SP AUSNET REVENUE RESET
APPENDICES

An independent review

Prepared for

AUSTRALIAN ENERGY REGULATOR

PB Quality System:

Document Reference:	SPA2008Reset_Appendices_v5_0.doc
Report Revision :	5_0
Report Status :	Final
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Approved by :	P Williams
Date Issued :	16 August 2007

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APPENDIX A
ASSET MANAGEMENT DOCUMENTATION STRUCTURE

APPENDIX A: ASSET MANAGEMENT DOCUMENTATION STRUCTURE

As discussed in section 2.2, SPA's asset management process is supported by a documentation hierarchy with the AMS at its core Table A-1, and Table A-2, list the specific documents that form this documentation set.

Table A-1 – Summary of foundation documents

Foundation element	Document title	Reference
Business Environment Assessment	Business Environment Assessment	AMS 10-02
Process and System Strategies	Asset Management Information Systems	AMS 10-10
	Asset Replacement and Refurbishment	AMS 10-11
	Capital Expenditure Prioritisation	AMS 10-12
	Condition Monitoring	AMS 10-13
	Environmental Management	AMS 10-14
	Health and Safety Management	AMS 10-15
	Knowledge and Record Management	AMS 10-16
	Network Performance Monitoring	AMS 10-17
	Operations Management	AMS 10-18
	Plant and Equipment Maintenance	AMS 10-19
	Process and Configuration Management	AMS 10-20
	Program Delivery	AMS 10-21
	Risk Management	AMS 10-22
	Skills and Competencies	AMS 10-23
Plant Strategies	Asset Data Gathering Networks	AMS 10-51
	Auxiliary Power Supplies	AMS 10-52
	Capacitor Banks	AMS 10-53
	Circuit Breakers	AMS 10-54
	Civil Infrastructure	AMS 10-55
	Communication Systems	AMS 10-56
	Control & Monitoring - SCADA	AMS 10-57
	Diesel Generators	AMS 10-58
	Disconnectors and Earth Switches	AMS 10-59
	Earth Grids	AMS 10-60
	Fire Detection and Suppression	AMS 10-61
	Gas Insulated Switchgear	AMS 10-62

Foundation element	Document title	Reference
	Infrastructure Security	AMS 10-63
	Instrument Transformers	AMS 10-64
	Line Easements	AMS 10-65
	Power Cables	AMS 10-66
	Power Transformers and Oil-filled Reactors	AMS 10-67
	Protection Systems	AMS 10-68
	Revenue Metering	AMS 10-69
	Secondary Cabling	AMS 10-70
	Static VAR Compensators	AMS 10-71
	Station Air Systems	AMS 10-72
	Surge Diverters	AMS 10-73
	Synchronous Condensors	AMS 10-74
	Transmission Lines	AMS 10-75
	Control & Monitoring - General	AMS 10-76
	Control & Monitoring - General	AMS 10-76

Source: Introduction & Agenda Presentation; SPA 2007.

Table A-2 – Summary of implementation documents

Implementation element	Document title	Reference
	ACCC Service Guidelines - Performance Measures	AMS 10-100
	Asset Life Evaluation	AMS 10-101
	BTS -RTS 220 kV Cable	AMS 10-102
	Capacitor Bank Utilisation Rates	AMS 10-103
	Capacitor Bank Reliability Analysis	AMS 10-104
	Circuit Breaker Fleet -Planning	AMS 10-105
	Circuit Breakers - Summary of Issues and Strategies	AMS 10-106
	Communication Sites	AMS 10-107
	Digital and Analogue Comms Network	AMS 10-108
	Digital Comms Network - 2012 with ADSS Extensions	AMS 10-109
	Disconnectors and Earth Switches	AMS 10-110
	Factors Affecting Transformer Life	AMS 10-111
	IEC 61850 Draft Migration	AMS 10-112
	Levels of Condition Monitoring for Transformers	AMS 10-113
	System Code Transmitter Performance Standards	AMS 10-115
	System Operational Availability	AMS 10-118
	Transmission Network Short Circuit Levels	AMS 10-119
	Installed Power Transformers and Oil Filled Reactors	AMS 10-120
	Life of Current Transformers	AMS 10-121
	Current Transformer Condition and Issues	AMS 10-122
	Condition Monitoring System Architecture	AMS 10-124

Source: Introduction & Agenda Presentation; SPA 2007.

APPENDIX B
MALVERN TERMINAL STATION (MTS) REDEVELOPMENT

APPENDIX B: 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 B-3.

Table B-3 – 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[1]
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.

B.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)[2].

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 1950's.

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'[3].*

1 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.

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

3 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 (refer 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[4]. Following this consultation process, SPA engaged Beca Carter Hollings & Ferner ("Beca")[5] 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)[6] 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[7]. 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[8].

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.

B.2 Drivers (need or justification)

MTS is an urban 220 kV terminal station established in the early 1950's, and most major assets at the site are understood to be original equipment. In 2002, due to the age and condition of the equipment, SPA engaged Sinclair Knight Mertz (SKM) to investigate the condition, performance, and risks associated with the MTS assets. The 2002 SKM report

4 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.

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

6 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.

7 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 three (3) to 15 year planning horizon. Note that the more extensive augmentations were envisaged by Beca to be in 2008.

8 The final site layout provides for two extra 220 kV switchbays, and reduces the number of transformers to two (2) 220/66 kV, and two (2) 220/22 kV transformers of increased capacity. This arrangement provides for the future expansion of the station.

made a number of important observations relating to the equipment condition, and the likely remaining life of the assets; specifically[9]:

220 kV switchgear

The 220 kV switchgear is of the bulk oil type, manufactured in 1952 and in fair condition, although bushing failures and oil leaks are beginning to be experienced on similar breakers elsewhere in the network. Spare parts are available only from retired circuit-breakers of the same type. A remaining useful life of six years has been assigned to this equipment.

Voltage transformers (VT)

The VTs have suspect insulation but are presently covered by adequate spares. A 10-year remaining useful life has been assigned.

220/22 kV transformers

The 220/22 kV transformers are single phase transformers with a nameplate rating of 45/55 MVA, with no on-load tap-changers. Two banks were installed in 1951/52, and the third bank in 1959. The units have a number of problems including high losses (estimated at $170,000 pa), and ageing insulation. A remaining useful life of not more than 10 years was assigned.

220/66 kV transformers

The 220/66 kV transformers are single phase transformers with a nameplate rating of 45/55 MVA, with no on-load tap-changers. The units were installed between 1956 and 1958, and have a number of problems including high losses (estimated at $196,000 pa), ageing insulation, and excessive moisture content. SKM noted that these transformers, if not refurbished, have a very limited remaining useful life, and recommended that they should be considered ‘high risk’ assets.

66 kV switchgear

The 66 kV switchgear is of the bulk oil type of 1952 manufacture. These units were noted as an emerging safety risk due to an accelerating rate of failure of bushing. SKM concluded these breakers should be replaced at the earliest opportunity for safety reasons.

22 kV switchgear

The 22 kV switchgear is also of the bulk oil type and manufactured between 1946 and 1950. The switchgear was noted as not meeting modern arc fault containment specifications, and is more hazardous for personnel within the switchroom than is allowed by modern practice. Noted problems include oil leaks from welds, leaking voltage transformer (VT) tanks, bus insulation problems, bushing deterioration, deterioration of arc control chambers, eroded contact assemblies, and mechanical wear within the operating mechanisms. Spare parts are not commercially available, and any spares created through the retirement of similar switchgear are suitable only for emergencies. Any oil leaks drain into the cable tunnel, and there is no fire segregation apparent in the switchroom or in the cable tunnel. As a result of the lack of segregation, there is a risk that an oil fire could result in total loss of supply to a wide area, including four zone substations, and two railway substations. SKM considered this switchboard a significant risk given the consequences of a major failure and recommended its replacement at the first available opportunity.

9 Section 4; Assets Management Study Malvern Terminal Station; SKM, October 2002.

66 kV and 22 kV Protection and Control Systems

The MTS 66 kV and 22 kV protection relays are between 30 and 50 years old, and are at the end of their serviceable life. Relays can no longer be kept within their operating tolerances, and spare parts are no longer available. SKM recommended replacement within the next five years.

Secondary cables

The secondary cabling dates from the establishment of the station, and is in poor physical and electrical condition such that they cannot be disturbed without causing damage.

Oil containment

The 220 kV transformer compounds have bund walls but no concrete floors. This does not comply with current Environmental Protection Agency ("EPA") guidelines on bunding. Oil leakage from the 22 kV bulk oil circuit breakers is discharged into the cable tunnel without containment.

Control building

SKM reported that the three-story masonry control building shows signs of water ingress through the masonry roofing and windows.

In summary, SKM determined (in 2002) that the major equipment items at MTS were anticipated to have a remaining useful life of less than 10 years. Moreover, SKM noted that the 220/66 kV transformers, 66 kV switchgear, and 22 kV switchgear are considered high risk assets, requiring immediate attention. Based on these observations, SKM concluded that the condition of the major equipment items at MTS was such that specific action needed to be taken to ensure the future reliability of the facility.

B.3 Strategic alignment and policy support

The SPA asset management strategy has the stated aims of[10]:

- maintaining a stable and sustainable network asset failure risk profile
- meeting network reliability and availability targets
- complying with all applicable codes and regulations (e.g. OH&S, environmental, security legislation)
- optimising asset life cycle cost.

The stated need for the MTS redevelopment project relates to a number of these asset management strategy objectives. Furthermore, the MTS project documentation cites various points of alignment with SPA's asset management strategy, overarching policies and plans. In particular:

- the 220 kV switchgear at MTS was scheduled for replacement in 2007/2008 as part of the SPA asset management plan for the 62 breakers of this type on the network. In addition, this switchgear is reported as becoming maintenance intensive (average 42 man hours p.a., planned plus unplanned, across the system)[11]

[10] Section 3.2; Electricity Transmission Revenue Proposal 2008/09 – 2013/14; SPA, 2007.

[11] Assets Management Study Malvern Terminal Station; SKM, October 2002, Page 14.

- replacement of the bulk oil filled equipment at MTS minimises the risks posed by oil filled equipment within switchyards in line with SPA policy[12]
- SPA has a Substation Control and Information Management System (SCIMS) implementation strategy to migrate from the older technologies. This strategy provides a digital technology overlay at the site, which can communicate with equipment as it is replaced. The SCIMS strategy has been applied to the MTS project[13]
- the MTS rebuild provides the opportunity to upgrade the station security and fire risk management measures in line with SPA policy[14]
- SPA's asset management strategy aims to identify equipment refurbishment, repair and replacement actions in advance of potential equipment failure. SPA achieves this through assessment of the potential risk of failure for each plant item. The MTS project documentation contains a detailed consideration of the equipment condition, likely remaining life, and risk of failure[15]
- SPA's asbestos removal project aims to comply with the Occupational Health and Safety (Asbestos) Regulations 2003. The MTS project involved the removal of asbestos[16].

Alignment of the MTS project with SPA's asset management strategy, overarching policies and plans has been identified in the MTS redevelopment project documentation.

B.4 Alternatives

The SKM report[17] considered a number of alternatives to address the need identified through their investigation (see section B.2). The SKM report specifically reviewed the timing (based on estimated remaining asset life), benefits and issues related to each of the following alternatives – as set out below.

The 'do nothing' base-case

The continued operation of MTS without any planned capital expenditure. This alternative was seen to be unacceptable to SPA's customers as it would result in the following.

- continuing high scheduled and unscheduled maintenance costs
- transformer insulation failure, and attendant loss of station capacity
- an increasing frequency of forced outages resulting in higher loss-of-load compensation costs, and declining reliability of supply
- additional spare parts expenditure.

This option was not considered further.

Deferred replacement

Under this methodology, existing assets are maintained in service as long as practicable through the following.

12 Ex-Post (Capex) Malvern Terminal Station (MTS) Redevelopment X320, X467; SPA, 2007, Page 6.

13 Assets Management Study Malvern Terminal Station; SKM, October 2002, Page 22.

14 Ex-Post (Capex) Malvern Terminal Station (MTS) Redevelopment X320, X467; SPA, 2007, Page 6.

15 Electricity Transmission Revenue Proposal 2008/09 – 2013/14; SPA, 2007, Section 3.2.

16 Electricity Transmission Revenue Proposal 2008/09 – 2013/14; SPA, 2007, Page 65.

17 Assets Management Study Malvern Terminal Station; SKM, October 2002, Section 5.

- continuation of (normal) planned maintenance practices
- effective management of spare plant and components to meet the requirements of unplanned outages
- maintaining the ability to replace any faulty item of plant or component within an acceptable time period.

The consequential costs of unplanned outages, increased planned maintenance, and callouts are borne until such time as the performance of the asset has deteriorated to the extent that continued service is impracticable. It is then replaced on a one-off basis. This alternative was costed, and found to be the second lowest cost alternative. Hence it was not the preferred option.

Planned replacement on asset class basis

This option involves a program of replacement by asset type within the station, or across the network (e.g. OKG 66 kV circuit breakers). This approach was recognised as being applicable when an asset class has a higher failure rate, or greater degree of deterioration than assets of other classes. The strategy was seen as not being suited to situations where station assets are of a similar age and condition, and hence the benefits are negated by the performance, and the operating costs, of the balance of the assets. Multiple outages, repeated engineering, as well as a deterioration in the station's overall performance, were also identified as issues.

This alternative was costed and found to be the second highest cost alternative. Hence this was deemed not to represent the preferred option.

Planned asset replacement based on condition (or performance)

This approach extracts the optimum remaining life of individual assets by utilising condition monitoring and testing, restorative maintenance. Replacement (when necessary) is carried out on an individual asset-by-asset basis. SKM were of the view that this strategy was generally not suitable to older stations. The likely extent of outages required, and the cost of testing, inspection and dismantling work, was such that more a detailed assessment of this alternative was not undertaken.

Planned replacement on a staged bay-by-bay basis

This option involves replacement of all plant and equipment within a bay. The entire bay is replaced at the time when the major equipment items within the bay require replacement. In SKM's view, the MTS switch-bays were all of a similar risk profile since all equipment was of a similar age and condition. Hence this alternative was not (formally) considered further.

Replacement as part of a complete 'brown field' refurbishment of an in-service station

This option involves the replacement of assets as part of a single refurbishment project and the work is undertaken while the substation is still in service (operational). Two variations were considered in detail and costed. These alternatives were identified as option 2a and 2b, representing the use of Air Insulated Switchgear (AIS) and Gas Insulated Switchgear (GIS) respectively. The GIS alternative was found to be the highest cost alternative, the AIS brownfield alternative was the lowest overall cost alternative, and was therefore the recommended option.

Planned replacement as part of a 'green-field' development of the station

Under this (general) approach, a complete new terminal station is developed (usually to replace an ageing station) and is located on a site which is either restricted, has other demands upon it, or a site which is operationally unsuitable for brownfield refurbishment. SKM determined that there was no suitable vacant land available in the surrounding area.

Hence the greenfield replacement of MTS was deemed to be impracticable, and so was not considered further.

The relative cost benefits of the various assessed alternatives are shown in Table B-4.

Table B-4 – Summary of net benefits of alternatives ($000)

Option	NPV capital costs	NPV O&M cost	NPV Transf Loss	NPV lost load conseq Cost	NPV total Cost
Deferred replacement	24,046	3,828	2,511	3,525	33,909
Planned brownfield replacement (AIS)	27,970	1,840	1,663	2,278	33,751
Planned brownfield replacement (GIS)	37,745	1,688	1,663	2,3 16	43,412
Planned replacement by asset class	30,625	2,187	1,383	2,591	36,785

Source: Assets Management Study Malvern Terminal Station; SKM, October 2002

Based on these results, the SKM report concluded that the least cost alternative was the replacement of switchyard assets and transformers with AIS equipment under a single brownfield refurbishment project[18]. In addressing the alternatives the SKM report also took account of a number of considerations that impact upon the value of the alternatives[19], specifically:

- technological advances – the impact of technology advances since the 1960s were taken into account in considering the alternatives (e.g. dead tank circuit breakers, multifunction protective relays having data communication facilities)
- operational constraints – maintaining adequate station security during construction. SKM assumed that it is unacceptable for the N-1 security level to be lost for more than a short period during construction work
- EPA compliance – MTS is not likely to comply with EPA requirements for oil containment. Therefore oil containment was assumed necessary for all alternatives
- transformer life extension and replacement – the costs to extend the life of the transformers trough refurbishment was addressed in considering the alternatives. Consideration was also given to the benefits of using modern transformers (i.e. more compact, lower weight, significantly lower losses, lower noise levels, improved transport and craneage, thee phase capability, on-load tapchangers)
- AIS, GIS, and Outdoor Hybrid GIS Switchgear – the use of different types of switchgear was considered (where appropriate) when addressing the alternatives.

It should be noted that the SKM investigation assumed the retention of the existing switching configurations in assessing each alternative. The revision of the station configuration was outside the scope of the SKM study, but was addressed by the Beca study (discussed below).

18 SKM conducted sensitivity analysis on the various alternatives and concluded that over a 25 year study period the ranking of the options remain unchanged,

19 Section 5.2, 5.3, and 5.4 (in part); ; Assets Management Study Malvern Terminal Station; SKM, October 2002

Following SPA's acceptance of the SKM recommendations, consultation was undertaken with VENCorp, Alinta and Citipower to identify their future requirements for the station. Following this consultation process, SPA engaged Beca to consider the practicality of a brownfield redevelopment at MTS, and to consider the feasibility of station layout options that would ensure any long term augmentation requirements would not be compromised by a 'like for like' station redevelopment using the same design and configuration.

In its report[20], Beca considered a range of alternative station layouts, and concluded that a station rebuild with a staged AIS breaker-and-half[21] 220 kV switchyard development was the least cost arrangement that met the project objectives[22]. In reaching this conclusion, Beca considered five station layout alternatives to address the following issues:

- small constrained site, and inability to purchase additional adjacent land
- requirement to maintain N-1 security of supply during construction
- significant future augmentation requirements for both switchyards (in particular the future diversion of Rowville to Richmond circuits into MTS)
- unfavourable incoming circuit layout.

In addition, the Beca report considered the cost of using either a three or four transformer (ultimate) arrangement for the 220/66 kV transformation. Beca concluded that both options were technically feasible; however the three transformer arrangement offered the lowest cost solution.

In 2005 a report was submitted to the SPA Board recommending the redevelopment of MTS as an AIS brownfield refurbishment project, as the most cost effective option. The Board report also recommended, in accordance with the recommendations of the SKM and Beca reports, the following project scope of work:

- replacement of all 220 kV, 66 kV and 22 kV switchgear and associated primary and secondary equipment
- replacement of the three banks of 220/66 kV, 45/55 MVA transformers with two new 220/66 kV, 225 MVA transformers
- replacement of the three 220/22 kV, 45/55 MVA transformers with two new 40/60 MVA transformers
- establishment of a new switch-room to accommodate the new 22 kV switchgear
- establishment of a new control building.

At the May 2005 SPA Board meeting, the MTS redevelopment project was approved as submitted[23].

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

21 'Breaker and a half' refers to a substation layout which provides a method of interconnecting several circuits and breakers in a switchyard so that three circuit breakers can provide dual switching to each of two circuits by having the circuits share one of the breakers (hence a breaker and one-half per circuit).

22 Note that the Beca report does not include an economic case for this arrangement, but concludes that the recommended option was the least cost alternative that met all the project objectives.

23 SPI Powernet Board Report, SPI PowerNet – Redevelopment Of Malvern Terminal Station; 13 May 2005.

B.5 Timings

The timing of the MTS capital expenditure was based on the condition of the equipment as identified through the SKM investigation. This investigation assigned likely remaining life estimates are follows[24]:

220 kV switchgear:	remaining useful life of six years.
Voltage transformer:	remaining useful life of ten years.
220/22 kV transformers:	remaining useful life of not more than ten years.
220/66 kV transformers:	if not refurbished (see footnote 18), have a very limited remaining useful life.
66 kV switchgear:	they should be replaced at the earliest opportunity on safety grounds.
22 kV switchgear:	should be scheduled to be replaced at the first available opportunity.
Secondary systems:	the 66 kV and 22 kV protection and control systems will need to be replaced within the next five years.

In summary, SKM determined that the major equipment items at MTS were anticipated to have a remaining useful life of less than 10 years. Moreover, SKM noted that the 220/66 kV transformers, 66 kV switchgear, and 22 kV switchgear, were considered high risk assets requiring immediate attention.

The SKM report was presented in October 2002. SPA subsequently undertook consultation with VENCorp, Alinta and Citipower regarding their future requirements for the station. Following this consultation, SPA engaged Beca[25] to consider construction practicality, and station layout options. This investigation was completed with the delivery of the Beca report in July 2004. SPA Board approval for the MTS project was granted in May 2005. The MTS project is currently in progress, with an anticipated completion in early 2008/09.

B.6 PB analysis

Having undertaken detailed review of the project documentation, the following section sets out PB's view on the prudency of this ex-post capex expenditure.

Clear need

The project documentation provided by SPA identifies that the condition of the substation equipment at MTS are such that the majority of these assets are nearing (less than 10years), or are at, the end of their useful lives. Given the equipment condition information presented in the project documentation, the role of the station in supplying a major area of south eastern Melbourne, and the related OH&S and environmental risks, PB is of the view that a justifiable need was identified[26]. The documentation provided to PB by SPA is also clear in identifying alternative options and in selection of the optimum solution.

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24 Section 4; Assets Management Study Malvern Terminal Station; SKM, October 2002.

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

26 PB's view of the justification for the project (the 'need') as well as analysis of alternative solutions and selection of the optimum solution, was informed through an independent review undertaken by SKM. PB is of the view that the SKM report presented a thorough engineering analysis of the equipment within MTS, and that this analysis was sound and reasonable.

Strategic alignment

Reference is also made in the project documentation to the applicable SPA strategies, overarching policies and plans. PB is of the view that SPA has demonstrated that the MTS project aligns with relevant polices and strategies.

Alternatives

In order to address the identified need at MTS, SPA has identified and investigated a range of alternatives. In addition, SPA consulted with key stakeholders to ensure that the selected alternative would not compromise long term augmentation requirements. PB has considered the range of alternatives examined and is of the view that the alternatives identified are reasonably comprehensive and represent practical solutions to address the identified need. Furthermore, PB is of the view that the analysis of the alternatives, and the selection of the preferred alternative (AIS brownfield redevelopment), was reasonable and prudent. The preferred alternative was shown in the documentation to be least cost of the alternatives that could meet the identified need, while addressing stakeholder augmentation requirements.

The project documentation also shows that the implemented project was considerably different in scope to that originally proposed (see below for further discussion). In the May 2005 Board report, SPA noted that these cost variations do not alter the option selection (i.e. the relative economic vales of the options remain the same). It is PB's view that this is not unreasonable, as the cost variations identified by SPA do not necessarily apply to all alternatives in the same manner. For example, temporary works to enable project sequencing applies differently to the various options (different works are required), while transformer sound enclosures may be required under all options.

Having reviewed the alternatives considered by SPA, PB is of the view that the preferred alternative does represent the most efficient of those alternatives considered to meet the identified need.

Timings

With regard to timing of the MTS redevelopment project, PB is of the view that it can be reasonably concluded that optimal timing for this project was within the current regulatory period. Given the condition of the equipment as recognised in the SKM report, PB is of the view that the original implementation timing of late 2006 was reasonable.

Prudent asset management and good industry practice

The SKM recommendation did not envisage the reconfiguration of MTS. Furthermore, other matters such as specific site constraints, compliance issues (e.g. Victorian Terrorism (Community Protection) Act 2003), and consultation outcomes (e.g. transformer sound enclosures), were also not envisaged in the SKM recommendations[27]. Consequently, the final project (as is currently being implemented), and the original proposal, are different. However, PB is of the view that the differences are adequately documented, and that they represent decisions that are consistent with prudent asset management and good industry practice[28].

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27 SPI Powernet Board Paper; SPI PowerNet – Redevelopment of Malvern Terminal Station - For Approval; SPA, 13 May 2005.

28 While there are elements of augmentation (as opposed to replacement) within the MTS project, they are consistent with an economic modern equivalent replacement strategy. In the case of the power transformers PB notes that this approach led to a short-term reduction of the station N-1 transformation capacity, with additional capacity deferred to 2008 (original timing).

B.7 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 $38.57 million. As discussed in section B.6, 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 based on early design investigations[29]. It was also noted in section B.6 that 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[30], 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 B-5 sets out PB's recommendation on the prudency and efficiency of the submitted expenditure associated with the redevelopment of the Malvern Terminal Station.

Table B-5 – 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.

B.8 Conclusion

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

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

30 Reference to benchmarking section 3.4.

- 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
- 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[31].

[31] 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).

APPENDIX C
BRUNSWICK TERMINAL STATION (BTS) REDEVELOPMENT

APPENDIX C: 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 C-6.

Table C-6 – 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 06 Commonwealth Games and the need for additional (unanticipated work).

C.1 Project 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[32].

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 (3) 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 including 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 work was undertaken in the 1960-70s, 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 giving 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[33]. 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 $17.51 million.

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

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

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 & 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 (2) years later in late 06/07.

C.2 Drivers (need or justification)

BTS is an urban 220 kV terminal station established in the early 1940s, and most major assets at the site are understood to be original equipment. In 02/03, due to the age and condition of the equipment, SPA engaged SKM to evaluate the replacement options for the BTS assets. In the SPA Authority to Proceed Approval Request dated 14 December 2002, SPA presents a summary of the SKM report findings for each of the major asset groups. The equipment condition at BTS is summarised as[34]:

220 kV switchgear

This switchgear is bulk oil type, and is approximately 50 years of age. They are maintenance intensive units which are no longer supported by the manufacturer, with no serviceable spares readily available. The circuit breakers are experiencing age related problems with high levels of wear within the mechanisms and deterioration of the bushings (similar deterioration in other units has resulted in explosive failures).

220/22 kV Transformers

The transformers are single phase units with a nameplate rating of 45/55 MVA, and are not fitted with on-load tapchangers. The three (3) transformers were installed in the early 1950s. They exhibit evidence of age related deterioration such as corrosion, major oil leaks, and advanced internal insulation deterioration. In addition, the transformers pose a number of problems, including:

- noise emissions – despite the noise barriers, noise emissions are in excess of the prescribed limits
- losses – transformer losses are three times those of modern, similar capacity transformers
- voltage regulation – the transformers do not have on-load tap changers and are limiting station capacity
- environmental risks – the oil volume of the transformers is significantly greater than similarly rated, modern transformers.

22 kV Cables – these cables were installed in the early 1950s, and as a result of age related deterioration, are considered to pose serious risks to the reliability of the station

22 kV Switchgear – are bulk oil type installed in the early 1940s and present with a range of problems, including:

- Interrupter deterioration is limiting fault switching capability
- bushing deterioration poses reliability and OH&S risks (explosive failures have been experienced in other units)

34 Pages 3 to 5, SPA Authority to Proceed Approval Request dated 14 December 2002; SPA 2002

- spares are not available and they are not supported by the manufacturer
- current arc fault containment requirements are not met and hence pose serious OH&S risks

Protection and control equipment – exhibits signs of age related deterioration, is no longer supported by manufacturers in terms of spares or technical resources. This equipment is considered to pose a serious threat to the reliability of the station.

SPA has also identified the consequences of failure of the equipment at BTS[35]. In summary, the failure consequences were recognised as:

- under normal conditions the unavailability of a circuit breaker, or one incoming 220 kV circuit, would have no immediate effect on distribution supplies. Such an event would impact on station reliability, with any subsequent loss resulting in major disruption to customer supplies
- a 220 kV circuit breaker fail to open event would result in immediate disruption to customer supplies to the inner northern suburbs of Melbourne
- BTS provides part of a multiple contingency withstand scheme for the Melbourne CBD. Loss of the BTS – RTS interconnection would result in a significant increase in exposure to the risks associated with disruption of supplies to the Melbourne CBD
- failure of the 22 kV switchboard would result in loss of customer supply to the inner northern Melbourne suburbs, as load transfers are largely not possible on the associated distribution networks
- environmental consequences – most major plant items at BTS contain large volumes of oil. Any major oil spillage is likely to overwhelm the site oil retention capability, resulting in oil escape into the Merri Creek and surrounding recreational parkland
- OH&S issues as noted above.

While the SKM report briefly discussed some of these matters, SKM in their report also noted that:

> *‘A detailed condition assessment of terminal station equipment did not form part of the scope of works. SPX PowerNet provided various assessments of equipment condition, including 220 kV circuit-breakers and transformers, and 22 kV switchgear.’*[36]

Consequently, the assessment in the SKM report, and that presented in the SPA Authority to Proceed Approval Request (14 December 2002), are essentially based on SPA’s assessment of the condition of the BTS equipment. No test reports, maintenance reports, or documentation addressing assessment of remaining life, was provided to support SPA’s assessment of the condition of the BTS equipment.

In summary, the project documentation provided identifies that condition of the major equipment at BTS is suffering from a number of age related problems. Additionally, the documentation suggests that the equipment’s capability to perform the require function is also becoming problematic (e.g. limited fault switching capability on 22 kV switchgear, station capacity limitations related to the transformer voltage regulation issues). Moreover, the documentation notes related OH&S issues, noise in excess of prescribed limits, and environmental risks (e.g. oil containment limitations).

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[35] Pages 5, 6; SPA Authority to Proceed Approval Request dated 14 December 2002; SPA 2002

[36] Page 3, Brunswick Terminal Station Asset Replacement Study Final F; SKM, Feb 2003.

C.3 Strategic alignment and policy support

SPA's asset management strategy has the stated aims of[37]:

- maintaining a stable and sustainable network asset failure risk profile
- meeting network reliability and availability targets
- complying with all applicable codes and regulations (e.g. OH&S, environmental, security legislation)
- optimising asset life cycle costs.

The stated need for the BTS redevelopment project clearly relates to a number of these asset management strategy objectives. However, the original BTS project documentation does not reference SPA's asset management strategy, overarching policies or plans. Some reference is however made to related policies, strategies and plans in the SPA Ex-Post (Capex) BTS Redevelopment X2A8 summary document dated 8 March 2007.

C.4 Alternatives

The SKM report considered a number of alternatives to address the identified need (see section C.4). The report gave considerations to the issues, practicalities, costs and benefits to conclude the following in relation to each of the alternatives considered[38].

The 'do nothing' base-case

The continued operation of BTS without any planned capital expenditure whatsoever (i.e. run to failure). This alternative was considered inappropriate due to the condition of the assets and the supply role of the station.

Replace on failure

Deferred replacement though remedial works to address known and immediate problems, then revert to continued planned maintenance until immanent (or actual) equipment failure necessitates replacement. This alternative would involve a staged transition to a new station layout. Given the equipment condition, this alternative requires additional monitoring in order to maintain station reliability, and to ensure personnel health and safety. This option requires a high level of ongoing expenditure, risk exposure, and consequential losses. Hence this alternative was not recommended.

Wholesale refurbishment of the facility on the existing site (brownfield refurbishment)

Essentially this involves undertaking to replace the entire station as a single integrated project. In addressing the brownfield refurbishment alternative, SKM considered the use of AIS, GIS, and hybrid switchgear. In particular, the impact on station layout and costs was considered in some detail, and factors such as technological advances, site and operational constraints, as well as environmental issues were also addressed. This was identified as the least cost alternative that addressed the identified need, and hence was the recommended option.

The SKM report concluded that the asset replacement alternative was the least cost alternative, and recommended that the BTS assets be replaced immediately as part of a

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37 Section 3.2; Electricity Transmission Revenue Proposal 2008/09 – 2013/14; SPA, 2007

38 Section 3 and 7; Brunswick Terminal Station Asset Replacement Study Final F; SKM, Feb 2003

single integrated replacement project[39]. The relative cost benefits of the various assessed alternatives are shown in Table C-7.

