‘Assets Works — Miscellaneous Works’. This information was provided and SPA included the following explanation of Miscellaneous Works:

> *Total operating and maintenance expenditure is forecast to be approximately $200 million per annum over the 2008-2014 regulatory period, of which Miscellaneous Works expenditure represents approximately 0.5%.*
>
> *Given the scope and diversity in operating a transmission network it is reasonable to expect a variety of activities to be undertaken that do not form part of either recurrent maintenance or major no recurrent asset works programs.*
>
> *Experience demonstrates the numerous activities that constitute Miscellaneous Works, as described in Section 1.1 ‘Project Scope’. These activities are often of a reactive nature due to the problems associated with pre-emptive programs (such as the Condition Based Maintenance), providing reliable forecasting requirements for these activities.*

SPA has advised that the works in Miscellaneous Works include:

- carrying out Post-implementation Reviews (PIRs) of projects
- carrying out Value Engineering/Value Management studies for proposed projects
- risk management activities
- insurance risk audits of terminal stations
- hydrostatic testing of fire service systems
- assessment of risk of line conductor drops
- assessment of risk of tower collapse
- technical and defect investigations
- line easement management:
  - new access track requirements due to changed conditions
  - repair of damaged access tracks and bridges
  - installation of access gates due to changed conditions
  - external costs for enforcement of easement rights and standards.
- maintenance (ad-hoc) of communication hardware, systems and services:
  - PABX & OTN.
- noise investigations:
  - take measurements in response to complaints and reports of excessive noise
  - non-capital response to resolve complaints
- temporary sound barriers
- non-asset solutions e.g. double glazing windows in buildings
- removal and disposal of out of service assets
- drawing management:
  - review and updating of drawings following system incidents.
- benchmarking studies:
  - cost of participation in external studies

  - external technical support for data gathering.
- engineering support:
  - engagement of external resources to assist in strategy and policy development e.g. development of 'Asset Management Strategy', 'Vision 2030', 'Asbestos Management Strategy', and 'Physical Security Strategy'
  - engagement of external resource to assist in development of engineering capability
  - engagement of external resources to establish the possible impact of changes to regulations and standards e.g. impact of changes to standards for exposure to EMF.
- asset rating development:
  - external resources to undertake ad-hoc reviews, testing and trials to extend asset ratings
  - research and development of asset enhancements.
- asset signage and warning systems:
  - replace illegible signs as required
  - install additional signs as required
- oil spill clean up:
  - supply of oil spill clean up materials
  - clean up and disposal of oil contaminated soils.
- membership of professional organisations e.g. CIGRE, Australian Standards Association
- participation in engineering forums
- training in new technology applications
- payment of microwave radio and other licences
- review of maintenance procedures e.g. SMIs and PGIs
- funding for engineering research & development:
  - Chair of Electrical Power Engineering.
- support of and improvements to Asset Management Information Systems:
  - Maximo
  - Defect Management System
  - Ratings database (RADAR)
  - TRESIS
  - Global Information System
  - hand-held devices.
- minor works programs — primary:
  - station earth grid testing
  - fault current testing of primary plant items
  - investigation and replacement of ground wire in stations
  - cable trench/duct repairs and refurbishment
  - vibration tests on synchronous condensers
  - investigation and mitigation of TV and radio interference from corona discharge.
- minor works programs — secondary:

- protection and setting reviews
- post-incident reviews
- secondary cable repairs
- audit of lead acid batteries in stations
- refurbishment of battery chargers
- investigation of new technology and applications.

- minor works programs — other:
  - dangerous goods and hazardous waste transport and disposal
  - EMF exposure investigations and mitigation activities
  - RF exposure investigations and mitigation activities
  - specialised maintenance equipment tests and repairs
  - testing and repair of spare equipment items
  - local manufacture of spares
  - investigation and management of ground subsidence issues e.g. at RTS
  - replacement of flexible operational earths (to provide increased rating)
  - replacement of stolen earth conductor in stations
  - engagement of temporary security services at terminal stations
  - remediation works for environmental pollution.

Alternatives

SPA considered two options. Option 1, do nothing, would involve permanent asset repairs being deferred and either temporary repair or temporary de-commissioning being performed. The monitoring and recording of asset and system deficiencies and defects would be undertaken for inclusion in a subsequent regulatory review.

Option 2 involves maintaining the Miscellaneous Works program which includes the implementation of the Miscellaneous Works activities as identified in the Project Scope. This would facilitate the identification of trends that may enable activities to be included in recurrent maintenance or major non-recurrent asset works programs.

SPA project justification

This project is justified on the basis of safety issues (in the event of asset failure) in relation to staff, contractors and the general public, reduction of financial risk resulting from increased operating costs if the assets fail in service, rebate penalties associated with asset availability and potential civil actions resulting from personal injury. There are also issues in relation to compliance with Electrical Safety (Network Assets) Regulations, compliance with Occupational Health & Safety Act and recommended preventative maintenance requirements for maintenance of insurance cover.

In addition Miscellaneous Works includes many of the minor, but essential, non-recurrent works associated with running a transmission business such as EMF and RF investigations and remediation, replacement of stolen assets and equipment and employment of temporary security guards.

Timing

Table 7-25 details SPA's planned external expenditure on the various aspects of the Miscellaneous Works program over three regulatory periods.

Table 7-25 – Miscellaneous works program expenditure

Item	02/03–06/07	08/09–13/14	14/15–18/19
Duration (years)	5	6	5
Expenditure ($)	11,134,000	6,500,000	6,350,000
Expenditure ($ per year)	2,227,000	1,080,000	1,270,000

Source: SPA Miscellaneous Works Projects 2008-2014

The reason for the reduction in expenditure from the current to the next regulatory period is that a number of assets works jobs that were previously included in Miscellaneous Works have now been included as separate asset works programs e.g. Condition Monitoring Development, Line Hardware Maintenance, Tower Bolt Replacement, and Tower Steelwork Replacement.

PB analysis

We have reviewed the information provided by SPA in relation to Miscellaneous Works and note that, with the exception of the radio licensing fees, it is of a very general nature. In addition, we have noted that some of the works mentioned appear to be of a capital nature.

Other works included in Miscellaneous Works appear as if they should be covered by recurrent expenditure such as some testing programs detailed in the Minor Works Programs Primary and Secondary, radio maintenance and licence fees. We also have noted the removal of larger projects previously included in the Miscellaneous Works category into categories of their own.

PB acknowledges the need for an allowance for Miscellaneous Works. However, PB has not been provided with sufficient information, or specific costing data, to justify the allowance requested in the SPA proposal. In addition, PB believes that it is extremely difficult to identify accurate historical expenditure due to changes in cost allocation categories[177]. On the information available, and drawing on experience and professional judgement, PB recommends that the external contractor allowance for the next regulatory period is set at 1.0% of the real controllable opex[178]. Table 7-26 shows PB's recommended annual and total allowances for Miscellaneous Works for the next regulatory period.

Conclusion

PB recommends that since no firm costing information has been provided by SPA in relation to Miscellaneous Works, an allowance of 1.0% of the real controllable opex shown in Table 6.10.1 of the SPA Revenue proposal be included in SPA's forecast expenditure for Miscellaneous Works.

177 Works that were previously included in 'miscellaneous works' category are now represented in separate cost categories.

178 Table 6.10.1 of the SP AusNet revenue proposal.

Table 7-26 – Miscellaneous works, PB recommended adjustment

Expenditure $m (real)	08/09	09/10	10/11	11/12	12/13	13/14	Total
Submitted	0.10	1.0	1.2	1.5	1.2	1.5	6.5
Proposed variation	0.594	(0.281)	(0.459)	(0.746)	(0.434)	(0.722)	(2.048)
PB recommendation	0.694	0.719	0.741	0.754	0.766	0.778	4.452

Source: PB analysis

7.5 OTHER OPERATIONAL EXPENDITURE CONSIDERATIONS

In this section we set out other opex considerations which have arisen as part of the PB review.

7.5.1 Labour escalator adjustment

PB notes that the forecasts in the SPA opex model are based on escalating the labour component of each line item by 2.83% real. This average increase above inflation was obtained from a BIS Shrapnel Report commissioned by Envestra, SPA and Multinet Gas. The SPA model uses a weighted escalator to forecast each line item in the model. The weighted escalator is determined by calculating the average labour percentage of each line item for the three year period 2004/05 to 2006/07 and escalating this labour percentage by 2.83%.

PB analysis

PB predicts that the labour market for trained electricity workers will remain tight for the next 3 years and over the longer term we believe that labour increases will track the long-term average. These predictions are based on the fact that the current shortage of skilled labour has been brought about by a combination of conditions, in the most part related to the high level of activity in infrastructure construction and refurbishment throughout the whole of Australia as well as the mining boom in Queensland and Western Australia. However, we do not believe that the current conditions will persist for the entire duration of the next regulatory period.

The cyclical nature of economic activity is caused in large measure by participants responding to alleviate economic pressures as they occur. Already there is evidence that companies have in place strategies to mitigate the current tight labour market conditions for skilled electricity workers. For example, distribution businesses and TNSPs throughout Australia have commenced comprehensive apprentice training programs and some have also commenced overseas recruitment programs. We believe that these programs will have an impact on the current tight labour conditions within the next few years.

In addition, large mining companies such as BHP that have traditionally only recruited within Australia have decided to commence using the ‘457 visa’ scheme to recruit foreign workers, including electricians. In an article in the *Australian Financial Review* of 2 February 2006, BHP announced that it would be approaching the Federal Government to assist its contractors recruit 200 foreign workers under the ‘457 visa’ arrangement. The article states,

> *The move, one of the largest single applications under the government’s section 457 temporary visa scheme, is aimed at averting the recent construction cost blow-outs that have hit most major resources companies.*
>
> *BHP Billiton is likely to target trades such as mechanical fitters, welders and electricians from overseas to work on the project…*

The article also includes a list of seven other major companies that have commenced to recruit foreign workers under the program including Rio Tinto, IBM, and Woodside Petroleum.

In the light of these developments, we believe that the current tight market conditions for skilled electrical construction workers will persist only for the next 2 or 3 years, after which time the demand/supply situation for skilled electricity workers will be rebalanced by the combination of the comprehensive TNSP and distribution businesses' apprentice training programs, continuation of current overseas recruitment programs, and expansion of the 457 skilled worker visa program. We understand that the 457 visa program has already attracted approximately 40,000 skilled workers to Australia.

SPA is currently negotiating its next Enterprise Bargaining Agreement (EBA) and the ambit claim from the unions represents a 5% increase per annum in rates and a 1.5% increase in superannuation contributions, in total a 6.5% overall increase in labour costs. Based on experience and outcomes in other jurisdictions we expect that a probable outcome would be an overall increase in labour costs in the order of 5.5%.

In order to determine the long-term, 20-year average annual percentage increase in total weekly earnings, the AER had the Australian Bureau of Statistics compile the 'Average Weekly Earnings, Industry, Australia (Dollars), Full Time Adult Males, Females and Persons for Electricity, Gas and Water Supply workers in Victoria' from November 1986 to November 2006. PB believes that the total weekly earnings for adult males is the appropriate data to use in forecasting the long-term average increase in labour costs as the nature of the electricity industry is such that there is considerable overtime worked in restoring supply after hours as well as carrying out programmed maintenance outside peak demand periods.

This data indicates that the average annual increase in total adult male full-time earnings is 4.94% over 20 years to November 2006. This is slightly lower than the average annual increase average weekly earnings, which was 5.09% over the same period.

In the light of the foregoing discussion, our recommendation in regard to future labour increases is 5.5% for the next 3 years, that is for 2007/08 and then the first 2 years of the next regulatory period; followed by annual increases of 4.94% for the remainder of the next regulatory period. The SPA opex model is designed to calculate the average annual percentage real increase in labour costs over the next six year regulatory period. To establish our recommended average real increase we have determined the nominal average increase based on 2 years at 5.5% and 4 years at 4.94% — 5.13% per annum. Based on a predicted CPI of 3.02%, our recommended real average annual increase is 2.11%, compared to the 2.83% real average labour cost increase used and modelled by SPA.

To determine the impact of its recommendation, PB has re-run the SPA opex model (30 April 2007 version) using our recommended 2.11% real labour escalator and this has reduced the total forecast operational expenditure for routine maintenance, asset works and corporate cost from $418.656m over the next 6 year regulatory period to $412.237m — a reduction of $6.42m (2007/08) over the next regulatory period with all other data kept constant. Table 7-27 shows the annual and total effect of reducing the labour escalation factor to 2.11% and maintaining all other data constant.

Table 7-27 – Labour escalation adjustment for routine maintenance, asset works and corporate costs

Expenditure $m (07/08 real)	08/09	09/10	10/11	11/12	12/13	13/14	Total
Submitted	65.129	67.481	69.686	70.946	72.118	73.296	418.656
Proposed variation	(0.460)	(0.692)	(0.934)	(1.183)	(1.441)	(1.709)	(6.419)
PB recommendation	64.669	66.789	68.752	69.763	70.677	71.587	412.237

Source: PB analysis

Conclusion

PB recommends that the labour escalation for opex labour should be reduced to 2.11% which would result in a reduction of $6.42m (2007/08) over the next regulatory period.

7.5.2 Asset works — internal costs

SPA has used benchmark data[179] to forecast support costs for routine maintenance and asset works. The SPA opex model applies a labour escalator to the labour component of these to forecast future costs. In the case of asset works – internal SPA costs, SPA has adopted the internal estimate from the 2006/07 year and held these costs constant in the SPA opex model over the next regulatory period. The SPA opex model[180] indicates that this constant amount is $2.247m per annum for 'Internal SPA Costs' over the next regulatory period. Due to the inconsistency of approaches used by SPA we requested additional information on the methodology used to determine these asset works – internal SPA costs.

PB analysis

The additional information provided by SPA indicates that it conducted a bottom-up build to determine the internal estimate costs for each specific asset works project. The internal estimated cost for Internal SPA Costs for all projects scheduled for the next regulatory period was $12.72m (2007/08 dollars) which translates into $2.12m per annum. However, SPA did not use this figure when forecasting its costs for the next regulatory period. Instead, it adopted the estimate for the 2006/07 financial year of $2.25m as the benchmark figure for the model.

PB has formed the view that as SPA has used a bottom-up approach to estimate the Internal SPA costs for each specific asset works project then this is the figure that should be included in the opex model. This is the same approach that SPA has used in determining the external contractor costs for each specific asset works project. Adoption of this recommendation would result in the SPA internal cost forecasts being reduced from $2.247m to $2.12m per annum, representing a total saving over the next regulatory period of $0.762m (2007/08 dollars).

Table 7-28 indicates the annual and total saving in forecast Asset Works expenditures resulting from the adoption of this recommendation, with all other data and inputs in the model held constant.

Table 7-28 – Asset works (internal SPA costs adjustment)

Expenditure $m (real)	08/09	09/10	10/11	11/12	12/13	13/14	Total
Submitted	13.570	14.588	15.521	15.525	15.528	15.531	90.263
Proposed variation	(0.127)	(0.127)	(0.127)	(0.127)	(0.127)	(0.127)	(0.762)
PB recommendation	13.443	14.461	15.394	15.398	15.401	15.404	89.501

Source: PB analysis

Conclusion

PB recommends that the bottom-up calculated amount of $2.12m be used for the internal SPA costs component of the Asset Works forecasts.

179 Base year 2006/07 estimated results based on 9 month actuals.

180 30 April 2007 version.

7.5.3 Non-regulated asset roll in

SPA proposes to roll in $118.7m of currently unregulated assets into the regulated asset base at the commencement of the 2008/09 financial year. SPA has calculated the effect on its entire opex of the asset roll in by applying an escalation factor determined by the percentage increase in regulated assets as a result of the roll in. The escalation factor is 1.032, an effective increase in opex of 3.2%.

PB analysis

PB does not believe that it is appropriate to escalate the entire opex forecast for the next regulatory period by an escalation factor in order to determine the effect on opex as a result of the proposed asset roll in. We do not believe it is appropriate to escalate the asset works components of the forecasts when additional assets are rolled in as these asset works costs relate to specific maintenance projects. PB therefore recommends that appropriate escalation factors are applied only to the recurrent maintenance and corporate cost components of opex – to more accurately reflect the impact of the proposed asset roll in.

Furthermore, PB is of the view that the escalation factor calculated by SPA, namely 3.2%, is an inappropriate escalation factor to use for forecasting the impact on recurrent routine maintenance of the proposed asset roll in. The new assets being rolled in have a substantially higher remaining life than the existing assets forming the regulatory asset base and hence their routine maintenance requirements should be significantly lower. Older assets, particularly those nearing the end of their technical life, usually require substantially higher levels of inspection and routine maintenance to maintain their serviceability and acceptable performance.

