AusNet Transmission Group Pty Ltd

Transmission Revenue Review 2017-2022

XC19 – SMTS H2 Transformer Replacement Project: Business Case (Public)

Submitted: 30 October 2015

Business Case Application for Approval

XC19 SMTS H2 Transformer Replacement Project

CAP #:	T0604
Project Initiator:	[C-I-C] [redacted]
Contact No:	[C-I-C] [redacted]
Initiating Dept / Div:	NSD
Prepared By:	[C-I-C] [redacted]
Date of Submission:	May 2013
Target Project Start Date:	July 2013
Proposed In Service Date	Jan 2016
Target Project Completion Date:	June 2016

SP AusNet
A member of Singapore Power Group

SP AusNet

1. RECOMMENDATION

Approval is sought for a total expenditure of up to $35.3 million (including contingency allowance, overheads and finance charges) for the replacement of the H2 330/220 kV transformer at South Morang Terminal Station (SMTS). A two-stage replacement approach is being proposed to manage the supply risk due to the lack of a spare transformer phase and the deteriorated condition of the H1 and H2 [redacted] transformers. The H2 transformer is replaced with a new transformer, but retained as a cold spare on site, in Stage 1. The H1 transformer will be replaced in Stage 2 with the retirement of the old H2 transformer. The staged replacement provides an economical option that also allows for a quick restoration of supply with the cold spare transformer following a failure of a 330/220 kV transformer. This business case is seeking funding for Stage 1 of the staged replacement of the two SMTS 330/220 kV transformers.

The project benefits exceed the project costs and it is economic to proceed with the H2 transformer replacement at SMTS. The project benefits include improved reliability of supply and reduced safety risk associated with an unlikely transformer bushing explosive failure. The project will ensure that SP AusNet meets the regulatory obligation to maintain the quality, reliability and security of supply of prescribed transmission services as stated in the National Electricity Rules. The project targets a completion date of June 2016.

2. STRATEGIC ALIGNMENT

Strategic Objective	Business Driver	Linkage
Strengthen	Regulated Network Reliability and Resilience	Strong
	Compliance	Moderate
Transform	Customer and Community	Strong
	Sustainability	Strong

3. FINANCIAL SUMMARY

Program / Project Expenditure Forecasts	2012 / 13	2013 / 14	2014 / 15	2015 / 16	2016 / 17	Total
Program / Project Direct Expenditure	59	3,491	17,409	9,390	384	30,732
Program / Project Total Expenditure	65	3,954	20,078	10,781	468	35,346
Revenue	3	108	1,106	2,402	2,921	147,155
NPV						146
Payback Period (Discounted)						45.9
Corporate WACC (Post Tax Nominal)						[redacted]

4. ENDORSEMENTS

[redacted]

Manager PMO
John Morris
Date: 28/5/2013

5. APPROVALS

[redacted]

General Manager Asset Management	Chief Financial Officer	Managing Director
Alistair Parker	Adam Newman	Nino Ficca
Date: 24/5/2013	Date:	Date:

6. CONTRIBUTION TO MISSION ZERO

This project will require work to be carried out in a live switchyard. The health and safety risks of working in a live switchyard will be treated by the following actions throughout the project delivery period:

- Apply proven policies and practices relating to safe working in switchyards
- Maximise the use of vacant locations for new construction
- Monitor the condition of plant that present a safety risk and barricade it off or take further measures should their condition deteriorate and require further action

7. BACKGROUND

SMTS is located approximately 23km north-east from Melbourne's CBD (Melway map reference 183 C-10) and it supplies 292 MVA of directly connected 66 kV load as well as load in the northern Melbourne metropolitan area. It consists of four switchyards operating at voltages of 500 kV, 330 kV, 220 kV and 66 kV.

SMTS is connected via six 500 kV lines from Sydenham Terminal Station, Keilor Terminal Station, Hazelwood Terminal Station and Rowville Terminal Station, and two 330 kV lines from Dederang Terminal Station. The 220 kV switchyard connects two outgoing lines to Thomastown Terminal Station. In 2008, a new 220/66 kV connection facility with two 225 MVA 220/66 kV (B) transformers was established at SMTS to transfer load from the heavily loaded Thomastown Terminal Station to SMTS, and allow for future population growth in Melbourne's northern growth corridor. The two 220/66 kV transformers provide transmission connection services to distribution network service providers, SPI Electricity and Jemena Electricity Networks.

The South Morang 700 MVA 330/220 kV single-phase H1 and H2 transformers are located between the 330 kV and 220 kV switchyards. The SMTS H1 and H2 transformers form part of the New South Wales – Victoria interconnector and connect the two Dederang to South Morang 330 kV transmission circuits to the 220 kV network supplying metropolitan Melbourne. The South Morang H1 and H2 transformers share the duty of supplying the Melbourne metropolitan area loads with the 500/220 kV transformers at Moorabool, Keilor, Rowville, and Cranbourne terminal stations.