Table C-7 – Summary of net benefits of alternatives (Dec 2000 $000)

Option	NPV capital costs	NPV O&M cost	NPV Transf Loss	NPV lost load conseq Cost	NPV total Cost
Replace on failure 220 kV, 22 kV & Secondary, Transformers in 2008	18,207	1,506	1,847	5,925	27,486
Replace on failure 220 kV, 22 kV & Secondary, Transformers in 2008	13,514	1,671	2,298	9,778	27,260
Replace on failure 220 kV, 22 kV & Secondary, Transformers in 2008	10,282	1,797	2,608	12,444	27,131
Replace now with 220 kV AIS	17,506	1,222	1,193	427	20,349
Replace now with 220 kV GIS	22,215	1,222	1,193	427	25,057

Source: Section 6; Brunswick Terminal Station Asset Replacement Study Final F; SKM, Feb 2003

In addition to these alternatives, the SKM report specifically considered the management of the BTS transformers. This analysis considered transformer refurbishment and new replacement alternatives. It was found that the NPV of retaining the existing transformers was $6.1m compared to the alternative of replacing the transformers which was estimated at an NPV of $5.0m (including associated works and estimated on the same basis). In addition, transformer replacement has the following benefits:

- the risks of unsuccessful refurbishment are avoided
- environmental risks associated with oil leakages are reduced
- better voltage regulation can be achieved through the provision of automatic on-load tap changers
- noise emission will be reduced
- parallel operation of the transformers will avoid inadvertent automatic load shed under outage contingencies
- a net reduction in greenhouse gases be achieved from reduced losses.

Hence it was found that the least cost alternative was replacement of the transformers, and this alternative was recommended regardless of the outcome for the overall station[40].

In 2003 a report was submitted to the SPA board recommending, as the most cost effective solution, the redevelopment of BTS as a brownfield refurbishment project. The board report also recommended the following project scope of work:

- refurbishment of the 220 kV and 22 kV switchyards including 220/22 kV transformers and associated protection, control and metering systems
- upgrading of drainage, bunding and oil containment.

39 Page 35; Brunswick Terminal Station Asset Replacement Study Final F; SKM, Feb 2003

40 Section 3.4.7; Brunswick Terminal Station Asset Replacement Study Final F; SKM, Feb 2003

At the March 2003 SPA board meeting, the BTS redevelopment project was approved as submitted[41].

C.5 Timings

The original timing of the BTS capital expenditure was based on the condition of the equipment as assessed by SPA. The project documentation identifies the condition of the major equipment as suffering from age related problems, and identifies a number of equipment functional problems. Additionally, OH&S, noise, and environmental risks were identified as issues requiring attention.

Independent assessment of BTS by SKM concluded that a brownfield asset replacement was the least cost alternative, and hence recommended immediate replacement as part of an integrated project[42]. It should be noted that SKM, in making this recommendation, did not make a detailed assessment of the equipment condition, but relied on assessments of equipment condition provided by SPA[43].

The SKM report was presented in February 2003, and board approval for the BTS project was granted in March 2003. While the original project timing involved completion in 04/05, the project was actually completed almost two (2) years later, in late 06/07, due to delays associated with the 06 Commonwealth Games and the need for additional (unanticipated work).

C.6 PB analysis

Having undertaken detailed review of the project documentation, the following section sets out PB's view on the prudency of this ex-post capex expenditure.

Clear need

The project documentation provided for the BTS project was relatively limited for a project of this scale and scale and complexity (risk). While the documentation presents a statement of the need (or issue), and discusses the alternatives considered, the available information concerning the analysis of the alternatives (cost benefit), and hence demonstration that the least cost solution was chosen, is limited. Given the lack of strategic alignment, the limited information relating to equipment condition and remaining useful life estimates (or similar – see also below), and the lack of a comprehensive cost benefit analysis to support the decisions taken, PB is of the view that for such a major and complex (high risk) project, the standard of project documentation supplied is relatively poor. SPA should be encouraged to ensure that decisions that underpin major project costs (or variations), are well documented.

The project documentation states that the condition of the major assets at BTS is such that many of these assets are in a deteriorating state. The documentation implies that the equipment is at, or near, the end of its useful life. The SKM analysis and conclusions were based on SPA's assessment of the equipment condition, and hence were not an independent assessment or verification of the equipment condition. However, despite this reliance, no documentation was supplied that provided an assessment of the estimated remaining useful life of the equipment items. No test reports, maintenance reports (or similar documentation)[44] was provided to substantiate SPA's assessment of the equipment condition. The documentation simply asserted the equipment was in a deteriorating state. The independent SKM report did however reflect SKM's concerns regarding equipment age and condition, as

41 SPI Powernet Board Report, Request For Approval Budgeted Capital Expenditure Refurbishment Of SPI Powernet Brunswick Terminal Station; 28 March 03.

42 Page 35; Brunswick Terminal Station Asset Replacement Study Final F; SKM, Feb 2003

43 Page 3. Brunswick Terminal Station Asset Replacement Study Final F; SKM, Feb 2003.

44 Test results and a failure investigation report were supplied for the 220 kV cable.

well as concerns regarding equipment functional issues, OH&S matters, noise, and environmental issues at the site. While the lack of substantiating documentation regarding equipment condition, or remaining useful life assessments (or similar) is of concern, PB is of the view that given the age of the equipment, the assertion that the BTS assets are in a deteriorating state does not seem unreasonable. Where the BTS assets are accepted as being in poor condition, and given the critical role of the station in supplying the inner northern suburbs of Melbourne, as well as the related OH&S and environmental risks identified, PB is of the view that a justifiable need was identified.

Strategic alignment

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 demonstrates little explicit consideration (arguably none) of this relationship (see above for comments on project documentation quality). However, PB recognises that implicit alignment is evident in that the BTS redevelopment addresses a number of SPA's asset management strategy objectives.

Alternatives

In order to address the identified need at BTS, SPA identified and investigated a range of alternatives in consultation with the key stakeholders. PB has considered the range of alternatives originally examined and presented in the SKM report, and is if the view that the alternatives identified were reasonably comprehensive and practical solutions to address the identified need. The SKM report also presented basic information to show that the recommended alternative (brownfield redevelopment) was the least cost of the alternatives identified. Based on SKM's analysis, PB is of the view that the preferred alternative was the most efficient alternative of those considered to meet the identified need. Furthermore, notwithstanding the limited information presented regarding the analysis of the alternatives (cost benefit analysis); PB is of the view that this analysis was prudent. However, PB is also of the view that the extent of the cost benefit documentation was not appropriate for a project of this size and complexity.

Timings

With regard to timing of the BTS redevelopment project, PB is of the view that where the BTS assets are accepted as being in poor condition, it can be reasonably concluded that optimal timing for this project was likely to be within the current regulatory period. While the original project timing involved completion in 04/05, the project was actually completed almost two (2) years later in late 06/07. This delay was attributed to the 06 Commonwealth Games, and the need for additional (unanticipated) work (see also below). PB accepts the delays due to additional (unanticipated) work, and is of the view that delaying the works to avoid the risk of potential impact on the 06 Commonwealth Games was prudent. Hence PB is of the view that completion in late 06/07 was reasonably optimal.

Prudent asset management and good industry practice

The original project proposal, as supported by the SKM report (i.e. brownfield redevelopment), did not account for a range of design and site related issues (e.g. transformer access roadway, etc). Consequently there are considerable variations between the final project (as implemented) and the original proposal costs. PB is of the view that while these differences are documented, the completeness of this documentation (as supplied) is limited. Moreover, notwithstanding that BTS was SPA's first metropolitan station rebuild project, the PB is of the view that a skilled asset manager would have reasonably anticipated (and accounted for) some of these variations in the original cost estimates (e.g. 22 kV switchgear rating, transformer access roadway). However, PB also accepts that a number of the variations were reasonably unforeseeable (e.g. temporary 22 kV connections, extent of rock), and that the variations documented were reasonably required. Additionally, PB is of the view that the costs presented for these variations appear reasonable. On the balance of the available information, PB is of the view that it is likely (on the whole) that the implementation decisions taken were consistent with prudent asset management practice.

C.7 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. As discussed in section C.6, there were subsequent changes to the BTS project scope that resulted from design issues, and site constraints. It is PBs 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 PBs view the SPA submitted total site redevelopment cost is reasonable. Moreover, given completion in 06/07, it is PBs view that the proposed timing of the project cash flow as presented by SPA (see Table C-8 below) is reasonable for a project of this type.

Table C-8 sets out PBs recommendation regarding the project value to be rolled into the RAB.

Table C-8 – 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	-	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: SPA Electricity Transmission Revenue Proposal 2008/09 – 2013/14, and PB analysis.

C.8 Conclusion

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.

APPENDIX D
INSTALLATION OF OPGW IN THE METRO AREA

APPENDIX D: 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 D-9. 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 $29.9 million. The OPGW1 project was completed in 05/06.

Table D-9 – 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

D.1 Project 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[45].

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 $2.75 million. This cost was revised in May 2003 to $3.14 million.

D.2 Drivers (need or justification)

Following an incident in May 2002 involving a third party damaging a fibre optic cable, SPA reviewed its policy relating to communications for protection and control signals. This incident left communications signals for a large number of critical transmission lines and terminal stations relying on a single route. The SPA optic fibre communications cables were mounted on distribution poles (poles in the street), and were of similar construction to almost all optical fibre cables located in the Melbourne Metropolitan area. Typically, these poles support electricity distribution of various lower voltages (e.g. 415, 22 kV), and other cables (e.g. public lighting, Telstra). Cables mounted on distribution poles are very vulnerable to damage from vehicle incidents, trees, and interference by utility contractors. Additionally, poles may be relocated by a utility without notification to SPA.

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

On average, SPA has four (4) outages of pole-mounted optic fibre cables each year involving multiple protection and control circuits. The typical time to repair a damaged cable in an unplanned outage varies from 18 hours to 5 days, depending on the extent of the damage. The number of outages required for planned maintenance is also expected to increase with aging of the optic fibre cables. During planned maintenance the cables can be out of service for 12 hours. Outages (for any reason) can result in similar (or the same) system impacts as the 2002 incident.

SPA report that a random survey of one 2.2km section of fibre optic cable revealed two (2) instances of tampering, several instances of trees growing into the cable, and an instance of a low voltage conductor in contact with the fibre optic cable. It was also reported that in other cases poles have been relocated, and the cable has been subject to strain or insufficient ground clearance.

The SPA communications network is a critical network element that carries protection and control signals vital to the operation of the transmission network. If these protection or control signals are lost, NEMMCO are empowered to require SPA to take the effected transmission lines out of service, blacking out most of Melbourne. The risks to SPA are serious plant damage and possibly causing the transmission network to become unstable (possible complete transmission network loss), or supply failure to large segments of Melbourne.

The NER has specific requirements in relation to protection and control communications facilities associated with transmission networks. The SPA review of the Melbourne metropolitan optic fibre network, notes that the existing dependence on pole mounted optical fibre cables does not meet SPA's obligations under the NER and the Victorian System Code.

Following review of its policies, SPA concluded that to adequately manage the risks, that the pole mounted fibre optic cable network should be reinforced with an OPGW tower mounted network. Because of the vulnerability of the pole mounted cable, the critical nature of this communications network, and the potentially long repair times, the SPA review recommended the OPGW cable should be installed, and an associated radio link relocated[46].

D.3 Strategic alignment and policy support

The OPGW1 project documentation is based on a review of SPA's policy for EHV[47] line intertrip[48] and accelerated protection signals and terminal station remote control signals. The documentation also discusses compliance with the requirements of the NER.

D.4 Alternatives

The A to P Approval Request, OPGW in Melbourne Metropolitan Area (14 May 2002) considered a number of alternatives to address the need identified through the SPA policy review. Specifically, the A to P gave consideration to the following alternatives:

The 'do nothing' base-case

This involves the continued operation of the exiting pole mounted optic fibre network in the Melbourne area with its attendant risks (see section D.2). This option was costed[49] and found to be the second most expensive option. It was therefore not recommended.

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46 Page 2; A to P Approval Request OPGW in Melbourne Metropolitan Area; SPA, 14 May 2002.

47 Extra High Voltage

48 Intertripping is a type of line protection scheme, and relies on high speed communications to maintain stable system operations.

49 Costing of the 'do nothing option' includes the cost of risk, taking into account the Value Of Lost Load (VOLL), rebates, etc. In the 2002 A to P and average VOLL of $20,000/MWh was used. This was

Increase line patrol frequency

Under this alternative the identified risks would be mitigated by increasing the frequency of line patrols[50]. This was found to be the most expensive option and was not recommended.

Install OPGW and radio

This option was costed and found to be the least cost alternative. Hence it was recommended.

Install radio only

This option involved the installation of radio links between each of the terminal stations to provide an alternative communications path. This alternative was not believed to be practical due to a lack of 'line of site" between each of the stations. It was also noted by SPA that even where there was line of site currently available, there was a high likelihood that this would be 'built out' in a few years. Consequently this option was not considered further.

Lease underground ducts

This alternative involves leasing underground duct space from Telstra to provide a more secure installation than the existing pole mounted arrangements. It was determined that this was difficult due to Telstra's position that it would rather sell bandwidth than lease duct space. Additionally, transmission times over Telstra bandwidth are not suitable for high-speed protection signals, and continual work being done in Telstra ducts would not mitigate the risk of cable damage. Consequently this option was not considered further.

Develop a diverse pole mounted route

This option involves development of alternative cable routes on existing distribution poles to form more diverse communications routes. While this option reduces the risk of communication interruption, it increases the risk of cable damage, and involves additional pole lease fees. Consequently this option was not considered further.

The A to P recommended, as the most cost effective option, the purchase, installation, and commissioning of OPGW on eight (8) metropolitan transmission lines and the relocation of one (1) associated radio link[51]. The direct present value cost of each of the costed alternatives is shown in Table D-10. In 2002 the SPA executive authorised the OPGW1 project, and the A to P was approved by an SPA director on 1 July 2002.

Table D-10 – Summary of net benefits of alternatives (2002 $000)

Option	PV direct costs
Do nothing and wear the risk until ground wire need replacing or other planned OPGW installation	3,671
Increase patrols to reduce risk & replace ground wire when it needs replacing and install other planned OPGW	3,503
Install OPGW (recommended alternative)	3,413

Source: A to P Approval Request OPGW in Melbourne Metropolitan Area; SPA, 14 May 2002.

revised in the 2003 A to P revision to the value of Unserved Energy for each station as defined in the Victorian Distribution Businesses Transmission Connection Planning report.

50 PB understands that this risk would be mitigated by increasing the likelihood of earlier detection of hazards.

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

D.5 Timings

The timing of the OPGW1 project was based on SPA's assessment of the risks presented by interruption of the pole mounted optic fibre communications network in the Melbourne metropolitan area. This project was originally planned to occur over the period from 2003 to 2019 when existing ground wires were to be replaced in order to address corrosion problems, or as part of other communications network works (as they occurred). However, following an incident in May 2002 involving third party damage to a fibre optic cable, SPA reviewed its policy relating to communications for protection and control signals, and decided to bring this work forward in order to reduce SPA's risk.

SPA's policy review resulted in the production of an A to P Approval Request in May 2002 which recommended the SPA purchase, install and commission OPGW on eight (8) metropolitan transmission lines and the associated relocation of a radio link. This A to P Approval Request was approved by a SPA director on 1 July 2002 as submitted. In May 2003 a revised A to P Approval Request was submitted that sought to increase the approved project budget from $2.75 million (as approved in July 02) to $3.14 million due to accommodate cost increases associated with additional traffic control and unforeseen installation difficulties[52]. This A to P revision, reassessed (in part) the alternatives, and reconfirmed that the recommend option was the least cost alternative. The revised A to P was approved by the SPA Managing Director in June 2003.

This project was completed in 05/06.

D.6 PB analysis

Having undertaken detailed review of the project documentation, the following section sets out PB's view on the prudency of this ex-post capex expenditure.

Clear need

The project documentation provided by SPA identifies the risks presented by interruption of the pole mounted optic fibre communications network in the Melbourne metropolitan area. Given the critical role of this communications network in the operation of the transmission system, and in particular the specific requirements of the NER and the Victorian System Code, PB is of the view that a justifiable need was identified.

It must be stressed that the SPA A to P Approval Request formed the essential basis for demonstration of the need, and alternative analysis and selection. As such this report is the key document in forming the views expressed in this analysis.

Strategic alignment

Reference is also made in the project documentation to the applicable SPA policy. PB is of the view that SPA has demonstrated strategic alignment of the OPGW1 project.

Alternatives

In order to address the identified need, SPA investigated a range of alternatives. PB has considered the range of alternatives examined, and is if the view that the alternatives were reasonably comprehensive and practical solutions to address the identified need. However, PB is of the view that the documented treatment of the alternatives was lacking. In particular:

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52 Page 2; A to P Approval Request, OPGW in Melbourne Metropolitan Area Revision; SPA, 21 May 2003.

- more information regarding the risks of the do nothing option was needed. Specifically, the failure rates assumed, the assumed magnitude of lost load, the value of unserved energy used and the cost of the rebates needed to be explicitly documented
- it was not clarified as to how increasing the frequency of line patrol would impact on failure rate or restoration time of this communications network, and why a fortnightly patrol was assumed in the analysis
- analysis of the lease underground ducts option concluded (in part) that such an arrangement was difficult due to Telstra related issues. However no evidence was presented to demonstrate Telstra's position (e.g. a letter from Telstra), nor was there any apparent consideration given to other possible duct providers such as Optus, or local electric distribution networks providers. Additionally, it was not clear if this option may have been more practical if the cable route had been reconsidered (perhaps in conjunction with the develop a diverse route option)
- the development of a diverse pole mounted route was dismissed on the basis that it increased pole leasing costs and it did not (adequately) address the risk. However, the risk to be addressed was the risk of loss of the existing communication network in its entirety, or the risk of extended outage of one of the redundant elements (8 hours or more). A third element in the two loop network may have considerably reduced this risk. It is acknowledged that the risk of cable damage is greater, but this is not the risk that the project is addressing. The analysis of this option needed to demonstrate that the option did not adequately address the risk identified in the needs analysis. Additionally, this option needed to be costed in order to demonstrate that the capital costs of the option, together with the likely additional cable damage costs and pole lease costs was not in fact a viable least cost alternative.

For the above reasons PB is of the view that the analysis of the alternatives was lacking. However, PB is of the view that it is likely that the conclusions drawn in the analysis would have been supported if a more complete analysis had of been presented. Hence PB has concluded that the preferred alternative (install OPGW and radio) was likely to have been a reasonable and prudent selection. PB recognises that the scale and cost of this project was relatively limited, and that the project documentation was accordingly brief. However, PB is of the view that SPA should have documented a more thorough analysis of the alternatives. Nonetheless, PB's is of view that the preferred alternative was still likely to have been the most efficient alternative to meet the identified need.

Timings

With regard to timing of the OPGW1 project, PB acknowledges the critical role of this communications network in the operation of the transmission system. PB also acknowledges that the NER and the Victorian System Code place specific requirements on the protection and control communications carried by this network. Hence this project is recognised as being a compliance matter. Consequently, it is PBs view that the implementation timing of this project was reasonable.

Prudent asset management and good industry practice

The project documentation suggests that the OPGW1 project was implemented in accordance with the original proposal. However, SPA approved a revised A to P in June 2003, to accommodate project cost increases associated with additional traffic control, and additional unforeseen installation issues (more complicated installation requirements than anticipated). PB is of the view that the differences are adequately documented, and represent decisions that are consistent with prudent project management. PB is also satisfied that the selected project is consistent with prudent asset management and good industry practice.

D.7 Costs

While the 2002 cost proposal for the OPGW1 project was some $2.75 million, SPA has proposed that the as commissioned cost is $2.92 million. As discussed in section D.6, subsequent implementation issues account for this cost variation. It is PBs 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 PBs view the SPA submitted total project cost is reasonable. Table D-11 sets out PB's recommendation regarding the project value to be rolled into the RAB.

Table D-11 – 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: SPA Electricity Transmission Revenue Proposal 2008/09 – 2013/14, and PB analysis.

D.8 Conclusion

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
- that the as commissioned cost of $2.92 million is reasonable in light of the nature of the project, the equipment involved, and the associated route issues.

APPENDIX E
REFURBISHMENT OF REDCLIFFS TERMINAL STATION (RCTS)

APPENDIX E: 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 E-12.

Table E-12 – 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 (5th) 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[53].

E.1 Project 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 Murraylink interconnector. It should be noted that the Murraylink bay and its associated equipment where 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 $11.60 million.

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 and extension of the existing control room.

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

E.2 Drivers (need or justification)

RCTS is an rural 220 kV terminal station established in the early to mid 1960s, and most major assets at the site are understood to be original equipment. In 2004, due to the age and condition of the equipment, SPA undertook an investigation into the condition, performance, and risks associated with the RCTS assets. The 2004 Redcliffs Terminal Station (RCTS) Redevelopment Study made a number of important observations relating to the equipment condition, specifically[54]:

220 kV switchgear

The 220 kV switchgear consist of a variety of air blast (4), minimum oil (2), and SF6 (2) types. The units are range from 40 to 55 years of age and exhibit a range of age related problems and performance limitations. In particular oil and air leakage, moisture entry, corrosion, mechanism wear (e.g. damping and latching problems). These units are maintenance intensive, spares and manufacturer's support is no longer available, and the necessary technical skills are not readily available. Explosive failures have also been reported (overseas), and the operation of the air blast units poses health and safety risks for personnel in their vicinity.

220 kV current transformers

The 220 kV current transformers consist of thirty-six units ranging from 39 to 55 years old. These units have a typical service life of approximately 35 to 40 years. They are exhibiting a range of age related problems including some oil leaks and advanced insulation degradation. Additionally the units do not comply with the current Metering Code requirements. The units contain large volumes of oil and have been subject to explosive failure and hence represent an OH&S risk. Refurbishment is likely to be required within the next five years, but in light of their age and degrading condition, refurbishment could not be economically justified and the units were recommended for replacement.

220 kV voltage transformers

The 220 kV voltage transformers consist of twelve CVT units of various types ranging from 21 to 37 years of age. The younger units are in good condition and are recommended to be retained; however there is history of failures in the population of some types of unit and replaced based on past problems was recommended. There are two wound VTs with no known problems and they are in relatively good condition. SPA policy however dictates that during station rebuilds bus VTs used for synchronizing are replaced to improve bus reliability.

220/66/22 kV transformers

The 220/66/22 kV transformers are considered to be in good condition, and as such their replacement or refurbishment is not warranted[55].

66 kV circuit breakers

The 66 kV circuit breakers consist of twelve units mostly of minimum oil type with one SF6 unit, and ranging in age from 26 to 42 years old. Generally the units are experiencing oil leaks, corrosion, and mechanism wear. Manufactures technical support and spares are no longer available. Most were recommended for replacement; however the two youngest units (26 years old) were considered adequate for further service.

54 Section 3; Redcliffs Terminal Station (RCTS) Redevelopment Study; SPA, October 2004

55 Page 5; Redcliffs Terminal Station (RCTS) Redevelopment Study; SPA, October 2004.

66 kV current transformers

The 66 kV current transformers consist of forty one units of various types ranging from 25 to 42 years old. The oldest units are showing advanced stages of insulation degradation (DGA tests), and there have been some have been in service failures of this type. The 25 year old units are also showing evidence of partial discharge (DGA tests) and it was concluded that it would be prudent to replace these units.

66 kV voltage transformers

The 66 kV voltage transformers consist of two units over 40 years old with a life expectancy of 40 to 60 years. Some history of oil leaks. In light of their age, likely remaining and major works at the site replacement was recommended.

Other general equipment

Other equipment such as disconnect switches and earthing switches generally exhibit problems such as moisture entry, corrosion, as well as mechanism and contact wear. The sealing systems on some surge arrestors and insulators are degrading and require replacement. However structural steel work, cable trenches and secondary cables are in good condition.

Control and protection systems

Elements of the control and protection systems contain life expired equipment, or do not comply with NER requirements. Replacement was recommended.

Oil Containment

There is generally sufficient bunding but the installation of an oil separation pit was recommended to ensure compliance with environmental standards and legislation.

Site buildings

The control building is in good condition internally and externally but does contain asbestos. The building does not conform to fire, terrorism or vandalism standards. Hence building security should be upgraded and asbestos should be removed to address OH&S issues. The compressor building and associated plant will be retired.

In summary, the report found that many of the major equipment items at RCTS were nearing the end of their useful life, and required major refurbishment or replacement. However, the report also noted that some equipment was in serviceable order, and recommends the continued service of these items.

E.3 Strategic alignment and policy support

The stated need for the RCTS redevelopment project relates to a number of SPA's asset management strategy objectives. Furthermore, the RCTS project documentation cites various points of alignment with SPA's asset management strategy, overarching policies and plans. In particular:

- replacement of the oil filled equipment at RCTS minimises the risks posed by this equipment within switchyards in line with SP AusNet policy[56]
- SPA has a Substation Control and Information Management System (SCIMS) implementation strategy to migrate from the older technologies. This strategy provides a digital technology overlay at the site that can communicate with

[56] Page 7; Redcliffs Terminal Station (RCTS) Redevelopment Study; SPA, October 2004.

equipment as it is replaced. The SCIMS strategy has been applied to the RCTS project[57]

- The RCTS rebuild provides the opportunity to upgrade the station security and fire risk management measures in line with SP AusNet policy[58]
- SPA's asset management strategy aims to identify equipment refurbishment, repair and replacement actions in advance of potential equipment failure. SPA achieve this through assessment of the potential risk of failure for each plant item. The RCTS rebuild project documentation contains a detailed consideration of the equipment condition, and risk of failure[59]
- SP AusNet's asbestos removal project aims to comply with the Occupational Health and Safety (Asbestos) Regulations 2003. The RCTS station refurbishment involves the removal of asbestos[60].

Alignment of the RCTS project with SPA's asset management strategy, overarching policies and plans has been identified in the RCTS redevelopment project documentation.

E.4 Alternatives

The report[61] considered a number of alternatives to address the need identified through the investigation (see section E.2). Specifically, the RCTS report gave consideration to the following asset replacement methodologies for the primary assets:

The 'do nothing' base-case

This alternative involves the continued operation of RCTS without any planned capital expenditure and replace on failure. This alternative was not considered suitable for terminal station plant in the noted condition, and hence was not evaluated further.

Deferred replacement

Under this methodology, existing assets are maintained in service as long as is practicable by:

- continuance of normal planned maintenance practices
- continuance of normal planned maintenance practices
- effective management of spare plant and components to meet the requirements of unplanned outages
- maintaining the ability to replace any faulty item of plant or component in an acceptably short time.

The consequential costs of unplanned outages, increased planned maintenance and callouts are borne until such time as the performance of the asset has deteriorated to the extent that continued service is impracticable. The asset is then replaced on a one-off basis.

This alternative was costed, and found to be the highest cost alternative for both the 220 kV and 66 kV switchyards. Hence this alternative was not recommended as the preferred option.

57 Page 44; Redcliffs Terminal Station (RCTS) Redevelopment Study; SPA, October 2004.

58 Page 7; Redcliffs Terminal Station (RCTS) Redevelopment Study; SPA, October 2004.

59 Sections 3, and 5; Redcliffs Terminal Station (RCTS) Redevelopment Study; SPA, October 2004.

60 Section 3; Redcliffs Terminal Station (RCTS) Redevelopment Study; SPA, October 2004.

61 Section 4; Redcliffs Terminal Station (RCTS) Redevelopment Study; SPA, October 2004.

Planned replacement on asset class basis

Typically this alternative involves a program of replacement of an asset type within the station (or across a network). This approach was recognised as being applicable when an asset class has a higher failure rate or greater degree of deterioration than assets of other classes. The strategy was seen as not being suited to situations where station assets are of a similar age and condition, and hence the benefits are negated by performance and operating costs of the balance of the assets. Multiple outages, repeated engineering, design and installation activities, as well as deterioration in the stations overall performance were also identified as issues for this approach. This alternative was costed and found to be the second highest cost alternative for both the 220 kV and 66 kV switchyards. Hence this alternative was not the preferred option.

Planned condition based replacement

This approach extracts the optimum remaining life of individual assets by utilising modern condition monitoring and testing techniques, restorative maintenance, and when necessary, replacement of the asset is then carried out on an individual asset-by-asset basis. SPA's report was of the view that this strategy was generally not suitable to older stations and that the outages required, and the cost of testing, inspection, and dismantling work was such that more a detailed assessment of this alternative was not carried out.

Bay-by-bay replacement

This strategy involves the replacement of all plant and equipment within a bay. As the major equipment within a bay requires replacement, the entire bay is then rebuilt. As the RCTS bay design was seen as being of similar risk profiles, and as all equipment was of a similar age and condition, this alternative was not considered further.

Brown field replacement of the complete station

This alternative involves the replacement of assets as part of a single coordinated refurbishment project carried out on the operational station. Following detailed analysis and costing this alternative was found to be the lowest overall cost alternative, and was the recommended alternative.

Green field replacement of the complete station

Under this alternative a complete new terminal station is developed (usually to replace an ageing station). This alternative would generally be associated with a station that is located on a restricted site, involves a site which has other demands upon it, or which is operationally unsuitable for a brownfield refurbishment project. The exiting RCTS site was recognised as having insufficient space to accommodate this development, and the acquisition of additional land was seen as cost prohibitive. Given the available space for a brown field development, this alternative was not viewed as cost effective and was not considered further.

In addressing these alternatives the RCTS report assumed the retention of the existing station configuration, and where applicable assumed the use of the spare bays to sequence the proposed works.

With regards to the primary assets, the RCTS report concluded that the brownfield redevelopment of the 220 kV and 66 kV switchyards at RCTS as a consolidated single project was the least cost alternative.

For the stations secondary assets (e.g. protection, control, etc), the report considered three options; specifically:

Base case

This option includes a partial SCIMS implementation with replacement of the existing control mimic, provide enhanced local control and monitoring capability. Base case – this option was found to be the least cost alternative, but was not recommended.

Option A

This supplements the Base Case and includes the provision of CB management facilities to achieve complete functionality of the new equipment (i.e. a full SCIMS implementation). While this option was found to be a marginally higher alternative (2.1% more), it was recommended as it was seen to offer lower risk and enable greater utilisation of the installed assets.

Option B

This is essentially the "Do Nothing" option. It was argued by SPA that the main driver for the secondary works is the removal of non-compliant and life expired equipment. Hence this option was not seen as addressing the identified need, and was not considered further.

In 2004 a report was submitted to the SPA board recommending, as the most cost effective option, the redevelopment of RCTS as a brownfield redevelopment project. The board report recommended the following project scope of work:

- Replacement of plant and equipment in the 220 kV switchyard
- Replacement of plant and equipment in the 66 kV switchyard
- Replacement of the 220/66 kV transformer and 66 kV protection
- Incorporation of the station control and information system (SCIMS)
- Associated upgrades of the station security and monitoring systems
- Refurbishment and extension of the existing control room.

The NPV summary for each of the costed 220 kV, 66 kV, and secondary equipment alternatives is shown in Table E-13, Table E-14, and Table E-15 respectively.

Table E-13 – Summary of net benefits of 220 kV switchyard alternatives (Dec 2003 $000)

Option	NPV capital costs	NPV O&M cost	NPV lost load conseq cost	NPV total cost
Deferred replacement	3,645	987	396.8	5,028.8
Replacement by asset class	4,047	320	161.7	4,529.7
Brownfield replacement	3,919	255	161.7	4,335.7

Source: Section 6; Brunswick Terminal Station Asset Replacement Study Final F; SKM, Feb 2003

Table E-14 – Summary of net benefits of 66 kV switchyard alternatives (Dec 2003 $000)

Option	NPV capital costs	NPV O&M cost	NPV lost load conseq cost	NPV total cost
Deferred replacement	2,081	494	2,078.8	4,654.8
Replacement by asset class	2,471	194	1,019.6	3,684.6
Brownfield replacement	2,376	187	1,019.6	3,583.6

Source: Section 6; Brunswick Terminal Station Asset Replacement Study Final F; SKM, Feb 2003

Table E-15 – Summary of net benefits of secondary equipment alternatives (Dec 2003 $000)

Option	NPV capital costs	NPV O&M cost	NPV total cost
'Base Case'	3,099	156	3,255
Option A	3,167	156	3,323

Source: Section 6; Brunswick Terminal Station Asset Replacement Study Final F; SKM, Feb 2003

At the November 2004 SPA board meeting, the RCTS redevelopment project was approved as submitted[62].

E.5 Timings

The timing of the RCTS capital expenditure was based on the equipment condition recognised through the RCTS investigation. The RCTS report assessment is that many of the major equipment items at RCTS are at or near the end of their remaining useful life. The RCTS report also finds that many of the secondary assets are also near life expired or are none compliant with the requirements of the NER. However the RCTS report does not make any specific recommendations with regards to timing of the recommended works.