To compensate for this effect, PB has calculated the weighted standard life of the SPA asset base at 48.13[181] years. At the beginning of the 2007/08 financial year, the SPA asset base had remaining life of 24.49 years so the assets have 50.7% of their life remaining. Based on our experience in other jurisdictions maintenance escalation factors of approximately 30% have been experienced as a result of substation and lines asset refurbishment/replacement programs, with higher efficiencies in the vicinity of 60%, resulting from secondary system replacement/refurbishment programs. We therefore recommend reducing the routine maintenance effort by a factor of 30% resulting from the rolling in of new assets. This recommendation results in the calculated raw escalation factor of 1.032 being reduced by 30% resulting in a recommended escalation factor of 1.022.

However as corporate overhead costs are allocated on a RAB share basis in SP AusNet's cost allocation methodology PB believes that the appropriate escalation factor to apply to corporate costs is 1.032 to reflect the appropriate allocation of corporate costs to the regulated accounts.

We have used the original SPA opex model (30 April 2007 version) to calculate the impact of these recommendations, with all other data constant. In addition, we have not escalated the taxes/leases and insurance components of routine maintenance due to the proposed asset roll in as these costs have been forecast separately for the next regulatory period and hence, we believe, will already include any impact resulting from the roll in of additional assets. PB's recommendations have reduced the total forecast operational expenditure for routine maintenance and corporate costs from $11.401m over the next 6-year regulatory period to $7.421m. This represents a reduction of $3.980 (2007/08 dollars) over the next regulatory period (with all other data kept constant). Table 7-29 displays the annual and total effect of this recommended alteration to the asset roll in escalation factor.

181 This estimate of weighted standard life is based on opening asset value and uses all relevant asset categories.

Table 7-29 – Asset roll-in adjustment

Expenditure $m (real)	08/09	09/10	10/11	11/12	12/13	13/14	Total
Submitted	1.773	1.838	1.898	1.932	1.964	1.996	11.401
Proposed variation	(0.598)	(0.639)	(0.674)	(0.683)	(0.690)	(0.696)	(3.980)
PB recommendation	1.175	1.199	1.224	1.249	1.274	1.300	7.421

Source: PB analysis

Conclusion

PB recommends that the asset roll in factor which is designed to adjust forecast routine maintenance costs to reflect the roll in of $118.7m of currently unregulated assets into the regulated asset base, be reduced from 1.032 to 1.022.

7.5.4 Self-insurance expenditures

SPA engaged SAHA International Limited to prepare a report *Evaluation of Self-Insurance Risks (Electricity Transmission)* to determine the self-insurance risk premium to include in its revenue submission.

PB analysis

We have reviewed the SAHA report and make the following comments:

- The real WACC used in the SAHA report to calculate the cost of financing the indirect costs (those costs associated with works put in hand to maintain operation of the assets while permanent repairs are carried out) is 6% where as the WACC used in the revenue proposal is 5.66%. This results in a difference of 0.34% in financing costs being included in the self-insurance premium estimates. However financing costs appear to only have been used in estimating self-insurance premiums for damage to towers and lines and therefore does not have a material impact on total self-insurance premiums.
- In assessing the risk of property damage to towers and lines, the incident frequency rate assumed for strain towers seems high when compared to the Victorian experience to date. PB notes that no strain towers have failed over the last 49 years but SAHA has assumed a failure rate of three towers per 100 years for pre-1965 strain towers and 0.7 strain towers per 100 years for post-1965. We are of the view that based on nine recorded incidents since 1958 involving 36 tower failures, none of which included a strain tower an assumed incident frequency rate of 0.01 (one strain tower failure in 100 years) would have been a reasonable assumption for pre-1965 strain towers. The self-insurance risk premium for this reduced incident rate for pre-1965 strain towers assuming on average five towers would be involved in any strain tower failure incident, is $8,900. The impact on the estimation of self-insurance risk premium for a 0.01 incident rate risk for pre-1965 strain tower failure is a reduction of $18,399 and we would recommend the total annual self-insurance premium be reduced by this amount.
- In estimating the additional risk premium for catastrophic events, the SAHA report only addresses the risk to tower transmission lines from earthquakes. Such events are of extremely low probability but can have significant impact, i.e. low probability but high consequence. According to the SAHA report, Victoria has not experienced an earthquake in the last 150 years that has resulted in a catastrophic event on transmission assets. Those earthquakes likely to have an impact are those with a magnitude greater than 5 on the Richter scale, have only occurred at Alpine locations or at locations where they did not create catastrophic impact on SPA

transmission assets. No earthquakes of magnitude greater than 6 have been recorded in Victoria.

SAHA has assumed a probability of a catastrophic event of 1 in 150 years and, due to the high consequence of such an event, the self-insurance risk premium is $122,144. We believe that as there is a 150-year incident-free history, an assumed incident rate of 1 in 200 years would be more appropriate. This would reduce the risk premium to $91,586 a reduction of $30,528. We would recommend that the total annual self-insurance premium be reduced by this amount, namely $30,528.

- In assessing the power transformer failure risk, SAHA has assumed that the failure rate for power transformers is 1%. While this figure is often used in the power industry, it is not supported by SPA’s power transformer failure history. Over the last 6 years SPA has experienced three power transformers failures and this equates to an annual failure rate of 0.21% over the transformer population of 238 transformers. Assuming this failure rate was to double due the ageing transformer population, which is supported by local and international industry experience, the forecast failure rate would rise to 0.42%. Based on this failure rate the power transformer self-insurance premium would be $484,806, a reduction of $669,494. We therefore recommend that the total annual self-insurance premium be reduced by $669,494.
- SAHA included the self-insurance premium for the risk of current transformer failures in the self-insurance premium for power transformers. As we have substantially reduced the assumed failure rate of power transformers to 0.42%, we believe that a separate self-insurance premium for current transformer failure risk should be included in the total self-insurance premium. In calculating the self-insurance premium for current transformer failure risk, we have relied on the data supplied by SPA and included in the SAHA report. We have assumed an incident rate for current transformer failures of 1 in 6 years and an average cost in 2007/08 dollars of $185,000. These assumptions result in a self-insurance premium of $30,839.50 for each of the 220 kV and 500 kV current transformers. We therefore recommend that the total annual self-insurance premium be increased by $61,679 for the risks associated with the failure of current transformers.
- In assessing the risk of circuit-breaker failure, SAHA has assumed a failure rate of 0.72% of the circuit-breaker population based on CIGRE data. However the SPA data supplied for 2005 and 2006 indicates only three failures which equates to a failure rate of 0.15%. As the SPA historical data is only available for a 2-year period, it would not be unreasonable to assume a failure rate of double this short term historical failure rate. This equates to an assumed failure rate of 0.3%. In addition, we understand that SPA plans to spend approximately $10m over the next 6 years on preventative circuit-breaker refurbishment work to reduce the risk of circuit-breaker failure. Based on these assumptions and using the estimated exposure rates in the SAHA report, we have recalculated the self-insurance risk premium as shown in Table 7-30.

Table 7-30 – Calculation of self-risk insurance premium for circuit-breaker failures

CB type	Number of CBs	Annual rate of CB failures %	Estimated exposure $	Estimated risk $
22 kV	114	0.30	25,000	8,550
66 kV	451	0.30	50,000	67,650
220 kV	339	0.30	200,000	203,400
275 kV	6	0.30	250,000	4,500
330 kV	21	0.30	250,000	15,750
500 kV	71	0.30	250,000	53,250
Total	**1002**			**353,100**

Source: PB analysis

This represents a reduction of $494,340 in the self-insurance premium recommended by SAHA and we recommend that the total self-insurance premium be reduced by this amount.

The adoption of PB's recommended changes to the self-insurance premiums results in a total reduction of $1,151,082 in the annual self-insurance premiums. The annual and total recommended reductions are shown in Table 7-31.

Table 7-31 – Self-insurance premium adjustment

Expenditure $m (real)	08/09	09/10	10/11	11/12	12/13	13/14	Total
Submitted	2.539	2.539	2.539	2.539	2.539	2.539	15.234
Proposed variation	(1.151)	(1.151)	(1.151)	(1.151)	(1.151)	(1.151)	(6.906)
PB recommendation	1.388	1.388	1.388	1.388	1.388	1.388	8.328

Source: PB analysis

Conclusion

PB recommends that the self-insurance premium included in the revenue proposal be reduced to $1.388m, an annual reduction of $1.151m resulting in a total recommended reduction of $6.906m (2007/08 dollars) over the next regulatory period.

7.6 CAPEX-OPEX TRADE-OFF

The SPA opex model is based on the assumption that the maintenance effort remains constant from the base year, and only the labour component is escalated throughout the next regulatory period. This assumption ignores the impact of the asset refurbishment/ replacement capital programs and also the asset works opex programs on the routine maintenance effort required to keep the asset in service. Essentially the model assumes that the refurbished and replaced assets require the same amount of routine inspection and rectification maintenance as the older assets they replace.

PB analysis

In our view this assumption results in the model predicting more maintenance expenditures than required, as older assets nearing the end of their service life almost always require more inspection and maintenance intervention than newly commissioned modern assets. The justification for new capital expenditure usually involves the identification of operational expenditure savings that can offset either partially or fully the new capital expenditure on a net present value (NPV) basis. Businesses cases generally contain this information and compare the capital and operational expenditures and savings against the 'do nothing' or 'business as usual' case. SPA has utilised the business case approach in formulating its capital works program; however, the 'do nothing' case is not included in the Authority to Proceed documents. Each business plan is based on the premise that something has to be done and hence only compares the NPV of probable solutions.

Had the 'Authority to Proceed' documents contained a 'base-case[182]' analysis then PB would have used this data to predict the expected opex savings that may have resulted from the implementation of the entire capital works program. In the event that this information was available, PB would recommend adopting the following methodology to predict the potential opex savings resulting from the full implementation of the proposed asset replacement capital works program:

- identify and quantify the magnitude of the opex savings from the projects reviewed
- ratio these opex savings to determine the possible savings from implementing the total asset replacement/refurbishment program;
- convert these opex savings into real 2007/08 dollars and calculate the annual real savings using the appropriate WACC as the discount factor (infinite series).

We believe that it is appropriate that an allowance is made between the proposed comprehensive asset replacement/refurbishment program and the maintenance effort forecast by the opex model which is based on historical data. Hence, PB has drawn on experience gained in other jurisdictions to forecast the opex savings expected from the implementation of the proposed asset replacement program. In our view, the replacement of aged substation assets results in approximately a 30% reduction in routine maintenance effort over the medium term. In addition, this reduction is greater in the initial few years after commissioning due to the fact that some routine maintenance cycles will not commence during the period under review. For example a circuit breaker installed towards the end of the next regulatory period will not be due for any routine maintenance until the following period. The SPA opex model methodology intrinsically forecasts the maintenance effort for assets with an average weighted remaining life of approximately 24.5 years.

We have used the data contained in SPA's revenue proposal[183] to determine the forecast annual asset replacement/refurbishment capital expenditures. This is given in Table 7-32. In addition we have used the data in SPA proposal to determine the closing RAB in 2006/07[184]. The forecast annual capital expenditures and the 2006/07 closing RAB have been re-cast in 2007/08 dollars. A surrogate for the SPA asset replacement cost in 2006/7 has been determined by increasing the RAB value in proportion to the ratio of the weighted average remaining life of the assets to the weighted life of all the SPA assets in 2006/07.

This approach implies that the total capital works program, as submitted by SPA, will be implemented and hence if this program is substantially altered, the input data for these calculations will need to be adjusted to reflect the changed situation. This would result in revised adjustments being calculated.

182 The 'do-nothing' case.

183 Table 11.2.1.

184 Table 7.6.1.

PB has applied the following methodology to calculate a recommended opex/capex trade off:

- re-cast forecast annual asset replacement/refurbishment capital expenditures into real 2007/08 dollars
- determine a surrogate for SPA's asset replacement costs as at 2006/07 and recast into 2007/08 dollars. This was done by increasing the 2006/07 closing RAB value in proportion to the ratio of the weighted average remaining life of the assets to the weighted life of all the SPA assets in 2006/07
- calculate the percentage of forecast annual capital expenditure relative to the base year SPA asset replacement cost
- reduce the percentage of annual capital expenditure relative to the SPA base year asset replacement cost, by 30%
- use the SPA opex model to calculate the annual reduction in recurrent maintenance expenditures using the ratios determined by this methodology.

Table 7-32 – Asset base roll-forward from 1 April 2008 to 31 March 2014 (nominal $m)

Value $m (nominal)	08/09	09/10	10/11	11/12	12/13	13/14
Opening asset base	2,222.9	2,322.8	2,423.3	2,522.6	2,621.4	2,718.7
New assets (capex)	143.5	151.4	156.2	161.7	165.3	199.4
Indexation	67.2	70.2	73.2	76.2	79.2	82.1
Depreciation	(110.8)	(121.0)	(130.2)	(139.1)	(147.2)	(144.4)
Closing asset base	2,322.8	2,423.3	2,522.6	2,621.4	2,718.7	2,855.9
RAB for return purposes	**2,222.9**	**2,322.8**	**2,423.3**	**2,522.6**	**2,621.4**	**2,718.7**

Source: SPA Proposal, table 11.2.1

The recommended adjustment to the maintenance component of Routine Maintenance to reflect the impact of SPA's proposed capital works program results in a total reduction of $4.789m (2007/08 dollars) over the next regulatory period.

Table 7-33 shows the annual and total recommended adjustment to the forecast routine maintenance component of SPA's forecast routine maintenance in real 2007/08 dollars with all other data and inputs kept constant.

Table 7-33 – Routine maintenance adjustment for opex/capex trade off

Expenditure $m (real)	08/09	09/10	10/11	11/12	12/13	13/14	Total
Submitted	18.058	18.420	18.789	19.166	19.550	19.942	113.925
Proposed variation	(0.208)	(0.430)	(0.660)	(0.900)	(1.147)	(1.444)	(4.789)
PB recommendation	17.850	17.990	18.129	18.266	18.403	18.498	109.136

Source: PB analysis

Conclusion

PB recommends that the maintenance component of the Routine Maintenance forecasts be adjusted to reflect the impact of the implementation of the capital works program over the next regulatory period. Adjusting the forecast maintenance component in accordance with the methodology described in this report results in a $4.789m (2007/08 dollar) reduction in the total maintenance spend over the period, with all other costs held constant

7.7 PB CONCLUSIONS AND RECOMMENDATIONS

In its revenue proposal, SPA forecast opex requirements of $445.291m (real) over the 6-year period. PB has identified several issues in these forecasts and has recommended what it believes to be appropriate variations to the forecast expenditure. In this section, we summarise these issues and present our conclusions and recommendations.

7.7.1 Recurrent opex

PB has examined SPA's forecast for recurrent opex and has found that the forecast for insurance premiums applies to both regulated and unregulated assets. PB recommends a reduction of 6.79% to reflect the percentage of unregulated assets covered by these premiums in the next regulatory period. This represents a reduction of $1.356m (real) over the 6-year regulatory period.

The recently negotiated North West Operation and Maintenance contract has delivered cost savings in the current regulatory period that do appear to be reflected in the forecasts. PB recommends a reduction in the annual routine maintenance forecasts of $0.428m (2007/08 dollars). This represents a reduction of $2.807m (real) over the 6-year regulatory period.

No allowance for a reduction in recurrent opex has been made to reflect the capex program. PB recommends a reduction of $4.790m (real) over the 6-year regulatory period.

SPA estimated its costs for 'asset works – internal SPA costs' using a bottom-up approach, but used a higher figure in its forecasts. PB recommends that the estimated figure be used, resulting in a reduction of $0.762m (real).

SPA adjusted its routine maintenance to reflect the roll-in to the regulatory asset base of $118.7m of currently unregulated assets. The escalation factor used to increase routine maintenance costs does not take into account the lower maintenance liability associated with the new assets (when compared to the average assets forming the asset base). PB recommends a reduction of $3.98m over the 6-year regulatory period.

PB also recommends a reduction in the escalator used to adjust labour costs from 2.83% (real) to 2.11% (real).

Table 7-34 details the recurrent operational expenditures as submitted by SPA and as recommended by PB.

The adoption of our recommendation would result in a reduction in forecast recurrent opex expenditures from $328.392m to $316.127m over the 6-year regulatory period, a total reduction of $12.265m (real 2007/08 dollars).

Table 7-34 – PB-recommended recurrent opex forecast expenditures

Expenditure $m (07/08 real)	08/09	09/10	10/11	11/12	12/13	13/14	Total
Submitted	51.559	52.893	54.164	55.421	56.590	57.765	328.392
Proposed variation	(0.840)	(1.305)	(1.780)	(2.268)	(2.762)	(3.310)	(12.265)
PB recommendation	50.719	51.588	52.384	53.153	53.828	54.455	316.127

Source: PB analysis

7.7.2 Non-recurrent opex

PB has examined SPA's forecast for non-recurrent opex by reviewing, in detail, six major Asset Works projects (55% of the total program) and reviewing and discussing a further two projects (5% of the total program), representing over 60% of the total forecast expenditures for Asset Works for the next regulatory period. In most instances PB has requested additional information relating to these projects and the information and data has been supplied and reviewed.