The six 330/220 kV single-phase transformers forming the H1 and H2 transformer banks at SMTS were installed in the 1960s and recent condition assessments suggest a rising probability of failure. In the absence of a spare unit; a major failure of a 330/220 kV transformer presents a security of supply risk with the probability weighted annual market impact cost rising from $4.5 M to $23.5 M over the period 2014 to 2017.

7.1. Asset Condition

330/220 kV Transformers

The H1 and H2 transformer at SMTS have been in service for about 45 years and condition assessments indicate they are approaching the end of their technical lives. AMS 10-141[1] describes the following key issues with the H1 and H2 transformers:

- The cellulose paper insulation has commenced tracking as is expected for transformers with a 45 year service live; confirming that the mechanical strength of the paper has deteriorated and that the insulation is approaching its end of service life. It increases the risk of transformer damage due to the sudden electromagnetic forces created by short circuit currents.
- High moisture levels, in the range of 3.5% to 4% by weight, have been measured for the SMTS H transformers. These high moisture levels and the specific transformer design lead to an increased risk of failure under high-load conditions.
- The condition of the oil of these 330/220 kV transformers has generally deteriorated to an advanced state requiring remedial work within 2 to 10 years.
- The condition of two of the 330 kV bushings cannot be determined as the measurement connection point has deteriorated to a level that does not allow access to establish the bushing condition. These

1 AMS 10-141 Asset Health Review for Power Transformers in Terminal Stations

bushing are consequently an undetermined failure risk and should be replaced. Monitoring of the four other 330 kV bushings confirms they are approaching end of life and will require replacement within 10 years.

- There is no compatible spare single-phase transformer for these six transformers, thus any failure will result in long outage times. There is a partially completed spare winding in a storage tank at SMTS, which would require installation in a specialized workshop. The changeover would require a minimum of 6 months assuming the core & tank of the failed unit are not damaged. Core damage during an internal failure would require a replacement transformer with potentially a two year replacement time.
- The 220 KV line-end [redacted] tap-changers are integrated within each of the 220 kV bushing arrangements. The tap-changers on these transformers are unique, and therefore any failure has a high consequence. The tap changers are the same age as the transformer with an increasing risk of major component failure due to duty and age related deterioration of the moving parts. The original manufacturer [redacted][2] no-longer provides support for these six transformers and no-longer supports the engineering upon which these tap-changers are designed. Thus, any major defect will require long lead times to 'reverse' engineer a solution and re-manufacture critical components. Thus the transformer bank could be out of service for up to 12 months to re-engineer a suitable solution for a failure within the 220 kV line tap-changers and winding components.
- The physical arrangement and proximity of the 330/220 kV single-phase units poses a risk that multiple units could be damaged from projectiles or through exposure to heat stress following an explosive failure. It is not possible to reduce the explosion and fire risks for the existing arrangement due to the electrical clearances required for operating voltages of 330 kV. Redesign of the transformer layout is required to facilitate sufficient electrical clearances for the application of fire or blast walls between phases.
- The H1 and H2 transformers also present operating constraints as they do not have a "natural" rating, thus a failure of the forced cooling system means the transformer bank has to be de-energised.
- All gas relays currently require replacement and or modifications to remove the risk of tripping due to seismic activity as demonstrated in 2011, when the transformers were forced out of operation following an earthquake.

Secondary Systems

The protection schemes for the H1 and H2 transformers are tabulated below. All panels except the loss of cooling protection panels are asbestos free.

Protection Scheme	X Protection	Y Protection
Overcurrent		CDG14
Transformer Protection	Biased Differential Duo Bias M	High Impedance DAD-N
LV Zone		DAD-N
Delta Earth Alarm	-	Areva P922

The CDG14 overcurrent relays are electromechanical relays installed in the 1970s. They are beyond their technical life, have no communication functionality and are no longer supported by their manufacturers.

Automatic voltage regulation schemes are not provided for the 'H' transformers. The existing 330/220/22kV manual OLTC control schemes are also obsolete.

2 [redacted] no longer operates as a transformer and tap changer manufacturer and has no design information or in-house expertise of these tap changers and specifically the transformer design.

X and Y protection for the No.1 and 2 330kV Buses are provided by EE CAG34 relays. The 330kV bus protection schemes are installed in panels with test link sections containing asbestos. The CAG34 relays have proven to be generally reliable, but they are of the old electromechanical type with no fault diagnostic and communication functions.

The 48V battery chargers were installed in 1978 and are reaching the end of their service lives. The 415V AC and 240V DC distribution boards are installed in panels containing asbestos. DC distribution boards with the latest standard design are proposed to be installed at SMTS under a separate project XA50. The removal of Asbestos Containing Material (ACMs) is recommended in accordance with the policy as stated in Asset Management Strategy AMS 10-01[3].