The RCTS report was presented in November 2004, following which board approval for the RCTS project was granted in November 2004. The project was scheduled to commence in 2004/05 for completion in 2006/07, but was delayed due to site difficulties and to allow coordination with a Powercor augmentation project. This project is in progress with a current anticipated completion in October 2007[63].

E.6 PB analysis

Having undertaken detailed review of the project documentation, the following section sets out PB's view on the prudency of this ex-post capex expenditure.

62 SPI Powernet Board Report, SPI Powernet (SPIN) – Redcliffs Terminal Station Refurbishment; 10 November 2004.

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

Clear need

The project documentation provided by SPA identifies that the condition of the major assets at RCTS (at the time of the RCTS report) are such that many of the primary assets are nearing, or at the end, of their useful lives. Similar observations are made in regards to the secondary assets which are also noted as not being NER compliant in a number of instances. Given the equipment condition information presented in the project documentation, the stations state interconnector role, and role in supplying the Redcliffs/Mildura area, as well as the related OH&S risks identified, PB is of the view that a justifiable need was identified.

It must be stressed that the RCTS report formed the essential basis for demonstration of the need, and alternative analysis and selection. As such the RCTS report is the key document in forming the views expressed in this analysis. PB is of the view that SPA should have presented corroborating equipment condition information in the form of test report summaries, and/or third part assessments of the available test and maintenance information[64]. Notwithstanding this, PB is of the view that the RCTS report presented a thorough engineering analysis of the equipment within RCTS, and that this analysis was sound and reasonable.

Strategic alignment

The RCTS project documentation makes reference to a number of SPA strategies, overarching policies and plans applicable to the project. Hence, PB is of the view that SPA has demonstrated strategic alignment of the RCTS project.

Alternatives

In order to address the identified need at RCTS, SPA have identified and investigated a range of alternatives. In addition SPA consulted with the key stakeholders to ensure that the proposed redevelopment works considered their requirements and were appropriately reflected in the final scope of works. PB has considered the range of alternatives examined, and is if the view that the alternatives identified were reasonably comprehensive and practical solutions to address the identified need. Furthermore, PB is of the view that the analysis of the alternatives, and the selection of the preferred alternative (brownfield redevelopment), was reasonable and prudent. It was noted that the preferred alternative for the secondary assets was not the least cost alternative, but was selected on the basis that it offered less risk and enable greater utilisation of the installed assets. PB accepts this view, and given the marginal nature of the additional expenditure (2.1% more), is of the view that this decision was prudent. The project documentation shows that the preferred alternative was the least cost of the alternatives that could meet the identified need. Hence, PB is of the view that the preferred alternative was the most efficient alternative to meet the identified need.

Timings

With regard to timing of the RCTS redevelopment project, PB is of the view that it can be reasonably concluded that optimal timing for this project was likely to be within the current regulatory period. Given the reported age and condition of the primary equipment, OH&S issues, non-compliance of some secondary equipment with the NER, as well as the stations role state interconnector role, and its role in supplying the Redcliffs/Mildura area, PB is of the view that the planned commissioning date of 2006/07 was reasonably optimal timing[65].

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64 PB acknowledges that the RCTS report did contain some collaborating information in the form of broad discussions of equipment test results. The RCTS report also contained a thorough analysis of operational and maintenance costs.

65 It should be noted that subsequent project implementation delays in the order of six (6) moths (to October 2007) do not alter this view.

Prudent asset management and good industry practice

The available project documentation suggests that the project, as is currently being implemented, has suffered significant cost increases in the order of 27% of the 2004 estimate[66]. The revised A to P[67] notes that the additional cost to complete the project is estimated at $3.2 million above the original estimate, with the project some 75% complete. In the revised A to P, SPA addresses the reasons for the cost increases as follows[68]:

- the project was delayed due to Powercor's 3rd transformer[69] requirement, and VENCorp's Very Fast Runback Scheme implementation
- the Murray Link cable location was incorrect and required design changes
- project scope and cost estimate were inadequate. In particular the project cost was underestimated due to
- the old estimating system was not reliable for brownfield station refurbishments
- the brownfield adjustment factor was incorrect (only 2% - and should have been 30%)[70]
- input costs have increased significantly and no escalation was allowed for in this project
- the quantity and complexity of the secondary cabling and interfacing work was underestimated with designs having not been fully completed at the time issuing the contract
- the project manager was found to be not suitable
- project change control processes were not followed and scope creep occurred.

SPA stated in the revised A to P that many of the cost increases should have been included in the original project scope.

The revised A to P addressed a number of alternatives to deal with the cost increases. Specifically, the following alternatives and conclusions were addressed

- discontinue the project – this would result in a substantial amount of work partly completed and not in a serviceable condition. It would impact on station security and not meet service standards and was not recommended
- finalise work completed to date and discontinue the project – that is complete the minimum amount of work required to restore the station to an operational state. This results in increased failure risk as assets requiring replacement would not be replaced, and additional costs (changing drawings, contract cancellation claims, standalone future project costs[71]). This alternative was therefore not recommended

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66 SPI Powernet Board Report, SPI Powernet (SPIN) – Redcliffs Terminal Station Refurbishment; 10 November 2004.

67 Page 1; Project Approval Committee Authority to Proceed REVISION> $250,000 – Transmission, RCTS Refurbishment (X432); SPA, 24 Apr 2007.

68 Pages 3, 4; Project Approval Committee Authority to Proceed REVISION> $250,000 – Transmission, RCTS Refurbishment (X432); SPA, 24 Apr 2007.

69 SPA reports that expected delay costs were recovered from Powercor.

70 SKM report that Brownfield factors of 23% to 29% above Greenfield costs are typical and would be higher for refurbishment of existing bays. The brownfield factor covers the additional costs associated with working live yards, integration of new and old works, and sequencing costs and commissioning.

71 That is, to replace major assets not addressed as a result of the project termination. SPA added in the revised A to P that analysis has found that deferral would need 10 years or more for this to break even.

- continue the project with a reduced scope of works – this involves deferring work that can be deferred and completing the remainder to restore the station to a secure position. This approach has the same problems as the above option and therefore was not recommended
- complete the project – complete the project and deliver the benefits identified in the original study. SPA noted that the relativities of the original options have not changed (as a result of the additional costs) and hence the project still has the lowest life cycle and was therefore completion at the increased cost was recommended.

The revised A to P reconsidered the original economic analysis with the additional costs added to each alternative as applicable[72]. It was concluded that even if the additional costs were identified at the start of the project, then the selected alternative would have still been chosen.

On the basis of this analysis, SPA concluded in their revised A to P that the project be completed to realise the full benefits identified in the original 2004 study at an additional cost of $3.20 million.

PB is of the view that the circumstances identified by SPA in their revised A to P are understandable given the complex nature of this type of project. However, PB is concerned that the rigor applied to project scoping[73], project costing, and project management, was less than that which could be expected of a prudent and skilled asset manager, and was not in keeping with good industry practice. It is PB's view that a prudent project management process would have resulted in earlier detection and intervention in this project[74], and while this would not have avoided much of the cost increases, it may have resulted in less scope creep, and earlier assessment of the management options. Consequently, PB is of the view that SPA's implementation of the RCTS project was not consistent with prudent asset management and good industry practice. However, notwithstanding this, PB is also of the view that had SPA been rigorous at the project outset, that the original project scope would have more closely reflected the as implemented project.

E.7 Costs

While the 2002 cost proposal for RCTS was some $10.6 million, SPA has proposed that the forecast as commissioned cost is expected to be $14.97 million. 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 Murraylink installation[75]. SPA further note that and independent report by SKM found that the site related costs were 30% to 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 PBs 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 A to P presents details of this cost increase, and SPA's considerations as to the appropriateness of the selected alternative in light of the additional costs (see section E.6).

As the need for the replacement of these assets has already been established, a 10 year deferral is not considered to be viable.

72 SPA are arguing that since many of the cost increases should have been included in the original project scope, that these cost increases should be added to the original alternatives (as applicable) in order to reassess if the brownfield option is still the least cost option.

73 In Appendix 1 of the revised A to P, SPA note such issues as the extension cable trench factored into the design did not actually exist, modifications to the battery room for fire rating and acid spills, and Neutral CTs to overcame harmonic problems.

74 It is noted that the project was some 75% complete at the time the revise A to P was prepared.

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

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 PBs view that the SPA submitted total site redevelopment cost is reasonable.

Table E-16 sets out PBs recommendation regarding the project value to be rolled into the RAB.

Table E-16 – 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	-	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: SPA Electricity Transmission Revenue Proposal 2008/09 – 2013/14, and PB analysis.

E.8 Conclusion

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 $14.97 million is reasonable given the scope changes which are not unexpected for a project of this complex nature.

APPENDIX F
TOWER SIGNAGE

APPENDIX F: 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 F-17.

Table F-17 – 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.

F.1 Project overview

In June 2001 an SPA employees 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[76].

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 SPA's 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. Under this project the majority of SPA's towers would be provided with suitable signage.

SPA prepared an A to P Approval Request in August 2002 seeking approval for an estimated $4.11 million 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.

F.2 Drivers (need or justification)

SPA typically attached nameplates to the first five towers into and out of each terminal station. Generally there are a large number of towers between stations (often hundreds) with no nameplates. This arrangement presents a safety hazard for work crews as it can make it difficult to clearly identify the circuit they are to work on. The investigation into the June 2002 line worker fatality identified this as a significant safety matter.

F.3 Strategic alignment and policy support

The tower signage project documentation identifies OH&S policies and regulations as the primary strategy and policy for this project.

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

F.4 Alternatives

In the SPA Safety Signage on Towers A to P Approval Request dated 8 August 2002, two alternatives were identified to address the recognised need (see section F.2). Specifically, SPA considered the following alternatives and concluded:

Do nothing

Essentially this alternative is to retain the current arrangements. This was considered not to be a suitable option as it did not address risk to staff and contractors. SPA concluded that they were "obliged to fix the problem as a matter of priority".

Erect tower signage

This involves fitting nameplates to each circuit on all towers. Following the fatality investigation, an expert panel concluded that the fitting of nameplates will improve safety, hence this alternative was recommended.

The recommend alternative was accepted by SPA and approved in October 2002.

F.5 Timings

The timing of the tower signage capital expenditure was based on the conclusions reached by the investigation into the June 2002 SAP line worker fatality. SPA concluded that the current tower signage arranges were unsatisfactory and must be addressed as a matter of priority as the situation represents a real safety hazard for work crews.

Following the investigation, in August 2002 SPA prepared the Safety Signage on Towers A to P Approval Request. In October 2002 this request was approved by an SPA director. It is understood that work commenced in 2003/04 and was completed in 2004/05.

F.6 PB analysis

Having undertaken detailed review of the project documentation, the following section sets out PB's view on the prudency of this ex-post capex expenditure.

Clear need

The project documentation provided by SPA identifies that the lack of tower signage represents a safety risk to crews, as it makes the correct identification of the circuit to be worked on difficult. The documentation notes that the lack of signage was (at least in part) a contributing factor in the death of a line worker in 2002. Given the essential nature of personnel and public safety in the electricity industry, and the signage arrangements in place at the time of the fatality, it is PBs view that a justifiable need was identified.

Strategic alignment

With reference to the applicable SPA strategies, overarching policies and plans, PB is of the view that SPA has demonstrated strategic alignment of the tower signage project in the supplied project documentation.

Alternatives

In order to address the need identified, the project documentation suggests that SPA considered two fundamental options; do nothing, and erect tower signage. The documentation notes that an expert panel was employed in assessing the alternatives. While other options may have been identified and considered by the expert panel, PB has not been supplied with any minutes, or similar documentation, to clarify if other alternatives were considered. PB has considered the alternatives examined, and is if the view that the alternatives identified were practical solutions to address the identified need. As 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. PB acknowledges that unambiguous circuit identification is a vital safety issue, and that suitable signage is appropriate to address this safety issue. Hence PB is of the view that the analysis of the alternatives considered, and the selection of the preferred alternative (tower signage) was reasonable and prudent.

Timings

With regard to timing of the signage project, PB is of the view that once SPA was made aware of the safety issues identified through the investigation, SPA had a duty to promptly address those issues. Consequently, PB is of the view that the timing of this project was appropriate.

Prudent asset management and good industry practice

It is understood from the project documentation, that the project as proposed in the August 2002 A to P Approval Request was implemented as envisage. Given the critical safety issues involved, and the timing of SPA's response, PB is of the view that the implementation of the tower signage project was consistent with prudent asset management and good industry practice.

F.7 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 $4.11 million, and, SPA has proposed that the as complete cost is $3.69 million. 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 addressed (note that SPA have approximately 13,000 towers and many require signage), 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 F-18 sets out PBs recommendation regarding the project value to be rolled into the RAB.

Table F-18 – 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	-	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: SPA Electricity Transmission Revenue Proposal 2008/09 – 2013/14, and PB analysis.

F.8 Conclusion

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, that 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 $3.69 million 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.

APPENDIX G
220 & 66 KV CT REPLACEMENTS STAGE 2

APPENDIX G: 220 & 66 KV CT REPLACEMENTS STAGE 2

The 220 & 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 and 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 G-19. This project is relatively small ex-post expenditure item and 0.93% of the SPA network-related capex in the current period.

Table G-19 – Capex for 220 & 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

G.1 Project overview [77, 78, 79]

In 2002 a 500 kV CT at Moorabool suffered explosive failure. Following a second explosive failure in late 2005, SAP undertook a complete review of CT condition. In addition, there has 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 & 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 (4) sets of 66 kV CTs, and 18 sets of 220 kV CT that have a high failure risk. It involves works at ten (10) terminal stations, as well as the purchase of six (6) sets of 220 kV CTs, and one (1) set of 330 kV CTs for spares.

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

G.2 Drivers (need or justification)[80]

SPA has over 1852 CTs in service with ages up to 55 years old. Figure G-1 shows the SPA CT age profile as at 2005. It is apparent from the figure that the largest numbers of units occur in the ranges of 20-25, 35-45 years of age.

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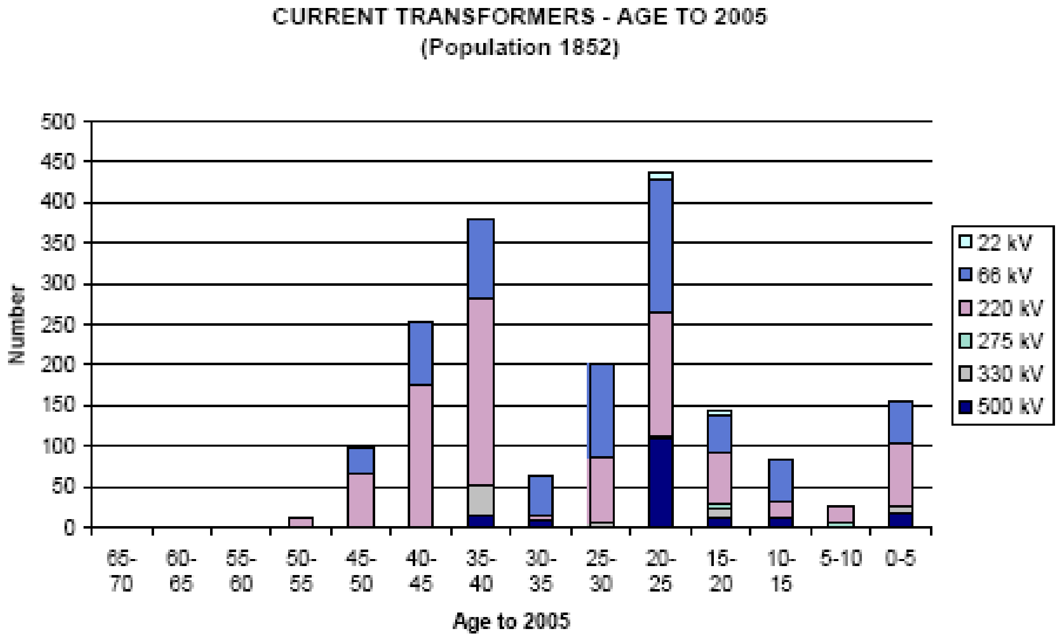
77 Project Approval Committee Authority to Proceed >$250,000 – Transmission, 220 kV & 66 kV CT Replacements at Various Locations: Stage 2; SPA, 29 January 2007.

78 CT Replacement Program; SPA, 16 March 2007.

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

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

Figure G-1– SPA current transformer age profile as at 2005[81]



Source: Page 4, Replacement Program For Current Transformers Capital Works Project Description; SPA, 12/01/07.

In 2002 a 500 kV CT failed explosively Moorabool, with a second explosive failure in 2005. A resulting SPA investigation found that a design deficiency in the insulation was the likely cause of the failures. These catastrophic failures lead SPA to develop a CT risk assessment model, based on DGA and other characteristics. The risk model ranks CT failure risk, and predicts when the CT replacement should be planned based on when it is considered unsafe for persons to access the vicinity (i.e. that is when the CT is close to a runaway failure).

In its analysis, SPA notes that the life of a particular type of CT is not absolute, but most have a life expectancy of approximately 30 to 50 years[82]. SPA also note that four (4) out of five (5) catastrophic failures over recent years have involved CTs purchased in the early 1980s[83]. As similar failures have been reported by other utilities, SPA are of the view that design margins for in this period may have been to fine for the manufacturing processes of the day. This suspected design issue is the key driver of CTs in the 20 years old category.

For CTs in the range of 35 years of age and older, SPA's risk assessment shows that many are reaching the end of their useful life. Figure G-2 shows the SPA model's view of this failure risk, and SPA note that since 2001 the MTBF rate has fallen from 7 years to 120 days[84].

The catastrophic failure of CTs due to insulation degradation can rapidly advance, and cause sudden explosive failure. This creates human safety risks, the risk of consequential damage to adjacent equipment, fire and environmental risks, as well as the risk of long unplanned system outages.

81 Page 6; AMS 10-64. AMS – Victorian Electricity Transmission Network Instrument Transformers; SPA, 23/02/07.

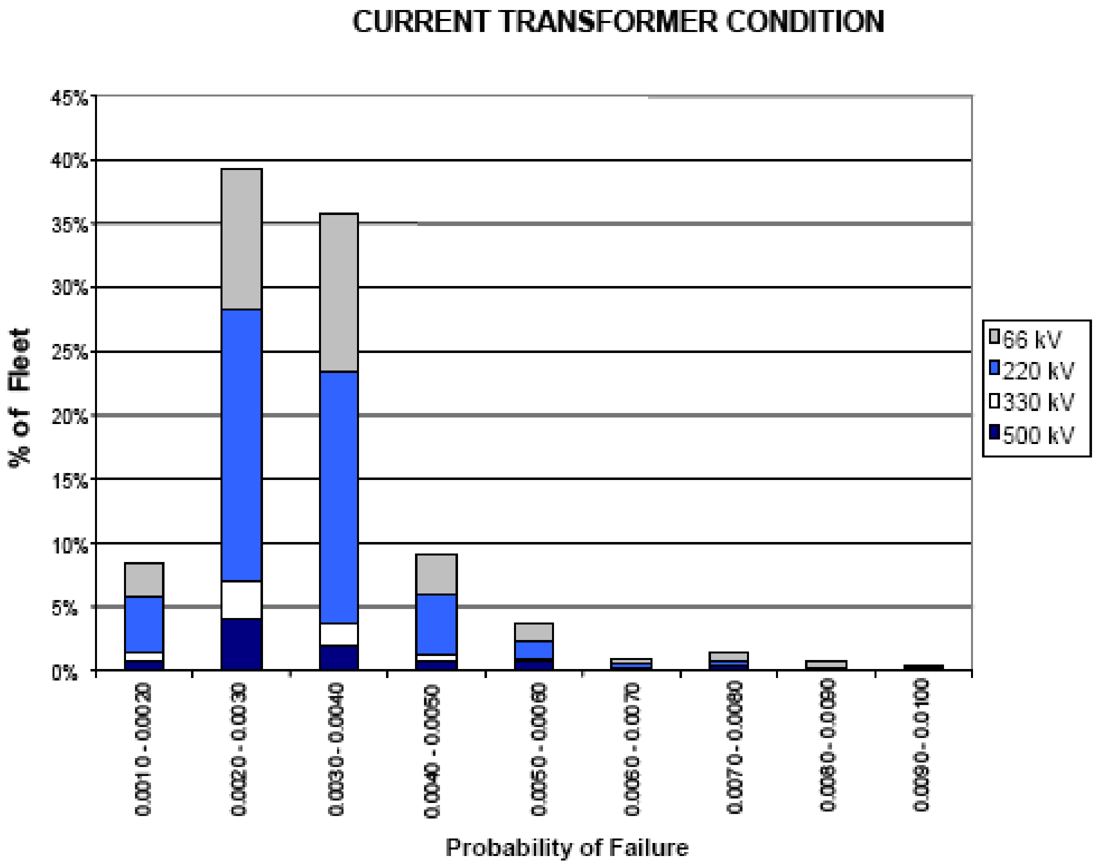
82 Page 4; CT Replacement Program; SPA, 16/03/07

83 Page 4; Replacement Program For Current Transformers Capital Works Project Description; SPA, 12/01/07

84 Page 12; AMS 10-64. AMS – Victorian Electricity Transmission Network Instrument Transformers; SPA, 23/02/07.

SPA has also identified the risk that some CTs may deteriorate faster than the risk model predicts. With a lead time of 30 to 38 weeks from order, and with limited spares holdings, SPA believes that there is increasing exposure to prolonged system interruptions[85].

Figure G-2 – SPA current transformer condition (as at 2005)[86]



Source: Page 10; AMS 10-64. AMS – Victorian Electricity Transmission Network Instrument Transformers; SPA, 23/02/07.

G.3 Strategic alignment and policy support

SPA's asset management strategy has the stated aims of[87]:

- maintaining a stable and sustainable network asset failure risk profile
- meeting network reliability and availability targets
- complying with all applicable codes and regulations(e.g. OH&S, environmental, security legislation)
- optimising each asset's life cycle costs.

The stated need for the TCT3 project relates to a number of these asset management strategy objectives. Furthermore, the TCT3 project documentation cites various points of alignment with SPA's asset management strategy, overarching policies and plans. In

85 Page 3; Project Approval Committee Authority to Proceed >$250,000 – Transmission, 220 kV & 66 kV CT Replacements at Various Locations: Stage 2; SPA, 29 January 2007.

86 Page 10; AMS 10-64. AMS – Victorian Electricity Transmission Network Instrument Transformers; SPA, 23/02/07.

87 Section 3.2; Electricity Transmission Revenue Proposal 2008/09 – 2013/14; SPA, 2007

particular: SPA's asset management strategy aims to identify equipment refurbishment, repair and replacement actions in advance of potential equipment failure. SPA achieves this through assessment of the potential risk of failure for each plant item. The TCT3 project documentation contains a detailed consideration of the equipment condition, likely remaining life and risk of failure[88].

G.4 Alternatives

In considering the identified need (see section G.2), SPA considered the following alternatives and concluded:

Do nothing

This alternative involves running the assets to failure and replacing on failure. As this would place personnel and plant at increased risk, and result in potentially long unplanned system outages. Spare holdings were also identified as being inadequate to respond to multiple failures. When costed this option was found to be the highest cost option, and was not recommended.

Defer new capital

This alternative involves continued CT monitoring with progressive replacement using spare CTs as the risk of failure becomes unacceptable (based on the CT risk model). SPA noted that this option is being used when a single unit fails in service. However, there are insufficient spares of the appropriate types to address the number of CTs identified at risk. When costed, this option was found to be the third highest cost option, and was not recommended.

Replace with new CTs

Essentially involves the replacement of suspect (high risk) CTs with new units as soon as possible. This alternative provides the lowest risk solution as well as freeing up a number of spares to further minimise the risks. When costed, this option was found to be the lowest cost option, and was the recommended alternative.

Integrate with potential CB replacement

This alternative involves the replacement of CTs based on a program integrated with the replacement of the associated CB. Investigations showed that replacement of the associated CB was not justified in every case. When costed, this alternative was found to be the second highest cost option, and hence was not recommended.

It was noted that SPA did not consider CT refurbishment as an alternative, as it was viewed as impracticable. The reason for this view is that the CT failures were due to insulation failure, and once insulation deteriorates it cannot be restored. Hence the only option is replacement[89]. Complete replacement of the CT insulation would involve remanufacturing, which is cost prohibitive and risky compared to the purchase of a new CT. Hence this alternative was not considered.

In early 2007, SPA's Project Approval Committee recommended the replacement of suspect (high risk) CTs with new units as soon as possible (i.e. replace with new CT alternative). The recommendation specifically identified the replacement of particular CT types in specific terminal stations that were not included in approved terminal station redevelopment projects.

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88 Replacement Program For Current Transformers Capital Works Project Description; SPA, 12/01/07. CT Replacement Program; SPA, 16/03/07.

89 Page 8; Replacement Program For Current Transformers Capital Works Project Description; SPA, 12/01/07.

Table G-20 presents the NPV summary for each of the costed alternatives. In February 2007, the Project Approval Committee recommended the preferred alternative and this was subsequently approved by two (2) SPA directors[90].

Table G-20 – Summary of net benefits of alternatives (2006 $000)

Option	PV capital costs	PV O&M cost	PV community cost	PV incentive scheme	Total PV cost
Do nothing	(2,806)	(4,677)	0	(1,212)	(8,695)
Defer new capital	(5,130)	(2,256)	0	(546)	(7,932)
Replace high risk 220 kV and 66 kV CTs	(6,054)	(158)	0	0	(6,212)
Integrate with potential CB replacement options	(7,904)	(416)	0	0	(8,319)

Source: Page 11, Project Approval Committee Authority to Proceed >$250,000 – Transmission, 220 kV & 66 kV CT Replacements at Various Locations: Stage 2; SPA, 29 January 2007.

G.5 Timings

The timing of the TCT3 capital expenditure was based on the condition of the equipment as identified through SPA's CT risk model and supporting processes. The SPA CT risk model ranks CT failure risk, and predicts when the CT replacement should be planned based on when it is considered unsafe for persons to access the vicinity (i.e. that is when the CT is close to a runaway failure). SPA defines this as the optimal replacement year[91]. Based on the assessment supported by the CT risk model, SPA implemented a program to replace high risk CTs that are not part of SPA's terminal station rebuild program.

In February 2007, the stage 2 CT replacement project was approved by two (2) SPA directors as recommended by the SPA Project Approval Committee. While Stage 1 of the CT replacement program is now complete, stage 2 (TCT3) is scheduled to commence in 2007/08 with an anticipated completion late in the year, and a further stage is scheduled for the 2008-2014 period (see section 5.4).

G.6 PB analysis

Having undertaken detailed review of the project documentation, the following section sets out PB's view on the prudency of this ex-post capex expenditure.

Clear need

The project documentation provided by SPA identifies that the condition of a significant portion of the CT population is such that many of these assets are nearing (less than 10 years), or at the end, of their useful lives. While the project documentation presents considerable discussion of the condition assessment of the CT population, and the related failure information, there is little collaborating data presented to support this discussion (e.g. summary of test findings, independent review). However, PB acknowledges that SPA's assessment of the equipment condition seems reasonable given the age of the equipment

90 Page 1; Project Approval Committee Authority to Proceed >$250,000 – Transmission, 220 kV & 66 kV CT Replacements at Various Locations: Stage 2; SPA, 29 January 2007.

91 Page 5; Replacement Program For Current Transformers Capital Works Project Description; SPA, 12/01/07.

and the stated failure history, along with the failure analysis information provide. Based on the 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, PB is of the view that a justifiable need was identified.

It must be stressed that the assessment of the equipment condition presented by SPA formed the essential basis for demonstration of the need. While the documentation lacks collaborating data (e.g. summary of test findings, independent review), PB is nonetheless of the view that the documentation does present a sound and reasonable engineering analysis.

Strategic alignment

The project documentation does make reference to the applicable SPA strategies, overarching policies and plans, and hence PB is of the view that SPA has demonstrated strategic alignment of the TCT3 project.

Alternatives

In order to address the identified need, SPA considered a range of alternatives. PB has considered the range of alternatives examined, and is if the view that the alternatives identified were reasonably comprehensive and practical solutions to address the identified need. Furthermore, PB is of the view that the analysis of the alternatives, and the selection of the preferred alternative (replace with new CTs), was reasonable and prudent. The preferred alternative was shown in the documentation to be least cost of the alternatives that could meet the identified need. PB is of the view that the preferred alternative was the most efficient alternative identified to meet the stated need.

Timings

With regard to timing of the TCT3 project, 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, PB is of the view that it can be concluded that the implementation timing of this project was reasonable.

Prudent asset management and good industry practice

As this project is yet to be implemented, it is not possible assess the project's implementation at this stage.

G.7 Costs

The capital cost of this project was estimated at $5.92 m in January 2007. This estimate covers the replacement (supply and installation) of four (4) sets of 66 kV CTs, and 18 sets of 220 kV CT. It involves the purchase of six (6) sets of 220 kV CTs, and one (1) 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 PBs view the SPA submitted total forecast cost estimate is reasonable. Table G-21 sets out PBs recommendation regarding the project value to be rolled into the RAB.

Table G-21 – 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	-	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: SPA Electricity Transmission Revenue Proposal 2008/09 – 2013/14, and PB analysis.

G.8 Conclusion

The 220 & 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 $3.88 m is reasonable given the voltages and the type of equipment involved.

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

APPENDIX H: REPLACEMENT OF 66 KV SHUNT REACTORS AT HOTS, KGTS, & RCTS

The replacement of shunt reactors project addresses aging 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 H-22.

Table H-22 – 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.

H.1 Project 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 became apparent that were found to cause by a high level of vibration. 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 (3) new 15 MVA shunt reactors, one 91) in each of the abovementioned terminal stations.

In February 2003 an SPA director approved the REACT1 project at an estimated cost of $3.89 million. The project was completed in September 2004 at a total cost of $3.14 million[92].

H.2 Drivers (need or justification)

These Shunt reactors play an important part in voltage control of the 220 kV outer grids. SPA has a total of six (6) shunt reactors installed in three (3) terminal stations in the northwest part of the network. Four (4) of these reactors were manufactured by HSB between 1971 and 1973. The design of these units is such that vibration is a significant concern as it can result in internal mechanical and insulation problems.

During the early operation of these units, a number of serious defects developed due to vibration resulting from a mechanical design weakness. Whilst site repairs were made, two units were returned to the factory for repair. This improved the vibration situation. However it failed to solve the problem, and in 1996 the vibration increased suddenly in the Redcliffs Terminal Station unit (RCTS). With VENCorp's agreement, this reactor remains out of service, despite it being an important element of the transmission network, and required under the VENCorp contract.

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

All four HSB shunt reactors have developed internal faults, which have resulted in insulation contamination. This cannot be rectified through refurbishment, and has resulted in an increased risk of failure of these units. As these reactors deteriorate, the risk that SPA will not be able to meet its contractual obligations to VENCorp is increasing.

H.3 Strategic alignment and policy support

SPA's asset management strategy has the stated aims of[93]:

- maintaining a stable and sustainable network asset failure risk profile
- meeting network reliability and availability targets
- complying with all applicable codes and regulations(e.g. OH&S, environmental, security legislation)
- optimising each asset's life cycle costs.

The stated need for the REACT1 project relates to a number of these asset management strategy objectives. In particular, the REACT1 project addresses the reliability of the reactors which is in accordance with the principles of the SPA's asset management strategy.

H.4 Alternatives

In considering the identified need (see section H.2), SPA considered the following alternatives and concluded:

Do nothing

This alternative replaces reactors when they fail. Based on the history of these reactors and their present condition, there is a high risk of failure. These reactors will also attract a rebate, which could become significant as reliability decreases. Unavailability of a reactor could also result in over-stressing of other plant due to high system voltages. This alternative was not considered further.

Refurbish and repair reactors

This alternative involves the repair and refurbishment of the existing reactors. There is however a fundamental design deficiency with this plant, and refurbishment was anticipated to amount to the equivalent of the provision of a new reactor (but without the attendant benefits). No Australian manufacturer is currently engaged in this work, and remanufacture would require specialist facilities. Additionally the insulation is contaminated and reinsulation is required. This alternative was not considered viable.