With the exception of the Miscellaneous Works category, each of the projects forms part of an overall program designed to address identified problems or defects. SPA has supplied sufficient evidence, including photographic records in most instances, to justify the need for the projects and the associated external contractor costs also appear reasonable. In addition the projects have been scoped such that they could be successfully executed over the next 6-year regulatory period. PB found that:

- the proposed SF6 Circuit-breaker Refurbishment program is both prudent and efficient and should be included in the proposed asset works program
- the proposed Tower Ground-level Corrosion program is prudent and external contractor costs appear reasonable
- the proposed Power Cable Repair program is reasonable except the allowance of $0.4m for external contractor costs for the forensic inspection of cable joints is unnecessary if the decision to replace all of the joints is made. In addition, PB has adjusted the project estimates provided by $0.1m to reflect the project costs in the SPA proposal. PB recommends reducing the external contractor cost to $7.0m for the next regulatory period
- the proposed Tower Painting program is prudent and external contractor costs appear reasonable
- the proposed Tower Foundation Maintenance program is justified and external contractor costs appear reasonable
- on the basis of the information supplied, PB has formed the opinion that the Miscellaneous Works external contractor costs are high and can be reduced by $2.05m over the next 6-year regulatory period for the reasons detailed in Section 8.4.6 of this report.

In many instances our recommendations on project timing are based on engineering experience and accepted practice. For example, once towers in corrosive environments start displaying full coverage of rust then delaying refurbishment results in additional cost to prepare the surfaces for painting and in some instance results in some members requiring splicing or replacement. Such corroded towers are generally not likely to collapse in the immediate future due to the inbuilt safety factors, but good engineering practice dictates that delaying corrective maintenance at this stage substantially increases remedial costs. These same comments apply to other projects such as the Tower Ground-level Corrosion project.

In relation to the Power Cable Repair program we have recommended that this project proceed due to the very high probability that the remainder of the cable joints will randomly fail over the medium term. This will result in significantly higher costs to repair and maintain supply as opposed to the costs of initiating a pre-emptive and programmed replacement project.

The total impact of PB's recommendations on Asset Works are detailed in Table 7-35. This table includes recommended adjustments to the labour rate escalator, the forecast internal SPA internal costs as well as the recommended changes to the external contractor forecasts.

In addition, it appears that some of the contractor expenditures associated with these projects are already expressed in 2007/08 dollars and do not, therefore, need to be escalated further prior to inclusion in the SPA opex model. PB believes that this has resulted in an overstatement of external contractor costs which have been included in the SPA opex model.

The additional total amount for contractor costs included in the SPA opex forecasts is $1.122m over the next six year regulatory period.

Also the estimate of internal SPA costs have been revised down from $2.274m to $2.12m to reflect the internal estimate of these costs as advised by SPA.

The adoption of our recommendations for non-recurrent opex would result in a reduction in forecast recurrent opex expenditures from $90.263m to $84.448m over the 6-year regulatory period, a total reduction of $5.815m (real 2007/08 dollars).

Table 7-35 – PB-recommended asset works forecast expenditures

Expenditure $m (real)	08/09	09/10	10/11	11/12	12/13	13/14	Total
Submitted	13.570	14.588	15.521	15.525	15.528	15.531	90.263
Proposed variation	(0.970)	(0.666)	(0.886)	(1.200)	(0.895)	(1.198)	(5.815)
PB recommendation	12.600	13.922	14.635	14.325	14.633	14.333	84.448

Source: PB analysis

7.7.3 Self-insurance

PB has examined the basis for SPA's self-insurance costs and found that SPA has over-estimated the risks of property damage to towers and lines, the occurrence of catastrophic events, the failure rate of power transformers and the risks of circuit breaker failures. PB has re-evaluated the self-insurance premiums in accordance with the analysis discussed in Section 7.5.4. The adoption of our recommendations results in a recommended self-insurance premium of $8.328m (2007/08 dollars), a reduction of $6.906m in the self-insurance premium as submitted by SPA, which was $15.234m.

Table 7-36 – PB-recommended self-insurance premium

Expenditure $m (real)	08/09	09/10	10/11	11/12	12/13	13/14	Total
Submitted	2.539	2.539	2.539	2.539	2.539	2.539	15.234
Proposed variation	(1.151)	(1.151)	(1.151)	(1.151)	(1.151)	(1.151)	(6.906)
PB recommendation	1.388	1.388	1.388	1.388	1.388	1.388	8.328

Source: PB analysis

7.7.4 Inventory costs

SPA classifies two types of spare parts, 'strategic spares' and 'normal line items'. It appears that SPA has included both types of spares in the 'inventory' category in the SPA capex proposal for inclusion in the RAB. From the accounting standard AASB116, 'normal line items' should not be capitalised and should be written off at the time of purchase and not capitalised.

When evaluating the ex-ante inventory PB has not been able to clearly identify a value of 'normal stores items' that should have been written down and allocated to opex at the time of purchase.

However, PB was able to identify that 10% of the inventory is turned over annually. We therefore recommend that forecast opex be increased by $40,000 per annum to reflect the value of the normal line items that should be expensed at the time of purchase. Table 7-37 shows the annual and total additional opex recommended for inclusion in forecast opex[185].

Table 7-37 – PB-recommended transfer to opex associated with Inventory costs

Expenditure $m (real)	08/09	09/10	10/11	11/12	12/13	13/14	Total
PB recommendation	0.04	0.04	0.04	0.04	0.04	0.04	0.24

Source: PB analysis

7.7.5 PB-recommended controllable opex forecast expenditures

Throughout this section of the report each of the recommended adjustments have been considered in isolation and the impact of the individual recommendations has been calculated with all other model inputs and data held constant. In calculating the total recommended adjustment to forecast operating expenditures, we have applied all the individual adjustments to the model concurrently. This will result in some compounding effects being incorporated in the model outputs. It is not possible to simply add up the individual recommended adjustments to arrive at our overall recommended forecast controllable operational expenditures.

The result of running the opex model with all our recommended adjustments is presented in Table 7-38. We have maintained the original SPA forecasts for taxes/leases and insurance in modelling our recommendations and determining proposed variations. The adoption of all our recommendations results in total forecast controllable opex for the 6-year regulatory period of $416.4m (real 2007/08 dollars), a reduction of $28.9m from the SPA submitted forecast for controllable operating forecasts of $445.3m.

Table 7-38 – PB-recommended controllable opex forecast expenditures

Expenditure $m (real)	08/09	09/10	10/11	11/12	12/13	13/14	Total
Submitted	69.441	71.858	74.123	75.417	76.621	77.831	445.291
Proposed variation	(3.530)	(3.738)	(4.475)	(5.292)	(5.495)	(6.358)	(28.888)
PB recommendation	65.911	68.120	69.647	70.125	71.127	71.473	416.403

Source: PB analysis

185 The review of Inventory costs can be found in Section 6.3.3 of this report.

8. SERVICE STANDARDS

The service target performance incentive scheme established by the AER has an objective to assist in the setting of efficient capital and operating expenditure allowances by balancing the incentive to reduce actual expenditure with the need to maintain and improve reliability for customers. This objective is met by establishing appropriate parameters to be included in the scheme and by settings appropriate values for targets and other attributes of the scheme.

The parameters forming the service target performance incentive scheme were fixed prior to the time when SP AusNet (SPA) was required to submit its Revenue Proposal. In this section, we review SPA's proposed values for these parameters, including recommending appropriate targets, collars, caps and weightings.

8.1 GUIDELINE

In 2007, the AER released a guideline *Service target performance incentive scheme* (the STPIS Guideline). The STPIS Guideline sets out the treatment of service standards in each TNSP's revenue cap decision:

- For SPA, the performance parameters are:
  - total circuit availability
  - transmission circuit availability for critical circuit elements at peak periods
  - transmission circuit availability for non-critical circuit elements at peak periods
  - transmission circuit availability critical circuit elements at intermediate periods
  - transmission circuit availability non-critical circuit elements at intermediate periods
  - frequency of 'off-supply' events
  - average outage duration.
- SPA must propose values for targets, caps and collars.
- Performance history over the last 5 years is to be used to set performance targets, but modified to take into account the impact that the proposed capex programs allowed for in the revenue cap may have on performance, statistical outliers and material changes in regulatory obligations.
- A proposed cap and collar may result in symmetric or asymmetric incentives.
- The weighting given to each performance parameter within the incentive scheme must in aggregate place 1% of revenue at risk.

The objectives of the service target performance incentive scheme are set out in clause 1.4 of the STPIS Guideline. These require that the incentive scheme should:

- contribute to the achievement of the national market objective
- be consistent with principles in NER clause 6A.7.4(b)
- promote transparency in: (1) the information provided by a TNSP to the AER and (2) the decisions made by the AER
- assist in the setting of efficient capital and operating expenditure allowances in its transmission determination by balancing the incentive to reduce actual expenditure with the need to maintain and improve reliability for customers.

In undertaking this review we have assessed the proposed values for targets, collars and caps against these objectives.

8.2 SPA'S REVENUE PROPOSAL

The performance parameters for SPA, as specified in the STPIS Guideline, are the same as those in its last revenue cap determination. The AER has advised that the incentive scheme will continue in the next regulatory period, except that the parameters for circuit availability should include transmission outages for customer and third-party-related works on the shared network. These works, managed by VENCorp, are currently not included in the scheme. SPA has included this variation in its Revenue Proposal. The variation will place SPA on the same reporting basis as other TNSPs.

SPA has also included variations to cap the impact of some events (at 7 days) and to exclude a range of events from the scheme. New weightings for the parameters are proposed.

SPA's proposed targets and weightings for each of the parameters, are set out in Table 8-1. Definitions for the terms used in the performance parameters can be found in Appendix Q.

Table 8-1 – SPA's proposed targets and weightings

Parameter	Unit of proposed target	Proposed target	Proposed weighting %
Circuit availability — total	%	98.68	20
Circuit availability — peak critical	%	99.28	20
Circuit availability — peak non-critical	%	99.36	5
Circuit availability — intermediate critical	%	98.49	2.5
Circuit availability — intermediate non-critical	%	98.62	2.5
Loss of supply events > 0.05 system minutes	number	4	12.5
Loss of supply events > 0.3 system minutes	number	3	12.5
Average outage duration — lines (capped 7 days)	hours	7	12.5
Average outage duration — transformers (capped 7 days)	hours	7	12.5

Source: SP AusNet Proposal

SPA's Revenue Proposal includes caps and collars that limit the amount of revenue at risk to 1% of the MAR. The full reward/penalty is applied at the cap/collar values such that if actual performance exceeds the cap/collar, the cumulative value of the weightings place a maximum of 1% of revenue at risk for poor performance and provide for a maximum 1% bonus for out-performing the targets.

All of the parameters contain caps and collars that are not symmetrical in that the rate at which the reward accrues is different (quicker) than the rate at which the penalty accrues.

The Revenue Proposal included rounding of targets to the nearest whole number for four parameters — the two loss of supply events and the two average outage duration parameters. SPA provided revised targets not rounded, at the request of PB. SPA also revised its target for the parameter 'loss of supply > 0.05 system minutes' to include an allowance for the impact of an increased capital works program. SPA has proposed revised targets, collars and caps as shown in Table 8-2.

Table 8-2 – SPA's revised targets and parameter values

Parameter	Unit of proposed target	Max penalty	Target	Max bonus	Weighting %
Circuit availability — total	%	98.36	98.67	98.83	20
Circuit availability — peak critical	%	98.51	99.28	99.67	20
Circuit availability — peak non-critical	%	98.78	99.35	99.64	5
Circuit availability — intermediate critical	%	97.12	98.50	99.19	2.5
Circuit availability — intermediate non-critical	%	97.49	98.64	99.22	2.5
Loss of supply events > 0.05 system minutes	number	8.64	5.64	4.14	12.5
Loss of supply events > 0.3 system minutes	number	3.63	1.32	0.17	12.5
Average outage duration — lines (capped 7 days)	hours	11.11	6.37	4.00	12.5
Average outage duration — transformers (capped 7 days)	hours	9.27	6.87	5.67	12.5

Source: SP AusNet, 24 May 2007, Calculation of the 2008/09-2013/14 service standards

8.3 PB'S APPROACH TO THE REVIEW

In undertaking this review we have:

- reviewed the rationale behind SPA's proposed targets, weightings, collars, caps and compared these with the objectives for the scheme as set out in the STPIS Guideline
- recommended targets, caps, collars and weightings to be included in SPA's service performance incentive scheme.

To inform the review, we have examined the following aspects of the proposed performance incentive scheme:

- robustness of data definitions
- soundness of the process for data collection and reporting
- confidence in the accuracy of historical data
- appropriateness of exclusions in historical data
- performance measure calculation.

We also asked for, and received, the following information from SPA:

- historical performance data for the proposed measures
- information on loss of supply events
- model used to determine the impact of forecast capex
- information about the probability distribution of network outage events
- information about the availability incentive scheme with VENCorp
- list of circuit elements, identifying critical elements and non-critical elements, as used in the Circuit Availability parameters.

8.4 DEFINITIONS

Robust definitions for each of the performance parameters are essential for repeatable outcomes. While the STPIS Guideline addresses most definitional issues, some additional clarification is required. In this section we discuss the specific definitions to be applied to SPA's performance parameters. A complete definition for each performance parameter is provided in Appendix Q.

8.4.1 Circuit availability

SPA has proposed circuit availability measures that include: (i) outages to critical and non-critical circuit elements; and (ii) outages during peak, intermediate and off-peak time periods. The STPIS Guideline requires that the definition of some terms is to be established in the transmission determination (including definitions of peak and intermediate periods, critical and non-critical circuits).

SPA defines these terms as follows:

- a circuit element is an item of primary transmission equipment including a line (whether overhead and/or underground), power transformer, phase shifting transformer, static var compensator, bus or line reactor, capacitor bank and voltage regulator, but does not include individual circuit breakers and isolators. It also does not include secondary transmission equipment such as protection equipment. SPA has provided a list of circuit elements. New circuit elements are added when they are placed in service
- a critical circuit element is identified by its likely impact on the network if an outage occurs. The list of circuit elements provided by SPA identifies whether the circuit element is classified as critical or non-critical
- a peak period applies from the first Monday in November immediately preceding 20 November, through to the first Friday in March, immediately after the 11 March. The peak period applies on weekdays between the hours of 1100 and 2200. Public holidays, weekends and any time between the hours of 2201 and 1059 are considered off-peak
- an intermediate period applies from 1 June through to 31 August inclusive, between the hours of 0700 and 2200. All weekends, public holidays and any time between the hours of 2201 and 0659 is considered off-peak
- an off-peak period is all other times (that are not a peak or intermediate period).

Circuit availability is calculated in accordance with the STPIS Guideline by taking the number of hours per annum the defined circuits are available times 100 divided by the total possible number of defined circuit hours (8,760 hours per year or part thereof).

The duration of each event is determined by taking the difference between the time at which the circuit element was first interrupted and the time that the circuit element was restored to service.[186] These times are recorded in the Maximo system.

8.4.2 Loss of supply event frequency index

SPA has proposed two parameters based on the frequency of loss of supply events: (i) for events exceeding 0.05 system minutes and (ii) for events exceeding 0.3 system minutes. Measurement is inclusive, so that all events that exceed the threshold of 0.3 system minutes are counted in both parameters.

[186] This is contrary to the SP AusNet booklet *ACCC service standards performance incentive (PI scheme)*, edition 2, 2006, p. 13. SP AusNet confirms the booklet is incorrect.

Performance is determined through an annual process of identifying loss of supply events from an examination of system incident reports. The numbers of events that exceed the frequency thresholds are then counted.

SPA calculates the system minutes associated with an event as the customer outage duration (in minutes) multiplied by the load lost (in megawatts) divided by the highest system maximum demand (in megawatts) that has occurred prior to the time of the event. For example, an outage of 100 minutes duration that interrupted 30 MW of customer load at a time when the highest system maximum demand on record was 7,900 MW would be assigned 0.380 system minutes (100 x 30/7,900).

The load lost is determined by using NEM metering and substation load data. This data is used to estimate the profile of the load over the period of the interruption by reference to historical load data. The un-served energy (load lost x duration) is calculated by integrating the estimated load profile curve. Interruptions affecting multiple connection points are aggregated when determining the number of events, that is, system minutes are calculated on the basis of events rather than connection point interruptions.[187]

The STPIS Guideline does not include a definition for system minutes; however, we understand that the methodology used by SPA to calculate this measure is consistent with industry practice.