Replace three (3) reactors now

This alternative provides reliable reactors for the next 40 years. This alternative also temporally relocates a reactor to replace a fourth unit in the medium term, and then involves the replacement of that fourth reactor at a later date. This was the recommended alternative.

In February 2003, SPA submitted a report to the SPA President recommending as the most cost effective option:

- the purchase three new reactors to replace defective reactors at KGTS, HOTS, and RCTS now
- the transfer of the MBTS reactor to HOTS with subsequent later replacement of this unit.

93 Section 3.2; Electricity Transmission Revenue Proposal 2008/09 – 2013/14; SPA, 2007

In February 2003 an SPA director approved the REACT1 project as submitted[94].

H.5 Timings

The timing of the REACT1 capital expenditure was based on SPA's assessment of the condition of the equipment. SPA's assessment concluded that the reliability of the shunt reactors has been poor, and they have reached the end of their useful life. Hence their replacement was recommended as soon as practical.

The SPA report was submitted for approval in December 2002. Subsequently approval for the REACT1 project was granted in February 2003. This project is currently in progress with an anticipated completion in 07/08, and the project was completed in September 2004.

H.6 PB analysis

Having undertaken detailed review of the project documentation, the following section sets out PB's view on the prudency of this ex-post capex expenditure.

Clear need

The project documentation provided by SPA identifies 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. Hence SPA concluded that these units were at the end of their useful lives. While the project documentation presents a brief discussion of the reactor condition, there is little collaborating data presented to support this discussion (e.g. summary of test findings, independent review, etc). It is PBs view that this significantly detracts from the analysis and justification presented for this project. PB does however acknowledge that given the age of the equipment, its history, and the nature of the equipment design, that SPA's assessment of the equipment condition seems reasonable. Based on the information provided regarding the equipment condition assessment, PB is of the view that a justifiable need was identified.

It must be stressed that the SPA assessment of the equipment condition formed the essential basis for demonstration of the need, alternative analysis and recommended actions. As such the SPA analysis is the key document in forming the views expressed by PB. PB is of the view that the SPA analysis presented was limited and lacked collaborating data (e.g. summary of test findings, independent review, etc) fundamental to a sound engineering analysis of equipment condition.

Strategic alignment

The project documentation does make limited inferred reference to the applicable of SPA's overarching plans. PB is of the view that the REACT1 project documentation lacks explicit strategic alignment with the applicable SPA strategies, overarching policies and plans.

Alternatives

In order to address the identified need, SPA undertook consideration of a range of alternatives. PB has considered the range of alternatives examined, and is if the view that the alternatives identified were reasonably comprehensive and practical solutions to address the identified need. Furthermore, PB is of the view that the analysis of the alternatives, and the selection of the preferred alternative (replace three reactors now), was reasonable and prudent. While the preferred alternative was not shown to be least cost alternative to meet the identified need, the arguments for dismissing the other alternatives were reasonable. PB is of the view that the preferred alternative was the most efficient alternative of those considered to meet the identified need.

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

Timings

The timing of the REACT1 project was based on SPA's assessment that the reactors are 30 years old and at the end of their useful lives. SPA specifically note that the reactors have become less reliable, and are at increased risk of failure, having developed internal incipient electrical faults and mechanical faults due vibration[95]. While the project documentation presents a brief discussion of the reactor condition, there is little collaborating data presented to support this discussion (e.g. summary of test findings, independent review, etc). It is PBs view that this significantly detracts from the analysis and justification presented for this project, and makes it difficult to assess the appropriateness of the project timing. PB does acknowledge that given the age of the equipment, its history, and the nature of the equipment design, that SPA's assessment of the equipment condition seems reasonable. Hence PB is of the view that the timing of this project was probably reasonable.

Prudent asset management and good industry practice

The original recommendation involved:

- the purchase three new reactors to replace defective reactors at KGTS, HOTS, and RCTS now
- the transfer of the MBTS reactor to HOTS with subsequent later replacement of this unit.

It is understood that the three (3) shunt reactors have been replaced, and the fourth (4th) unit (from MBTS) is now available for installation during 2007[96]. Consequently the final as implemented project is in accordance with the original proposal. Based on the project documentation, PB is of the view that the implementation of the REACT1 project is consistent with prudent asset management and good industry practice.

H.7 Costs

The original cost estimate for the REACT1 project was some \$3.89 m, while the as implemented total cost is understood to be \$3.14 m[97]. Given the voltages and type of equipment involved, PBs is of the view that the proposed cost of this project is reasonable. Table H-23 sets out PBs recommendation regarding the project value to be rolled into the RAB.

Table H-23 – 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	-	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: SPA Electricity Transmission Revenue Proposal 2008/09 – 2013/14, and PB analysis.

95 Page 3; A to P Approval Request, Replacement of 15 MVAR 67.5 kV Shunt Reactors at HOTS, KGTS and RCTS; SPA, 11 December 2002.

96 Page 6; EX-POST (CAPEX) - Replacement of 15 MVA 67.5 kV Shunt Reactors &Replacement of Radiators on 550 kV & 242 kV Reactors: SPA, 06/03/07.

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

H.8 Conclusion

The REACT1 project is addresses aging and faulty reactive support equipment in three (3) 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
- 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 now), 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, that that 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 that the project implementation is consistent with prudent asset management and good industry practice
- that the as commissioned cost of $3.14 m is reasonable given the voltages and type of equipment involved.

APPENDIX I
REPLACEMENT OF 16MM PIN INSULATORS STAGE 2

APPENDIX I: REPLACEMENT OF 16MM PIN INSULATORS STAGE 2

The Replacement of 16mm Pin Insulators (Stage 2) project addresses aging 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 I-24.

Table I-24 – Capex for 16mm 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[98]

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.

I.1 Project 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 five years.

The Tinsulator project targets aged 16mm 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 a Portland[99].

I.2 Drivers (need or justification)

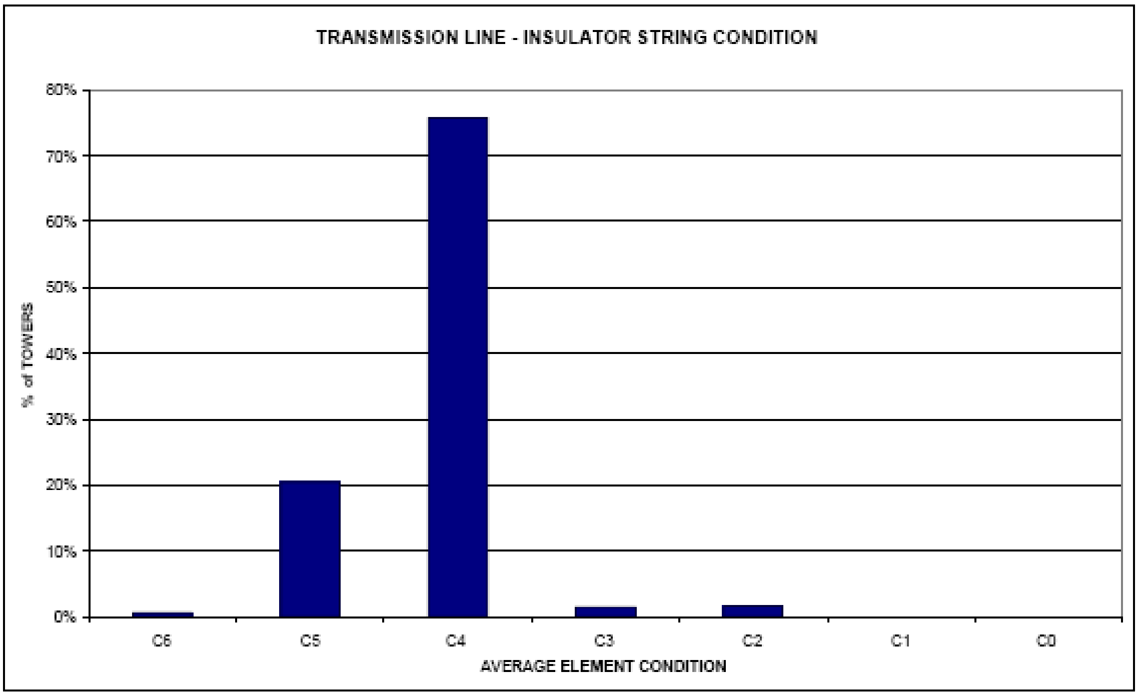
SPA has an extensive population of line insulators and associated hardware. There have been several in-service failures in the last 20 years, mostly occurring in the last five years. As a consequence, SPA has developed a transmission line risk model that includes risk

98 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.

99 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.

assessment of the associated insulators. This assessment is based on service life and visual examinations to identify wear or corrosion[100]. Visual examinations in the field involve classification using a rating scale of 1 to 6, where a 6 is considered "as new", while a 1 has significant deterioration. High-risk insulators are insulators with a condition assessed in the range of 1 to 4. The risk model also accounts for the local consequences of insulator failure, and particularly the risk to the public of a conductor drop. Figure I-1 shows SPA's assessment of the condition of the insulator population[101]. SPA's assessment indicates that a significant proportion of the overall insulator population is in poor condition.

Figure I-1 – SPA insulator condition[102]



Source: Page 13; AMS – Victorian Electricity Transmission Network Transmission Lines AMS 10-75; SPA, 05/02/2007.

With the average age of the insulators being 45 years old, SPA believes that the risk of exposure to a conductor drop is increasing rapidly. Figure I-2 shows SPA's assessment of the risk of insulator failure as determined by the risk model.

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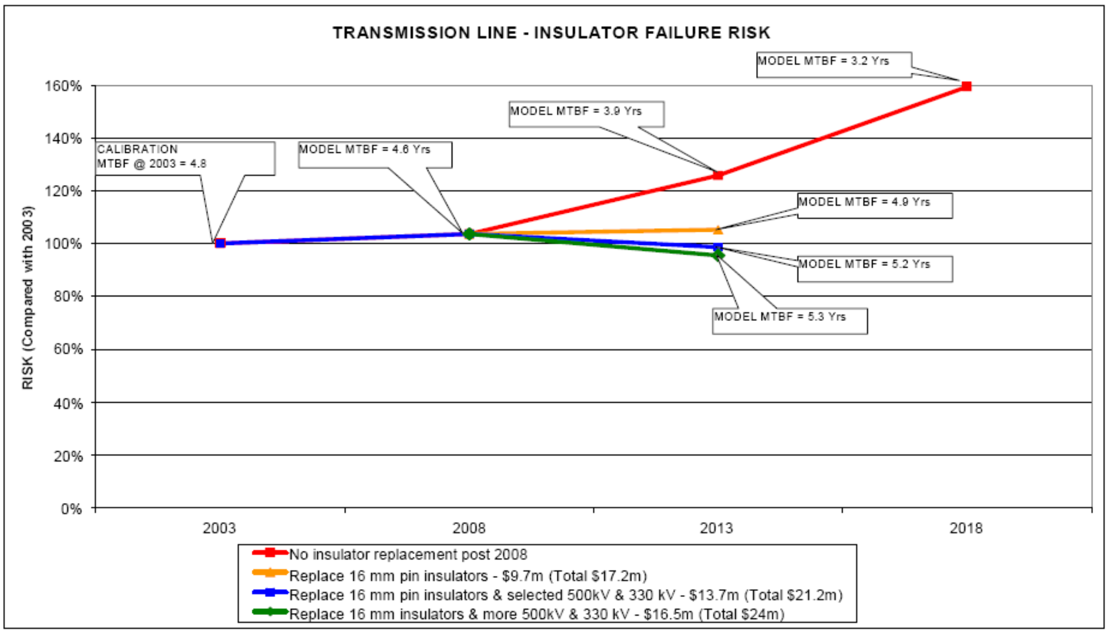
100 While field examination can identify wear and corrosion problems, it cannot identify defects such as weakening cement or fatigue embrittlement.

101 Section 1.3.3; AMS – Victorian Electricity Transmission Network Transmission Lines AMS 10-75; SPA, 05/02/2007.

102 Section 1.3.3; AMS – Victorian Electricity Transmission Network Transmission Lines AMS 10-75; SPA, 05/02/2007.

Figure I-2– SPA insulator risk model assessment



Source: Page 6, 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.

In addition to the overall risk ranking of the insulator population, SPA has identified specific corrosion problems with insulators on the ALCOA Portland Smelter 500 kV line (project X651). SPA notes that due to the proximity of this line to the sea, there has been accelerated rusting of the line hardware and insulators. The SPA analysis notes that there is a risk of failure through pin fatigue due to bending in the insulator pins as the ball and socket couplings are locked with rust[103].

There are also a range of insulators that have known type defects that lead to such problems as internal cracking due to mechanical stress, pin fractures due to fatigue, and mechanical strength below industry safety factors of 2.5[104].

Associated line hardware (e.g. dampers, spacers, termination assemblies) are typically of forged or cast galvanised steel, iron, or aluminium alloys. These items suffer wear and corrosion, as well as fatigue due to vibration or cyclic loading[105].

In summary, SPA have determined that a significant proportion of the insulator population is in poor condition, and that due to location consequences there are a number of high risk situations that require specific action to be taken to ensure network reliability and safety.

103 Page 3; 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.

104 Page 3; 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.

105 Section 1.3.3; AMS – Victorian Electricity Transmission Network Transmission Lines AMS 10-75; SPA, 05/02/2007.

I.3 Strategic alignment and policy support

SPA's asset management strategy has the stated aims of[106]:

- maintaining a stable and sustainable network asset failure risk profile
- meeting network reliability and availability targets
- complying with all applicable codes and regulations(e.g. OH&S, environmental, security legislation)
- optimising each asset's life cycle costs.

The stated need for the Tinsulator project relates to a number of these asset management strategy objectives. In particular, the Tinsulator project addresses the transmission line reliability, and public safety issues which are in accordance with the principles of the SPA's asset management strategy.

I.4 Alternatives

For the X668 project (a major portion of the Tinsulator project group) SPA considered the following alternatives to address the identified need (see section I.2) and concluded[107]:

Do nothing

This alternative involves replacing insulators and associated hardware on failure. A 12 month deferred version of this was also considered. These alternatives were not recommended, as SPA believes the risk to system reliability and security, as well as public safety, property damage, and fire from line drops is not acceptable. SPA also notes that unplanned replacement of failed insulator strings is more costly than a planned replacement program. These alternatives were costed and found to be highest and third (3rd) highest cost alternatives. Hence these alternatives were not recommended.

Replace high-risk insulators without replacing hardware

This alternative involves replacing the insulators according to the risk ranking, but retaining all associated hardware. This was not recommended due to the risk that faulty hardware also leads to line drops with the same risks as the "do nothing" option. This alternative was costed and found to be second (2nd) highest cost alternative.

Replace high-risk insulators with polymeric insulators, and hardware

This alternative involves replacing the insulators according to the risk ranking along with all associated hardware, but using polymeric insulators. This alternative was recommended as the use of polymeric insulators addresses the risk of corrosion and wear of the insulator pins. This alternative also has the benefit of removing the need for periodic washing (reducing opex costs). It was noted that polymeric insulators have an anticipated life equivalent to porcelain, but at a lower cost. As associated hardware is also a cause of line drops, replacing this hardware during insulator replacement is a more efficient solution. This alternative was costed and found to be lowest cost alternative. It was recommended on this basis.

Table I-25 presents the NPV summary for each of the costed alternatives.

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106 Section 3.2; Electricity Transmission Revenue Proposal 2008/09 – 2013/14; SPA, 2007

107 Pages 3-5, 10; 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.

Table I-25 – Summary of net benefits of alternatives (2006 $000)

Option	PV capital costs	PV O&M cost	PV community cost	Total PV cost
Do nothing	$0	($4,818)	$0	($4,818)
Delay the replacement program	($2,347)	($682)	$0	($3,028)
Replace high risk insulators without line hardware	($2,318)	($1,353)	$0	($3,671)
Replace-high risk insulators with polymeric insulator, with hardware	($2.500)	($2)	$0	($2,502)

Source: Page 10; 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.

For the X651 project (the Portland line project) SPA considered the following alternatives to address the identified need (see section I.2) and concluded[108]:

Do nothing

This alternative involves replacing the insulators on a failure basis only. A month deferred version of this was also considered. These alternatives were not recommended, for similar reasons to those given above. These alternatives were costed and found to be the highest and second highest cost alternatives.

Replace the insulators and fittings with the lines "Dead"

This alternative involves replacing the insulators and fittings under a line outage (i.e. lines "dead"). This alternative was costed and found to be the third highest cost alternative. Due to the high cost of rebates this option was not recommended.

Replace insulators and fittings using porcelain insulators, "Live"

This alternative involves replacing the insulators and fittings with the lines in service (i.e. live line). This alternative was costed and found to be the fourth highest cost alternative. It was noted that as polymeric insulators have an expected life equivalent to that of porcelain insulators, but at a lower cost, this alternative was not recommended.

Replace insulators and fittings using polymeric insulators "Live"

This was the recommended alternative, as polymeric insulator performance is expected to be superior to porcelain in a coastal environment. Polymeric insulators are also lower cost than porcelain with an expected equivalent life. This alternative was costed and found to be the lowest cost alternative.

In March 2007, the Project Approval Committee recommended two (2) 16mm pin insulator replacement projects (X668, and X651). The A to P reports recommending as the most cost effective option the replacement of porcelain insulators and associated hardware with polymeric insulators. In March 2007, the recommendation for X668 was approved as

108 Pages 3-5; 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.

submitted by the SPA Managing Director and Chairman[109]. The recommendation for project X651 remains unapproved[110].

Table I-26 presents the NPV summary for each of the costed alternatives.

Table I-26 – Summary of net benefits of alternatives (2006 $000)

Option	PV capital cost	PV opex costs	PV community costs	Total PV cost
Do Nothing	$0	($2,050)	$0	($2,050)
Delay the replacement program to 2008/09	($566)	($483)	$0	($1,050)
Replace insulators & hardware on SU Twrs with Polymerics -"Dead"	($755)	($4)	$0	($759)
Replace insulators & hardware on SU Twrs using Porcelain -Live Line	($705)	($39)	$0	($743)
Replace insulators & hardware on SU Twrs using Polymerics -Live Line	($603)	($4)	$0	($607)

Source: Page 10; 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.

I.5 Timings

The timing of the insulator replacement project capital expenditure is based upon SPA's assessment of the condition if the insulator population. In particular, the risk ranking assigned by SPA's risk model sets the priority order of for the replacement projects. Figure I-2 shows SPA's assessment of the risk of insulator failure as determined by the risk model. This model shows an increasing risk of exposure to insulator failure (a conductor drop). SPA's program of insulator replacement is intended to manage the risk as depicted in this figure to maintain a stable (and sustainable) network asset failure risk profile in accordance with SPA's asset management strategy.

In March 2007 project number X668 was submitted for approval, with approval as submitted gained on 27 March 2007. This project is planned to commence in April 2007 with an anticipated completion in March 2008[111].

Project number X651 was also submitted for approval in March 2007. It is understood that approval has not yet been granted. This project is planned to commence in April 2007 with an anticipated completion in March 2008. This project is planned to commence in April 2007 with an anticipated completion in March 2008[112].

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109 Page 1; 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.

110 Page 1; 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. The version of the document supplied to PB in April 07 has not been approved.

111 Page 7; 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.

112 Page 1; 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. The version of the document supplied to PB in April 07 has not been approved.

I.6 PB analysis

Having undertaken detailed review of the project documentation, the following section sets out PB's view on the prudency of this ex-post capex expenditure.

Clear need

The project documentation provided by SPA identifies that the condition of a significant portion of the insulator population is poor (high-risk) and that there is an increasing risk of line drops. Hence SPA concluded that replacement of high risk insulators was warranted. The project documentation presents discussion of problems and condition of the insulator population, along information relating to the proportion of insulators in each condition class. It is PBs view that SPA's insulator condition assessment is a thorough engineering analysis, and that this analysis was sound and reasonable. Hence, given the insulator condition information presented in the project documentation, the network reliability and stability risks, as well as the attendant public safety, property damage and fire from line drops, PB is of the view that a justifiable need was identified.

It must be stressed that SPA's insulator condition assessment formed the essential basis for demonstration of the need, and alternative analysis and selection. As such this condition assessment is a key element in forming the views expressed in this analysis. PB is of the view SPA's assessment of the insulator condition represents a thorough engineering analysis of the insulator condition, and that this analysis was sound and reasonable.

Strategic alignment

The project documentation makes only inferred references to the applicable SPA overarching strategies, policies, and plans. PB is of the view that the Tinsulator project documentation lacks explicit strategic alignment.

Alternatives

In order to address the identified need, SPA undertook consideration of a range of alternatives. PB has considered the range of alternatives examined, and is if the view that the alternatives identified were reasonably comprehensive and practical solutions to address the identified need. Furthermore, PB is of the view that the 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. The preferred alternative was shown in the documentation to be least cost of the alternatives that could meet the identified need. PB is of the view that the preferred alternative was the most efficient of the alternatives identified to meet the stated need.

Timings

The timing of the Tinsulator project(s) is based on SPA's assessment of the high risk insulators. The project documentation presents discussion of problems encountered and the condition of the insulator population, along information relating to the proportion of insulators in each condition class. PB is of the view that SPA's transmission line risk model presents a thorough analysis of the condition of the insulator assets, and hence given the condition of the insulators identified by the model, and the proposed risk profile (Figure I-2)[113], PB is of the view that the timing of this project was probably reasonable.

Prudent asset management and good industry practice

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113 Essentially, the proposed insulator risk profile remains flat over the current and next regulatory period. This is in line with SPA's stated policy of maintaining a stable risk profile.

As these projects (X668, X651) are yet to be implemented, it is not possible to assess whether the implementation is consistent with prudent asset management and good industry practice.

I.7 Costs

SPA has proposed that the forecast cost of these projects (X668, X651) is expected to be $2.07 m. Given the voltages, the geographically distributed nature of an insulator replacement program, and the types of insulators proposed (polymeric), it is PBs view the SPA expected cost estimate is reasonable. Table I-27 sets out PBs recommendation regarding the project value to be rolled into the RAB.

Table I-27 – 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	-	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: SPA Electricity Transmission Revenue Proposal 2008/09 – 2013/14, and PB analysis.

I.8 Conclusion

The Tinsulator project addresses aging 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
- 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 $2.07 m is reasonable in of the voltages involved, the geographically distributed nature of an insulator replacement program, and the types of insulators proposed (polymeric).

APPENDIX J
REFURBISHMENT OF BENDIGO TERMINAL STATION (BETS)

APPENDIX J: 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 J-28.

Table J-28 – 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 (7th) 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.

J.1 Project 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 (3) 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 (2) banks of 220/66/22 kV single-phase transformers, and a 220/66/22 kV three-phase transformer. Other major MTS 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[114] 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 $15.1 million.

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

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

switchyard along with the replacement of associated secondary equipment, and the extension and refurbishment of the control building.

J.2 Drivers (need or justification)

BETS is a regional 220 kV terminal station established in the early to mid 1960s, and many of the primary assets are understood to be original equipment. In 2004, due to the age and equipment condition concerns, SPA undertook and investigation the condition, performance, and risks associated with the BETS assets. The resulting report made a number of important observations relating to the equipment condition and remaining life, specifically[115]:

220 kV circuit breakers

The 220 kV circuit breakers are air blast type of various models with a range of ages from 37 to 50 years of age. These units are reported to exhibit a range of age related problems, and have specific performance limitations. In particular it is reported that the units are maintenance intensive due to age related defects such as corrosion, erosion and abrasion of contact surfaces, and increasing incidences of air leaks. There is a lack of spares and manufacturers support, as well as diminishing technical skills to carryout the complex maintenance requirements. The unit's performance limitations relate to limited short circuit capability, and inability to meet the requirements of the proposed high speed switching schemes.

220/66/22 kV transformers

Of the 220/66/22 kV transformers, one is a modern three phase unit expected to be serviceable for another 25 years. The six single phase units are expected to be serviceable for a further five to fen years.

220 kV current transformers

The 220 kV current transformers are oil filled type, ranging from 30 to 45 years of age. They are reported to be physically in good condition with negligible corrosion or visible leakage. As the typical service life for 220 kV current transformers is 35 to 40 years it is reported as likely that some refurbishment work will be required within the next five (5) years. Explosive failure of this equipment has been experienced and hence there are significant OH&S risks, as well as risks to adjacent equipment.

Voltage transformers

The voltage transformers range in age from 21 to 41 years of age and are of varying types. Some are reported to have suspect insulation, while spares are also noted as a maintenance issue.

Other 220 kV items

Other 220 kV items involve plant such as disconnect switches and instrument transformers also show evidence of age related deterioration such as mechanical wear of the mechanisms and insulation deterioration. The ratings of the busbars are also reported as being inadequate for known future requirements.

66 kV circuit breakers

The 66 kV circuit breakers are of various types and conditions, ranging from 3 to 45 years old. Four units are suitable for continued service (2 capacitor bank, and 2 transformer units). Two (2) units have a number of operations and are recommended for replacement even

[115] Section 3; Bendigo Terminal Station (BETS) Redevelopment Study; SPA, December 2004

though they are 27 and 37 years old respectively. Two units are 45 years old and have low current and fault ratings, as well as reported performance and reliability issues. Five units are bulk oil and are 36-37 years old. They have functional limitations (low current and fault rating, not suitable for the proposed protection scheme). To realise project efficiencies, and manage safety and reliability issues, these units are to be replaced in accordance with SPA's bulk oil circuit breakers strategy.

66 kV current transformers

The 66 kV current transformers are of various types ranging from 32 to 40 years of age. Three units show well advanced age deterioration, and units of this type have suffered in service failure. Consequently replacement of these units was recommended. All other units are of a type with known problems, and in particular moisture ingress. A remaining life of less than 10 years was assigned.

66 kV voltage transformers

The 66 kV voltage transformers are of various types ranging from 30 to 40 years of age with no evidence of recorded problems and a life expectancy of 40 to 50 years. However to achieve metering code compliance replacement should be in the event of major works being undertaken within the 66 kV switchyard.

22 kV Switchyard

Redevelopment of the 22 kV switchyard was deferred to around 2010 pending replacement of the transformers in coordination with the Powercor augmentation requirements.

Secondary equipment

The secondary equipment (including control and protection) is of various ages and conditions ranging from relatively new to "life expired". Some equipment (e.g. metering, protection) is not NER compliant, has performance or maintenance issues, and has experienced in-service failures. Replacement of some secondary equipment and associated systems was proposed to address these issues.

Oil containment

There is no existing oil containment or separation provisions and upgrade works are required to comply with environmental standards and legislation.

Control building

The control building is of timber framed construction and is understood to contain asbestos in the roof and walls. The building is in poor condition, has poor security against unauthorised entry, and the building construction has been assessed as being a fire risk. Therefore, regardless of future redevelopment works the entire building condition should be addressed in the immediate future.

In summary, the report determined that a significant proportion of the major equipment items at BETS were maintenance intensive and suffering age related problems. Ability to maintain the equipment, functional limitations, as well as OH&S and environmental issues, were cited as justification for this work. Based on these observations, the report concluded that the condition of a significant proportion of the major equipment items at BETS was such that action needed to be taken.

J.3 Strategic alignment and policy support

SPA's asset management strategy has the stated aims of[116]:

- maintaining a stable and sustainable network asset failure risk profile
- meeting network reliability and availability targets
- complying with all applicable codes and regulations(e.g. OH&S, environmental, security legislation)
- optimising each asset's life cycle costs.

The stated need for the BETS redevelopment project relates to a number of these asset management strategy objectives. Furthermore, the BETS project documentation cites various points of alignment with SPA's asset management strategy, overarching policies and plans. In particular[117]:

- the 220 kV switchgear at BETS was scheduled for replacement by 2013 as part of SPA's phasing out of all air-blast circuit breakers
- all 220 kV disconnect switches are remotely operable to be consistent with the SPA's asset management strategy
- replacement of the bulk oil filled equipment at BETS minimises the risks posed by oil filled equipment within switchyards in line with SP AusNet policy
- SPA SCIMS implementation strategy has been applied to the BETS project
- The BETS rebuild provides the opportunity to upgrade the station security and fire risk management measures in line with SP AusNet policy
- The BETS redevelopment project documentation contains assessment of the equipment condition of the station and installed equipment
- SP AusNet's asbestos removal project aims to comply with the Occupational Health and Safety (Asbestos) Regulations 2003. The BETS station refurbishment involves the removal of asbestos.

Alignment of the BETS project with SPA's asset management strategy, overarching policies and plans has been identified in the BETS redevelopment project documentation.

J.4 Alternatives

The BETS Redevelopment Study ("the report") considers a number of alternatives to address the identified need (see section J.2). In considering the alternatives, the report separately addressed each of the key asset groups (e.g. switchyards, transformers). It should be noted that the power transformers were assessed and confirmed as suitable for continued service. Hence the power transformers are not considered within the following alternatives.

Specifically, for the 220 kV and 66 kV switchyards the report gave consideration to the following alternatives:

Do nothing

This is essentially the replace on failure option. That is, the continued operation of BETS without any planned capital expenditure whatsoever. This approach has risks that were considered unacceptable for the 220 kV terminal station plant in its noted condition. Furthermore, immediate OH&S, environmental and technical requirements were identified. This alternative was not considered further.

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116 Section 3.2; Electricity Transmission Revenue Proposal 2008/09 – 2013/14; SPA, 2007

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

Deferred replacement

This alternative maintains the existing assets in service as long as is practicable by addressing the OH&S, environmental, and maintenance requirements to extend the service life while maintaining the necessary reliability and operational performance. This alternative was costed, and found to be the highest cost alternative. Hence it was not recommended.

Replacement by asset class (or bay-by-bay)

This strategy involves the replacement of equipment based on age, performance or other related issues. The bay-by-bay approach is of value where a "standard" bay design can be applied repeatedly or where the stations risk profile can be directly related to the performance of specific bays. For BETS bay by bay replacement is largely ineffective due to the similar age and performance of the major equipment items which precludes targeting of "troublesome" bays. As such, replacement by asset class was considered more appropriate for BETS. This alternative was costed, but found to be the highest cost alternative for the 66 kV switchyard, and the second highest for the 220 kV switchyard. Hence this alternative was not recommended.

Replacement based on condition

This approach extracts the optimum remaining life of individual assets by utilising modern condition monitoring and testing techniques, restorative maintenance, and when necessary, replacement of the asset is then carried out on an individual asset-by-asset basis. When this approach is applied to older plant, it is intrusive and expensive as a result of regular plant outages for testing and condition assessment. Additionally, the relationship of failure modes to equipment condition is not well established for the respective equipment items. Therefore it was deemed not suitable and was not investigated further.

Brown field replacement

This alternative involves the replacement of assets as part of a single integrated project carried out on an operational station. This alternative was costed and found to be the lowest overall cost alternative, and hence was the recommended alternative.

Green field replacement

This approach develops a complete new terminal station, usually to replace an ageing station, which is either located on a restricted site, involves a site with other demands upon it, or which is operationally unsuitable for a brownfield refurbishment project. This option was determined not to be cost effective, nor of any technically advantage, hence this alternative was not considered further.

The report concluded that the brownfield replacement of the 220 kV and 66 kV switchyards represented the most favourable outcome in terms of NPV. The NPV for each of the costed 220 kV and 66 kV switchyard alternatives is given in Table J-29, and Table J-30.

Table J-29 – Summary of net benefits of 220 kV switchyard alternatives (Dec 2004 $k)

Option	NPV Capital Costs	NPV Operational Costs	NPV Community Costs	NPV Total Costs	NPV Direct Costs (Ops + Capital)
Deferred Replacement	4,075	2,087	11,165	17,327	6,162
Replacement by Asset Class	4,904	1,115	10,103	16,123	6,019
Brownfield Replacement	5,290	242	2,532	8,064	5,532

Source: Pages 8, 9. Bendigo Terminal Station (BETS) Redevelopment Study; SPA, December 2004.

Table J-30 – Summary of net benefits of 66 kV switchyard alternatives (Dec 2004 $k)

Option	NPV Capital Costs	NPV Operational Costs	NPV Community Costs	NPV Total Costs	NPV Direct Costs (Ops + Capital)
Deferred Replacement	1,617	354	2,288	4,259	1,971
Replacement by Asset Class	1,781	226	2,261	4,268	2,007
Brownfield Replacement	1,620	172	2,235	4,026	1,792

Source: Pages 8, 9. Bendigo Terminal Station (BETS) Redevelopment Study; SPA, December 2004.