8.4.3 Average outage duration

The average outage duration parameter is calculated in accordance with the STPIS Guideline. SPA assigns a duration to each individual circuit element outage. The duration of each event is determined by taking the difference between the time at which the circuit element was first interrupted and the time that the circuit element was restored to service (or when supply restoration was offered to the customer). The outage duration of each event is then capped at 7 days (10,080 minutes). Capping has the affect of limiting the contribution of any one event to the measure.

The average outage duration time of all events is then calculated as the sum of the event outage durations (with each event capped at 7 days) divided by the number of outage events.

8.5 DATA COLLECTION AND REPORTING

Given that data is to be used in a service performance incentive scheme, data collection and reporting must be based on robust and repeatable processes. This will ensure that valid comparisons can be made over the appropriate time period.

SPA's data collection has been subject to the AER's annual audit process. PB examined the auditor's reports for the period 2003 to 2005 and found that the audits had examined SPA's data collection and reporting processes and found them suitable.

The audits did not include data related to 'loss of supply' events, as these parameters were assigned a zero weighting in the current incentive scheme. PB examined the data collection and reporting system established by SPA for these parameters. We found the process relied on manual collation of data from internally produced system incident reports and reports to VENCorp about loss of supply events.

PB requested information about loss of supply events and were provided with a dump of information from the Maximo system that is used by SPA to record network outage events. We were able to correlate this information with the number of loss of supply events reported by SPA in its Revenue Proposal. In all cases, the calculation of the parameter matched the outage information held for that event. PB selected a year at random (2004) and audited all of

[187] SP AusNet, 14 May 2007, *Calculation of the 2008/09-2013/14 service standards*, p.14

the outage data for that year by examining the information recorded for each network outage event, determining if supply to end-users had been lost or not and whether a valid exclusion had been applied. PB found the information to have been reliably reported. PB concludes that historical data and future data collected using these processes should be suitable for use in a service performance incentive scheme.

8.6 TARGETS

The STPIS Guideline requires that targets be equal to the average performance history over the most recent 5 years (appropriately adjusted for statistical outliers, changes in the capital works program and material changes in regulatory obligations, as discussed later in this report). Targets may be based on a different time period where this is consistent with the objectives set out in clause 1.4 of the STPIS Guideline.

The historical data reported by SPA, as shown in Table 8-3, is discussed in the following sections.

Table 8-3 – SPA's service performance 2002 to 2006

Parameter	Actual performance					
	2002	2003	2004	2005	2006	Ave
Circuit availability — total	98.88	99.30	99.23	99.18	99.14	99.15
Circuit availability — peak critical	98.96	99.69	99.96	99.75	99.76	99.62
Circuit availability — peak non-critical	99.11	99.84	99.56	99.53	99.77	99.56
Circuit availability — intermediate critical	97.96	99.48	99.69	99.39	99.34	99.17
Circuit availability — intermediate non-critical	99.49	99.31	99.39	98.07	98.96	99.05
Loss of supply events > 0.05 system minutes	—	3	2	5	5	3.75
Loss of supply events > 0.3 system minutes	—	0	0	2	2	1.00
Average outage duration — lines (capped 7 days)	6.14	9.12	2.73	7.64	6.23	6.37
Average outage duration — transformers (capped 7 days)	7.50	7.66	4.86	6.64	7.69	6.87

Note: Actual performance includes the impact of (VENCorp) customer augmentation works

Source: SP AusNet, 24 May 2007, Calculation of the 2008/09-2013/14 service standards and spreadsheet AER Outage Calculation Summary.xls

8.6.1 Circuit availability and average outage duration parameters

SPA has based its proposed targets for circuit availability and average outage duration on the 5 years from 2002 to 2006. The data from 2003 has been audited though the AER's annual audit process, while the data for 2002 has not been audited.

In its audit reports, SKM noted that SPA had excluded some events due to third parties that did not meet the exclusion criterion. SKM noted that the targets for the current regulatory period had been based on data that excluded these types of events and, therefore, that it would be appropriate to continue to exclude these events when determining service performance.

PB discusses exclusion criteria in Section 8.12. It recommends that the standard exclusion criterion for third parties be applied in the next regulatory period. This recommendation represents a change to the exclusion criteria that has been applied in the current regulatory period, affecting the historical data on which targets are to be based. In its audit reports, however, SKM notes that the quantum of third party exclusions (for 2006) to be relatively small, and mostly on assets beyond the scope of the scheme.[188] Hence, PB has not made an adjustment to the targets.

SKM also identified that the standard exclusion criteria requires that shunt reactor availability should be counted in the peak time availability measure. PB notes that the ACCC had accepted that these items may be excluded from the peak and intermediate circuit availability measure. PB recommends this approach be continued, hence, no adjustment of targets is required to reflect this change to the standard exclusion criteria.

8.6.2 Loss of supply parameters

For the loss of supply parameters, SPA has based its proposed targets on the 4 years from 2003 to 2006.

No historical data is available prior to 2003 because SPA was not required to report on this measure and did not record its performance in a suitable form from which data could be derived. PB considers that the 4 years of data that is available may not include a full range of performance outcomes; specifically, that it does not contain a year of performance significantly below the average. In recognition of this risk, SPA has proposed a comparatively lower weighting for these parameters.

SPA did not specifically record whether events met the criteria for exclusion from the calculation of this measure. However, SPA provided a dump of data from Maximo and marked those 'loss of supply events' that had been reported and those that had not been reported. PB examined data about network outages for 2004 and confirmed that events had been appropriately excluded in accordance with the STPIS Guideline.

8.7 ADJUSTED TARGETS

While requiring that targets are based on average historical performance, the STPIS Guideline allows adjustments for statistical outliers, changes in the capital works program and material changes in regulatory obligations.

SPA has made adjustments to the targets for the circuit availability and loss of supply parameters to reflect changes to its capital works program and to incorporate outages due to the expected volume of customer augmentation works requested by VENCorp. Additionally, a cap has been introduced to outage events that exceed 7 days for the purposes of determining performance for the average outage duration parameter.

8.7.1 Adjustments to circuit availability targets

Adjustments to reflect changes to the capital works program are based on a bottom-up assessment of the outages hours associated with future projects (approximately 3,200 equipment items). Each project was assessed so that works causing multiple outages on the same transmission element were optimised, reducing the overall network outages to approximately 1,200 work packages. Standard outage times were established and applied. Where the equipment could be rebuilt in a new location (rather than in situ), the outage duration was reduced.

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188 SKM, 2007, *Audit of SP AusNet service standards performance reporting, performance results for 2006*, p.15

PB reviewed the formation of the work packages and the average outage times applied to the work packages. We found that:

- the estimation process was soundly structured and appropriately applied
- in allocating the calculated SPA capex outage hours to peak, intermediate and off-peak periods, SPA assumed a percentage split based on historical capex and opex outages during these periods of 3.34%, 10.88% and 85.78% respectively. PB considers that this allocation should have been based on historic capex outages only and has recalculated the allocation from the historical information provided by SPA as 1.89% for peak periods and 6.02% for intermediate periods.

As a substantial number of outage hours are associated with station rebuild project, we checked the overall allocation of outage hours for each station rebuild project and compared these to outage estimates for projects of similar size and scope[189]. Table 8-4 shows the outcome of this analysis. In PB's opinion, the assignment of outage hours was appropriate for the projects described.

Table 8-4 – Analysis of circuit outage hours for station rebuild projects

Station	Outage hours	Impact on network	Project cost $m	Assess-ment	Comment
HWPS	7,907	large	36.6	ok	Staggered replacement of 220 kV CBs. Outages to suit generator maintenance outages
KTS	6,216	large	39.6	ok	Replacement of 500 kV, 220 kV and 66 kV switchyard, extensive outage hours. Some vacant bays, and some flexibility to move. KTS is breaker and half — less outages than for other stations
TTS	8,225	large	43.7	ok	In situ replacement of (mostly) single switched transformers (2), 220 kV and 66 kV switchyards, with substantial temporary works to avoid long outages.
HWTS	2,420	medium	19.4	ok	Replacement of 500 kV CBs, extensive outage hours. Some bays are single switched and are in situ replacement
GNTS	1,423	medium	21.3	ok	Small rural station, replacement of one transformer, 220 kV and 66 kV switchyards
GTS	2,086	medium	28.5	ok	Small rural station, replacement of three transformers, 220 kV and 66 kV switchyards
RWTS	1,027	medium	29.4	ok	Small urban station, replacement of two transformers, 220 kV and 66 kV switchyards
BLTS	1,132	medium	51.9	ok	Congested urban station, in situ replacement of all transformers, 220 kV, 66 kV and 22 kV switchgear. Cost high due to all transformers being replaced
RTS	318	small	89.7	ok	Replacement with GIS adjacent to existing assets, outage hours minimal

Source: PB analysis

189 The benchmarks include information obtained on outage hours for projects reviewed in the recent Price Determination for Powerlink (QLD) and confidential information available to PB.

A similar process was used to estimate the impact of customer works. The volume of work forecast was based on the 2006 VENCorp Annual Planning Report and the distribution companies jointly produced Transmission Connection Planning Report. Circuit availability was calculated using outage plans developed to complete these projects. PB reviewed the estimation process and found that:

- the distribution companies have adopted a conservative approach in preparing their planning report. By examining previous reports, it is evident that some projects specified in the planning report are subject to deferral, replacement with non-network solutions or modification in scope.[190] PB notes that SPA has made no allowances for a reduced volume of work; however, targets are not sensitive to changes in the volume of work. For instance, reducing outage days by 5% has no material impact on the proposed targets.[191] PB notes that SPA bears the risk that the demand forecasts and assessment of new customer works may vary from that forecast by the distribution companies. Hence, PB considers it appropriate that performance targets are based on a conservative planning approach
- VENCorp's revenue proposal is now available. It proposes works that are different to those contained in the 2006 planning report used by SP AusNet. PB has examined the forecast revenue requirements of VENCorp and recommended reductions. However, targets are not sensitive to changes in the volume of uncommitted work and, hence, no adjustments have been made
- the outage duration for each forecast project has been estimated in days, based on SPA's experience. In determining the impact on circuit availability, however, each day's outage has been taken as 24 hours. In PB's view, some projects (OPGW associated with new generator connections, control schemes, wind monitoring schemes and the thermal upgrade of lines) allow the circuit element to be returned to service each night, and hence require an outage of only 8 to 10 hours per day. PB recommends that the estimated outage duration for these projects be reduced to 10 hours per day
- some 'fault level mitigation' projects (where the scope is known) have been included in the forecast, despite the proposed new exclusion criterion which allows such projects to be excluded
- in 2013, 36 days have been allowed for (unspecified) fault level mitigation projects. Given the proposed new exclusion criterion, PB recommends that this allowance be removed.

Table 8-5 shows PB's recommended adjustments to the average historical data to account for the increased customer works and capex program, while Table 8-6 shows the recommended targets.

In making these recommendations, PB notes that it has relied on the capital works projects forecast by SPA and VENCorp for the 2008/09–2013/14 period. In this report, PB has made recommendations to reduce the capex for works proposed by SPA by about 14%. These cost reductions relate to both the timing and scope of the work packages reviewed by PB.

PB has assessed the potential for a reduction in outage hours associated with its recommendations for a reduced capex program. We found that the following have no material impact on outages hours: replacement of post type CTs; replacement of SCADA; response capability; RTS scope of 220 kV circuit breaker replacement (as substantially greenfield build); and HWPS scope for post insulators, CVTs, surge arrestors and isolators. The exclusion of connection assets from the circuit availability parameters and the exclusion of planned outages from the loss of supply and average outage duration parameters means that the deferral of transformer replacements and the RTS 66 kV switchyard have no impact on the

[190] Examples are the replacement of a proposed new Terminal Station at Tullamarine with a generator at Somerton and the deferral of a transformer at Redcliffs Terminal station for a number of years.

[191] The 5% reduction was not applied to the estimates for the impact of (unspecified) generator connections and tower relocations, as these estimates were made independently of the planning reports.

incentive targets. PB concludes that the reduction in SPA capex works has no material impact on the calculation of incentive targets.

VENCorp has now released its 2007 Annual Planning Report, which indicates a significant reduction in the amount of capital works for customer augmentations required in the 2006–10 period when compared to earlier reports. As the SPA estimates of outage hours reflect the forecasts of the 2006 Annual Planning Report, some adjustments may be necessary. VENCorp has not yet revised its revenue proposal and hence PB has not been able to estimate the overall impact of this reduction in capital works on SPA service performance. Given that the proposed adjustments for customer works proposed by VENCorp are small, however, it is not expected that a reduction in capex will significantly impact the recommended targets.

Table 8-5 – Recommended adjustments to circuit availability parameters

Parameter	SPA proposed			PB recommended		
	Cust. work	SPA capex	Total	Cust. work	SPA capex	Total
Circuit availability — total	-0.049	-0.425	-0.474	0.002	-0.424	-0.421
Circuit availability — peak critical	-0.157	-0.183	-0.340	-0.079	-0.013	-0.092
Circuit availability — peak non-critical	-0.018	-0.188	-0.206	0.008	-0.043	-0.035
Circuit availability — intermediate critical	-0.072	-0.604	-0.676	0.020	-0.099	-0.079
Circuit availability — intermediate non-critical	-0.044	-0.359	-0.402	-0.021	0.073	0.052

Source: SPA spreadsheet AER Outage Calculation Summary.xls and PB analysis

Table 8-6 – Impact of adjustments to circuit availability parameters

Parameter	Historical average	Adjust for SPA and other capex	Recommended target
Circuit availability — total	99.15	-0.42	98.73
Circuit availability — peak critical	99.62	-0.09	99.53
Circuit availability — peak non-critical	99.56	-0.03	99.53
Circuit availability — intermediate critical	99.17	-0.08	99.09
Circuit availability — intermediate non-critical	99.05	0.05	99.10

Source: SPA spreadsheet AER Outage Calculation Summary.xls and PB analysis

8.7.2 Adjustments to loss of supply targets

In determining the proposed targets for the loss of supply parameters, SPA assumed that the values must be an integer and therefore proposed targets based on historical performance rounded to the next highest whole number. Rounding to whole numbers effectively moves the target away from the long term average of performance and, because the target value is small (about 4), rounding creates a material asymmetry in the scheme. For this reason, PB does not recommend that rounding be applied.

PB notes that the AER recently accepted rounding of targets for the loss of supply parameters in its Decision[192] for the Queensland TNSP Powerlink, stating that:

> *The AER notes concerns expressed in the Powerlink submission about applying values for loss of supply event measures that are not rounded to the nearest event. After considering these concerns, the AER will round the targets for these measures to the nearest whole number, which will result in a minor softening of the loss of supply event targets. The AER considers this is a minor but appropriate adjustment that recognises the achievable outcomes for these measures in any one year. The AER does not consider that rounding to the nearest whole number will substantially impact upon the incentives provided to Powerlink and will maintain robust performance targets.*

PB accepts the AER's view and has applied rounding (to the nearest whole number) to the targets, collars and caps for the loss of supply measures.

Adjustments to reflect changes to the capital works program are based on the percentage increase in outage hours determined from the bottom-up assessment described for circuit availability in Section 8.7.1. The proposed change is an increase of 126%. The adjustment assumes that there is a direct relationship between outage hours and the loss of supply events. PB considers that this assumption is reasonable. Typically on SPA's network, two network elements must incur outages simultaneously for a loss of supply to occur. If the risk of a second network outage remains the same (there is no evidence to suggest that it will vary) then doubling the duration of the outage of a network element will, on average, result in twice the number of loss of supply events exceeding the thresholds.

Table 8-7 shows the adjustments made to the average historical data to account for the increased capex program. PB notes that planned outages are not included in this parameter so that changes in the volume of customer works have no impact.

Table 8-7 – Impact of adjustments to loss of supply parameters

Parameter	Historical average	Adjust for customer works	Adjust for other capex	Target	Rounded target
Loss of supply events > 0.05 system minutes	3.75	0.00	1.89	5.64	6
Loss of supply events > 0.3 system minutes	1.00	0.00	0.32	1.32	1

Source: SPA spreadsheet AER Outage Calculation Summary.xls and PB Associates

8.7.3 Adjustments to average outage duration targets

SPA initially proposed targets for the 'average outage duration' parameters based on historical performance rounded to the next highest whole number. PB notes that the unit of measure used by SPA for the average outage duration measure is 'hours', whereas the STPIS Guideline states that the unit should be 'minutes'. At PB's request, SPA has provided unrounded values in hours from which PB calculated the incentive targets in minutes.

In determining the average of historical performance, SPA has capped the impact of each event at 7 days (168 hours). Only events in 2003 and 2006 exceeded the cap. In 2003, the NPSD to BLTS 220 kV feeder was off supply for 210 hours and in 2006, the BTS to RTS 220 kV feeder was off supply for 1,797 hours. The impact of these events was capped at 168 hours for each event.

192 AER, June 2007, *Powerlink Queensland transmission network revenue cap 2007–08 to 2011–12*, p.129

While the variability in this measure could be further reduced by lowering the cap from 7 days to (say) 5 days, PB Associates is of the view that the 7-day cap is sufficiently low in value to limit the risk to SPA of single long events.

SPA provided historical data that included capping of events at 7 days. No further changes are required to reflect the introduction of a cap.

Table 8-8 – Impact of adjustments to loss of supply parameters

Parameter	Historical average	Historical average with 7-day cap	Recommended target	
	hours	hours	hours	minutes
Average outage duration — lines	11.97	6.37	6.37	382
Average outage duration — transformers	6.87	6.87	6.87	412

Source: SPA spreadsheet AER Outage Calculation Summary.xls and PB Associates

8.8 RECOMMENDED TARGETS

Table 8-9 shows the targets recommended by PB.

Table 8-9 – Recommended targets

Parameter	Unit of proposed target	Recommended target
Circuit availability — total	%	98.73
Circuit availability — peak critical	%	99.53
Circuit availability — peak non-critical	%	99.53
Circuit availability — intermediate critical	%	99.09
Circuit availability — intermediate non-critical	%	99.10
Loss of supply events > 0.05 system minutes	number	6
Loss of supply events > 0.3 system minutes	number	1
Average outage duration — lines (capped 7 days)	minutes	382
Average outage duration — transformers (capped 7 days)	minutes	412

Source: PB analysis

8.9 RAMPING FACTORS

For the performance incentive scheme to provide an appropriate incentive to SPA, the difference between the cap and collar values should be significantly wider than the natural fluctuation in the measure that might arise due to exogenous events. Otherwise, natural variations in performance could lead to significant revenue swings and/or the cap/collar values being exceeded. To avoid this effect, the cap and collar values should ideally be about two standard deviations of the historical data, that is, if the natural variation is a normal distribution, one year in twenty would be expected to reach the cap or collar through natural variation. Use of a lesser standard deviation is not recommended, for instance, a standard deviation of 1.5 would lead to a probability of the cap/collar being reached approximately one in every seven years.

SPA has applied a cap at one standard deviation above the target and a collar value at two standard deviations below the target. It states that the asymmetry reflects the fact that performance is already high and therefore improvements are more difficult to achieve than performance reductions.

The use of standard deviations assumes that the distributions are normal, which is not possible to determine with such small datasets. Hence, a degree of caution needs to be exercised in using statistical methods to assist the setting of appropriate collars and caps.

PB notes that setting caps at two standard deviations for some measures results in the values being above 100% performance. This occurs for all of the circuit availability parameters except for the ‘circuit availability — total’ parameter, and it is therefore appropriate to set a lower cap. For these parameters, PB recommends that caps be set at one standard deviation. For all other parameters, performance is sufficiently less than 100% that a cap can be set at two standard deviations and this is recommended.

For consistency with the rounding of targets to the nearest whole value, the values of collars and caps for the loss of supply parameters have been rounded by applying two standard deviations from the target and then rounding the caps or collar to the nearest whole number. This resulted in no rounding to collars and caps for the loss of supply events greater than 0.05 system minutes and rounding of the cap from 4.31 to 4.00 for the loss of supply events greater than 0.3 system minutes.

Table 8-10 shows our recommended collar and cap values.

Table 8-10 – Recommended ramping factors for service performance parameters

Parameter	Actual performance		SPA’s proposed values			Recommended values		
	Range	Standard deviation	Collar	Target	Cap	Collar	Target	Cap
Circuit availability — total	0.42	0.16	98.36	98.67	98.83	98.41	98.73	99.05
Circuit availability — peak critical	1.00	0.39	98.51	99.28	99.67	98.76	99.53	99.92
Circuit availability — peak non-critical	0.73	0.29	98.78	99.35	99.64	98.95	99.53	99.81
Circuit availability — intermediate critical	1.73	0.69	97.12	98.50	99.19	97.71	99.09	99.78
Circuit availability — intermediate non-critical	1.41	0.58	97.49	98.64	99.22	97.94	99.10	99.68
Loss of supply events > 0.05 system minutes	3	1.50	8.64	5.64	4.14	9	6	3
Loss of supply events > 0.3 system minutes	2	1.15	3.63	1.32	0.17	4	1	0
Average outage duration — lines (capped 7 days)	435	142	667	382	240	667	382	98
Average outage duration — transformers (capped 7 days)	170	72	556	412	340	556	412	268

Source: SPA spreadsheet AER Outage Calculation Summary.xls and PB Associates.

8.10 SELECTION OF WEIGHTINGS FOR EACH PARAMETER

The overall amount of revenue at risk under the incentive scheme is 1%. Of this, SPA has proposed weightings that placed one half of the revenue at risk for parameters related to security of supply (spread across a number of circuit availability measures) and the remainder allocated equally to parameters related to reliability of supply (two loss of supply event measures) and operational response (two outage duration measures).

PB considers that the following factors are important in setting appropriate weightings:

- weightings should provide a material incentive. With the aggregate incentive set at 1% of revenue, a parameter specific weighting of less than 10% of the total revenue at risk is considered to be too weak to provide an incentive[193]
- the parameter 'loss of supply greater than 0.3 system minutes' should be allocated the highest weighting so as to match transmission customers' high expectations regarding reliability of supply
- circuit availability on critical feeders should be weighted higher than for non-critical feeders in order to meet the principles of the NER part 6A relating to providing an incentive to improve/maintain reliability to elements important to spot prices
- circuit availability on feeders at peak times should be weighted higher than at off-peak times in order to meet the principles of the NER part 6A relating to providing reliability at times of greatest value to users.

PB notes that SPA will have revenue at risk on the reliability of supply parameters for the first time. While consumers typically value reliability above security of supply, SPA states in its Revenue Proposal that its reliability performance is already very good, being better than all other Australian TNSPs. Additionally, as noted previously, only 4 years data is available for the loss of supply parameters and the data may not include a year of performance significantly below the average. SPA proposes to adopt a lower weighting factor in recognition of this risk. PB considers that this is a reasonable approach. It is therefore appropriate to place less revenue at risk on this parameter than on circuit availability.

The recommended weightings are shown in Table 8-11.

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193 Where the parameters are not independent, weightings for a sub-measure can be less than 10%. For instance, a circuit availability parameter for feeders may be set at 5% and a circuit availability parameter total (including all equipment) may be set at 25%. Under this arrangement, a feeder outage would incur a 30% penalty (5 plus 25).

Table 8-11 – Recommended parameter weightings

Parameter	SPA proposed weighting	Recommended weighting
Circuit availability — total	20	20
Circuit availability — peak critical	20	20
Circuit availability — peak non-critical	5	5
Circuit availability — intermediate critical	2.5	2.5
Circuit availability — intermediate non-critical	2.5	2.5
Loss of supply events > 0.05 system minutes	12.5	12.5
Loss of supply events > 0.3 system minutes	12.5	12.5
Average outage duration — lines (capped 7 days)	12.5	12.5
Average outage duration — transformers (capped 7 days)	12.5	12.5

Source: SP AusNet Proposal and PB analysis

8.11 CONSIDERATION OF THE VENCORP AVAILABILITY INCENTIVE SCHEME

SPA's Network Agreement with VENCorp provides for rebates to be paid to VENCorp when network elements are not available for service. Because the scheme applies a financial incentive based on network performance, there exists a potential for the rebate scheme and the service target performance incentive scheme to conflict.

SPA state[194] that the characteristics of the rebate scheme are:

- the calculation of the rebate is carried out for each circuit element and reflects the time of day and time of season. Hence, the rebate rates are reflective of the potential impact faced by network users whenever SPA removes a network element from service
- the scheme incorporates liability limitations and rebate payment capping. SPA's total liability under the current scheme is capped at $12.0m per annum (real, $2003/04). A value of around $6m (real, $2003/04) is targeted and included in SPA's revenue forecasts. There is also a cap per event of $1m (real, $2003/04)
- some outage events (such as those requested by third parties) are excluded from the scheme
- SPA is compensated via its regulated revenue for the expected rebate value associated with outages. The annual value is included as a component of the opex forecasts. SPA's financial exposure is in relation to the variance from predicted availability that may occur.

Conflicts between the schemes may occur if opposing cost signals are provided; however, PB is of the view that the schemes do not conflict.

PB examined the schemes and found that the key attributes of the schemes are aligned, including definitions for circuit elements, critical and non-critical elements, peak and intermediate and off-peak times. The exclusion criteria, while not the same, lead to similar events being excluded.

194 SPA Revenue Proposal, Appendix B, p.2-3.

We found that the value of incentives varied between the schemes with the rebate scheme providing a finer targeting of incentives on services that customers value than the broader-based service target performance incentive scheme.[195] We did not find, however, any instances where the schemes provided opposing cost signals.

8.12 ADDITIONAL EXCLUSION CRITERIA FOR THE 2009–13 PERIOD

The STPIS Guideline contains 'standard' exclusions that exclude the impact of certain events from the calculation of the parameters. The guideline provides that SPA may propose additional exclusions in its Revenue Proposal. For the next regulatory period, SPA has proposed to exclude an additional eight types of events from the action of the scheme.

Additionally, the exclusions applied by SPA in determining its performance for 2002 to 2006 were as set out in Appendix G of its revenue cap determination. These exclusions were not accepted by ACCC and do not align with those contained in the STPIS Guideline.

Each of these inconsistent or new exclusion categories is discussed below, while Table 8-12 provides a summary of our recommendations.

Table 8-12 – Recommended changes to standard exclusions

Exclusion	Type	PB recommendation
Shunt reactors	Current	Accept
Third party	Current	Reject
Voltage control	Current	Accept
Fault-level mitigation works	New	Revise and accept
Line up-rating	New	Reject
Interconnector upgrades	New	Reject
Switchyard busbar up-rating	New	Reject
Brunswick to Richmond 220 kV planned maintenance cable outages	New	Reject

Source: SP AusNet, 14 May 2007, Calculation of the 2008/09-2013/14 service standards

Shunt reactors (currently applied)

For circuit availability peak critical and peak non-critical parameters, outages on shunt reactors (during peak periods) are currently excluded. PB considers that this exclusion is reasonable, given that shunt reactors are typically not required to be in service during peak periods.

195 The rebate scheme provides variable rebates for each circuit element based on the criticality of the element to the network. It relies on network modelling to determine incremental cost of an outage to customers should a second contingency event occur. Hence, it is considerably more complex to set up and maintain.

Third party (currently applied)

SPA has modified the standard exclusion for third parties to include:

- any outage requested by a third party for construction or demolition activities on land over which the TNSP has an easement
- outage requests on a third-party system.

The first change represents an extension to the standard exclusion and was proposed by SPA at the last revenue cap determination. Although the ACCC rejected the proposal, SPA has applied the criterion in the current period.

PB concurs with the ACCC's view that the timing of construction and demolition activities can be influenced by SPA and that the incentive scheme should therefore apply. PB recommends that this exclusion criterion should not apply in the next regulatory period.

The second change is consistent with the standard third-party exclusion, which states:

> *Exclude from 'circuit unavailability' any outages shown to be caused by a fault or other event on a '3rd party system' e.g. intertrip signal, generator outage, customer installation (TNSP to provide list).*

It is unclear why SPA have specifically included the additional words '*outage requests* or other event on a third-party system'. PB is of the view that they do not help to clarify the definition. PB is of the view that the standard exclusion criteria should not be varied.

Voltage control (currently applied)

SPA proposes to exclude outages that are required to control voltages within required limits, both as directed by NEMMCO and where NEMMCO does not have direct oversight of the network (in both cases only where the element is available for immediate energisation if required). This exclusion is currently applied by SPA through a more general exclusion for an outage which is requested by NEMMCO, except where the reason for that request is an act or omission of SPA.

PB considers that this exclusion is reasonable, given that SPA is required by the NER to follow such a direction of NEMMCO. The new exclusion criterion has already been included in the 'standard' exclusions set out in Appendix A of the STPIS Guideline, but has not been included in those specified for SPA. Its adoption will align the exclusion criterion for SPA with the standard criterion. PB recommends that the new exclusion criterion be adopted.

Fault-level mitigation works (new exclusion)

SPA proposes to exclude fault-level mitigation works as VENCorp has not formulated a strategy to deal with this issue and the solution chosen can have significantly different outage requirements. SPA also proposes to exclude fault-level mitigation works associated with new customer connections for the same reason.

PB concurs with SPA's view. We consider that the fault-level mitigation works are extra ordinary and that plans are not yet firm enough that a reasonable estimate of the impact of the works can be determined. Hence, PB considers that this exclusion criterion is reasonable.

We note that two projects involving fault-level mitigation works have been identified and are included in the adjustments of targets to reflect the forecast capex program. These are:

- JLTS 220 kV Fault Limiting Reactors and Fault Level Mitigation Works at JLTS and MWTS
- WMTS 66 kV Bus Tie Series Fault Limiting Reactor.

We recommend that the criterion be revised to specifically exclude these projects from the criterion.

Line up-rating (new exclusion)

Line up-rating where replacement of line conductors is required has a significant effect on circuit availability and as there is none forecast for the next reset period SPA proposes to exclude outages for this work if a line up-rating is requested by a customer.

PB is of the view that SPA should bear the risk that customer-requested works vary from that forecast. PB recommends that this exclusion criterion not be adopted.

Interconnector upgrades (new exclusion)

Interconnector upgrades are generally very large projects with substantial outage requirements. No projects of this nature are specifically forecast by VENCorp so SPA proposes to exclude this work category rather than attempt to make a provision.

For the reasons detailed above in 'line up-rating', PB recommends that this exclusion criterion not be adopted.

Switchyard busbar up-rating (new exclusion)

Works required to up-rate a busbar rating for fault level or normal current are to be excluded as the outage requirements for this work may be significant depending on the station configuration. As there is no definite forecast works SPA proposes to exclude this work category rather than attempt to make a provision.

For the reasons detailed above in 'line up-rating', PB recommends that this exclusion criterion not be adopted.

Brunswick to Richmond 220 kV planned maintenance cable outages (new exclusion)

SPA proposes to carry out planned maintenance work on its Brunswick to Richmond 220 kV cable over the forthcoming regulatory control period. The asset is underground and has to be excavated for such work to proceed. SPA claims that those years containing such work would have maintenance outages materially above the historical average and therefore proposes to exclude such outages from the action of the incentive mechanism.

The cable joints have been failing before their expected technical life and the replacement program involves the replacement of six joints per annum over the 6-year regulatory period. As discussed in Section 7.4.3, the need for replacement has been established.

Only one parameter, the 'circuit availability – total' parameter, is likely to be affected by the planned outages associated with the joint replacement program. This is because planned outages are specifically excluded from the loss of supply and average outage duration parameters and, given the importance of the BTS-RTS cable during peak and intermediate periods, the planned work would most likely be performed in off-peak periods.

PB notes that the STPIS Guideline does not allow incentive targets for circuit availability parameters to be adjusted for changes in the amount of maintenance work. Nor does the guideline contain specific exclusions for the failure of equipment to reach its technical life. PB considers that it is not unreasonable to expect a TNSP to carry the risk that equipment requires more or less planned maintenance than envisaged at the time of purchase. For this reason, PB recommends that the proposed exclusion criterion not be adopted.

8.13 SUMMARY

SPA proposed targets, caps, collars and weightings for the nine service performance parameters specified by the AER in its guideline *Service target performance incentive scheme*. As allowed by the guideline, the targets were based on historical performance, adjusted for the forecast SPA capex work program and the inclusion of customer augmentation works forecast by VENCorp and the distributors.

In its review, PB found that the adjustments for the circuit availability parameters had been based on the assumption that all outages were for a duration of 24 hours. As some circuits can be returned to service overnight, PB reduced the outage hours associated these works. Additionally, outage hours for fault-level mitigation works had been inappropriately included (as they meet the proposed exclusion criteria) and were removed. The allocation of estimated outage hours associated with capex works to peak, intermediate and off-peak periods was found to be incorrectly based on historical capex and opex outages during these periods and was recalculated on historic capex outages only. These changes result in higher targets for the five circuit availability parameters. PB accepted the proposed targets for loss of supply and average outage duration parameters.

SPA had proposed caps at one standard deviation above the targets and collars at two standard deviations below the targets. In PB's view, the caps should be set at two standard deviations above the targets unless this results in a cap being above 100% performance. This occurs for all of the circuit availability parameters except for the 'circuit availability — total parameter'. For these parameters, PB recommends that caps be set at one standard deviation. For all other parameters, performance is sufficiently less than 100% that a cap can be set at two standard deviations and this is recommended.