For the stations secondary systems (e.g. protection, control, etc), the report considered three options; specifically:

Minimum replacement (base case)

This involves replacing only those assets that urgently requiring attention.

Coordinated replacement

This alternative targets asset replacement on a scheme by scheme basis, introducing digital control and monitoring systems to leverage new technologies.

Holistic replacement

This involves upgrading the remaining secondary systems that are still in their original state, but which do not require urgent replacement in order to achieve the overall renovation of the installed station secondary systems.

The report concludes that the coordinated replacement option provides the least cost overall solution as shown in Table J-31. Note that the coordinated replacement option is undertaken in conjunction with the minimum replacement (base case) option.

Table J-31 – Summary of net benefits of secondary equipment alternatives (Dec 2004 $k)

Option	NPV Capital Costs	NPV Operational Costs	NPV Community Costs	NPV Total Costs	NPV Direct Costs (Ops + Capital)
Minimum Replacement	3,601	244	-	3,845	3,845
Coordinated Replacement	3,491	243	-	3,734	3,734
Holistic Replacement	3,605	230	-	3,835	3,835

Source: Pages 8, 9. Bendigo Terminal Station (BETS) Redevelopment Study; SPA, December 2004.

In December 2004, a report was submitted to the SPA board recommending (delivers the most cost effective outcome) the redevelopment of BETS as 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.

The board report also recommended the following project scope of work:

- Replacement of eight 220 kV circuit breakers, associated current transformers, disconnect and earthing switches
- Replacement of 220 kV busbars
- Replacement of nine 66 kV circuit breakers and associated current transformers
- Replacement of one 66 kV bus voltage transformer
- Replacement of all 220 kV and 66 kV porcelain 'cap and pin' insulators
- Replacement of the 220166122 kV transformer protection and control
- Replacement of the 220, 66 and 22 kV busbar protection and bus tie control schemes
- Replacement of the 66 kV feeder protection and control schemes
- Replacement of 220 kV circuit breaker protection and control schemes, incorporating CB management facilities
- New station control and information management systems (SCIMS) for upgraded controls
- New 220 kV surge arrestors on the transmission circuit
- New 220 kV VT selection scheme to replace bus voltage transformers
- New duplicate protection battery system
- New building extension and partial refurbishment of existing building
- New blast-wall between transformers No.2A and No.2B
- Associated upgrades of the station security and monitoring systems
- Installation of oil containment and stormwater treatment facilities.

The BETS redevelopment project was approved by the board as submitted[118].

J.5 Timings

The timing of the BETS capital expenditure was based on the condition of the equipment as identified through the BETS Redevelopment Study[119]. In general this report concluded that much of the primary equipment in the 220 kV and 66 kV switchyards was maintenance intensive and suffering age related problems. Specifically, due to problems maintaining this aging equipment, functional limitations, as well as OH&S and environmental issues action was recommend.

The report noted that the assessed equipment condition varied from relatively new, to a range of equipment at or near (within 5 to 10 years) its useful life. However, the report also noted that the power transformers, some circuit breakers, and other equipment throughout the were anticipated to have remaining serviceable lives in excess of 10 years, or that the equipment would be replaced as part of works scheduled at a later time (i.e. the Powercor capacity augmentation expected in 2010). Consequently, not major equipment at BETS was to be replaced under this project.

The BETS Redevelopment Study was delivered in December 2004, with board approval for the recommend project achieved in the same month. At that time it was anticipated that the

118 SPI Powernet Board Report, SPI Powernet (SPIP) - Bendigo Terminal Station Refurbishment; SPA, 16 December 04.

119 Section 3; Bendigo Terminal Station (BETS) Redevelopment Study; SPA, December 2004.

project would commence in 04/05 and be completed in 06/07. SPA now anticipates completion in 07/08.

J.6 PB analysis

Having undertaken detailed review of the project documentation, the following section sets out PB's view on the prudency of this ex-post capex expenditure.

Clear need

The project documentation provided by SPA identifies that the condition of many of the major assets at BETS are such that they are at, or near (within 5 to 10 years), the end of their useful life. However, no test reports, maintenance reports (or similar documentation), was provided to substantiate SPA's assessment of the equipment condition, or conclusions on the equipments reaming useful life. While the lack of substantiating documentation concerning equipment condition is of concern, PB is of the view that given the age of the equipment, the assertion that the BETS assets are in a deteriorating state does not seem unreasonable. Where the BETS assets are accepted as being in poor condition, and given the role of the station in supplying the northern and eastern parts of the 220 kV state grid, the stations impact on the inter-state inter-connectors, as well as the related OH&S and environmental risks identified, PB is of the view that a justifiable need was identified.

It must be stressed that the BETS Redevelopment Study report formed the essential basis for demonstration of the need, and alternative analysis and selection. As such this report is the key document in forming the views expressed in this analysis. PB is of the view that the report presented a reasonably thorough engineering analysis of the equipment within BETS, and that the analysis it presented was sound and reasonable[120]. However, PB is also of the view that the report should have contained more information to substantiate the reported condition of the equipment (e.g. test report or maintenance report summaries, etc).

Strategic alignment

With regards to the relationship between the BETS refurbishment project and the applicable SPA strategies, overarching policies and plans, PB is of the view that SPA has demonstrated strategic alignment of the BETS project.

Alternatives

In order to address the identified need at BETS, SPA identified and investigated a range of alternatives. In addition SPA consulted with the key stakeholders to ensure their requirements were considered in selecting the preferred alternative. PB has considered the range of alternatives examined by SPA, and is if the view that the alternatives identified were reasonably comprehensive and practical solutions to address the identified need. Furthermore, PB is of the view that the analysis of the alternatives, and the selection of the preferred alternative (brownfield redevelopment), was reasonable and prudent. The preferred alternative was shown in the documentation to be least cost of the alternatives that could meet the identified need. It was also clear from the documentation that the preferred alternative targeted the specific equipment that was identified in the need assessment as requiring attention, while retaining other equipment that was identified as serviceable. PB is of the view that the preferred alternative was the most efficient alternative identified to meet the need.

120 As an aside, the quality of the BETS redevelopment documents (in general), and in particular the scoping, costing and logistical, considerations, speaks of the improvements in SPA's station rebuild technology over the current regulatory period

Timings

The timing of the BETS redevelopment project was based on the condition of the equipment as identified through the BETS Redevelopment Study[121]. The report noted that the equipment condition varied from relatively new, to a range of equipment at or near (within 5 to 10 years) its useful life. In general the report concluded that much of the primary equipment in the 220 kV and 66 kV switchyards was maintenance intensive and suffering age related problems, and that functional limitations, as well as OH&S and environmental issues necessitated the project at that time. PB recognises the critical role of BETS in supplying northern Victoria and it role in the state inter-connectors, as well as the related OH&S and environmental risks identified in the BETS Redevelopment Study. However, it is difficult to conclude that project timing was reasonably optimal, due to the lack of supporting equipment condition information (particularly demonstrable remaining life estimates). Based on the supplied information, it is PBs view that it may have been possible to defer the BETS project by as much as two years.

Prudent asset management and good industry practice

The original BETS Redevelopment Study addressed the project in a reasonably comprehensive manner, and the nature of the site appears to have allowed the project to proceed without any significant or unforeseen issues. Matters such as specific site constraints, compliance issues, and consultation outcomes appear to have been addressed by the study, or were not consequential to the project outcome. Hence, the documentation suggests that the project as implemented is largely in accordance with the original proposal. Consequently, PB is of the view that the project implementation (excluding the question of project timing) was consistent with prudent asset management and good industry practice.

J.7 Costs

While the 2002 cost proposal for BETS was some $15.6 m, SPA has proposed that the as commissioned cost is $14.4 m. 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 PBs view the SPA submitted total site redevelopment cost is reasonable. Table J-32 sets out PBs recommendation regarding the project value to be rolled into the RAB.

Table J-32 – 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	-	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: SPA Electricity Transmission Revenue Proposal 2008/09 – 2013/14, and PB analysis.

J.8 Conclusion

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 $14.45 million. PB has reviewed the project information provided by SPA and has formed the following views:

121 Section 3; Bendigo Terminal Station (BETS) Redevelopment Study; SPA, December 2004.

- that 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
- that 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
- that the BETS Redevelopment Study report presented a reasonably thorough engineering analysis of the equipment, and that the analysis was sound and reasonable
- that the BETS Redevelopment Study report required more information to substantiate the reported condition of the equipment
- the project documentation demonstrates the strategic alignment of the BETS 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
- that 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
- that 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 two years
- that while 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
- that the as commissioned cost of $14.45 m 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.

APPENDIX K
REFURBISHMENT OF HAZELWOOD POWER STATION SWITCHYARD (HWPS)

APPENDIX K: 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 K-33.

Table K-33 – 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.

K.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.

K.2 Drivers (need or justification)

SPA has advised[122] that the level of risk presented by the potential for bushing failure on the 40-45 year old bulk oil type 220 kV circuit breakers[123] is unacceptable. The bushings have developed numerous problems such as oil leaks, moisture ingress, overheating due to spring relaxation, corrosion and general deterioration of primary insulation and top-cap assemblies. The circuit breakers themselves are also exhibiting age and duty-related deterioration such as mechanism wear, arc-erosion of interrupter components, moisture ingress and corrosion. There are 25 of these circuit breakers at HWPS.

The consequence of failure of the bushings (which are oil filled and have integrated current transformers) typically leads to explosion and fire. This can result in catastrophic shattering of porcelain insulating shells, with consequential damage to adjacent plant and equipment, as well as risk of serious injury to any persons in the vicinity. Furthermore, any potential bushing failure is likely to have a direct impact on the generator, the transmission line, or on the associated transformer located within the same yard. Reduction in the risk of bushing failure is the key driver supporting the proposed capex associated with this project.

122 Through an internal technical and economical assessment report submitted as part of the project review "Refurbishment of Hazelwood Power Station 220 kV Switchyard", 21 January 2007

123 GEC-AEI type JW420 bulk oil circuit breakers.

Other benefits of this investment decision have been identified by SPA as[124]:

- the avoided risk of internal flashovers and other failure modes of the aging bulk oil circuit breakers
- avoided capex associated with the need for oil bunding around each of the circuit breakers to comply with SPA environment policies
- reduced operating and maintenance costs over the forecast period, particularly associated with
  - frequent and time-consuming routine maintenance
  - expensive unplanned maintenance
  - the lack of manufacturer spares or support
  - issues associated with working in confined spaces (within the tanks)
- difficulties with respect to the size and manoeuvrability of the circuit breakers
- reduced consequential losses associated with asset failure risk. This includes threats to health and safety, environmental damage such as oil leaks, reduced reliability and system stability impacts, exposure to availability penalties, and collateral damage to adjacent plant.

The risk of bushing failure for these specific circuit breakers is compounded by the difficulty in performing condition monitoring. The design of the units requires the oil to be fully drained and for the unit to be partially disassembled, which makes oil sampling difficult[125].

The twenty four circuit breakers (CBs) proposed for replacement occupy the positions 2 through to 25 in the ranked listing of over 1000 circuit breakers within the condition based asset risk model established by SPA. These units have been assigned a mean time before failure of around seven years (as at 2008). This is forecast to increase to one failure every two years if no action is taken prior to 2013. SPA has categorised the breakers in question as 'very high' risk assets. The SPA model indicates that each of the circuit breakers has the same relative risk, which is almost eight times higher than any other type of circuit breaker within the switchyard. With respect to the consequences of asset failure, failure of two of the circuit breakers would result in significantly higher consequential costs than the remaining 22 as they act as single switches connecting generators to the network[126].

The output of SPA's CB (whole population) risk model shows that in 2008 around 95 220 kV CBs have a 'very high'[127] risk ranking, and that this number increase to around 117 by 2013 if no investment is undertaken. The HWPS circuit breakers make up a large proportion of these 'very high' risk units.

SPA has advised there have been three explosive failures of the JW420 series circuit breakers since 1992, and that one of theses incidents occurred at HWPS.

A range of additional and qualitative benefits of the proposed project have been identified, consistent with SPA strategies and polices, these include the following:

- furthering the roll-out of contemporary condition monitoring for new plant

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124 ibid, Page 14

125 Condition monitoring requires analysis of the oil contained within the bushing. The testing which is undertaken is known as dissolved gas analysis (DGA).

126 The consequence of single switches is that there is no operational redundancy which may otherwise provide security in the event of switch failure.

127 The 'very high' risk category is defined as those circuit breakers having a meant time before failure (MTBF) of less than 8.8 years.

- reduction of the number of oil filled plant within switchyards and the associated fire risks
- furthering the introduction of standard equipment types within the stations
- the rationalisation of spares holdings
- reduction of the risk of adverse publicity and attention through the disruption to customer and generator connections.

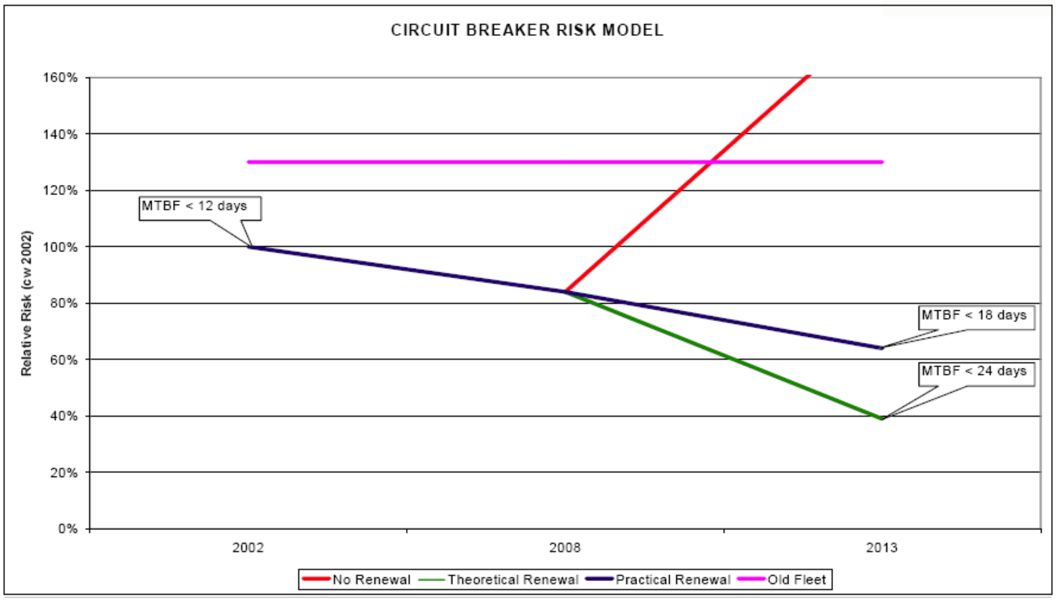
Underpinning SPA's proposal is a media release[128] which advised that the Hazelwood Mine West Field has been approved by the Victorian Government, assuring the long term operation of the Hazelwood power station.

K.3 Strategic alignment and policy support

SPA's overall Asset Management Strategy is comprehensive and structured to include a number of individually documented process, system and plant strategies. A number of these include direct references to circuit breakers, in particular bulk oil circuit breakers.

SPA's asset management strategy[129], discusses the businesses objective of delivering a 20% improvement in circuit breaker risk through the progressive replacement of 260 air blast and bulk oil circuit breakers by 2013. This target is represented in Figure K-1, derived from the SPA circuit breaker risk model[130].

Figure K-1 – Output of SPA's circuit breaker risk model



Source: SPA presentation on its circuit breaker risk model

The SPA asset management strategy associated with bulk oil circuit breakers[131] sets out the planned replacement of bulk-oil CBs over the next 12 years. It also describes how this approach aims to prioritise the timing of replacement according to thermal loading and other key factors. The CB strategy aims to ensure that bushings are given regular (not greater than

128 Media release by the Minerals Council of Australia, September 2005.

129 SPA, Asset Management Strategy, AMS 10-01, Section 7.4.

130 Use of the risk models in the development of the proposed SPA investment program is discussed in more detail in Section 2.2 of this report.

131 AMS 10-54 – Circuit Breakers, Section 1.7.2.

4 year) DGA and moisture tests. The practice of salvaging CB parts (to the extent reasonable) is also encouraged.

Furthermore, SPA asset management strategy refers to plans to redevelop HWPS between 2011-2013, that it will undertake regular condition assessment of bushings, and that it must adopt OH&S practices dealing with confined spaces, and implement a number of local procedures to address oils spills[132].

SPA has provided PB with information regarding the EPA guidelines for oil containment and bunding and the effect of these requirements on its design philosophies. PB notes that the existing CBs are exempt from the bunding requirements on the basis that SPA has plans to replace them shortly.

SPA also provided documentation[133] to support the technical specification requirements associated with new plant located in the Latrobe Valley, as advised by VENCorp and co-ordinated with the Victorian System Code.

Strategic co-ordination with other projects

At HWPS, six GEC (Type FMJL) post-type CTs are to be replaced in 2007 as part of a separate program of works, plus the roll-out of the SCIMS and CB management system.

SPA has advised that over the next regulatory period there will be some control and monitoring work undertaken at HWPS, but no other material (primary or secondary) work is proposed. Only minor replacement works have been undertaken at HWPS over the existing regulatory period, and SPA has advised that none of this work will be devalued by the proposed capex program.

VENCorp has augmented a number of the circuit breakers over the preceding period to mitigate fault level issues, and is planning[134] the installation of series reactors at Jeeralang for the same purpose.

K.4 Alternatives

SPA has identified seven alternatives to address the asset failure risk within HWPS, as follows:

- the ‘do nothing’ base case, where assets are replaced on failure and no planned capital expenditure is proposed
- deferred replacement, where existing assets are refurbished to extend their technical life, at which point the circuit breakers will be replaced
- planned replacement by asset class, this involves targeted replacements by asset type within the station or across the network
- planned condition based replacement, where individual assets are replaced as their condition deteriorates
- bay-by-bay replacement, where all assets within each switchbay are replaced at the same time
- targeted brownfield replacement, including replacement of parts of the switchyard on the existing site while some assets were in operation
- greenfield replacement, involving construction of the entire switchyard on a new site.

132 AMS 10-106 – Circuit Breakers – Summary of Issues and Strategies, Section 1.3.9.1.

133 SPA, Circuit Breaker Ratings and Use Of ROIs.pdf

134 Refer to VENCorp Board Approval – Hazelwood reconfiguration, 18 September 2006.

SPA considered the risks presented by the bushings of the bulk oil JW420 circuit breakers are significant enough to eliminate the do nothing base case. Furthermore, it advised that a number of the existing circuit breakers at the site are relatively new and of a different design to those being considered for replacement and therefore suitable for continued service. Given this situation, the planned condition based replacement, the bay-by-bay replacement and the greenfield replacement options have not been considered further.

With respect to the do nothing scenario, which effectively represents a run to failure approach, SPA has presented an economic evaluation which highlights that the cost of replacing a CB, after a major failure at HWPS, is likely to range between 1.7-2.2 times the cost of its planned replacement, depending on the criticality of the circuit breaker's role. This is based on an assessment of the premium associated with an emergency response, the direct and ongoing maintenance costs, and the consequential damage.

SPA short-listed the deferred replacement and the targeted brownfield replacement options for detailed technical review.

The targeted brownfield replacement option involves immediate redevelopment at a cost of $36.6m (real, 2006/07), staggered over a six year period. The scope of work includes:

- replacement of 24 bulk oil JW420 dead tank type circuit breakers and associated equipment based on a 'like for like' design
- establishment of a new building to house the new protection, monitoring and control equipment that supports the new primary plant, as well as new auxiliary supplies
- new cabling, as required between the new plant, the new building, and the existing relay room.

The deferred replacement option involves a two stage approach to works at HWPS. Stage 1 includes early expenditure of $5.4m (real, 2006/07) in 2008/09 for

- the refurbishment of the air compressor system integral to the performance of the critical JW420 circuit breakers
- removal, refurbishment, and re-installation of the bushings of the critical JW420 circuit breakers
- other minor works on the circuit breakers (e.g. replacement of valve seals, re-lubrication of the mechanical drive system)
- bunding of the bulk oil circuit breakers to ensure compliance with environmental polices
- replacement of all pin and cap type insulators
- the repair of moving contact systems and replacement of bearings on all disconnect switches.

Stage 2 of the deferred replacement option is identical to the targeted brownfield replacement option but with project commencement being delayed until 2018/19 (10 years). Given that no replacement parts are available, the limited historical success of refurbishment of the CB bushing's, and the increased exposure of the CBs to other age-related failure modes, SPA believes that achieving this 10 year investment delay may not be possible.

Options analysis

For each option selected for detailed review, SPA has prepared capital cost estimates (based on the defined scope of works), operational costs (based on historical maintenance records over the previous 15 year period), and consequential costs associated with the forced outage of lines, transformers or generators connected at HWPS. This information is used as the basis for a comparison of the (present value) life-cycle costs associated with each option.

The results of this economic assessment are presented inTable K-34. This analysis shows that the targeted brownfield replacement alternative is the most cost effective (i.e. lowest total costs present value at $33.6m). The deferred replacement option is significantly (20%) more expensive than the preferred option.

Table K-34 – Results of present value analysis for HWPS redevelopment

Option	capital costs	operational costs	consequential costs	total costs
Deferred replacement	36.2	2.4	1.8	40.4
Targeted brownfield replacement	31.5	1.7	0.4	33.6

Source: SPA report on the refurbishment of HWPS

PB notes that the dominant factor in selection of the preferred option is the capital cost (present value). The operational costs and consequential costs only have a secondary influence in terms of impact on the total (overall) cost and hence the selection of the most economic option.

The key assumptions underlying this assessment include:

- use of a 6.6% discount factor and a 46 year planning horizon
- real escalation of capital costs at 5% per annum
- the stage 1 refurbishment as part of the deferred replacement option being staggered over two years (and not escalated)
- operational costs for both planned[135] and unplanned[136] maintenance activities derived from the previous fifteen years of historical MAXIMO data, escalated at 5% per annum in real terms
- a value of customer reliability of $29,600/MWh applied to un-served energy as part of consequential costs
- loss of generation valued at historical annual average market prices[137] as a part of consequential losses
- failure rates and repair times derived from historical CEA[138] and CIGRE[139] studies (as opposed to site specific data), and adjusted using scaling factors established by SPA based on comparison of the published data with the respective age[140] and duty[141] of plant being reviewed
- failure rates accounting for general failures, failure to trip, failure to close and failure without command.

The approach adopted by SPA in quantifying consequential losses, as part of its economic analysis, has defined aged based thresholds of 20 years, 40 years and 55 years, to determine the applicable probability of failure for individual CBs. All of the circuit breakers at HWPS reside in the 40 to 55 year old bracket at the proposed replacement date, and on this

135 $1,657 per JW420 CB per annum for planned maintenance.

136 $1,218 per JW420 CB per annum for unplanned maintenance.

137 Valued at $4,202 per hour 200 MW (nominal) machine.

138 Canadian Electricity Association (1998).

139 CIGRE (1979).

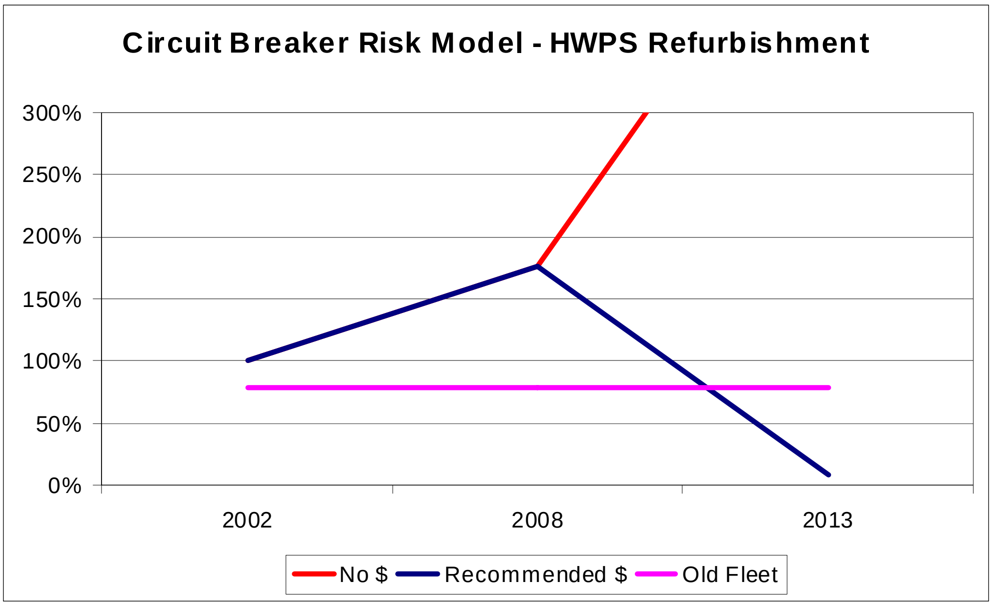
140 Scaling factors for age were 0.5 for 0-20 years, 1 for 20-40 years, 2 for 40-55 years and 4 for 55+ years.

141 Scaling factors for duty were 1 for annual operations less than 65 and 2 for greater than or equal to 65.

basis, the failure rates applicable are 2.58%, which is representative of 1 unit failing per annum for every 39 units in service.

The reduction in risk, on a station basis, at HWPS is shown in Figure K-2, which is derived from the application of SPA's circuit breaker risk model.

Figure K-2 – Output of SPA's circuit breaker risk model for HWPS



Source: SPA analysis

The key observations from Figure K-2 are as follows:

- that the 2002 reference risk level exceeds the 'old fleet' curve, resulting from the fact that the HWPS circuit breakers are already beyond the standard life which SPA has attributed to its 220 kV circuit breakers
- that the rate of change of risk with time increases significantly if no expenditure is undertaken142
- This increase in risk under the 'do nothing' option is driven by two factors, the progression of the CBs along the age-based failure curves, and a change in the shape of the failure curve based on the accelerating deterioration of the bulk oil units with age
- the comparatively low (minimal) risk in 2013 in the event that the proposed expenditure is undertaken
- an improvement in (relative) risk of 175% between 2008 and 2013 in the event that the proposed expenditure be undertaken.

With respect to the system-wide (as opposed to station based) CB asset model risk (refer Figure 6–1), it is noted that replacement of the 24 JW420 CBs at HWPS prior to 2008 would reduce the relative risk level by 7.9%, and that replacement prior to 2013 would cause a relative reduction of 15.5%.

142 It is noted that joining the risk data points linearly gives the impression that the relationship between time and risk may be linear. PB understands that this is not necessarily the case and that, for example, the 'do-nothing' option does not result in a step change in rate of change of risk (with time) at 2008 – as may be inferred by the chart shown in Figure 0-6.

K.5 Timings

SPA has advised that the replacement program for works at HWPS has been further refined as an outcome of additional planning work since its revenue submission. The expenditure associated with the updated work program is shown in Table K-35.

Table K-35 – 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 (original)	8.2	4.1	8.8	3.5	5.8	6.2	36.6
Updated SPA proposal	4.9	11.7	8.6	3.4	5.6	1.5	35.7
difference	(3.3)	7.6	(0.2)	(0.1)	(0.2)	(4.7)	(0.9)

Source: SPA analysis

The 2008/09 expenditure accounts for project establishment, design, trenching, infrastructure and communications work. While the ongoing profile accounts for the annual replacement of 9, 7, 2, 5 and finally 1 circuit breaker per annum[143]. The age at replacement will range between 43 to 50 years, and as at 2008 these 24 circuit breakers occupy positions 2 through to 25 in the ranked listing of the 1000 plus circuit breakers in the CB current fleet[144].

As part of the sequencing, co-ordination, and prioritisation of this project, SPA has considered the asset model ranking of individual circuit breakers, advice from the connected generator (International Power), the system wide importance of the lines being switched, availability rebates, planned outage recall times, logistical issues, and OH&S matters when undertaking the site works. SPA advises that the long project duration and extended expenditure profile is dictated by the nature of brownfield replacement works (each unit must be done in a progressive manner, as opposed to multiple units being replaced at once), the critical role the circuit breakers play in the switchyard, the bulk oil characteristics of the units, and the length of time taken to replace each unit.

K.6 PB analysis

Having undertaken a detailed review of the project documentation presented by SPA, the following section sets out PBs view on the prudence and efficiency of this proposed capex expenditure.

Clear Need

SPA's technical assessment of plant at HWPS confirms that the primary need for this project is related to the management of risks associated with electrical and mechanical failure of the bulk-oil circuit breaker bushings. Given the increasing age and deteriorating condition of these breakers, and the associated OH&S, environmental, plant outage, and collateral damage consequences identified, PB is of the view that a justifiable need has been established. This is confirmed by a significantly increased rate of change of relative risk associated with the CBs in the event of 'no renewal' (ref. Figure 6–1), and also the fact that the specific CBs at HWPS rank in positions 2 through to 25 within a fleet of over 1000 units.

143 It is noted SPA provided inconsistent advice on the annual replacement numbers on 06/06/2007, and that this was an error based on lack of access to appropriate data (as confirmed on 08/06/2007), so original advice adopted.

144 Note that lower numbers indicate higher priority.

Strategic Alignment

During this review, PB has identified a general consistency between the proposed project and documented SPA policy. The project delivers a 15.5% reduction in the circuit breaker (relative) risk through to 2013.

PB notes; however, that the basis for SPA's objective to seek a reduction in quantified risk (as defined) of 20%, relative to the 2008 position, has not been substantiated. PB is not aware of any economic justification for the absolute target reduction number (e.g. why a 0% or 40% reduction would be more or less appropriate), nor any alignment of this target to other measures (such as service standards).

We note that the project does deliver on the SPA circuit breaker plant strategy to replace all bulk oil CBs over the next twelve years (viz. 2007 to 2019); however it is noted that this project involves replacement of the circuit breakers across the early years of the period only (viz. 2008 to 2013) – suggesting that there is some opportunity to defer the expenditure while still meeting the overarching asset strategies.

With respect to the summarised plant strategy (AMS 10-106), the SPA proposal to advance redevelopment of HWPS by three years appears to be inconsistent with its stated approach to initiate the redevelopment of HWPS in 2011. No specific reason for advancing the HWPS project is given by SPA.

The approach at HWPS appears to be consistent with a targeted asset replacement strategy that makes due allowance for the historical investment made by VENCorp over the current regulatory period. This recent investment supports the *targeted brownfield replacemen*t approach.

Alternatives

When investigating the alternatives to mitigate the circuit breaker failure risk at HWPS, PB has formed the opinion that SPA has undertaken a comprehensive review and has considered and documented its assessment of a number of reasonable alternatives. In some cases, we believe that additional transparency would have been gained by explicitly assessing, and eliminating, alternatives though the economic analysis presented.

Furthermore, PB believes that consideration and assessment of some sub-options, in addition to the preferred option, would better support SPA's economic findings underpinning the proposed capex[145].

In undertaking analysis of SPA's detailed economic assessment, PB has observed some input assumptions which appear to disadvantage the *deferred replacement* option:

- a lack of recognition of any impacts of the Stage 1 refurbishment works on the operation and maintenance costs of the 24 circuit breakers
- the 5% real escalation of capex that is programmed beyond 2012, and 5% for opex across the entire period.

PB has also identified that two aspects of the scope of works for the *deferred replacement* option are somewhat subjective:

- while claiming the figure is optimistic, SPA has not supported the decision that the $5.4m Stage 1 works defer the targeted replacement by 10 years with any technical information

145 For example, the inclusion of the targeted replacement of circuit breakers noted as having consequence of failure an order of magnitude higher.

- the need for bunding as part of Stage 1 works may be considered debatable – given that the circuit breakers are currently exempt from this requirement, and that the intention is to replace them in the medium term in co-ordination with procedures to address potential oil spills. PB notes that SPA has separately proposed a capex allowance of $11.6m to address oil and water management issues at various sites. Without undertaking a detailed review of this project, and giving the benefit of doubt to SPA that there is no duplication of work, we have assumed that this has not included works at HWPS, but SPA should confirm this matter.