The weightings proposed for each parameter were found to be appropriate.

For the next regulatory period, SPA has proposed to exclude an additional eight types of events from the action of the incentive mechanism. Exclusions relating to shunt reactors, voltage control, and fault-level mitigation works (revised to exclude only unspecified works) seem reasonable. PB recommends that five criterion relating to third parties, line up-ratings, interconnector upgrades, switchyard busbar up-ratings, and the Brunswick to Richmond cable, be rejected.

In summary, we recommend that the values for the nine performance parameters shown in Table 8-13 be included in SPA's performance incentive scheme.

Table 8-13 – Recommended performance incentive scheme

Measure	Unit	Max penalty	Start penalty	Target	Start bonus	Max bonus	Weighting (%)
Circuit availability — total	%	98.41	98.73	98.73	98.73	99.05	20
Circuit availability — peak critical	%	98.76	99.53	99.53	99.53	99.92	20
Circuit availability — peak non-critical	%	98.95	99.53	99.53	99.53	99.81	5
Circuit availability — intermediate critical	%	97.71	99.09	99.09	99.09	99.78	2.5
Circuit availability — intermediate non-critical	%	97.94	99.10	99.10	99.10	99.68	2.5
Loss of supply events > 0.05 system minutes	number	9	6	6	6	3	12.5
Loss of supply events > 0.3 system minutes	number	4	1	1	1	0	12.5
Average outage duration — lines (capped 7 days)	minutes	667	382	382	382	98	12.5
Average outage duration — transformers (capped 7 days)	minutes	556	412	412	412	268	12.5

Source: PB analysis

CONCLUSIONS

PB has been engaged by the AER to conduct a review of SPA in support of the AER undertaking its revenue determination assessments. This work has involved conducting a review of SP AusNet's past and forecast capital expenditure (capex), its operational expenditure (opex) and its service standards proposals.

Through its assessment of the historic (ex-post) and forecast (ex-ante) expenditure proposals for both capex and opex, PB has been able to formulate an independent view on the prudency and efficiency of the past expenditure and also the reasonableness of that proposed for the forthcoming regulatory period.

In this independent review of the SPA expenditure proposals PB has considered, examined and provided its expert opinion, on the following items and expenditure categories:

- capital governance framework, processes and investment decision making
- high-level benchmarking and comparative analysis
- historic (ex-post) network capex over the current regulatory period
- forecast (ex-ante) network capex
- historic and forecast non-system capex (e.g. IT, vehicles, 'support-the-business' costs etc.)
- forecast operational expenditure (opex)
- service standards.

The process adopted by PB in undertaking this review involved presentations, a series of meetings between PB and SPA to discuss detail on opex, capex (system and non-system) and service standards, detailed technical reviews on a number of selected individual projects and internal analysis and deliberation by the PB team.

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

In this section we set out PB's key conclusions arising from the independent review of the SPA revenue proposal.

CAPITAL GOVERNANCE AND INVESTMENT DECISION MAKING

As part of the review, and through the detailed project reviews, PB has examined the processes and systems associated with SPA's investment decisions and the management of its transmission assets. PB makes the following observations regarding SPA's governance processes and systems:

- SPA has well structured and well documented policies and processes to support its core transmission service provision role, and the responsibilities and accountabilities within the business are clearly defined

- typical of a well governed, integrated corporation, SPA has a business structure and has established a number of committees to appropriately support its asset management and investment approval and decision making processes

- SPA's processes and practices are highly conscious of the regulatory framework within which it operates and attempts to address its regulatory needs as an integrated aspect of its operations

- given SPA's management oversight, its AtoP approval thresholds, its detailed procurement manual and its capex optimisation and prioritisation process, PB considers the internal framework is effective at capturing capex and opex efficiencies

- SPA's project execution tracking process is contemporary and auditable, but has not necessarily precluded some projects running over budget and examples of poor project management.

PB makes the following observations regarding SPA's asset management strategy:

- SPA's asset management strategy is contemporary and fosters a strong incentive for continual improvement, evidenced by SPA seeking an independent benchmarking review of its AMS

- the detailed use of quantitative risk modelling and assessment processes is of a very high quality and in PB's opinion would be close to best practice; the capability of SPA to systematically identify individual asset risk and track its network, program and asset risk profiles over time is to be commended

- SPA's risk model application is highly focussed on the probability of failure aspect of the risk and as the model evolves improvements could be made to the treatment of failure consequences

- SPA has gone to reasonable lengths to advise that the detailed risk model outputs form only one input to its detailed engineering and economical assessments, and this is consistent with the evolving status of the models, however this also leads to the widespread use of 'engineering judgement' that is less transparent when considering the need and basis for investment

- SPA's economic evaluation practices are reasonable, however the assessment methodology is not well documented, and seems open to individual opinion on how to undertake assessments and errors. SPA appears to be addressing this issue through the use of standardised evaluation spreadsheets.

PB makes the following observations regarding SPA's co-ordination with other parties:

- the separation of responsibilities for asset management and replacement and augmentation of transmission in Victoria, appear to have highly focussed each business to their respective functions

- it is not clear how VENCorp and SPA co-ordinate or consistently apply the probability of failure information developed by SPA through its detailed asset risk models into the respective planning processes

- SPA interacts with VENCorp and other connected parties on a regular basis to ensure optimisation and efficiencies in capex plans are captured, and this is generally undertaken on a project by project basis

- the use of modern equivalents and co-ordinated augmentation/replacement projects are apparent and appear to be effective and efficient

- SPA's internal processes explicitly recognise and capture the flexibility required during iterative negotiations with connected parties, with an objective of ensuring a holistically efficient approach to network investment.

HIGH-LEVEL BENCHMARKING AND COMPARATIVE ANALYSIS

As part of this review PB has undertaken some high level comparative analysis and has reached the following conclusions.

The expenditure levels proposed by SPA (and VENCorp), in the main, compare reasonably with TNSPs expenditure in other jurisdictions.

However, there are indications that SPA' replacement capex alone is relatively high. A further exception to this are the comparisons which involve substation numbers where the relatively few, comparatively large, substations in Victoria, lead to the 'capex per substation' measures being high. The combined SPA/VENCorp operating expenditures benchmark well against other TNSPs, with the combined Victorian transmission business showing below average costs in all benchmark categories – again, with the exception of those comparisons involving substation numbers.

Nothing in the high-level benchmark study leads PB to believe that the expenditure levels proposed by SPA are considerably out of line with what might reasonably be expected when compared with other Australian TNSP businesses. This statement is made in the context of PB recognising the inherent difficulties in attempting to accurately compare TNSP performance (especially given the unique arrangements in Victoria).

PB's high-level, age-based, replacement analysis suggests that the proposed ex-ante capex expenditure is higher than would otherwise be anticipated given SPA's stated approach to asset management, and their relatively sophisticated approach to asset risk modelling.

PB's high level analysis on indicative replacement capex based purely on asset age would lead us to expect that the ex-ante capex proposal ought to be in the range of $650m to $830m, and probably about $750m.

Against this expectation, SPA has proposed a total network ex-anti capex of $795.3m. While SPA's proposed figure is within the expected range, it falls slightly above the middle of the upper end of these estimates. If SPA's asset management approach was purely based on asset age, this result could reasonably be expected. However, SPA maintains that their asset management is based on equipment condition, and not age. On this basis it would be expected to observe that the proposed ex-ante capex would fall on the lower side of the expected range. That is, condition based replacement should give savings over aged based replacement. Based on this analysis, this would not seem to be the case. Consequently, PB is of the view that the proposed ex-ante capex expenditure of $795.3m is higher than would otherwise be anticipated given SPA's stated approach to asset management, and their relatively sophisticated approach to asset risk modelling.

Some unit costs seem a little high but PB believes that any adjustments are unlikely to materially alter the aggregate forecast capex requirement.

PB analysis of the equipments costs provided by SPA included benchmarking of items covering 78% of the forecast capital expenditure. PB found that a number of items were lower, or about the same, as the benchmarks established by PB. However, PB found that when compared to the benchmark, the costs for large power transformers and reactors were at the high end of the expected range, but not unreasonable. Finally PB found that control room building costs where higher than the benchmark by more than 20%.

Although control room building costs are higher than the benchmark, PB notes that this cost is small. As such, adjustment to this item is unlikely to materially alter the aggregate forecast capex requirement.

HISTORIC (EX-POST) NETWORK CAPEX

PB's review of a selection of SPA proposed ex-post capex projects has led to the following conclusions.

The detailed review of selected projects revealed evidence of reasonably prudent asset management through the application of appropriate investment decision-making processes.

In all cases examined by PB, a justifiable need was identified and the range of alternatives identified were reasonably comprehensive and represented practical solutions to address the identified need.

In general, the analysis of the alternatives, and the selection of the preferred alternative, was reasonable and prudent, with the preferred alternative being shown to be the least cost of the alternatives assessed that met the identified need.

While some of the project documentation does demonstrate strategic alignment with SPA's asset management strategy, overarching policies and plans, there is considerable inconsistency across the projects examined. Also, in some cases the extent of the documentation in relation to equipment condition, alternative analysis, cost–benefit analysis, and project variations was not considered appropriate for the project.

In almost all cases examined the project implementation timing was reasonable.

However, in some cases it was difficult to determine that timing was optimal due to the quality of the documentation (particularly the cost–benefit and equipment condition information). This was particularly the case for the Bendigo Terminal Station (BETS) redevelopment project.

In a number of the projects significant variations occurred during implementation.

While the standard of documentation was inconsistent, on the whole, given the nature of the projects (e.g. brownfield developments), the fact that many estimates were based on preliminary design information, and other factors (e.g. latent site conditions), these variations are not unexpected or inconsistent with prudent asset management and good industry practice.

In almost all cases examined it was clear that the project implementation was consistent with prudent asset management and good industry practice.

PB believes that the 'as commissioned costs' proposed by SPA are generally reasonable given the nature of the projects (e.g. brownfield developments, project scope, etc), the equipment and voltages involved, and the issues encountered during implementation (e.g. community requirements, latent site conditions, etc).

It is PB's view that on the balance of the available information that it is likely that SPA has been prudent and efficient with regard to the management of its ex-post capex.

Overall, while the detailed reviews did identify a number of issues, these related essentially to the quality of the documentation, as opposed to the underlying issues or analysis being presented. That is, in a number of cases the conclusions drawn in the documentation were not well supported by the documented evidence (as supplied). For example, equipment condition was asserted to be poor and reasonably beyond repair or refurbishment, however in a number of cases little corroborating evidence was presented (e.g. BETS project). Consequently, while it was difficult in some cases to find that SPA had demonstrated prudency and efficiency, from an external technical perspective, and in the broader context of this assessment (refer above), it is PB's view that on the balance of the available information that it is likely that SPA has (in general) been prudent and efficient in regards to the management of its ex-post capex.

Based on the information provided by SPA, and PB's investigations and assessments, it is PB's view that ex-post network capex expenditure proposed by SPA is, in general, timely, reasonable and efficient.

PB's recommendation on ex-post capex is summarised in Table C-1.

Table C-1 – Final recommendation for the total historic network capex to be included in SPA's RAB

Expenditure $m (nominal)	2003 stub period	03/04	04/05	05/06	06/07	07/08	March 08 WIP	Total
Proposed total	24.4	38.6	58.4	76.5	93.3	103.3	21.9	416.2
Recommended total	24.4	38.6	58.4	76.5	93.3	103.3	21.9	416.2
Adjustments total	-	-	-	-	-	-	-	-
Adjustments total %	-	-	-	-	-	-	-	-

Source: PB analysis

FORECAST (EX-ANTE) NETWORK CAPEX

PB has undertaken a detailed review of six projects within SPA's forecast ex-ante allowance. The projects have covered all project categories and all asset types and comprise 29% of the proposed capex allowance of $795m. PB's general observations from this detailed review include:

There is considerable evidence that SPA uses its detailed risk models as a preliminary and systematic tool to inform its general views.

In addition to using its detailed risk models, the reviews showed that SPA also uses good electricity industry practice and engineering judgement to capture a number of aspects within its projects not specifically addressed through the risk models – namely compliance matters, operational improvements and economical efficiencies (such as not revisiting sites frequently to undertake piecemeal works).

The risk model inputs are based on contemporary and systematic condition monitoring programs (such as oil and dissolved gas analysis, and dielectric tests) that enables the model outputs to reflect the dynamic and changing characteristics of critical plant. This fosters an environment that strongly encourages continual improvement;

SPA has presented reasonable and appropriate arguments to support the approach that run to failure is a less efficient and practical outcome compared to targeted and planned replacements.

This is based on tangible experiences after previous explosive failures where significant health and safety risks are presented and where significant premiums are incurred to repair and replace assets in emergency timeframes.

The specification of transformers for replacement purposes appears to incorporate a moderate amount of augmentation.

While this has been co-ordinated with plans presented by VENCorp and connected parties, and in some cases aligned with the strategic increase in capacity from 150 MVA to 225 MVA at metropolitan sites with high load growth, additional economical justification seems warranted in some cases.

The timing of some expenditure appears to be aggressive and PB believes that there may be a number of opportunities to prioritise tasks and prudently defer some expenditure.

As a general finding, PB has identified that the expenditure proposed by SPA has a good technical and risk based foundation, however the timing of the expenditure appears to be aggressive and there appear to be a number opportunities to prioritise tasks and prudently defer some expenditure. This needs to be considered in light of the 'wall of wire', and the trough in expenditure between 1974 and 1979.

PB believes that SPA can make better use of the assets it releases as part of the progressive redevelopment.

PB has recommended the deferral of some expenditure on the basis that SPA can make better use of the 'good condition' assets it releases as part of the progressive redevelopment and this mitigates the consequences of asset failures. The availability of additional (refurbished) spares should allow SPA to take fewer risks with plant that it identifies as deteriorating rapidly; and it is noted that SPA proposed to release a relatively new transformer at Richmond Terminal Station without discussion on its intended application.

There does not appear to be any capex allowance that should be re-classified as contingent projects.

PB has not identified any capex that is material and foreseen but unlikely to proceed based on definitive triggers.

PB's project targeted observations from this detailed review include:

There is substantiated need for replacement of CBs at Hazelwood, but the scope of works is not efficient.

At HWPS, the replacement of circuit breakers is driven by a clear need underpinned by asset failure risks, and as evidenced by historic events. However, SPA has not demonstrated a clear basis or economic justification for the replacement of a number of other assets within the yard and PB has made a minor adjustment to the capex allowance to reflect an efficient scope of works.

There is substantiated need for rebuilding the 220 kV switchyard at Richmond, but not all elements of the proposed scope of work are prudent and efficient.

At Richmond, PB concurs that the 220 kV switchyard warrants redevelopment given its critical role in supplying the Melbourne CBD, the condition of the assets and the technically inferior configuration of the yard. However the timing, and therefore prudency of work to replace and augment the 220/66 kV transformers should be re-evaluated and coordinated with Citipower given the prospective augmentation needs, the refurbishments planned by SPA and the availability of spare units to mitigate the consequences of failure. Works concerning the 66 kV switchyard can naturally follow replacement of the transformers and should be driven by increased failure risks as the asset deteriorate.

There is substantiated need for replacing a number of high risk CTs, but SPA has been aggressive in the timing of the replacements and inefficient development of its allowance.

Concerning the targeted CT replacements (outside station redevelopments), we observed that SPA relied upon the dynamic output of the asset risk model to establish a program of CT replacements across numerous sites and at various voltage levels. This allowance was established based on life expectancy threshold of 10 years, yet we consider the outcomes of this approach are not prudent or efficient, which results in a moderate reduction in capex while still mitigating the key risks.

SPA's transformer replacements outside the station rebuilds are supported in some cases only.

In some cases, the need to replace a number of specific transformers outside the significant station redevelopment program does not appear to be substantiated and does not explicitly and appropriately consider the application of the various spares available to SPA to mitigate the risk of operational failures. In particular, the augmentation component of the Dederang transformer replacement should be co-ordinated with works proposed by VENCorp as this may have a material impact on import capability into Victoria.

Significant control and monitoring equipment (SCADA) upgrades and replacements are supported; however the need for some enhancements has not been demonstrated.

The works to replace and upgrade critical components of the control and monitoring system (SCADA) at both the control centres and various terminal stations is consistent with historical practice and prudent and reasonable given the integral role of these systems in the real time operation of the network. However, in the opinion of PB, some aspects associated with enhancements and augmentations to the system warrant further justification.

SPA's proposal for an allowance to respond to unforeseen events is inefficient.

The small and non-specific allowance proposed by SPA to allow it to respond to unforeseen issues over the 2008/09-2013/14 regulatory period appears inconsistent with the efficiency based ex-ante regulatory regime and does not mitigate any material risk given the discretionary nature and timing of much of the forecast allowance.