Of these observations, PB believes that the most material is the use of a 5% real escalation factor for future cash flows. Sensitivity analysis indicates that use of a 3% factor alters the economic analysis to such an extent that the *deferred replacement* alternative has a marginally lower present value cost than the *targeted brownfield replacement* option.

Furthermore, use of no real escalation, suggests that the *deferred replacement* option is materially cheaper (23% less) than SPA's preferred option (viz. $25.7m compared with $33.6m). Notwithstanding that SPA has applied its cost escalators in a biased manner, PB believes there is no basis to include a significant real cost escalator across the entire NPV analysis time frame, in particular as there has already been some allowance in development of the capital cost estimates used in the assessment. Given this outcome, PB recommends that the *deferred replacement* option, involving the initial expenditure of $5.4m, is a more prudent and efficient development alternative. It is however, noted that while this option reduces the asset failure risk presented by the bulk oil CBs, it does not reduce it materially.

PB is of the view that the 6.6% interest rate used for the HWPS cash flow analysis is reasonable[146], given it is slightly higher than SPA's proposed pre-tax real WACC rate of 6.25% at present.

PB is of the view that the input assumptions, methodology, and outputs of SPA's determination of operation costs, and consequential cost models, are reasonable and representative for the purposes of differentiating between the development options considered at HWPS.

Timings

Notwithstanding PB's finding that a more economically efficient option is to defer the *targeted brownfield replacement* program, PB has identified that SPA's' proposed sequence of replacement of the 24 bulk oil circuit breakers is reasonable over the six year period. In particular, we note the need to replace each unit in a co-ordinated and sequential manner. However, it is noted that the six units that have the highest consequence of failure are scheduled for replacement in the final three years – a counterintuitive outcome considering these would rank as the highest priority units. PB understands that this approach has been adopted in the light of preliminary advice from the connected parties, and will in practice be heavily influenced by the power station maintenance program. PB considers that the staggered development approach adopted by SPA is reasonable given the complexity of the switchyard configuration.

At an overall network level, the timing of SPA's *targeted brownfield replacement* of bulk oil circuit breakers at HWPS is aligned with its strategic policy to replace these types of 'very high' risk units, and to reduce the overall relative risk by a target of 20%.

K.7 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

146 As agreed between PB and the AER via email dated 21 June 2007.

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[147]. 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[148] 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 been presented with or reviewed any such analysis and believes SPA has not justified a need for this expenditure. 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[149] 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 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 – that of the critical work associated with

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

148 50kA fault rating, 3,150A load rating.

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

the removal, refurbishment, and re-installation of the bushings on the circuit breakers[150] – although we recognise that this may be reflective of the intensity of the work requirements and therefore do not propose any adjustments.

K.8 Subsequent update

During discussions with SPA (subsequent to PB's initial review of its project documentation), the business has advised that its application of a real 5% escalation of capital costs beyond the 2012 period was an error and that the original cost estimates already include an allowance for ongoing material and labour escalation.

As identified by PB, and underpinning our initial conclusion that the *deferred replacement* option was more appropriate than the *targeted brownfield replacement* option, this input assumption plays a critical role in the overall economical assessment. Given SPA's acknowledgment that the escalation was inappropriate, SPA has revisited its economic analysis comparing the two alternatives. SPA considered that the technical feasibility of the original *deferred replacement* option was not substantiated due to the very low success rate in refurbishing the bushings of the bulk oil CBs.

SPA has advised that its historical success rate of dismantling, refurbishing, and re-installing the bushings has been as low as 25%. On this basis, SPA has re-defined the *deferred replacement* option to account for upfront replacement of 14 units to release bushings to allow the remaining ten units to be refurbished successfully, followed by subsequent replacement in 2018/19 (10 years). Effectively this reflects in a capex spend of $4m for the stage 1 refurbishments; $22m for the stage 1 replacements; followed by a further capex spend of around $15.5m in 2018/19. SPA considers the likelihood of successfully refurbishing 10 circuit breakers, given the replacement of 14 of a similar type to release parts, is still highly optimistic and that this should be considered in conjunction with the economic assessment outcomes.

As part of the updated economic assessment, SPA also included a revised calculation of the operation and maintenance costs, and the consequential costs for each option. The results of the updated evaluation are presented in Table K-36.

Table K-36 – Results of revised present value analysis for HWPS

Option	capital costs	operational costs	consequential costs	total costs
Deferred replacement	31.5	1.0	1.1	33.5
Targeted brownfield replacement	31.5	1.0	0.6	33.0

Source: SPA analysis

This assessment indicates that the *targeted brownfield replacement* of all the circuit breakers provides a marginal economic benefit (dictated by reduced consequential losses), and SPA has maintained that its preferred alternative is still the replacement of all 24 circuit breakers across the next regulatory period. This approach is also heavily qualified given the optimistic success rate assumed for the refurbishment of the CBs.

In considering SPA's revised economic assessment, PB recognises the high sensitivity of the outcome to the underlying assumption regarding the technical feasibility of refurbishing the circuit breaker bushings, and the fact that while refurbishment reduces the risk of failure of old and aging circuit breakers, it does so only to a moderate degree. Effectively SPA has identified the breakeven point at which the *targeted brownfield replacement* will be economically prudent – if the all ten CBs last ten years or more, it will be economically

150 More than 100 person-days per unit.

efficient to defer the expenditure - if one of the units requires premature replacement or its refurbishment is not successful, then the *targeted brownfield replacement* option is likely to be efficient.

Notwithstanding SPA's original alternative to refurbish all 24 circuit breakers, PB concurs that it is unlikely that limited refurbishment of 10 circuit breakers at HWPS will defer their replacement by 10 years. Leading on from this, and with the deteriorating condition of the CBs and the likely risk posed by bulk oil units that will be approaching 55 years of age, we consider the *targeted brownfield replacement* is a reasonable, efficient and prudent development to progress at HWPS.

K.9 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 apparent, and has recommended a capex reduction of $4m to account for this.

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 K-37.

Table K-37 – 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[1]	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

Note 1, as amended by SPA
Source: SPA Proposal and PB analysis

APPENDIX L
REPLACEMENT OF POST-TYPE CURRENT TRANSFORMERS

APPENDIX L: 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 L-38.

Table L-38 – 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.

L.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[151] 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.

L.2 Drivers (need or justification)

Being a compliance based capex program, SPA has advised that the key drivers for the CT replacements include:

- a reduction in the likelihood of damage from explosive failures and fires and associated consequences
- management of Occupational Health and Safety (OHS) risk, and provision of a safe workplace for employees
- provision of a reliable service, specifically a reduction in the unplanned outage risks of lines transformers and generators.

In a population of around 1,850 units, SPA has experienced seven major failures of CTs since 1985. Importantly, five of these have occurred since 2002, with two major failures in 2006 and of the five units, four have been of CTs manufactured in the early 1980's (i.e. 20-25 year age bracket). The failures have occurred across a number of sites and at all voltage levels, plus there have been two failures of the same type of 500 kV CT at the same site.

The potential consequences of major failures include OHS issues with insulating porcelain being spread across wide areas; access restrictions; the imposition of NEM constraints, loss of supply to customers; availability rebates due to plant unavailability being imposed; collateral damage to adjacent plant; oil spills and fires. The failure mechanism is associated

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

with insulation breakdown aggravated by over voltages from electrical switching and lightning impulses, and results in rapid deterioration that is difficult to forecast accurately[152].

SPA's CT risk model indicates that the probability of failure for post-type CTs remains constant and low at 1 in 2500 until they are 22 years of age, doubling to around 1 in 1,115 at the age of 28, and then increasing to around 1 in 125 at the age of 50 years.

The age profile of the existing SPA CT assets is characterised by large volumes in the 20-25 and 35-45 age brackets. SPA has advised of growing industry recognition that design margins reduced too far during the late 70's and early 80's compared with older units, and that this has been supported by other Australian utilities experiencing major failures of CTs designed at this time. SPA has also indicated that its targeted replacement program is focussing on the 20-25 year old units while the station refurbishment program is addressing the risk associated with the older units.

SPA's increased condition monitoring of high risk CTs has precluded a number of units failing in service, as evidenced by forensic tests on retired items indicating significant levels of insulation failure.

SPA's CT asset risk model calculates a life expectancy for each unit and SPA considers a reasonable threshold to undertake a detailed assessment to replace a CT is a life expectancy of less than or equal to 10 years.

In a number of cases (approximately 23%), SPA has included the installation of capacitive voltage transformers (CVTs) to account for the voltage taps that were provided and used in the post-type CTs proposed for replacement. Such taps have been used for the purposed of energy metering, quality of supply measurements, synchronisation checks and condition monitoring.

L.3 Strategic alignment and policy support

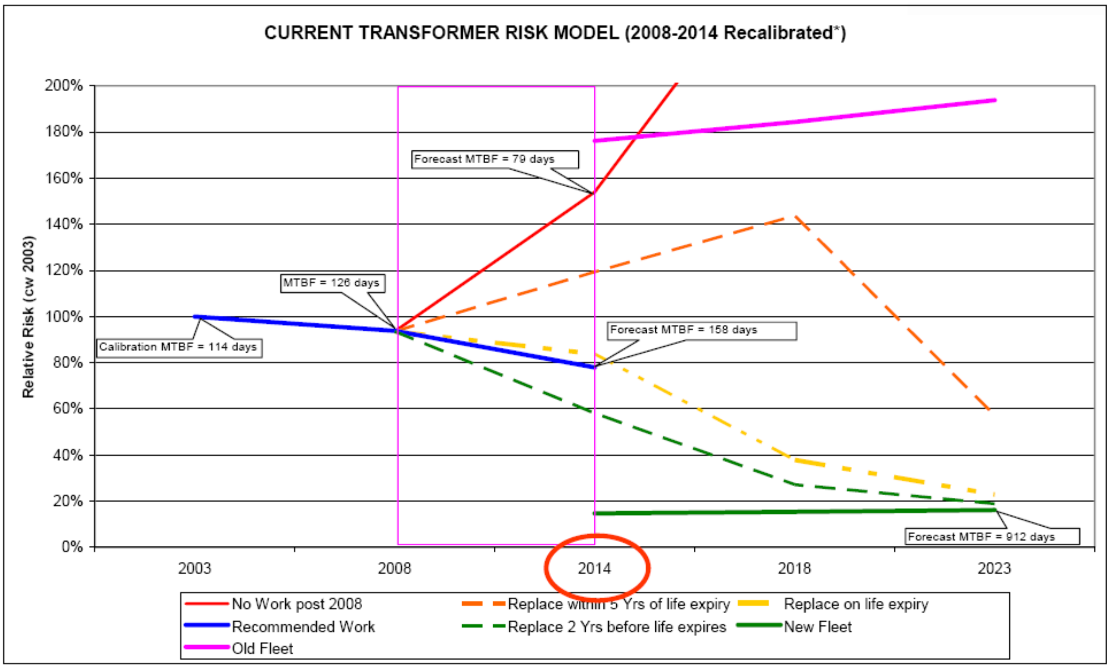
SPA's overall Asset Management Strategy is comprehensive and structured to include a number of individually documented process, system and plant strategies. A number of these include direct references to current transformers.

SPA's asset management strategy[153] discusses SPA's objective of replacing 580 single phase oil insulated CTs at various sites by 2013 (including both its station refurbishments and its targeted replacement program). The basis for this approach is a benchmark Mean Time Between Failure (MTBF) rate of 120 days and effectively the target has been established based on the desire to ensure all units with a life expectancy of less than or equal to 10 years are replaced over the next six years (prior to 2013/14). The targeted risk profile is presented in Figure L-1, where it can be seen that the 'no work post 2008' approach will result in a 50% increase in relative risk in 2013 compared with the 2008 position brought about by a reduced MTBF rate from 126 days to 79 days.

152 Recent technical reference papers indicate that under test conditions, condition monitoring can provide as little as one hour to eleven days notice of failure of CTs, subject to the type of CT.

153 SP AusNet, Asset Management Strategy, AMS 10-01, section 7.2 and AMS 10-64 – Instrument Transformers.

Figure L-1 – Output of SPA's current transformer risk model



Other documented strategies to improve SPA's ability to quantify deteriorating CT conditions and to reduce the risk of major explosive failures include:

- replace all 220 kV GEC FMJL type CTs at Jeeralang Terminal Station
- replace all GEC FMJL type CTs at Hazelwood Terminal Station
- replace all high risk Tyree 220 kV and 330 kV CTs
- replace 580 single phase oil insulated CTs by 2013
- continue DGA analysis during schedules maintenance
- increase oil sampling of Tyree CTs to an annual cycle
- increase enhanced condition monitoring of high risk CTs
- implement the 'Asset Health' reporting system
- implement annual RFI scans as part of station condition inspection
- implement off-line tests for plant that has no insulation medium sampling
- implement regular SF6 gas purity testing for 500 kV CTs, as well as an auto isolation policy for loss of SF6 pressure on 500 kV CTs
- monitor the failure and replacement programs of other utilities
- continue to forensic analysis of retired units to provide continuous feedback
- continuation of the CAMS monitoring of output voltages of CVTs
- increased spares inventories for CTs and CVTs, plus condition testing of spares to verify performance.

L.4 Alternatives

SPA has identified and considered three alternatives in its consideration of the risk posed by failing CTs:

- the ‘do nothing’ base case where assets are run to failure and no planned expenditure is proposed
- planned replacement by asset class, this involves targeted replacements prior to failure within a station or across the network
- bay by bay replacement, where all assets within a switchbay are replaced at the same time.

SPA also advised that CT refurbishment has not been considered as a feasible option as previous experience resulted in only minor improvements in monitored quantities, with no prospect of reversing insulation failure, and only slight extension of asset life.

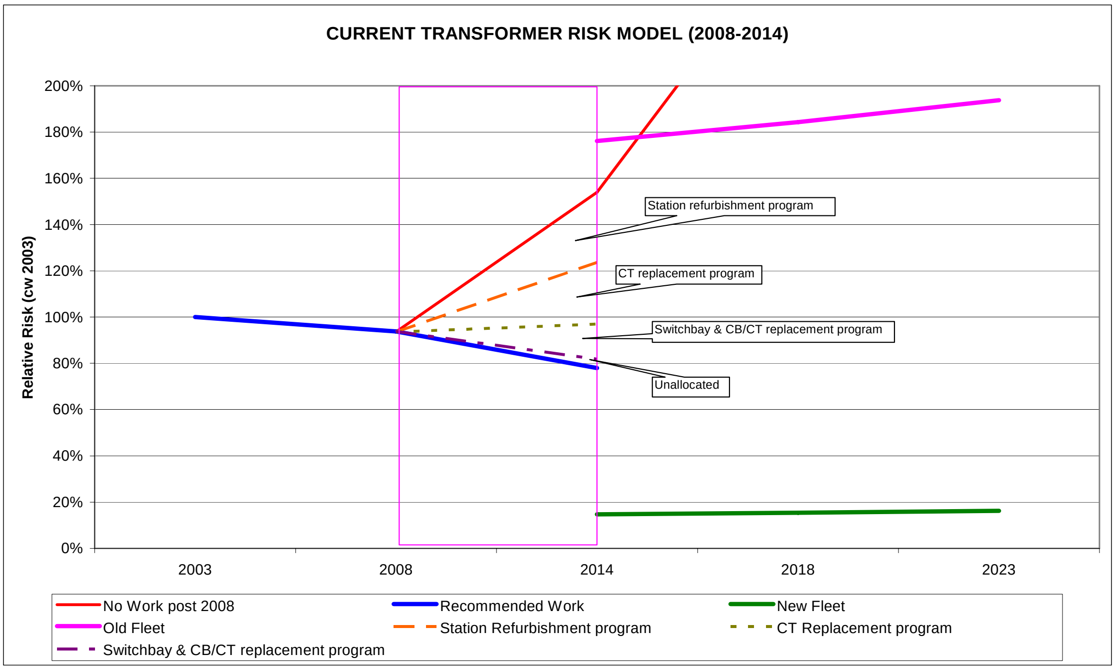
SPA has advised and presented an indicative economic analysis to support the position that the cost associated with the replacement of a failed CT far exceeds the planned replacement cost. This assessment is underpinned by the consequences of an explosive failure within a yard, particularly the emergency clean up costs and extended timeframes associated with the repair. Changes to work practices would also be required, along with the establishment of blast walls to protect field staff from the prospect of further explosive failures.

SPA advises that a *planned replacement by asset class* approach for CTs is preferred, as the program focuses strongly on high risk but relatively young CTs that are installed at locations where the associated electrical plant (primarily circuit breakers) is still in acceptable working condition. SPA concluded that the selective replacement of CTs within the defined program, which are all relatively young (less than 25 years old) and have a life expectancy of less than 10 years, provides the best outcome to address much of the risk associated with major CT failures.

This approach is to be considered in conjunction with SPA’s proposal to replace a large number of older CTs as part of its station refurbishment program, as well as its switchbay replacement program, which includes the replacement of around 200 sets of CTs at seven sites.

The reduction in risk across the asset category is represented by Figure L-2, which is derived from the application of SPA’s current transformer risk model.

Figure L-2 – Output of SPA's current transformer risk model for the targeted replacement and station refurbishment works.



The key observations from Figure L-2 are:

- the large increase in risk if no expenditure is undertaken after 2008 (red curve)
- the CT replacement program drives a relative risk improvement of around 30% of the total improvement of 75% between 2008-2014
- an overall relative improvement between 2003-2014 of around 22%
- twice as much improvement in the relative risk level between 2008-14 compared with that gained between 2003-2008
- some improvement in relative risk that is unallocated to specific capex (which is an anomaly, based on the extension of the risk model to include some CTs that are not in the on-line model – there is no capex associated with this reduced risk).

L.5 Timings

As part of the sequencing, co-ordination and prioritisation of this project, SPA has considered the condition-based asset model ranking of individual CTs, which quantifies rates of deterioration using an estimate of remaining life, the relative risk ranking and age. Practically, the implementation will also be co-ordinated with the other aspects of SPA's capex program so that efficiencies can be captured when other works are undertaken at switchyards that require CTs to be replaced.

This approach involves a staged expenditure profile, as shown in Table L-39, which accounts for 48, 4, 11 and 10 sets of CTs being replaced at voltage levels of 220 kV, 275 kV, 330 kV and 500 kV, respectively.

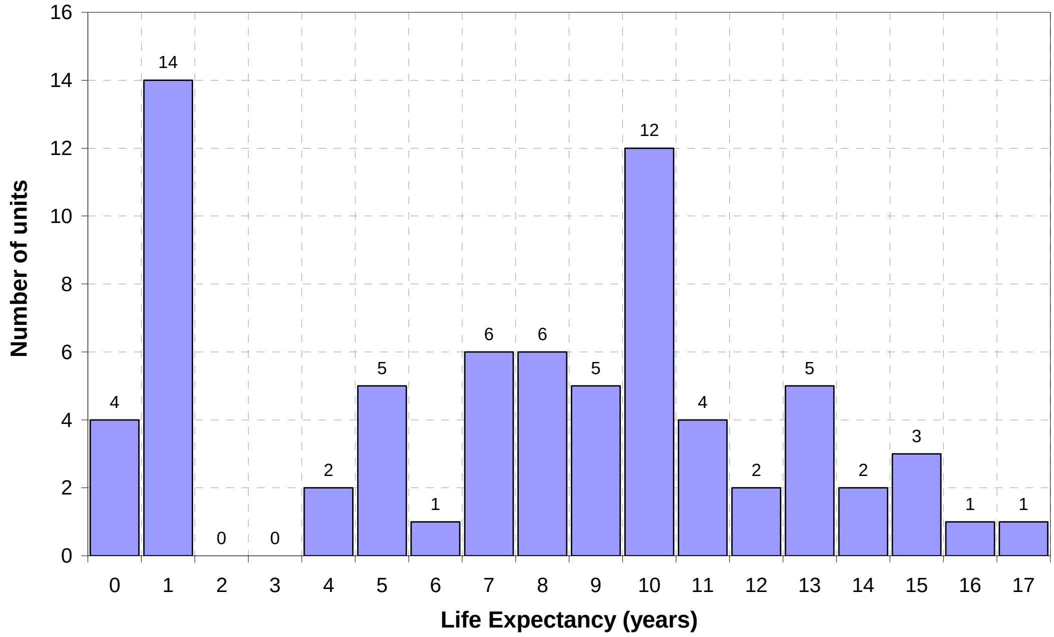
Table L-39 – Summary of SPA's proposed CT replacements

Expenditure, $m (as spent, real 07/08)	08/09	09/10	10/11	11/12	12/13	13/14	Total
ITEM	4.8	6.1	5.2	4.2	2.7	1.4	24.5
Units installed at 500 kV	6	-	4	-	-	-	10
Units installed at 220 kV, 275 kV or 330 kV	1	17	12	20	9	4	63
Voltage transformers	-	4	5	-	3	5	17

Source: PB analysis

This risk model output measure of 'life expectancy' for each of these CTs is presented in Figure L-3.

Figure L-3 – Life expectancy of CTs proposed by SPA for replacement.



L.6 Subsequent update

As part of discussions with SPA during our detailed review, PB raised some concerns regarding the apparent intentions to replace a number of CTs with high life expectancy (greater than 10 years) in the early stages of the 2008/09 to 2013/14 regulatory period. In particular, this was the case for an expensive set of 500 kV CTs at Loy Yang Power station switchyard (LYPS). SPA advised the original CT risk model outputs forming the basis of SPA's revenue proposal, were prepared based on the information available at the time of the submission, which was October 2006. SPA advised that the life expectancy figures presented in Figure L-3 are based on the latest output of the CT risk model, as of May 2007 and therefore did not reflect its current CT replacement intentions. SPA explained the material change in CT life expectancy figures was due to the nature of the regular and ongoing condition monitoring of the CT assets, and that the outputs of its risk model are relatively volatile and dynamic. The life expectancy of CTs may be shortened and extended substantially over a short period of time. SPA advised that in the case of the LYPS CTs, a previously identified problem was found to be less serious than envisaged. To offset this finding though, SPA also identified an issue regarding high dissolved gas levels with a fleet of 220 kV CTs subsequent to a post mortem examination of a failed unit at Terang (TGTS). Effectively the 18 CTs with a life expectancy of greater then 10 years in Figure L-3 are not currently planned for replacement; however as of May 2007 SPA has identified a similar number of CTs that have rapidly deteriorated so that their life expectance has reduced to less than 10 years. This updated life expectancy of CTs proposed for replacement by SPA is shown in Figure L-4, which confirms that SPA is only preparing to replace CTs with a life expectancy of less than or equal to 10 years.

Figure L-4 – Updated life expectancy of CTs proposed by SPA for replacement.

Given the dynamic nature of the CT risk model outputs, SPA has reinforced its position that the forecast capex on post-type CTs is very much an allowance only (in the context that the specific CT's nominated for replacement at this point in time may not be replaced) – since as time progresses the business will prioritise and manage its replacements based on the latest monitoring results, as required. In PB's view this is a sensible and practical approach.

On this basis, has not proposed to refine its CT program capex allowance based on the updated information as of May 2007. The application of SPA's CT asset failure risk models in this manner reflects the continual improvement process associated with SPA's risk based approach to asset management.

L.7 PB analysis

Having undertaken a detailed review of the project documentation presented by SPA, the following section sets out PBs view on the prudency and efficiency of this proposed capex expenditure.

Clear Need

Given the recent increase in major failures of CTs whilst in operation, and the difficulty in forecasting the rapid deterioration of these devices using ongoing condition monitoring, PB is satisfied of the general need to target the replacement of CTs across the network. In particular, PB considers the target criteria of replacing units that are relatively young (because older ones are generally targeted as part of station redevelopments) and rapidly deteriorating (low life expectancy) is a reasonable and pragmatic approach. The OHS related risks of catastrophic failure and other consequences are tangible and justify strategic capex investment. We concur with SPA that run to failure is not a practical or feasible option for CTs.

Strategic Alignment

During this review, PB has identified outcomes from the proposed project that are consistent with documented SPA policy. This project involves replacement of 73 sets of single phase CTs (approximately 220 single phase units) and delivers a reduction of around 25% in the relative risk across the CT asset category. The project goes a significant way to achieving the objective of replacing 580 single phase oil insulated CTs. PB highlights that the outcomes of SPA's investment decision drives a reduction in relative risk of more than 20% compared to the 2003 position and, a 15% reduction relative to the 2008 position, and that this material improvement in relative risk level has not been substantiated.

It is noted that a number of sets of CVTs are also scheduled for installation to accommodate for the ability of replaced CTs to be used to provide voltage indications.

Alternatives

Through our detailed review, PB has formed the opinion that SPA has considered all reasonable and practical alternatives to ensure the integrity of its CT assets and therefore maintain a safe working environment. The co-ordination of a replacement program targeted at rapidly deteriorating CTs in conjunction with efficient replacements as part of station refurbishments is a logical and appropriate outcome. We concur with SPA that refurbishment of oil insulated post-type CTs is difficult, and provides limited return on investment.

The presentation of a simple cost-benefit analysis comparing the run to failure option as considerably more expensive than planned and targeted replacements, further supports the need for capex.

Timings

At a high level, the expenditure program proposed by SPA appears to be reasonably smoothed to ensure its deliverability and balance available resources, it is however front end weighted (i.e. the proposed expenditure in 2009/10 is more than 4 times that in 20013/14). This is supported by the observation that there are a number of critical CTs with a life expectancy of less than 2 years. SPA has qualified the proposed program to the extent that it is the best forecast under the current circumstances and that with ongoing condition assessment (e.g. dissolved gas analysis), the implemented order and timing of replacements may vary.

Fundamentally, SPA's forecast for CT replacements outside of the station refurbishment projects is driven by the dynamic measure of life expectancy from the CT risk model and the defined consequences of the failures. In PB's view this is a sensible and practical approach. SPA considers there is considerable asymmetric risk regarding the timing of the replacements due to the very high potential consequences of failure, and has adopted a conservative approach based on the replacement of CTs well before their life expectancy reduces to zero.

PB agrees with this principle, but has identified that a significant portion (>64%) of the CTs proposed for replacement under this program have a life expectancy greater than or equal to seven years, with over 25% of the CTs proposed for replacement having a life expectancy equal to ten years, as of May 2007. The decision to adopt a life expectancy threshold of less than or equal to 10 years is a very sensitive input to determine the required capex. In PB's opinion, the use of the 10 year threshold appears to be an aggressive approach and given that SPA has not demonstrated a justified need to material reduce the risk associated with CT failures compared with the risk in 2008, then we conclude that a significant proportion of the proposed program is not prudent in the given timeframe.. Furthermore, a number of the

CTs in the proposed capex program are based on the replacement of the more expensive 500 kV CT types (i.e. there is also an inefficient aspect of the proposal where the cost of 500 kV CTs has been included for 220 kV units, given the subsequent update).

Given that PB has identified some aspects of SPA's expenditure is not prudent or efficient, and on the basis that the model is dynamic, and that some opportunities for optimisation need to be considered, hawse have established a revised expenditure program that reflects our opinion of a reasonable, prudent and efficient capex allowance given the latest information provided by SPA's risk model. Our approach has considered the life expectancy to establish priorities, the location to establish efficiencies, and used the same cost of the replacements as proposed by SPA to arrive at a pragmatic capex allowance. This final allowance is summarised in Table L-40, and some key aspects of our proposed expenditure profile include:

- a reduction in the total number of CT sets from 73 sets to 41 sets, as shown in Figure L-5
- minimal replacement of CTs that have a life expectancy greater than 7 years
- replacement of fifteen CTs with a life expectance of 7 years or greater - to capture economies of scale efficiencies
- single, critical CT replacements at Wodonga (WOTS) and Heywood (HYTS)
- wide scale replacements at Yallourn (x 16), Moorabool (x 10), Templestowe (x 8) and Fishbend (x 5)
- an allowance for the replacement of 1 x 220 kV, capacitor bank CT
- no replacements at Altona (ATS), Dederang (DDTS), Hazelwood Terminal (HWYS), Hazelwood Power (HWPS), Loy Yang (LYPS), Rowville (ROTS) South Morang (SMTS), Springvale (SVTS), Tyabb (TBTS), or West Melbourne (WMTS)
- a considerable reduction in the number of 500 kV CTs to be replaced
- a considerable reduction in the number of CVTs to be installed.

Figure L-5 – Life expectancy of CTs recommended for replacement by PB.

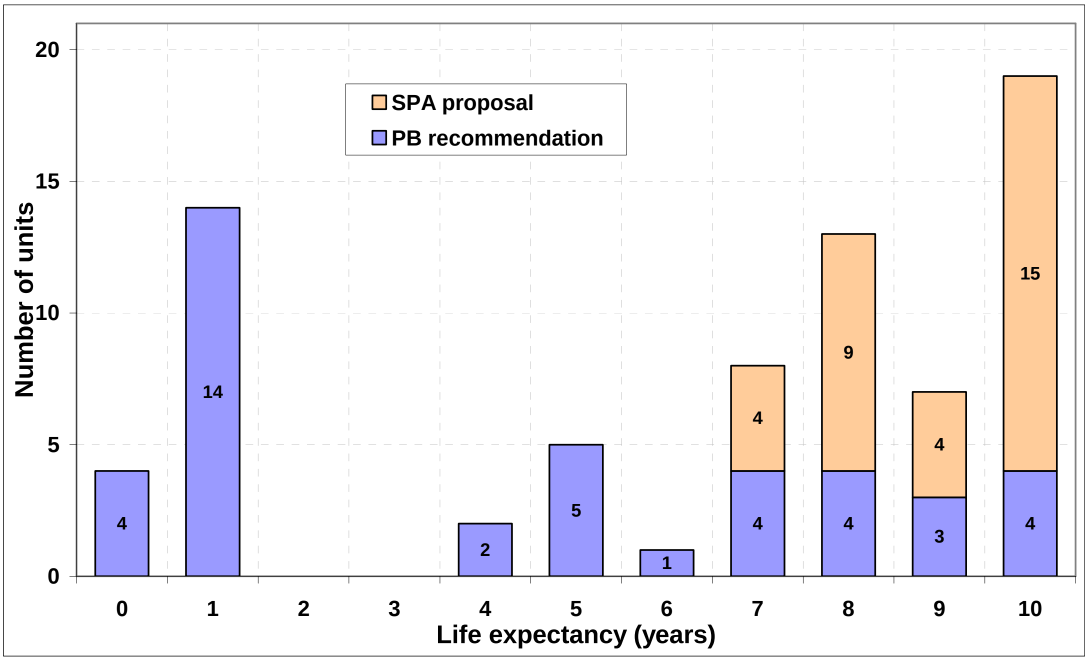


Table L-40 – Summary of recommended CT replacements

Expenditure $m (as spent, real 07/08)	08/09	09/10	10/11	11/12	12/13	13/14	Total
Expenditure	2.8	2.5	2.4	1.7	1.7	1.4	12.5
Units installed at 500 kV	1	-	-	-	-	-	1
Units installed at 220 kV, 275 kV or 330 kV	8	8	8	6	5	5	40
Voltage transformers	-	4	2	-	-	-	6

Source: PB analysis

PB considers this is a reasonable, prudent and efficient outcome as the profile captures the fact that there is some catch-up to deal with CTs that already have a very low life expectancy (front loaded expenditure) and that given the long run average failure of the SPA CT asset base, about 4-5 CTs are expected to reach the end of their life expectancy each year.

PB expects the revised capex allowance will have some impact in reduction in relative risk improvements proposed by SPA. The replacement of 73 sets of CTs reduced the relative risk level by around 30% - PB estimates that by capturing the most critical 41 sets, a reduction in risk of at least 20% will be achieved. This outcome will still ensure the overall CT asset risk is very similar to that in 2008, and PB believes this is an acceptable outcome and consistent with SPA's overall asset management strategy

L.8 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 L-41.

Table L-41 – 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.

L.9 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, the 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 justified need for all aspects of the proposed replacements. On this basis PB has recommended a revised expenditure profile that reflects what is considered 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 L-42.

Table L-42 – 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

APPENDIX M
RESPONSE CAPABILITY FOR UNDEFINED WORKS

APPENDIX M: 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 M-43.

Table M-43 – 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.

M.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 can not be described in any specific terms, but will be related to events associated with key assets.

M.2 Drivers (need or justification)

The need for this allowance is driven by SPA's desire to be able to respond to unforeseen events, such as adverse weather conditions, changes in Legislation or Code obligations, or general asset failure, without impacting on its planned capital expenditure program.