SPA's use of 'S-curves' to establish capex profiles may, in some cases, overstate the time at which expenditure is likely to occur.

PB is of the view that the S-curves presented by SPA for the replacement of its 220 kV CTs and for the installation of insulator strings are reasonable. However, for a key project category (major station rebuilds, which makes up over 48% of the forecast network capex), SPA has provided conflicting information regarding the s-curve it has used to transpose 'as commissioned' expenditure to 'as spent'. Potentially SPA has overstated the time at which expenditure is likely to occur.

Notwithstanding this ambiguity, we have some evidence that SPA has used an s-curve that benchmarks well against publicly available material and our internal references. On this basis, we have not recommended an overall adjustment to SPA's 'as spent' expenditure profiles.

SPA has presented limited information on the 27 S-curves it has developed and applied to its forecast projects, or the methodology adopted to determine them. Prior to the AER accepting SPA's expenditure profiles, we do recommend that SPA provides further assurances on the actual S-curves it has applied.

The cost estimating contingency factor included in station rebuild projects is not supported or efficient.

PB's recommends the removal of cost estimating contingency allowances as part of station rebuilds, affecting the forecast allowance by around $19m. Such an allowance is unwarranted and inefficient given the nature of the cost estimating process applied by SPA.

There is no basis to make high level adjustments to SPA's forecast capex allowance outside the detailed project reviews.

In light of the multi-pronged approach to PB's review, and some indications that SPA's replacement capex appears relatively high, we have no basis to recommend high level or systemic adjustments to SPA forecast capex (outside recommendations associated with the use of contingencies for the station rebuild projects).

The labour and material escalators adopted by SPA in its forecast capex are prudent and efficient.

PB's considers the once-off adjustments to costs to reflect recent increases in labour and material costs seen between 2005/06 and 2006/07 are suitable, and maintaining these in real terms over the forecast regulatory period is a reasonable, prudent and efficient outcome.

As an outcome of our detailed project reviews, and one high level adjustment to remove contingencies, PB's recommendation on an efficient and reasonable forecast capex for network investment is $676m, a reduction of 15% from the original proposal. This is shown in Table C-2.

Table C-2 – Final recommendation for SPA's total forecast network capex allowance

Expenditure $m ('as spent', real 07/08)	08/09	09/10	10/11	11/12	12/13	13/14	Total
Proposed total[1]	125.8	127.5	130.8	131.0	128.5	151.8	795.3
Recommended total	115.7	112.8	125.0	109.7	92.9	119.9	676.1
Adjustments total	(10.1)	(14.7)	(5.8)	(21.3)	(35.6)	(31.9)	(119.2)
Adjustments total %	(8%)	(12%)	(4%)	(16%)	(28%)	(21%)	(15%)

Note 1, excluding the minor adjustments proposed by SPA as part of our review for two projects.
Source: PB analysis

NON-SYSTEM CAPEX

PB's review of non-system capex has led to the following conclusions and recommendations:

Comparative analysis indicates that the total non-system capex proposal made by SPA is in line with similar businesses.

Using top-down benchmarking measures, PB found that the total non-system capex proposal made by SPA was in line with similar businesses. We reviewed the non-system expenditure against the number of staff, the RAB at the last review, average opex and average capex and determined that SPA was typically below the industry average. At a high level, PB is of the opinion that SPA's non-system capex is reasonable.

High-level benchmarking would suggest that the SPA expenditure on Support the Business is reasonable.

For Support the Business we were able to benchmark SPA against one other transmission business and found that SPA were expending an equal amount in Support the Business when using measures informed by staff numbers and value of the RAB. Given this outcome, PB is of the opinion that at a high level SPA expenditure on Support the Business is reasonable.

Some of the inventory is subject to annual turnover and should therefore be removed from the value for capitalised spares.

PB found that SPA has included normal stores items that under accounting practice should be written down rather than capitalised. PB conducted an ex-post review of the inventory and from information supplied by SPA identified that approximately 10% of the inventory is turned-over annually. Under accounting practice, capitalised spares are not expected to be turned over on an annual basis; therefore PB recommends that 10% is removed from the proposed ex-ante inventory total. PB recommends that no change is made to the ex-post inventory total as some normal spares have been reallocated and any estimation may introduce unacceptable errors.

The non-system capex should be adjusted to account for the reduction in vehicle replacement periods.

SPA uses vehicles as part of its regulated transmission business. SPA forecast that vehicles are replaced on a 3 year basis or 100,00km. From our detailed analysis, PB noted that the average turn around of vehicles was every 5 years or 100,000km. Therefore PB recommends that the ex-ante forecast is adjusted to the historic average.

PB believes that errors in process have led to IT costs being overstated by approximately 4%.

PB conducted high level benchmarking of SPA's IT ex-post proposal against one other transmission business. From this benchmarking, we identified that SPA were expending a similar amount on IT per person as the other business. We also carried out further analysis by benchmarking using measures informed by the value of the RAB, and opex and capex levels and identified overall SPA were expending an equivalent amount.

PB has analysed the IT entry in detail and has identified three errors that overstated the IT costs by approximately 4%.

The recommendations resulting from PB's review of non-system historic capex is given in Table C-3.

Table C-3 – Final recommendation for the total historic non-system capex to be included in SPA's RAB

Expenditure $m (real 07/08)	2003	03/04	04/05	05/06	06/07	07/08	Total
Proposed total	6.3	13.1	10.8	22.5	11.2	8.3	72.1
Recommended total	6.3	13.1	10.8	22.5	11.2	6.9	70.8
Adjustments total	-	-	-	-	-	(1.3)	(1.3)
Adjustments total %	0%	0%	0%	0%	0%	(16.0%)	(2.0%)

Source: PB analysis

The recommendations resulting from PB's review of non-system forecast capex is given in Table C-4.

Table C-4 – Final recommendation for SPA's total forecast non-system capex allowance

Expenditure $m (real 07/08)	08/09	09/10	10/11	11/12	12/13	13/14	Total
Proposed total	10.0	11.7	8.6	9.1	10.5	10.0	59.8
Recommended total	9.4	11.1	8.0	8.5	9.9	9.4	56.2
Adjustments total	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(3.7)
Adjustments total %	(6.1%)	(5.2%)	(7.1%)	(6.7%)	(5.8%)	(6.1%)	(6.1%)

Source: PB analysis

FORECAST OPERATIONAL EXPENDITURE

PB has undertaken a review of the SPA past (ex-post) opex and has used this to inform an independent view on the prudency and efficiency of the forecast (ex-ante) opex – as proposed by SPA. Following our review of the opex proposal, PB has arrived at the following conclusions:

The insurance premium associated with the SPA regulated transmission assets has been incorrectly allocated. We recommend that the annual insurance premium is reduced by $1.36m (6.79%) over the next regulatory period.

SPA has advised that the allocation between regulated and unregulated assets for the next regulatory period has been forecast to be 93.21% (regulated) and 6.79% (unregulated). However, it appears from the PB review that the *total* transmission premium may have been incorrectly allocated to the regulated business, instead of just that proportion applicable to the regulated assets. Based on the proposed roll in of $118.7m of unregulated assets, PB believes that the insurance premiums in the SPA opex model should be reduced by 6.79% to reflect the percentage of unregulated assets covered by these premiums in the next regulatory period. The total reduction for the next 6 year regulatory period would be $1.36m (2007/08).

The new arrangements for the provision of operation and maintenance services in northern and western Victoria should be factored into the 2006/07 base year reference point. This would result in a reduction in opex of $2.81m (2007/08) over the next 6 year regulatory period.

A new contractor has been appointed to provide operation and maintenance services for northern and western Victoria. PB is of the view that the commencement of this new contract, at the beginning of the 2007/08 financial year, has an impact on the adoption of the 2006/07 financial year results as an efficient base year reference point for forecasting opex expenditures into the next regulatory period.

PB has calculated that this new contract would lead to a capex reduction of approximately $0.43m in 2006/07. We have used the SPA opex model to estimate the impact of this reduction (in the base 2006/07 year) in the maintenance line item and believe this to be $2.81m over the next 6 year regulatory period.

It appears that SPA has escalated some of the external contractor costs for asset works even though they are already expressed in 2007/08 dollars. This has overstated external contractor costs by $1.12m over the next 6 year regulatory period.

PB has identified an issue with the forecast external contractor expenditures as some costs are already expressed in 2007/08 dollars. Accordingly, costs already expressed in 2007/08 dollars do not need to be escalated prior to inclusion in the SPA opex model.

External contractor costs included in some projects are too high. As a result, we recommend reductions ($2.55 million) in the cost of two projects over the next 6 year regulatory period.

Whilst PB acknowledges the need for an allowance for ‘Miscellaneous Works’, we have not been able to confirm any specific costing information for these works. Hence, we recommend that the external contractor allowance for the next regulatory period is set at 1.0% of the real controllable opex included in the SPA revenue proposal[196]. PB’s recommended total allowance for Miscellaneous Works for the next regulatory period is $4.45m (real 2007/08).

In addition, PB has noted an allowance of $0.5m for forensic investigation of all joints replaced during the power cable repair project. We do not believe that these investigations are required as all joints on the cable are scheduled for replacement during the next regulatory period.

The likely average annual real increase in labour costs over the next regulatory period will be 2.11%. This would result in a reduction in the total forecast recurrent opex costs of $6.42m (real 2007/08) over the next regulatory period.

We believe that the likely outcome of the current EBA negotiations will be 5.5%. The average annual increase in total adult male full time earnings for Electricity, Gas and Water Supply workers in Victoria over the last 20 years is 4.9%. This forms the basis for the PB recommended reduction in the labour escalation rates.

PB understands that in its opex model, SPA escalates the labour component of each line item by 2.83% real. This average real labour increase was obtained from a BIS Shrapnel Report commissioned by Envestra, SPA and Multinet Gas. To determine the impact of reducing the real labour escalator, PB has adjusted the escalator (applied to the labour component in each line item in the model) to 2.11%.

The allowance for Asset Works (internal costs) should be reduced from $2.25m per annum to $2.12m per annum (2007/08). This adjustment would result in a saving of $0.76m (2007/08) over the next 6 year regulatory period.

SPA has developed bottom-up internal estimate costs for each specific asset works project. The internal estimated cost for Internal SPA costs for all projects scheduled for the next regulatory period is $12.72m (2007/08 dollars) which translates into $2.12m per annum. However, SPA does not appear to have applied this figure when forecasting its costs for the next regulatory period, instead it appears to have adopted an estimate for the 2006/07 financial year of $2.25m as the benchmark figure for the model.

196 Table 6.10.1.

PB has formed the view that as SPA has used a bottom-up approach to estimate the internal (SPA) costs for each specific asset works project, then this figure that should be included in the opex model. This would be consistent with the approach used in determining the external contractor costs for each specific asset works project. Adoption of this recommendation would result in the Internal SPA Cost forecasts being reduced from $2.25m to $2.12m per annum, representing a total saving over the next regulatory period of $0.76m (2007/08).

Inclusion of $118.7m of unregulated assets into the RAB will have a 30% smaller impact on recurrent maintenance than that suggested by SPA. This will result in a $3.98m (2007/08) opex reduction over the next regulatory period.

PB believes that as the new assets ($118.7m) being included in the asset base have a substantially higher remaining life than the existing assets forming the regulatory asset base, their recurrent maintenance requirements should be significantly lower. We estimated that the inclusion of the new assets will lead to a reduction in recurrent maintenance of some 30% below that estimated by SPA.

Based on experience in other jurisdictions, PB believes that maintenance escalation factors of approximately 30% can be expected as a result of substation and lines asset refurbishment/replacement programs, with higher efficiencies in the vicinity of 60%, resulting from secondary system replacement/refurbishment programs. We therefore recommend reducing the recurrent maintenance effort by a factor of 30% resulting as a result of rolling in of new assets. The 30% reduction results in a recommended escalation factor of 1.022 in lieu of the 1.032 factor used by SPA in its modelling.

In addition, we have not included taxes and insurance forecasts in these calculations as these costs have been estimated separately and we have assumed they incorporate the impact of the proposed asset roll in.

The allowance made by SPA for self-insurance is higher than necessary and we recommend a reduction of $6.9m (2007/08) in total over the next (6 year) regulatory period.

SPA engaged SAHA International Limited to prepare a report Evaluation of Self-Insurance Risks (Electricity Transmission) to determine the self-insurance risk premium to include in its revenue submission. We have reviewed the SAHA report and recommend that self-insurance premiums for some categories can be reduced due to the lower risk of loss and or collateral damage.

The two categories where PB has identified significant cost differences due to our view of a lower probability of asset failure are power transformers and circuit breakers. In both these instances SAHA has relied on industry average failure rates to assess self-insurance premiums. PB has reviewed SPA actual historical failure rates for these asset classes, and after taking a conservative approach to future failures has calculated considerably lower self-insurance premiums. PB also notes the substantive asset replacement programs involving both of these asset classes.

The SPA opex model does not adequately reflect the impact of the proposed asset replacement and refurbishment program when forecasting future recurrent maintenance.

The SPA opex model assumes that the maintenance effort remains constant from the base year, and only the labour component is escalated throughout the next regulatory period. This assumption appears not to account for the impact of the planned asset refurbishment and replacement capital programs, or for the asset works opex programs associated with routine maintenance effort aimed at keeping the assets in service.

To forecast the likely reduction in recurrent maintenance resulting from these replacement and refurbishment programs PB has drawn on experience gained in other jurisdictions and our professional judgement. It is our view that the replacement of aged substation and lines assets results in approximately a 30% reduction in routine maintenance effort over the medium term. This reduction is greater in the initial few years after commissioning due to the fact that some routine maintenance cycles may not commence during the period under review.

We believe future recurrent maintenance will be reduced by a total of $4.790m (2007/08) over the next 6 year regulatory period.

The adoption of our recommendation results in total forecast controllable opex for the 6-year regulatory period of $416.3m (real, 2007/08 dollars), a reduction of $28.9m from the SPA submitted forecast for controllable operating costs of $445.2m. The result of re-running the (SPA) opex model to include all of the PB recommended adjustments is presented in Table C-5.

Table C-5 – Final recommendation for SPA's total controllable opex forecast

Expenditure $m (real 07/08)	08/09	09/10	10/11	11/12	12/13	13/14	Total
Proposed total	69.4	71.9	74.1	75.4	76.6	77.8	445.2
Recommended total	65.9	68.1	69.6	70.1	71.1	71.5	416.3
Adjustments total	(3.5)	(3.8)	(4.5)	(5.3)	(5.5)	(6.3)	(28.9)
Adjustments total %	(5.0%)	(5.3%)	(6.1%)	(7.0%)	(7.2%)	(8.1%)	(6.5%)

Source: PB analysis

SERVICE STANDARDS

PB has undertaken a review of the targets, weightings and other parameter values proposed by SPA for the nine incentive parameters that form the service target performance incentive scheme. PB is able to make the following comments:

Incentive targets now include customer augmentation works, adjustments for the proposed capital works program and a 7-day cap on events impacting the average outage duration parameter.

SPA adopted a bottom up approach to making adjustments that was soundly structured and appropriately applied.

The assumptions underpinning some targets were found to be unsupported and the targets have been tightened.

In its review, PB has found that the adjustments for the circuit availability parameters were based on the assumption that all outages occurred for a duration of 24 hours. As some circuits can be returned to service overnight, PB reduced the outage hours associated these works. Additionally, outage hours for fault level mitigation works had been inappropriately included (as they meet the proposed exclusion criteria) and were removed. The allocation of estimated outage hours associated with capex works to peak, intermediate and off peak periods was found to be incorrectly based on historical capex and opex outages during these periods and was recalculated on historic capex outages only. These changes result in higher targets for the five circuit availability parameters. PB accepted the proposed targets for loss of supply and average outage duration parameters.

Parameter weightings were found to be appropriate but the caps and collars have been adjusted.

SPA proposed caps at one standard deviation above the targets and collars at two standard deviations below the targets. In PB's view, the caps should be set at two standard deviations above the targets unless this results in a cap being above 100% performance. This occurs for all of the circuit availability parameters except for the 'circuit availability – total parameter'. For these parameters, PB recommends that caps be set at one standard deviation. For all other parameters, performance is sufficiently less than 100% that a cap can be set at two standard deviations and this approach is recommended.

Of eight additional exclusions, only three have been found to be appropriate.

SPA proposed to exclude an additional eight types of events from the action of the incentive mechanism. In PB's view, exclusions relating to shunt reactors, voltage control, and fault level mitigation works (revised to exclude only unspecified works) seem reasonable. PB recommends that five criterion relating to 3rd parties, line up-ratings, interconnector upgrades, switchyard busbar up-ratings, and the Brunswick to Richmond cable, be rejected.

In summary, PB recommends that the values for the nine performance parameters shown in Table C-6 be included in SPA's performance incentive scheme.

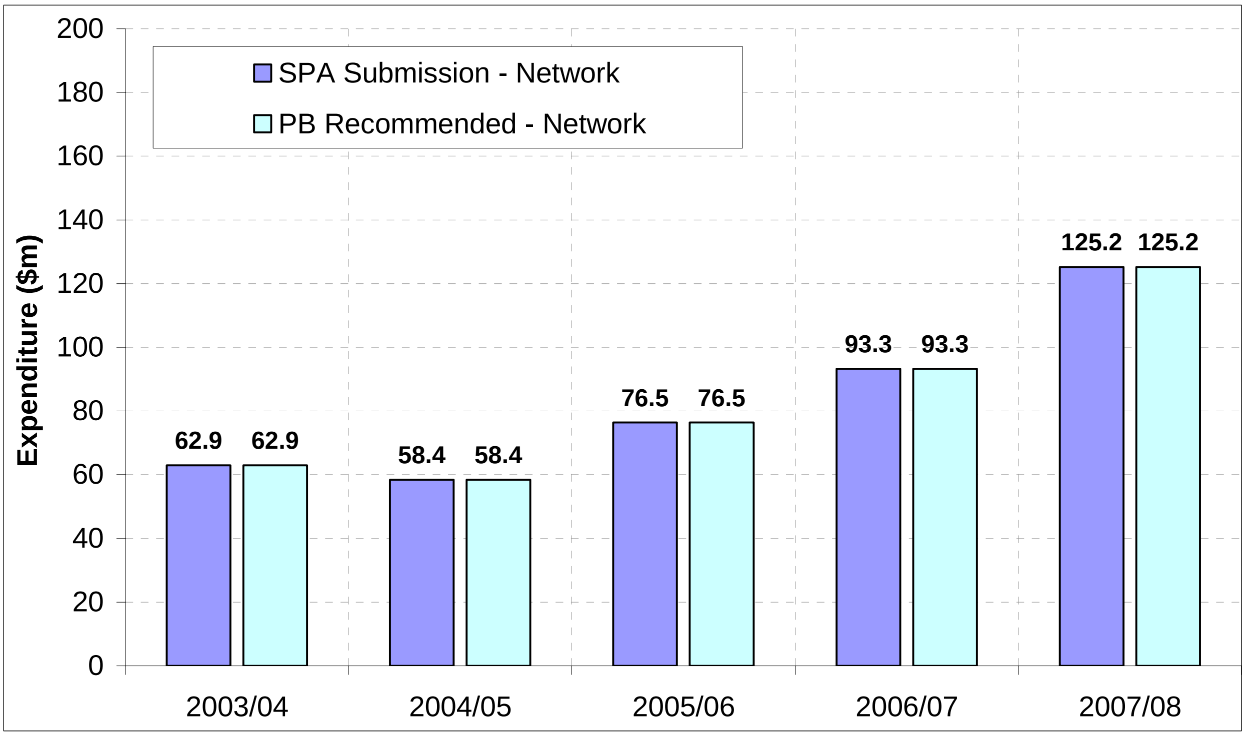
Table C-6 – Recommended performance incentive scheme

Measure	Unit	Max Penalty	Start Penalty	Target	Start Bonus	Max Bonus	Weighting (%)
Circuit Availability – total	%	98.41	98.73	98.73	98.73	99.05	20
Circuit Availability – peak critical	%	98.76	99.53	99.53	99.53	99.92	20
Circuit Availability – peak non-critical	%	98.95	99.53	99.53	99.53	99.81	5
Circuit Availability – intermediate critical	%	97.71	99.09	99.09	99.09	99.78	2.5
Circuit Availability – intermediate non-critical	%	97.94	99.10	99.10	99.10	99.68	2.5
Loss of supply events > 0.05 system minutes	number	9	6	6	6	3	12.5
Loss of supply events > 0.3 system minutes	number	4	1	1	1	0	12.5
Average Outage Duration – lines (capped 7 days)	minutes	667	382	382	382	98	12.5
Average Outage Duration – transformers (capped 7 days)	minutes	556	412	412	412	268	12.5

Source: PB analysis

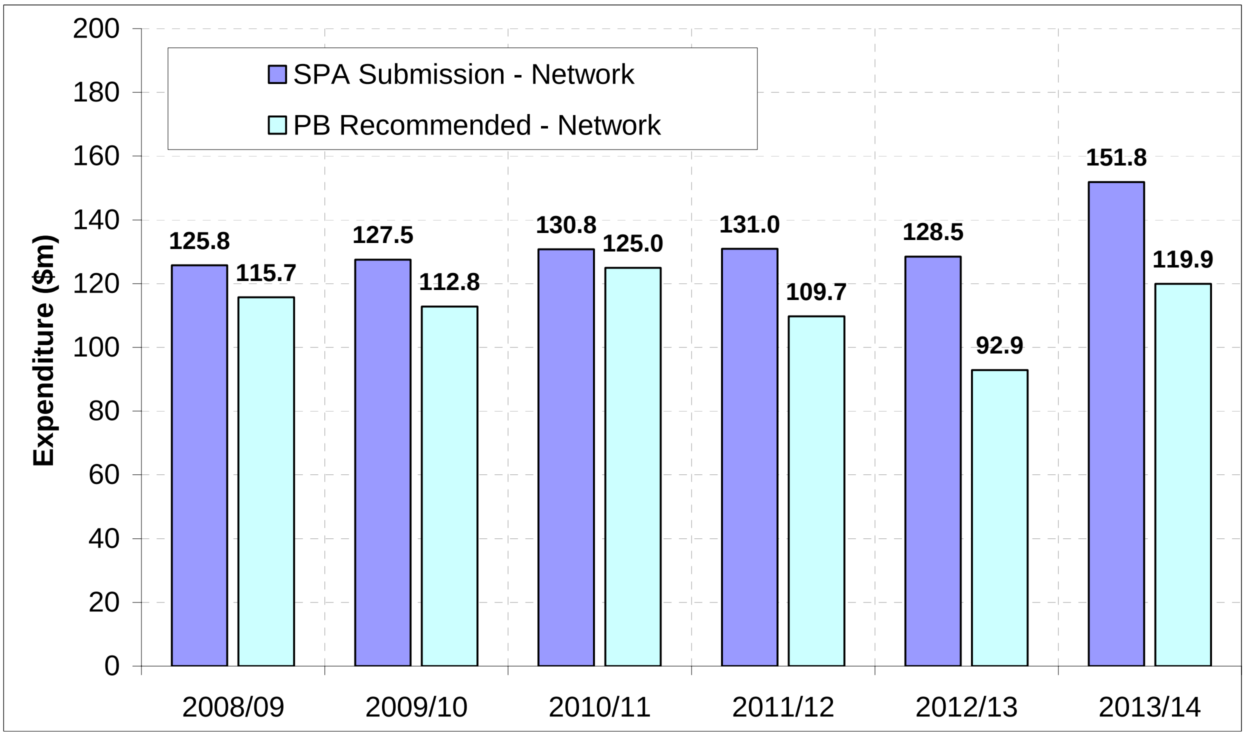
SUMMARY OF PB EXPENDITURE RECOMMENDATIONS

Figure C-1 – Adjustments to historic (ex-post) network capex ($m nominal)



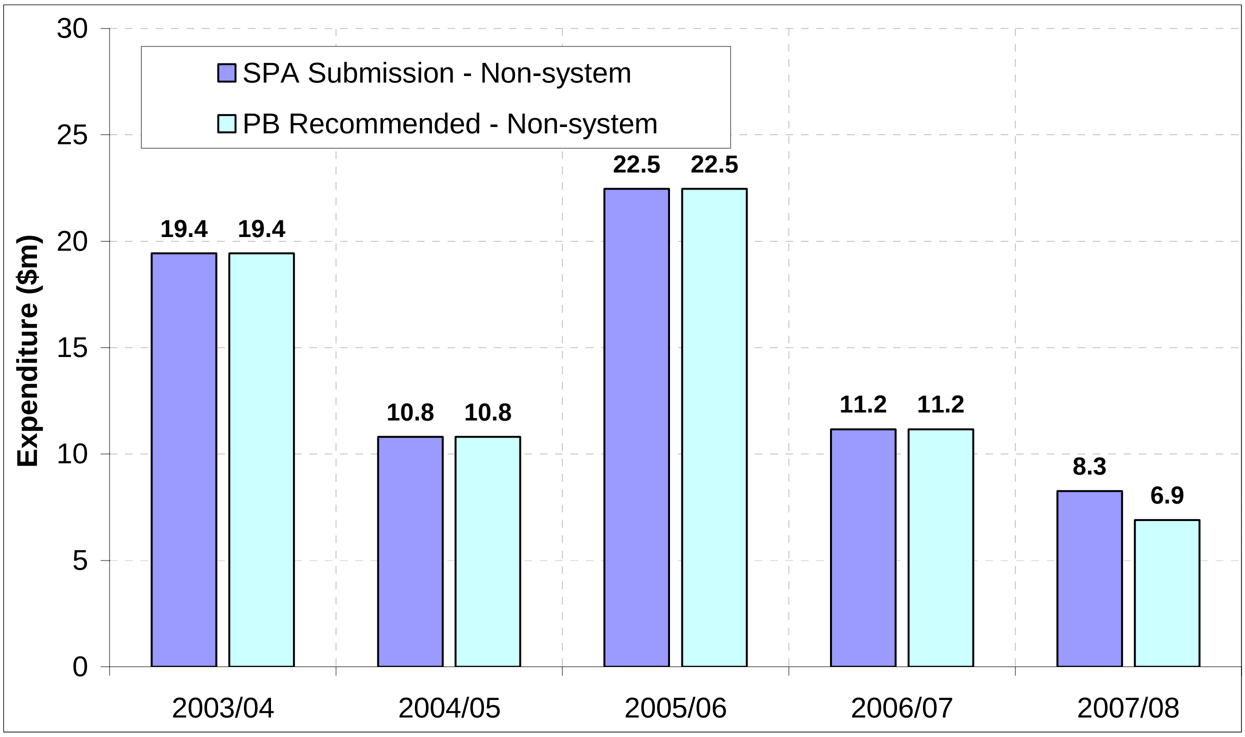
Source: PB analysis

Figure C-2 – Adjustments to forecast (ex-ante) network capex ($m real 07/08)



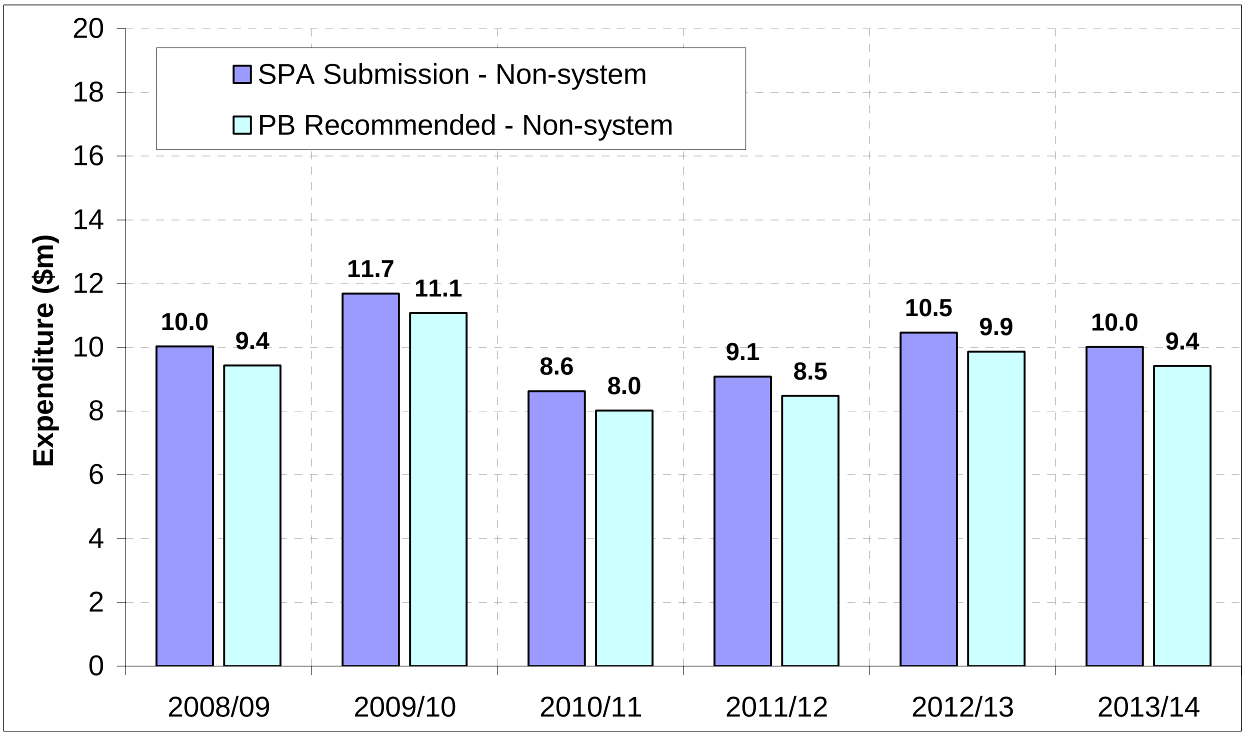
Source: PB analysis

Figure C-3 – Adjustments to historic (ex-post) non-system capex ($m real 07/08)



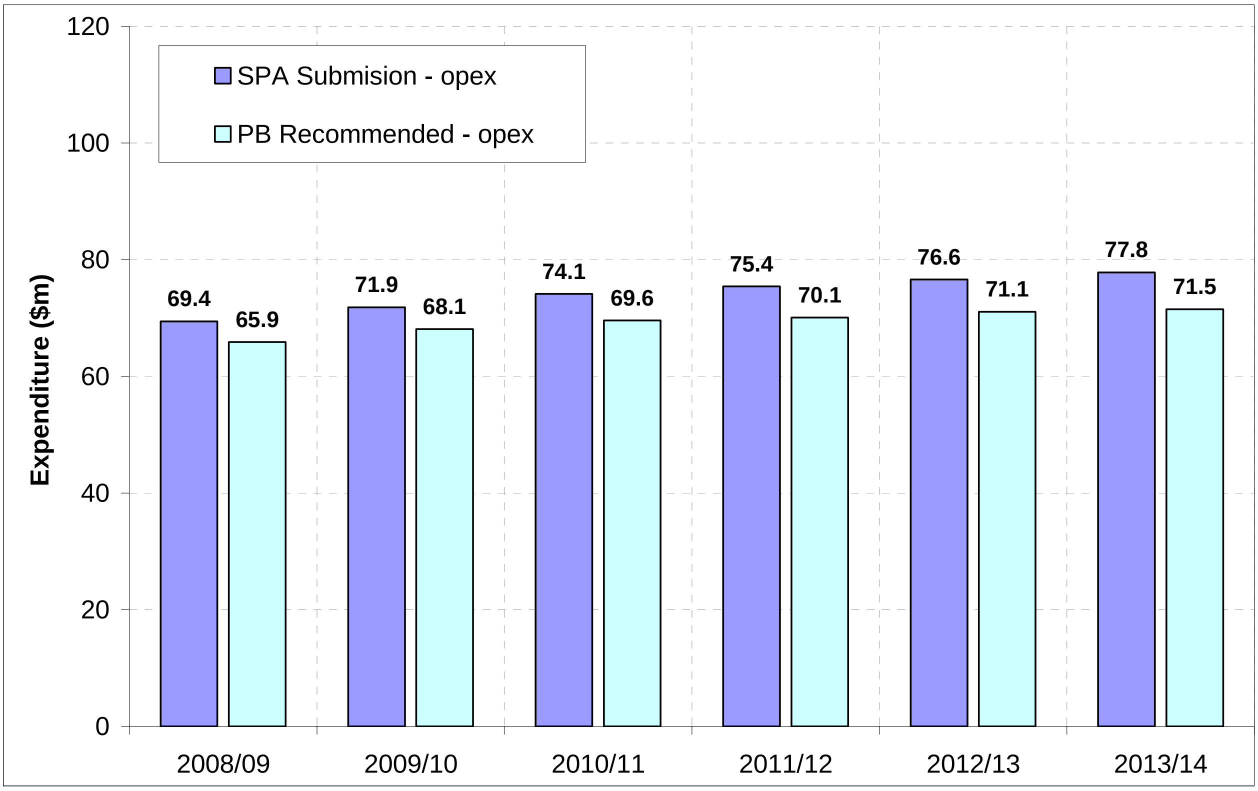
Source: PB analysis

Figure C-4 – Adjustments to forecast (ex-ante) non-system capex ($m real 07/08)



Source: PB analysis

Figure C-5 – Adjustments to forecast (ex-ante) opex ($m real 07/08)



Source: PB analysis