Historical experience over the 2003 to 2008 regulatory period has shown considerable expenditure, in excess of $45m, has been spent on unforeseen asset related works. These works have related to the need to maintain or improve operational capability and the examples presented indicate works have been required at multiple terminal stations and for multiple purposes, including but not limited to:

- replacing control schemes
- oil and gas sampling kits
- upgrading switchyard lighting
- replacing CVTs
- protection scheme replacements
- installing SCIMS
- instrumentation upgrades
- replacement of shunt reactors.

SPA considers that a small allowance to cater for small projects that are difficult to forecast is prudent.

M.3 Strategic alignment and policy support

The allowance is not directly linked to any strategic policy; however SPA recognises that the allowance, while not sufficient to address any large unforeseen expenditure requirements, will provide some opportunity for work to commence without impacting on the proposed program of works. This approach aligns to the objective of ensuring the businesses risk profile is attenuated, as required, and that the most efficient options are implemented

M.4 Alternatives

The alternatives considered by SPA were to either include an allowance or exclude it. On the basis that the consequences of excluding the allowance would be the potential deferral of planned replacement projects and a subsequent increase in asset failure risk, in the event that an unforeseen event occurs, SPA included the allowance to mitigate this risk of unforeseen events.

M.5 Timings

SPA has included the allowance in the first year of the regulatory period, to ensure the risk associated with unforeseen events is minimised across the entire regulatory period.

Subsequent to our review, SPA has advised that the submission templates were incorrect and that the correct expenditure profile should provide for the allowance to be spread evenly across the six year forecast, in accordance with Table M-44.

Table M-44 – Corrected capex profile 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 (updated)	0.92	0.92	0.92	0.92	0.92	0.90	5.5

Source: SPA update

M.6 PB analysis

PB appreciates the difficulty in undertaking a comprehensive and detailed bottom-up approach to capex forecasting across a six year outlook. In the interests of efficiency during the preparation of the forecast - every minor project can not be captured and there is a chance that unforeseen events not previously considered will arise. There is some merit in including a general allowance for unforeseen events; however this concept needs to be considered in the context of the regulatory regime and the level of detail, outcomes and perceived accuracy of SPA's forecasting process.

PB considers the inclusion of a minor works allowance to improve SPA's response capability to unforeseen events transfers the risk of such events to customers, who are unable to influence the degree of risk. Further, PB contends that the inclusion of a minor works allowance of this nature is inappropriate given the efficiency based structure of the ex-ante regulatory regime, and that the outcome is not likely to be revenue neutral should no unforeseen events occur. Given that the timing of the majority of SPA's planned replacement capex is somewhat discretionary, PB considers there will be minimal incremental risk in delaying some projects (valued at the token $5m) by up to six years to account for some unforeseen expenditure needs. SPA has had to address both minor and major unanticipated projects in it capital program over the current period. At its own volition, SPA has accepted that its asset management and capital management processes must flexible enough to allow such projects to be incorporated into its work plans on an ongoing basis without compromising its forecast replacement program.

In addition to the regulatory framework, the need for this unforeseen expenditure allowance must be taken into consideration with SPA's associated programs to improve its response capability and the other projects, programs and estimating processes adopted.

With respect to the expenditure proposed to enhance SPA's response capability, we note an additional allowance amounts to $20.8m, identified for:

- a suite of emergency transmission line structures that allow restitution of damaged towers. The structures are suitable for 220, 330 or 500 kV and can be stored ready for transport with other line insulators, fittings and associated equipment
- adequate spare cable joints and fittings to respond to 220 kV cable faults. SPA has 3 critical cable installations and requires a fault response capability for them
- circuit breakers at each transmission voltage including multiple units at 220 kV and 66 kV where there are large numbers installed on the system. The project must also include the purchase of disconnectors to allow restitution of a complete switch-bay in the event of a catastrophic failure
- a range of current transformers at each transmission voltage is required to provide a response capability. There is a significant program of replacement for these items however often damage is caused by non-electrical aspects of the equipment such as moisture sealing and where these are detected replacements are required
- optical and Multiplex (MUX) equipment
- portable radio base station and optic fibre equipment, housed in a caravan to be used for disaster recovery. Known as the emergency communications caravan
- communications infrastructure replacement
- network management overarching platform
- generic secondary equipment
- the purchase and storage of a spare 220/22 kV transformer and accessories suitable to enable it to be used as a temporary replacement for 11 transformers at BTS, BLTS, RWTS, RTS and WMTS.

In addition to these projects, we also note that as part of its estimating process, SPA has include a contingency level of around 5% for each of the station rebuild projects in its forecast capex program – this accounts for around $40m, it has adopted brownfield factors of around 10% in number of projects, plus another $2.3m for the non-prescriptive development of technical and design standards, provision of data to VENCorp and environmental noise management.

M.7 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, and that SPA's forecasting process should be much more accurate given the learning process across the current regulatory period.

M.8 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 can not 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 M-45.

Table M-45 – 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	—	—	—	—	—	—	—

Note 1, as amended by SPA
Source: PB analysis

APPENDIX N
TRANSFORMER REPLACEMENTS

APPENDIX N: 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 N-46.

Table N-46 – 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.

N.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. Three of these are at specific locations (Dederang, Bendigo and Yallourn), while two of these address a fleet problem across a number of metropolitan stations. This expenditure has been co-ordinated 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.

N.2 Drivers (need or justification)

The key driver behind the replacement of the transformers as part of this project is to maintain the transfer capacity to critical areas of the network given the deterioration of the aging assets. The deterioration is exacerbated by the increased loading of the units under system normal conditions, which increases the operating temperature and hence the rate of insulation aging. In addition to the incipient faults discovered and repaired, SPA has experienced nine major transformer failures since 1995.

The Dederang transformer proposed for replacement (designated 'H1' and rated as 330/220 kV, 225 MVA) forms a key component of the interconnection between Victoria and NSW. It is comprised of three single phase units and these have been in service from between 42-46 years. While there are no incipient faults identified, these units are the oldest main tie[154] transformers in service in Victoria, and the risk of failure for either the transformers or their bushing's is increasing. The units have suffered numerous faults[155] and have undergone previous programs of refurbishment[156]. A number of SPA transformers of similar design have failed in service. The three units are ranked in positions 46, 44 and 34 in the condition model.

The Bendigo transformer proposed for replacement (designated '2A & 2B' and rated as 230/67.5/22 kV and 125 MVA) forms one of a pair of transformers supplying the regional area surrounding Bendigo. The transformer is comprised of a bank of six separate units and these have been in service from between 44-48 years. While there is no evidence of faults within the transformer windings, the need for replacement is driven by risks associated with main tank oil leaks, bushing oil leaks (into the main tank contaminating the insulation medium), delaminated bushings and ageing and obsolete tap changers. There is also considerable risk due to the physical arrangement of the transformers that failure of one will lead to damage to one or more of the other units. This transformer is virtually identical to one that was replaced in 2007 at Terang, and identical to another scheduled for replacement at Glenrowan in 2012/13. The six units are ranked in positions 39, 35, 29, 29, 20, and 20 in the condition model. SPA has identified that there are a number of technical issues associated with these units that are not captured in the detailed risk models – these include the physical layout and the risk neighbouring units expose to one another, the lack of spares for tap changer mechanisms, and the excessive noise levels produced.

The Yallourn transformer proposed for replacement (designated 'No5 Group' and rated 230/11 kV and 54 MVA) supplies the water pumps for a local power station. It was originally designed as a generator step-up transformer and has been in service for around 50 years. It has a history of failures, including a major repair and the need for oil replacement, and measurements indicate high levels of contamination and moisture. SPA considers this unit has already continued in operation beyond its expected life and has done so on the basis that it serves a relatively small load (12% of its nominal capacity) and is supported with a full spare unit. This unit is ranked at position 58 in the condition model.

SPA has 21 metropolitan three phase transformers (rated 220/66 kV and 150 MVA) built by the same manufacturer and designed to fundamentally the same specification. The units range between 38 and 43 years of age. Six of these units are being replaced as part of the station redevelopment program (one at Thomastown, three at Richmond and two at Geelong). The remaining 15 units are all ranked high (between 34-64) in the transformer condition model and a number of these transformers have shown deterioration indicators (based on oil sampling results) that are consistent with international standards of excessive ageing rates. SPA advises that the excessive aging rates are symptomatic of the high load growth in the metropolitan areas and the probabilistic planning criteria adopted whereby units are exposed to higher loading under system normal conditions. SPA considers the risk of failure of the deteriorated units is unacceptable so in addition to the station based replacements and refurbishments proposed, it has made an allowance to replace two of the 220/66 kV transformers. The most critical units as of 2008 are those located at West Melbourne, Springvale, Morwell and Ringwood.

154 Main tie transformers are those that operate between the voltages of 500, 330, 275 and 220 kV only, as opposed to connection transformers that include windings operating down to 66, 22 and 11 kV.

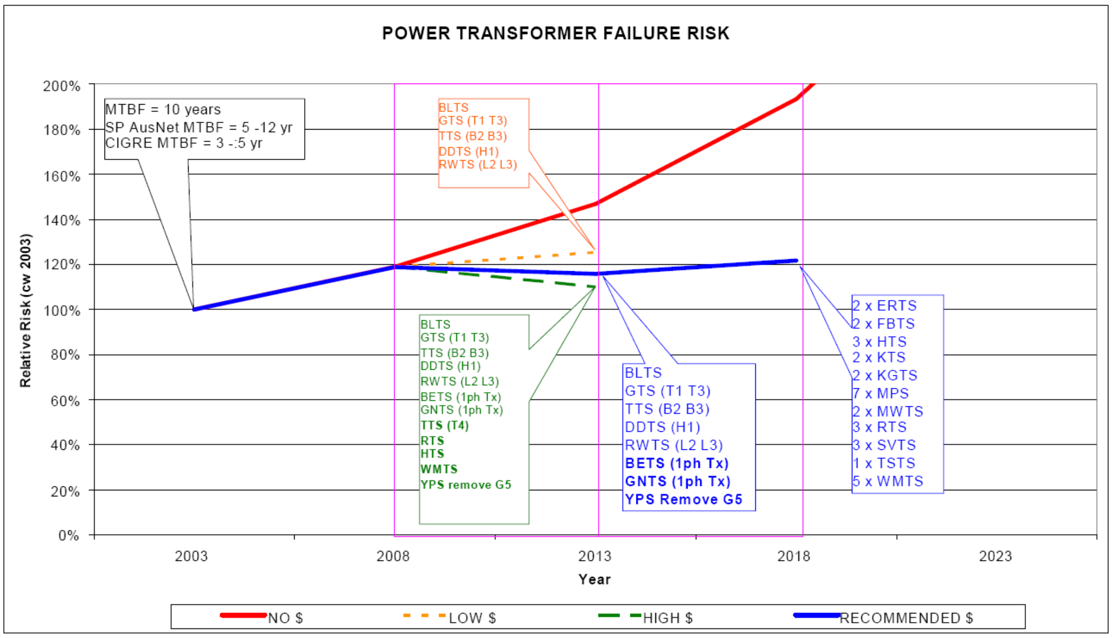
155 Notably, explosive bushing failures in 1965 and 1986, and a non-repairable discharge fault in 2000.

156 Bushings replaced with refurbished units in 1987 and reclaimed oil in 1998.

N.3 Strategic alignment and policy support

SPA advises that its major failure rate is 0.2% per transformer per annum compared with the national average of 0.4%. Through its documented[157] asset management strategy, SPA has set an objective to maintain a constant risk profile with respect to power transformers for the period 2008-2018. This risk level is escalated compared with that in 2003, and is shown in Figure N-1.

Figure N-1 – Output of SPA's power transformer risk model.



This outcome is reflective of a MTBF of between 5-12 years depending on the failure mechanism. SPA uses the output of its detailed risk model to monitor the individual performance of its transformers as well as the relative movement in relation to the performance of the fleet overall. It uses a condition score trigger point of 40 to identify transformers that require further investigation.

The principle strategies employed by SPA to manage its power transformers failure risk are:

- development of replacement or refurbishment plans for all units over 25 years of age
- replacement of metropolitan units at approximately 55 years of age and/or based on condition assessment results
- except in specific circumstances, no refurbishment of units older than 35 years, plus refurbishment of two units per year across a range of transformer types
- replacement of two three phase units (post 1964) plus 57 less efficient and single phase units (pre 1964) at multiple terminal stations to maintain a stable risk profile
- continuation of the routine condition assessment and testing (initiated in 2000) to prioritise units requiring additional attention
- progressive replacement winding temperature indicators and cooling controls with modern equivalents
- the integration of re-testing of critical bushings within the monitoring and replacement program

157 AMS 10-01 – Asset Management Strategy, section 7.2, in conjunction with AMS 10-67 – Power Transformers and Oil Filled Reactors

- implementation of a management program for insulating oils, to include OLTC diverter switch repairs, shunt reactors, oil leak repairs, oil filtering and reclamation, and progressive replacement of non-scheduled PCB oils, etc
- contingency response planning, including strategic spare holdings, fire suppression systems, blast/firewall installations based on network criticality and terrorism risk.

N.4 Alternatives

SPA has considered three basic options to mitigate the risk of major transformer failures over the 2008/09 to 2013/14 regulatory period, including run to failure, refurbishment to restore reliability and extend the asset life, and upfront replacement. Replacement options include either targeted transformer replacements or station based rebuilds, where the preferred outcome will be subject to the condition of associated key plant within the selected terminal station.

Notwithstanding SPA's firm position that a run to failure approach does not comply with good electricity practice, it also considers that it is far less economic compared with planned and co-ordinated replacements. SPA provided a representative economic analysis that showed the cost of recovering from a catastrophic failure was inefficient given the consequences of explosive failure, which includes:

- cost penalties to clean up the explosive failure
- considerable increases in ongoing maintenance costs associated with the installation of protective barriers around future worksites
- considerable costs associated with re-establishing workforce confidence through the use of testing plant and training staff
- the urgent purchase, manufacture and delivery of a replacement unit
- post mortem investigations to determine the extent of damage and reasons for failure
- costs associated with the transport and installation of any spare units.

For the Dederang transformer, SPA considered that additional refurbishment would not be a practical option given the deteriorating insulation identified. Given this fact, and in combination with other technical limitations such as the unit's relatively high electrical losses, the ongoing restrictions on import capability imposed by the low short time thermal capability, and the lack of on load tap changers to provide voltage control, SPA has proposed the planned and co-ordinated replacement of the unit. In discussions with VENCorp, and in accordance with VENCorp's previous request regarding transformers at Dederang, the replacement unit is expected to allow for some augmentation and be matched to the rating of the existing three phase units (i.e. designed to allow 340 MVA throughput with fans and 400 MVA for a short duration).

For the Bendigo transformer, given the critical role the transformer pays as one of a pair supplying the area, and coupled with the old age and poor state of the six single phase units, SPA proposed for it to be replaced. The numerous issues including increased maintenance associated with multiple oil leaks, plus obsolete tap changers suggest refurbishment is not practical or economic in the short to medium term. SPA has estimated a refurbishment option to be around $3m, but has not supported this figure. Furthermore, in order to capture economies of scale, the replacement is planned to coincide with the Glenrowan station rebuild which includes replacement of identical transformers. SPA's replacement has included some augmentation to account for Powercor's forecast plans for augmentation at Bendigo.

For the Yallourn transformer, no specific alternatives were considered to the replacement of the unit.

For the fleet of 150 MVA metropolitan transformers, SPA has advised any replacement decision shall be made based on the relative rates of deterioration between the various units. Replacement has been shown to be economically and technically feasible compared with refurbishment options (which only tend to improve reliability rather then considerably extend service life) and the inefficient costs of replacing a unit after it has failed in service.

N.5 Timings

SPA has advised of its proposed commissioning program in accordance with Table N-47.

Table N-47 – Summary of the transformer replacement and refurbishment timing

Project type	08/09	09/10	10/11	11/12	12/13	13/14
Transformer replacement	Dederang	-	Bendigo	Yallourn	-	2 x 150 MVA
Transformer refurbishment	Richmond					South Morang
Station rebuilds		Ringwood	Geelong Thomast'n		Brooklyn Richmond	Glenrowan

Source: PB analysis

The Dederang transformer timing of March 2009 is timed to pre-empt VENCorp's proposed installation of a fourth unit in around 2011/12. This will simplify each project, limit outages and the subsequent load at risk and provide for efficiencies with respect to project management and commissioning.

The Bendigo unit is timed to be installed in 2011/12 with an additional new unit included as part of the Glenrowan station refurbishment. This strategy will ensure two new 150 MVA units are installed at Bendigo and the ex-Bendigo 125 MVA unit will be transferred to Glenrowan in 2012/13.

The Yallourn unit is timed to be replaced at the earliest opportune moment (August 2011) given the deteriorated state of the unit.

The 2 x 150 MVA units as pert of the major fleet are included in the forecast allowance in 2013/14 based on commissioning dates of August 2013; however SPA has indicated that it is likely one or both of these will be advanced, as informed by reviewed rates of deterioration.

SPA has advised that use of 150MVA replacement units is dictated by a desire to adopt standard transformer sizes across the network.

N.6 PB analysis

Having undertaken a detailed review of the project documentation presented by SPA, the following section sets out PBs view on the prudency and efficiency of this proposed capex expenditure.

Clear Need

At a high level, the aging profile, high maintenance costs, deteriorating condition and numerous major transformer failures experienced since 1995 support SPA's proposal to replace transformers over the period 2008/09 to 2013/14. SPA is proposing to replace 59 individual transformers tanks as part of the 2008/09 to 2013/14 period (including 12 within this project) and has replaced 34 over the 2003/04-2007/08 period.

However, through PB's analysis of this project it has not been apparent that SPA has demonstrated a clear and unambiguous need for replacement of all the units driven purely by SPA's risk related needs – in some cases such as Dederang and Bendigo the work is co-ordinated with augmentation projects. Furthermore, SPA has advised that the replacements have not been assessed in conjunction with the use of the existing strategic spare transformers[158] and the units to be released as part of the wider station replacement program (i.e. the other 47 tanks)[159] on the basis that run to failure poses unacceptable health and safety risks. In PB's opinion, the spare units have the capacity to minimise the consequences of major transformer failures considerably (given that transformers have considerable automatic protection systems designed to minimise the impacts of faults and the associated health and safety risks) and the prudency of replacement of each of the transformers has not been clearly established with this in mind. Given these provisions - plus the other spare transformer banks available at sites such as Dederang and Yallourn - we consider that in some case a prudent approach is likely to be with deferred replacement.

Specifically, we note:

- in the case of Bendigo, the six single phase transformers rank relatively low (39, 35, 29, 29, 20, 20)[160] in the SPA risk model. Given this status, coupled with the opportunities to mitigate the transformer failure risk through the co-ordinated application of the units released from Terang and those expected to be released from Glenrowan, PB is not satisfied there is a clear need for the replacement of these six tanks
- the need for replacement of the Yallourn transformer in the short term appears supported given the units very high ranking (58) in SPA's asset risk model. However, whether or not there is an ongoing need remains unclear. In addition, further alternatives appear feasible given the low load supplied, and these are discussed further in the alternatives section
- With respect to the fleet of transformers, Figure N-1 indicates the incremental difference between the low expenditure (orange curve), the recommended expenditure (blue curve) and the high expenditure (green curve) is low and a need to extend the transformer replacements significantly beyond the station rebuilds is not clear. Notwithstanding this apparent lack of need, PB considers that as there are five 150 MVA transformers ranked at a position of 50 or higher in the asset risk model, sufficient need does exists to include an allowance based on one new unit as opposed to two. Such an allowance would also be consistent with SPA's proposal to re-develop West Melbourne towards the end of the regulatory period and further mitigate the risks of failure of critical metropolitan transformers. This outcome should also be considered in light of the availability of a spare metropolitan transformer and the release of units from Geelong[161]
- for the Dederang unit, the individual tanks rank moderately high in the risk model output (46, 44 and 34). In light of these ranking positions and the availability of a local spare unit, we consider the need for replacement is marginal based on

158 It is noted that in addition to the existing metropolitan and regional 220/66 kV spares, an additional 220/22 kV spare transformer shall be procured in 2013/14.

159 It is also noted that SPA has advised that transformers that have been deemed not fit for service are not kept for use at other stations.

160 It is also noted that none of these unit rank above the trigger level of 40.

161 The Geelong units appear to be in reasonable condition relative to others that remain in service.

SPA's needs alone. The timing of the replacement and co-ordination with augmentation is discussed further in the timing section.

Strategic Alignment

The replacement of the five transformers (12 separate tanks) proposed by SPA under this project aligns with its strategic policy to mitigate a growing risk exposure and achieve a reduced risk profile for the period 2008-2014. However as noted above, it appears the reduction in overall transformer risk across the network through the replacement of the selected transformers is becoming marginal once the station rebuild projects (including the replacement of another 59 tanks) has occurred.

Three of the five transformers proposed for replacement are comprised of single phase banks connected to form one unit. This is consistent with SPA's documented strategy for transformers and we agree that this is a prudent approach as these units are typically more prone to oil leaks and have higher electrical losses.

It is also noted that in three of the five cases considered (Dederang, Ballarat and Yallourn), allowance has been made for reasonable levels of augmentation without direct and specific justification. In the case of the replacement units for the fleet of 150 MVA transformers, SPA has advised the nominal rating will remain the same but that they shall have improved cyclic ratings compared with the existing units – in practice this will lead to increased transfer capability and arguably some degree of augmentation. While PB considers that increased capacity can be delivered at a reasonably incremental cost when purchasing transformers and that amongst other things adopting standard transformer sizes across the network delivers strategic benefits with respect to procurement practices and utilisation of spares, we consider further substantiation of the augmentation components is warranted.

Alternatives

While at a high level SPA has indicated consideration of a number of different alternatives to the replacement of its aging transformers, it has not presented an explicit and reasonable economical basis to exclude deferred replacement or refurbishment in a number of cases. PB considers that given the circumstances surrounding each individual transformer replacement, there are further opportunities to capture efficiencies and defer some of the works covered in this project.

Regarding other technical alternatives, specifically, we note that for the case of the Yallourn unit, and while the unit ranks very highly (58) in the condition model, prior to PB being in a position to recommend the allowance for its replacement is prudent and efficient, we consider an investigation into alternative 11 kV supplies for the relatively low load should be evaluated. The strategic and long term value of investing in new 220/11 kV transformation appears inefficient for this size load. On this basis we recommend no allowance be made for the Yallourn transformer unless further alternatives are evaluated and recognition of the ongoing need is established.

Timings

As part of SPA's documented considerations regarding the replacement of transformers under this project, it is clear that SPA has recognised the needs of connected parties (namely the distribution businesses) and VENCorp as part of its considerations. This has particularly been the case at Bendigo (where the works are highly co-ordinated with augmentation works at Glenrowan) and Dederang. PB considers such co-ordination provides good opportunities to capture economies of scale and may support the advanced replacement of transformers; however this has not been substantiated by SPA as part of its proposal.

Specifically with respect to the Dederang proposal, we have concluded the need is marginal based on the relative risk ranking and asset condition alone. Augmentation benefits with replacement using a higher capacity unit are potentially very high – to the extent that VENCorp is proposing the installation of a fourth unit at Dederang somewhere between

20010-2013. On the balance of information presented by SPA and VENCorp, we are not satisfied both projects (i.e. the replacement of one of the existing units and the installation of a fourth unit) are needed. Given that the replacement option is likely to be more cost effective than the fourth unit[162], we think a prudent outcome is likely to be the replacement option. Given this outcome, we recommend the prudent timing of SPA's investment be deferred to 2013/14 to align with the augmentation needs. On the basis that the project will be a co-ordinated augmentation/replacement we also consider an appropriate allowance for inclusion in SPA's forecast capex is 50% of the total installation, where VENCorp will be required to justify the outstanding 50% in a co-ordinated consultation process. PB has adopted the generalised split of 50%:50% across each business to account for the likelihood that the benefits of installing a new, higher capacity unit will be evenly spread across the two different drivers.

N.7 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.

N.8 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

162 As there is likely to be no significant expenditure associated with switchgear

- 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 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 - 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 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 N-48.

Table N-48 – 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

APPENDIX O
REDEVELOPMENT OF RICHMOND TERMINAL STATION

APPENDIX O: 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 O-49.

Table O-49 – Proposed capex for the redevelopment 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.

O.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[163] (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.

O.2 Drivers (need or justification)

SPA has advised that there are a number of key drivers influencing the need and timing of the proposed redevelopment at RTS. These include:

- a reduction in asset failure risk, primarily associated with the 220/66 kV transformers, the 220 kV circuit breakers, the 66k circuit breakers, the 220 kV current transformers, and the aging protection, monitoring and controls for the transformers and exit feeders
- a reduction in operational and maintenance costs, particularly for the minimum oil, spring mechanism 220 kV circuit breakers and various types and numerous numbers of 66 kV circuit breakers

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

- pending augmentation requirements, where the capacity of the 220/66 kV transformers will be inadequate to meet forecast demand levels within the eastern central business district and inner suburban areas to the east and south east of Melbourne, and the considerable limitations on available space for new plant
- allowances for improved reliability, operational flexibility and strategic development, based on the restrictive and unsuitable electrical and physical configuration of the 220 kV switchyard
- a reduction in health, safety and access risks, associated with both asset failures and the geotechnical subsidence hazards that makes the site unsuitable for typical and efficient maintenance and operation.

It is noted the 22 kV switchyard is subject to the greatest subsidence due to the poor quality of fill at the site. Given the critical role of the 22 kV yard and the nature of the oil-filled plant within it, the retirement and replacement of this switchyard was advanced and is currently underway. This work is expected to be completed by early 2008.

With respect to the future asset failure risks:

- three of the four 220/66 kV transformers proposed for replacement have condition based rankings as of 2008/09 of 58, 50 and 45 in a population of 217 units, where the rankings range from 69 to 0 (with the higher number reflecting the most deteriorated units) and where SPA uses a threshold of 40 to identify units that should be subjected to more detailed assessments based on previous experience. The three units targeted are generally regarded as being in a state of accelerated deterioration given their high loadings and increased operating temperatures due to the retrospective installation of sound enclosures
- four of the six 220 kV circuit breakers would have a ‘very high’ condition ranking in 2013, reflective of a mean time between failure of around seven years and suggesting one failure every 1.75 years
- twelve of the twenty-two 66 kV circuit breakers would have a ‘high’ condition ranking in 2013, reflective of a mean time between failure of around fifteen years and suggesting one failure every 1.25 years
- as of 2008, the twelve post-type 220 kV CTs monitored in SPA’s risk model have an average life expectancy of nine years (ranging from a low as six to as high as twelve years), while the remaining six units are not suited to on-line condition monitoring
- nineteen of the 36 220 kV protection relays will be replaced with modern digital equivalents by 2013 as the transformer and feeder exit protection systems are currently based on old electromagnetic technology and have not been updated.

A range of additional and qualitative benefits of the proposed project have been identified, consistent with SPA strategies and polices, including:

- the removal of site specific access hazards associated with the congested switchyards
- opportunities to upgrade the station security and fire suppression systems
- a reduction in the number of oil filled plant items in close proximity to the Yarra River
- extension of the standardisation of equipment types across sites and asset categories, it facilitates the retirement of large fleets of assets nearing the end of their technical lives, and it the releases plant for use as spares elsewhere
- the reduction of risks of adverse publicity and political attention caused by disruption to customer supplies caused by poor reliability of assets.

O.3 Strategic alignment and policy support

Given the nature of this station redevelopment, the proposed scope of work has an influence on reducing SPA's risk profile across four of the five asset risk models developed – namely the circuit breaker, the transformer, the current transformer and the secondary system models, as shown in Figure O-1 to Figure O-4.

Figure O-1 – Reduction in transformer relative risk with replacement of three units

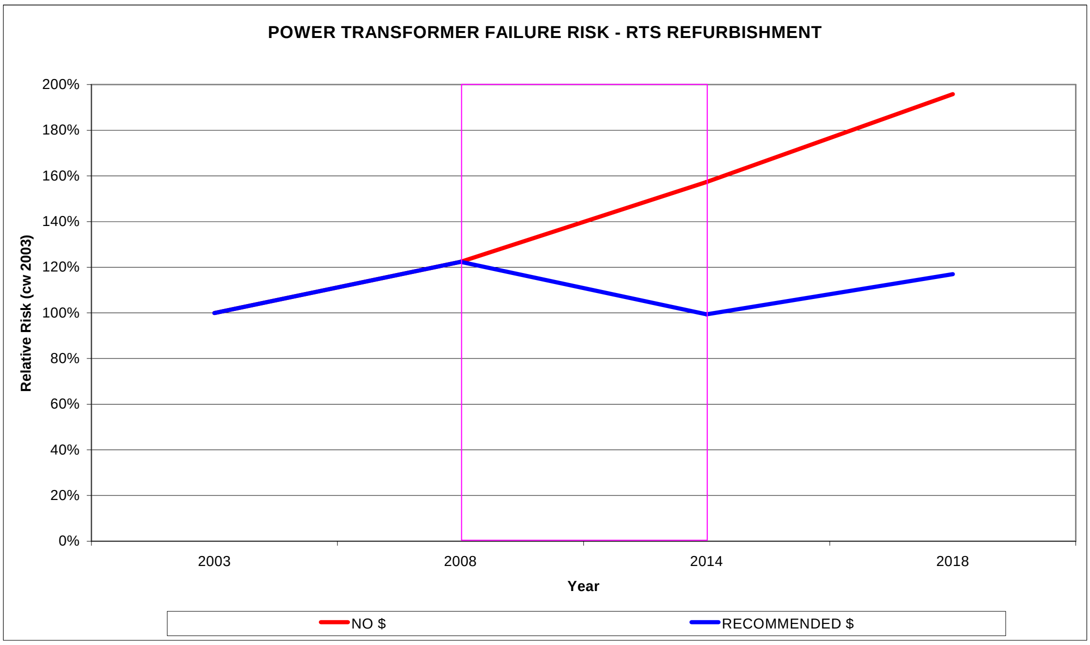


Figure O-2 – Reduction in CT relative risk with replacement of 36 units

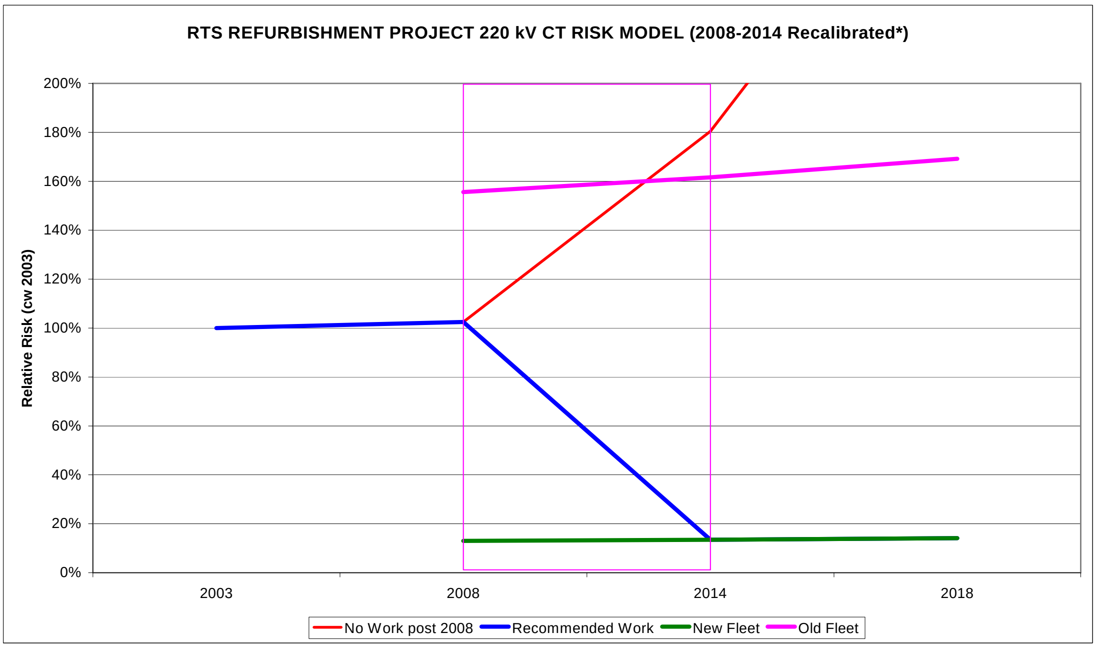


Figure O-3 – Reduction in CB relative risk with replacement of 6 units

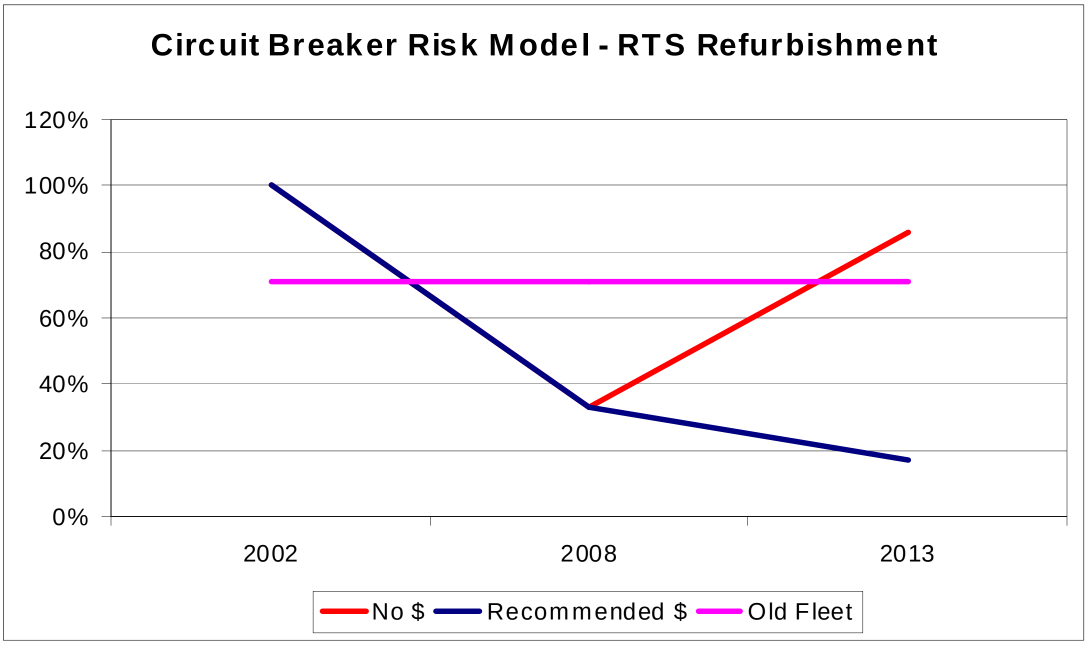
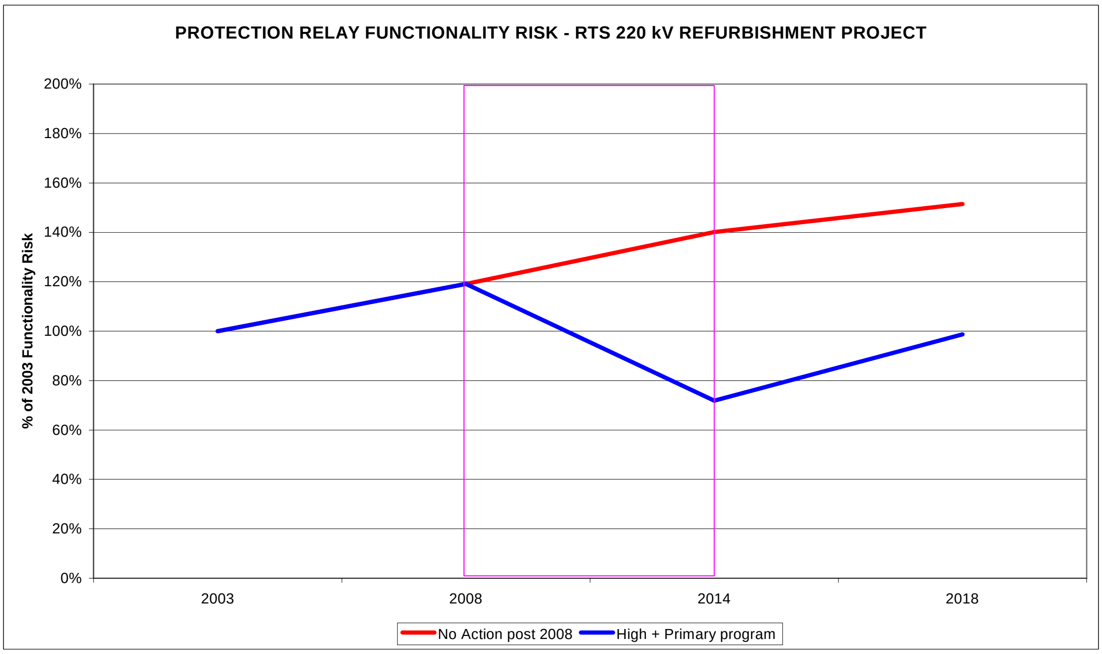


Figure O-4 – Reduction in protection relay relative risk with replacement of 19 units



Furthermore, the RTS redevelopment documentation refers to a number of additional areas where outcomes of the project aligns with SPA's stated asset management strategies, policies and plans, such as:

- the removal of health and safety risks associated with the congested site the aging machine building, and the hazards caused by subsistence and asbestos
- replacement of smaller 150 MVA transformers with higher capacity 225 MVA units in accordance with SPA's assessment of the need for higher individual units at stations of high load and limited space

- the adoption of modern technologies (GIS plant) to minimise environmental impacts and improve aesthetics along the Yarra river
- the integration of appropriate security measures befitting a strategic metropolitan supply station.

O.4 Alternatives

SPA has considered and documented a wide range of options as part of its review of the refurbishment of RTS. Specifically, the range of options has included:

- the ‘do nothing’ base case, where assets are replaced on failure in an unplanned manner
- deferred replacement, where assets are refurbished to extend their technical lives
- planned replacement by asset class, this involves the targeted replacement of asset types with the greatest risk within the station
- planned condition based replacement, where individual assets across a number of different types are replaced as their condition deteriorates
- bay by bay replacement, where all assets within a switchbay are replaced at the same time
- like for like brownfield replacement of the entire station on the existing site
- like for like greenfield replacement of the entire station on a new site
- the use of load transfers to facilitate brownfield replacement
- establishment of an additional, small greenfield station to reduce loading and minimise risk of supply interruptions
- development of local embedded generation to reduce loading and minimise risk of supply interruptions
- targeted replacement and reconfiguration using indoor GIS at the existing site
- targeted replacement and reconfiguration using conventional outdoor AIS at the existing site.

In consideration of the technical and logistical aspects associated with the existing RTS station, SPA has approached the three key aspects of the yard separately. It has first considered the 220 kV switchyard, followed by the 220/66 kV transformers, and finally the 66 kV switchyard, with due consideration to the interacting aspects of each.

For the 220 kV switchyard, SPA short-listed and considered both large-scale or small-scale greenfield development, the use of load transfers or embedded generation to facilitate redevelopment, or redevelopment on site using indoor GIS. The do nothing option was dismissed on the basis of the unacceptable risk posed by the aging circuit breakers and current transformers and the high and increasing maintenance costs. The greenfield options were dismissed primarily due to the high establishment costs, the complexity of the planning and development approvals, and the need for additional easements and relocation of existing line entries and exists. The use of load transfers and embedded generation were dismissed given the insufficient capacity of the distribution network, complexity and high costs associated with these options. The redevelopment option using GIS was deemed to be the most flexible, practical and economical option to SPA that addressed all of the problems associated with the existing switchyard. It minimised the relocation to incoming and outgoing lines, it utilised existing infrastructure, it minimised the cost of civil works and planning and approval requirements (irrespective of the complexities associated with the local council’s heritage overlay associated with the machine building) and importantly it provided free space for future (re)development. SPA has recommended the indoor GIS development option.

For the 66 kV switchyard, a similar analysis was undertaken using the same basis as that for the 220 kV switchyard. The do nothing option, the greenfield development and the load transfer options were each dismissed. SPA arrived at the conclusion that given access to the additional space released by the 220 kV GIS development, a conventional AIS switchyard should be developed rather than an indoor GIS version. The approach was considered most cost effective, and some efficiency was identified given the potential for integration with some elements of the existing outdoor yard.

For the three aging 220/66 kV transformers, SPA undertook a review of the refurbishment options available to it. In general, SPA has adopted a practice of only undertaking refurbishment for units that are of a median age to ensure that greatest long term return on its investment. This approach has been informed through a major refurbishment exercise undertaken in the mid 1990's on a transformer similar to those at RTS, where only limited life extension was achieved for a unit that had already aged considerably. Specifically in the case of RTS, and for the most critical unit (ranked 58), it concluded that although there were no incipient faults, refurbishment was not an option due to the units advanced age and deterioration levels as determined by oil and dissolved gas analysis (DGA) tests. Further, there are also complexities associated with its on-site location resulting in the unit not being suitable for a drying-out process. For the next most critical transformer (ranked 50), SPA advised that while the tests indicate that the internal condition of the unit is in an advance state of degradation, some refurbishment (including a major clean, repair of numerous oil leaks and replacement of oil) is required to extend its life to 2012/13. The third transformer (ranked 45) is in reasonable internal and external condition for a unit of its age, with only minor refurbishment costs associated with oil leaks expected over its remaining life.

SPA's redevelopment considerations are also closely aligned with the impending need for 220/6 kV transformer augmentation. This is discussed further in the following section concerning the timing of the redevelopment.

Given the preferred approach, identified through its options analysis, SPA sought independent advice from engineering consultants Connell Wagner regarding the strategies available to it when replacing the 220 kV and 66 kV switchyards. The study considered key technical criteria for redevelopment including long term planning, geotechnical issues, configuration and failure mode analysis, auxiliary facilities and the feasible sequencing of works. The key recommendations from this study included:

- 220 kV redevelopment using indoor GIS in a building on the site of the existing machine building
- 220 kV reconfiguration using 12 circuit breakers in a breaker-and-a-half arrangement to increase reliability and security
- installation of larger 225 MVA 220/66 kV transformers
- 66 kV redevelopment using indoor GIS plant and a reconfigured double bus arrangement (this was not accepted in the final project design).

This study also drew upon two detailed independent reports from GHD regarding investigating the defects associated with the existing machine building and the geotechnical impacts of the site movement.

O.5 Timings

SPA has advised there are a number of influences leading to its proposal to redevelop RTS at the end of 2013/14. These include:

- the subsidence at the site,
- the large volume of equipment that has a high risk of failure based on condition monitoring experience

- the growing consequences and supply interruptions likely to impact on the Melbourne CBD for any major plant failure
- the lead time required to gain customer and stakeholder sign-off
- the need to augment the 220/66 kV transformation based in CitiPower's assessment, subjectively timed for 2011/12.

SPA has advised that the site subsidence and equipment condition leads it to conclude that there is significant risk that the project timing may need to be advanced.

One of SPA's key inputs into both the timing and need for redevelopment at RTS is driven by the impending need to augment the 220/66 kV transformation capacity to cater for future load growth. The responsibility for this aspect is primarily assigned to Citipower, with United Energy Distribution having an incidental interest. CitiPower has advised SPA and documented in its 2006 Transmission Connection Planning Report that (subject to developments at Brunswick Terminal Station), the need for augmentation at RTS is required around 2012/13.

O.6 PB analysis

Having undertaken a detailed review of the project documentation presented by SPA, the following section sets out PBs view on the prudency and efficiency of this proposed capex expenditure.

Clear Need

In general, and through our investigation of SPA' project documentation, we concur that there are a number of needs that lead to the investigation of redevelopment options for the aging and critically located RTS. In particular this relates to the condition and configuration of the 220 kV switchyard.

However at present, SPA has not presented a single, cohesive economic justification for the wide scope of works captured in the redevelopment of RTS. Given the proposed commissioning date for this project is towards the end of the 2008/09 to 2013/14 regulatory period, there is some basis for this current situation. Information and supporting evidence presented by SPA is contained within a number of both internal and external reports addressing separate, but important aspects of the work. In PB's view, a single economical and technical analysis would provide a much stronger supporting basis for the proposed scope of works. We note the limited economic analysis presented by SPA appeared to support the need (benefits) for transformation augmentation only - without any discussion of costs - and whilst it adopted a reasonable methodology, it appeared to contain a number of assumptions that warranted further explanation[164].

Given the current position, our review has considered the competing needs of the project as described by SPA, and the reasonableness of the $90m allowance in the overall capex allowance.

Through our analysis we have some reservations about the wide-scale nature of the works – effectively it is proposed that the entire station except the 220/22 kV transformers and the recently redeveloped 22 kV switchyard is replaced. While this approach captures some economies of scale and minimises future asset failure risks, it is not clear how the high overall cost is justified or efficient.

164 In particular, the mean time to repair was presented as 2.6 months and does not account for the availability of a spare transformer, and the assessment did not clearly show how distribution system load transfers were used to minimise the exposure to unserved energy for transformer failures, circuit breaker failures or double contingencies.

On this basis, PB assessment considers the sequential and individual stages of the work, as describe by SPA, involving the 220 kV rebuild, the 220/66 kV transformer replacements, followed by the 66 kV switchyard rebuild.

Specifically, PB is satisfied that the existing configuration and condition of the plant within the 220 kV switchyard is a major risk at RTS. The exposure to multiple plant outages for CB or CT failure is high based on the open ring configuration, and the condition of four of the six circuit breakers will become very high risk in the near future. We also note that VENCorp has considered augmenting the 220 kV switchyard to close the open ring arrangement. Furthermore, the high cost of maintaining the 220 kV plant coupled with the old and redundant 220 kV protection relays supports redevelopment. Leading from this, PB considers that the relatively high costs of an indoor GIS 220 kV switchyard are substantiated given the strategic benefits of providing future space for further redevelopment – but that sufficient analysis has not been undertaken to clearly justify the twelve CB breaker-and-a-half arrangement, as opposed to a simpler and more cost effective eight CB ring bus arrangement that provides a very similar level of operational flexibility. Given the information presented, PB contends that the twelve CB option is not efficient and recommends that an eight CB design be adopted. We concur with SPA and Connell Wagner that the existing open ring 6 CB option does not provide the level of reliability and operation flexibility for a modern, critical inner suburban terminal station.

With respect to the replacement of three of the four 22/66 kV transformers and release of the fourth as a spare for use elsewhere, on the information presented PB considers the underlying need for this is primarily aligned with the asset failure risk associated with the two transformers with a condition score of 58 and 50, respectively, but that CitiPower's requirements to increase the capacity by 2012/13 are a secondary and material benefit. Furthermore, given the availability of a spare transformer for RTS, SPA's inclusion of a capex allowance for refurbishment of two of the 220/66 kV transformers, plus Citipower's advanced stage of augmentation at BTS (which includes the development of a 66 kV switchyard) and the augmentation of transformer capacity at MTS, PB considers the replacement of the three transformers at BTS can be practically and prudently deferred beyond the 2008/09 – 2013/14 regulatory period without considerable risk or consequences associated with asset failure. Furthermore, any such expenditure should be supported by a joint business case including the SPA replacement and the Citipower augmentation aspects.

Regarding the 66 kV switchyard replacement, and whilst there are a large number of CBs in the 'high' category for failure, there appears to be no material increase in risk supporting the complete replacement of the switchyard prior to 2013/14. In PB's view, the relatively high costs of planned and unplanned maintenance for the 66 kV circuit breakers, coupled with some targeted type replacements should be presented in an economic analysis before any capex allowance is recommended. PB can not currently support this component of the expenditure in the proposed timeframes without further assessment and a prudent need has not been demonstrated.

The large reduction in risk associated with the 220 kV development means RTS as an integrated station will still have a significantly reduced risk profile at the end of the 2013/14 period even without the 66 kV redevelopment occurring prior to that time.

Regarding the subsidence of the yard, PB considers the detailed report prepared by GHD in April 2005 outlines some cost effective remedial actions and monitoring processes that will ensure the geotechnical risks are manageable in the long term. The subsidence in itself does not appear to be a key driver in determining the need or timing of redevelopment.

Strategic Alignment

During this review, PB has identified a general consistency between the proposed scope of work and documented policy and strategy.

This is evidenced by the reduction in relative asset failure risk across four of the five asset risk models, and the intent to capture economies of scale by integrating various components of work into one large project. The approach adopted by SPA also shows strong strategic drive evidenced by the level of technical analysis undertaken at such an early stage of the development both internal and external to SPA. This approach has included consideration of the connected distribution businesses and VENCorp's longer term needs.

Alternatives

While SPA has presented numerous options and considerations as part of its technical and risk based assessment of RTS, PB considers some critical and feasible sub-options have not been explicitly considered. In particular, PB expects the various approaches to staged development of the site should be evaluated on a consistent basis and in an open and transparent manner (such as redevelopment of the 220 kV switchyard, followed by the transformers, followed by the 66 kV switchyard,). This approach is consistent with previous experience and outcomes, and is evidenced by SPA's decision to specifically advance the redevelopment of the critical 22 kV yard at RTS to within the current regulatory period. The approach is also consistent with the sequential assessment presented by SPA regarding the needs at the site.

While acknowledging that SPA is currently working with Citipower and VENCorp to determine the final 220 kV switching arrangement, PB considers that in order to arrive at the final design configuration of the switchyards (informing views on the number of circuit breakers required), some form of cost-benefit analysis should also preclude the decision to adopt of full breaker and a half arrangement within the 220 kV yard. On the information presented, PB has determined an efficient and prudent approach is to adopt an eight circuit breaker ring bus design for the 220 kV switchyard.

Timings

Given the number of different asset types at Richmond that have a high or very high condition based rating (particularly in the 220 kV switchyard), there is some merit in capturing the wide scale redevelopment of the site into one large project and PB accepts the statements by SPA that there are a number of influences driving the timing of investment. In particular, the increasing risk of asset failure, the need for transformation augmentation and the lead time required to undertake such a large project and have it commissioned prior to 2013/14.

Notwithstanding SPA's advice that the timing of the project may need to be advanced, and as discussed previously in the analysis of the need for expenditure, PB considers that prudent and efficient opportunities exist to stagger the works across a longer period of time. The design and configuration of the 220 kV yard certainly warrants attention as a priority - and PB supports the proposed timing. With respect to the 220/66 kV transformer replacement, we believe that the proposed expenditure to refurbish two of the units - coupled with the advanced stage of commitment with respect to 66 kV establishment at Brunswick (BTS), means it is prudent and practical to defer the transformer replacements until the full benefits of BTS and MTS are determined. In PB's view, the timing of 2013/14 for this aspect of the project has not been clearly demonstrated. This position is also supported by the fact that there is a spare metropolitan transformer to minimise the consequences of major transformer failures at RTS. PB also considers a more detailed assessment be undertaken to support the timing of the replacement of the 66 kV yard and that this naturally follows the works on the 220 kV yard given the site logistics and need to create space.

O.7 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 and allowance of 5% as a contingency, 10% for the brownfield allowance and a further 11% for a building to enclose the plant.

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 a weighted allowance of over 6% for unforeseen contingencies and a weighted 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.

O.8 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[165]), 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
- 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 detail economical assessment
- while the overall unit costs for assets appear reasonable and consistent compared with benchmark costs based 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 O-50.

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

Table O-50 – 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[1]	—	—	—	7.2	44.8	37.7	89.7
Proposed variation	—	—	—	(7.2)	(24.5)	(20.0)	(51.7)
PB recommendation[1]	—	—	—	—	20.3	17.7	38.0

Note 1, cost based on 220 kV switchyard replacement only and reduction in number of CBs from 12 to 8.
Source: PB analysis

APPENDIX P
REPLACEMENT OF STATION AND CONTROL CENTRE SCADA

APPENDIX P: 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 P-51.

Table P-51 – 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.

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

P.2 Drivers (need or justification)

The need for SPA to invest in its station and control centre SCADA systems is driven by the need to operate a secure, reliable and effective transmission system. The SCADA systems represent a crucial component of critical national infrastructure and industry standards dictate the long run average availability should be 99.95% (which relates to outages of around 4 hours per annum).

The key drivers considered by SPA in developing its proposed expenditure include:

- regulatory and other legal obligations, including compliance with the National Electricity Rules, Operating Agreements and Data Communication Standards

- end of effective asset life, allowing for additional and contemporary functionality plus improved security levels
- upgrades, improvements and enhancements, to allow for further integration and automation of monitoring and operational activities.

SPA has not provided any evidence of decreasing availability or increased component failure rates.

P.3 Strategic alignment and policy support

Through its documented asset management system[166], SPA has developed a number of strategies to maintain its compliance obligations and maximise the availability of its SCADA systems. These include:

- the replacement of RTU models, where spares are unavailable
- installing modern Substation Control and Information Management System (SCIMS) in new stations or when undertaking major station refurbishment or replacement works
- the removal of station mimic controls through incorporation of their functions into Intelligent Electronic Device's (IED) or SCIMS
- establishing a comprehensive database of design principles, operation and software for control schemes
- replacing Static VAR Compensator controls.

These strategies are underpinned by SPA's compliance to:

- schedule 5.1a of the NER, related to the network performance requirements to be provided or co-ordinated by TNSP's
- clause 4.11.2 of the NER, related to the minimum performance criteria required of a TNSP for operational control and indication communication facilities, and formulated through NEMMCO's Standard for Power System Data Communication
- the TNSP Operating Agreement between SPA and NEMMCO.

With respect to the end of life replacement of SCADA system components, SPA has advised that the master station and associated IT infrastructure have asset lives similar to standard high end IT equipment, which is typically 5 years.

P.4 Alternatives

SPA has considered three options to maintain the ongoing integrity of the SCADA systems. These include a do nothing option, a complete system replacement or incremental and ongoing upgrades.

While being the cheapest option, the 'do nothing' approach has been determined by SPA as unacceptable because of:

- the decreasing ability of the system to withstand security threats as vendor support declines
- decreasing levels of service as fault resolution times increase
- reduced ability to adapt to changing business needs

166 AMS 10-01 – Asset Management Strategy, section 7.10, in conjunction with AMS 10-57 – Control and Monitoring.

- increasing difficulty in meeting specified compliance obligations
- the need for increased skilled staff to support the system as vendor support declines.

The complete system replacement option has been evaluated and found to be inappropriate given the high costs associated with both the replacement of system hardware and software, but also the costs of retraining staff and reconfiguring databases. Benchmark costs for this analysis were obtained form other utilities within the Australasian region.

The incremental upgrade option involves the routine upgrade of the Areva EMP platform and hardware. This approach provides for material improvements in performance and security plus some new functionality as the software evolves, and ensures vendor support for ongoing updates and fixes. The incremental upgrades option is consistent with SPA's past experience, where it has been shown to provide the lowest cost and technically acceptable outcome on a number of occasions over the past 12 years. SPA has not provided any specific evidence to support this statement.

SPA has proposed the incremental upgrade option over the 2008/09 to 2013/14 regulatory period, based on previous experience and the need to securely maintain the critical SCADA system to meet the availability requirements of both SPA as an operator of the transmission network and NEMMCO as an operator of the network and the market systems.

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

- control centre - end of life replacement, including replacement of the historian system, host servers, the outdated Conitel protocol, and inadequate overview displays and auxiliary equipment
- control centre - upgrade of the Master Station, including upgrade of the SCADA/EMS application, extension of the SCADA/IP network components, enhancements to the security of SCADA applications, enhancements to the historian system and dynamics applications, and improvements to operation decision making software, custom applications and the Rowville computer Room
- control centre - system improvements and enhancements, including new software applications, a new simulation based operator training system, new real time telemetry protocol, and a new fire suppression system
- substations - end of life replacement, including replacement of the C2020, C225, C25, MD3000 and MD4000 series of RTU's, local alarm systems and Megadata interfaces
- substations - general upgrades, this allows for the replacement of underpowered processors at thirteen sites, upgrading of the remaining C50 series RTU's, targeted upgrades at two nominated Terminal Stations, upgrading the offline test bed and developing a pilot program to introduce the new internationally developed IEC 61850 substation protocol
- substations - system improvements and enhancements, which allows for the extension of systems to monitor and possibly control additional intelligent devices and battery chargers, and allow for interconnections with other systems such as the communication network.

P.5 Timings

Consistent with previous experience, SPA's SCADA based replacements are forecast to proceed on a continuous and on-going basis. The timing of the majority of this expenditure will be discretionary in nature and dynamic to best align with other works. Importantly, much of the work can be co-ordinated and integrated with other projects (such as the station refurbishments); however prioritisation will occur as guided by the need to mitigate the risk of failure of systems based on historical evidence or those with extended repair times.

Other influencing factors regarding prioritisation of works include the inability of systems to meet the NEMMCO Data Communications standards, the inability of some systems to be upgraded to digital communications formats, limited or no spares availability or vendor support, and limited repair and replacement skills.

Notwithstanding the discretionary nature of much of the works, there are still a number of specific events across the 2008/09 to 2013/14 period influencing the expenditure profile. In particular the major and minor SCADA/EMS upgrades in 2009/10 and 2012, respectively, are dictated by the vendor's product roadmap. The upgrade of the dynamics rating algorithm in 2008/09 is timed to maximise the availability and integrity of this critical operational system.

P.6 PB analysis

Having undertaken a detailed review of the project documentation presented by SPA, the following section sets out PBs view on the prudency and efficiency of this proposed capex expenditure.

Clear Need

The primary need for expenditure in this project category is associated with maintaining the reliability, availability, functionality and integrity of a critical control and monitoring system affecting the entire Victorian transmission system. Given these matters, PB considers the SCADA system warrants targeted and appropriate investment, and we concur with SPA that a 'do nothing' option is inconsistent with past practice and an inappropriate approach going forward.

In the case of SPA's proposal, the general need is driven by clearly defined legal and regulatory obligations; however as part of our review we have been unable to correlate the level of expenditure proposed with either historical experience nor an underlying need evidenced through an increase in failures or a reduction in the availability of key system components. This aspect warrants further investigation given the high value associated with the SCADA replacement program.

Furthermore, a number of aspects of SPA's proposal appear to relate to augmentation of the SCADA system and the provision of enhanced functionality. While we accept that augmentation of the SCADA system would not typically align with VENCorp's augmentation planning role for the shared transmission network, we would still expect SPA to prepare a more detailed business case (highlighting for example, the opportunities to capture operational efficiencies) to support the large extent of enhancement expenditure proposed. Given the limited information SPA has presented to support proposed enhancement components of the capex, we conclude that a demonstrable compliance or risk based need has not been established and are therefore recommend the $8.2m allowance be removed. Going forward, it is not clear how SPA would justify this amount internally, nor how it would be optimised or prioritised. The description of the improvements and enhancement works also appears to include some duplication of scope such as improvement to systems that are also targeted for replacement (i.e. the historian system), and provide limited strategic or operational benefits through increased monitoring provisions (i.e. battery chargers, etc).

Strategic Alignment

During this review, PB has identified the scope of works proposed, specifically the upgrade and replacement of software and hardware at the control centres and substations, aligns with the comprehensive, well considered and documented policies and strategies associated with control and monitoring equipment.

However, as part of our review we have not been able to identify how this project relates to other separate allowances, namely the provision of $11m for the management of secondary systems and the provision of $9m for the replacement of station controls. Simply from the naming convention adopted, PB considers there may be some common scope across these separate items, but has provided SPA with the benefit of doubt that this has not occurred. Without detailed review of these two projects, any adjustments on this basis would be unsubstantiated.

Alternatives

In PB's view, and given the documented description of the alternatives considered, SPA has considered most practical and appropriate options to comply with its operational obligations and to mitigate critical SCADA system failures. SPA did not support its proposal with an economical and technical analysis comparing the complete system replacement option against the incremental upgrade, and without having reviewed such an analysis, we consider SPA's arguments related to the high capital and training costs associated with the complete replacement option to be reasonable and logical. We also concur with SPA that given the critical role of the SCADA systems, and the direct and immediate consequences of its failure, the do nothing option is not a feasible approach going forward. The incremental upgrade approach aligns most practically with the existing experience and systems within SPA.

Timings

The staged and ongoing expenditure for this project appears to be consistent with the nature of the project, but could be further supported with reference to historic experience.

P.7 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.

P.8 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 P-52.

Table P-52 – 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

APPENDIX Q
SERVICE PERFORMANCE PARAMETER DEFINITIONS

APPENDIX Q: SERVICE PERFORMANCE PARAMETER DEFINITIONS

Parameter 1	Transmission circuit availability
Sub-parameters	Total circuit availability
	Transmission circuit availability (peak critical)
	Transmission circuit availability (peak non-critical)
	Transmission circuit availability (intermediate critical)
	Transmission circuit availability (intermediate non-critical)
Unit of measure	Percentage of total possible hours available
Source of data	TNSP outage reports and system for circuit availability*
	Agreed list of critical circuits and plant*
	A peak period applies from the first Monday in November immediately preceding the 20th day of November, through to the first Friday in March, immediately after the 11th of 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 is considered off-peak*
	An intermediate period applies from the 1st of June through to the 31st of 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)*
Definition/formula	Formula:
	$\frac{\text{No. hours per annum defined (critical / non – critical) circuits are available}}{\text{Total possible number of defined circuit hours}} \times 100$
	Definition: The actual circuit hours available for defined (critical/non critical) transmission circuits divided by the total possible defined circuit hours available
	Note that there shall be an annual review of the nominated list of critical circuits/system components
Inclusions	‘Circuits’ includes overhead lines, underground cables, power transformers, phase shifting transformers, static var compensators, capacitor banks, and any other primary transmission equipment essential for the successful operation of the transmission system (SP AusNet to provide lists)
	Circuit ‘unavailability’ to include outages from all causes including planned, forced and emergency events, including extreme events
Exclusions	Unregulated transmission assets.
	Connection assets
	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 lists)
	Exclude from ‘circuit availability (peak critical)’ and ‘circuit availability (peak non-critical)’ any outages of shunt reactors*
	Outages 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)*
	Fault- level mitigation works, except for that associated with JLTS 220 kV Fault Limiting Reactors and Fault Level Mitigation Works at JLTS and MWTS; and WMTS 66 kV Bus Tie Series Fault Limiting Reactor*
	Force majeure events

Notes: Items marked * were not included in original definitions of STPIS Guideline, Jan 2007

Parameter 2	**Loss of supply event frequency**
Sub-parameters	Number of events greater than 0.05 system minutes per annum
	Number of events greater than 0.3 system minutes per annum
Unit of measure	Number of events per annum
Source of data	TNSP outage reports and system for circuit availability
Definition/formula	Formula: $$\text{System minute} = \frac{\text{Customer outage duration (minutes) * load lost (MW)}}{\text{System maximum demand (MW)}}$$
	Definition: A count of the number of events in a year that have an impact of more than 0.05 or 0.3 system minutes as appropriate. A system minute for an event is the customer outage duration (in minutes) times the load lost (in megawatts) divided by the highest system maximum demand (in megawatts) that has occurred prior to the time of the event*
Inclusions	All unplanned outages exceeding the specified impact (that is, 0.05 system minutes and 0.3 system minutes)
	All parts of the regulated transmission system
	Extreme events
	Forced outages where notification to affected customers is less than 24 hours (except where NEMMCO reschedules the outage after notification has been provided).
Exclusions	Unregulated transmission assets (e.g. some connection assets)
	Successful reclose events (less than 1 minute duration)
	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
	Planned outages
	Force majeure events

Notes: Items marked * were not included in original definitions of STPIS Guideline, Jan 2007

Parameter 3	**Average outage duration**
Sub-parameters	Transmission lines
	Transmission transformers
Unit of measure	Minutes
Source of data	TNSP outage reports and system
Definition/formula	Formula: $$\frac{\text{Aggregate minutes duration of all unplanned outages}}{\text{Number of events}}$$
	Definition: The cumulative summation of the outage duration time for the period, divided by the number of outage events during the period
	The start of each outage event is the time of the interruption of the first circuit element. The end of each outage event is the time that the last circuit element was restored to service*
	The impact of each event is capped at 7 days*
Inclusions	Faults on all parts of the regulated transmission system (connection assets, interconnected system assets)
	All forced and fault outages whether or not loss of supply occurs
Exclusions	Planned outages
	Momentary interruptions (duration of less than one minute)
	Force majeure events

Notes: Items marked * were not included in original definitions of STPIS Guideline, Jan 2007