7.2. Safety and Environmental Considerations

330/220 kV Transformers

The H1 and H2 transformers at SMTS have oil-impregnated paper (OIP) 330kV bushings. The condition of two of the 330 kV bushings cannot be determined as the measurement connection point has deteriorated to a level that does not allow access to establish the bushing condition. The remaining four bushings are showing signs of advanced age deterioration. The 330kV bushings present a small but increasing risk of an explosive failure. A failure of a transformer bushing has a high probability of causing a fire and many such failures have resulted in the complete destruction of the transformer plus damage to other equipment. SP AusNet's network experienced 220 kV bushing failures and transformer fires in 1965 &1987 at Dederang Terminal Station from this failure mechanism. Four recent interstate bushing failures in Queensland and New South Wales have involved catastrophic transformer failures. These failure modes present a safety risk to personnel working in the vicinity of the transformer due to the nature of the failure which under adverse circumstances could sometimes result in projectiles or oil fires.

The overall oil sealing system requires remedial work to reduce the increasing number of oil leaks as the gasket performance deteriorates due to thermal cycling of the material. Two tanks are demonstrating significant oil leaks approaching 100 litres / year and require remedial action within the next reset period.

7.3. Demand and Network Capacity Constraints

The South Morang 330/220 kV transformers comprise three single-phase units per transformer bank and are rated at 700 MVA (continuous) and 750 MVA (for 30 minutes).

As described in the 2012 VAPR[4], the South Morang H1 transformer is loaded higher than the H2 transformer due to the fault level management strategy that requires the SMTS 220 kV busbars to be operated decoupled. Within the next five years (under Victorian peak demand conditions) the load may exceed the South Morang H1 transformer's short-term thermal rating for an outage of the South Morang H2 transformer. Significant energy imports from New South Wales and Murray generation may need to be limited to avoid overloading the H1 transformer under these conditions.

Under this scenario, reduced imports from New South Wales and reduced Murray generation will have to be replaced by other generation to supply Victorian metropolitan load to avoid over loading the SMTS H1 transformer. This generation re-dispatch may increase Victorian market electricity prices due to the need to dispatch higher cost plant in Victoria, South Australia, and Tasmania. Also, if replacement generation is fully dispatched or unavailable, load reduction may be required to avoid overloading the South Morang H1 transformer[5].

The augmentation responsibility for SMTS lays with the Australian Energy Market Operator (AEMO) for the shared transmission network and with the distributors SPI Electricity and Jemena Electricity Networks for the transmission connection assets. To address the loading limitations for the 330/220 kV transformers at SMTS, SPI PowerNet has undertaken joint planning with AEMO to ensure that the asset renewal and augmentation plans are integrated, and an economic investment decision is made regarding the capacity and asset renewal requirements at SMTS. AEMO has established that it is not economic to augment the 330/220 kV

3 AMS 10-01 Asset Management Strategy

4 Victorian Annual Planning Report 2012, published by AEMO, Table 3-24

5 Victorian Annual Planning Report 2012, published by AEMO, Table 3-24

transformer capacity at SMTS and this business case is hence only considering replacement with the same size transformers[6].

8. WORK TO BE UNDERTAKEN

The following is a summary of the proposed scope of work:

- Supply and install a new double switched 330 kV bay in bay F for the connection of a new H transformer to the No.1 and No.2 330 kV bus comprising two live tank circuit breakers, two sets of current transformers, four ROIs, a voltage transformer, rack structure, primary and secondary connections, and new 330 kV bus 1 and 2 extensions. Install new 330kV overhead line connection to the new transformer.
- Supply and install three 330/220 kV single phase transformers (700 MVA bank) including modifications of the footings, oil containment, bunds, fire wall, drainage, rack structure, primary and secondary connections directly north-west of the existing H2 transformer.
- Supply and install two 330 kV CB management relays and two duplicated H3 transformer protection schemes. Extend the existing 330 kV bus protection and interface the new transformer protection to existing 220 kV CB management.
- Supply and install two 1 MVA, single phase station service transformers with new changeover and AC distribution boards. Interface the new protection and control schemes to existing DC distribution boards.
- Retain the H2 transformer as a temporary cold spare transformer.

Strategic Procurement	The 330/220 kV 700 MVA transformer is a long lead time item that requires consideration when planning the delivery of this project		
Program Timing	The project is scheduled to be completed by June 2016		
Composition of projects within the program	N/A		
Other Associated Projects	**Project Number/Title**	**Approved (Yes/No)**	**Cost**
Stage 2 of the staged replacement of the two SMTS 330/220 kV transformers is expected within the next 10 years	N/A		

6 Eastern Metropolitan Melbourne Thermal Capacity Regulatory Investment Test (RIT-T)

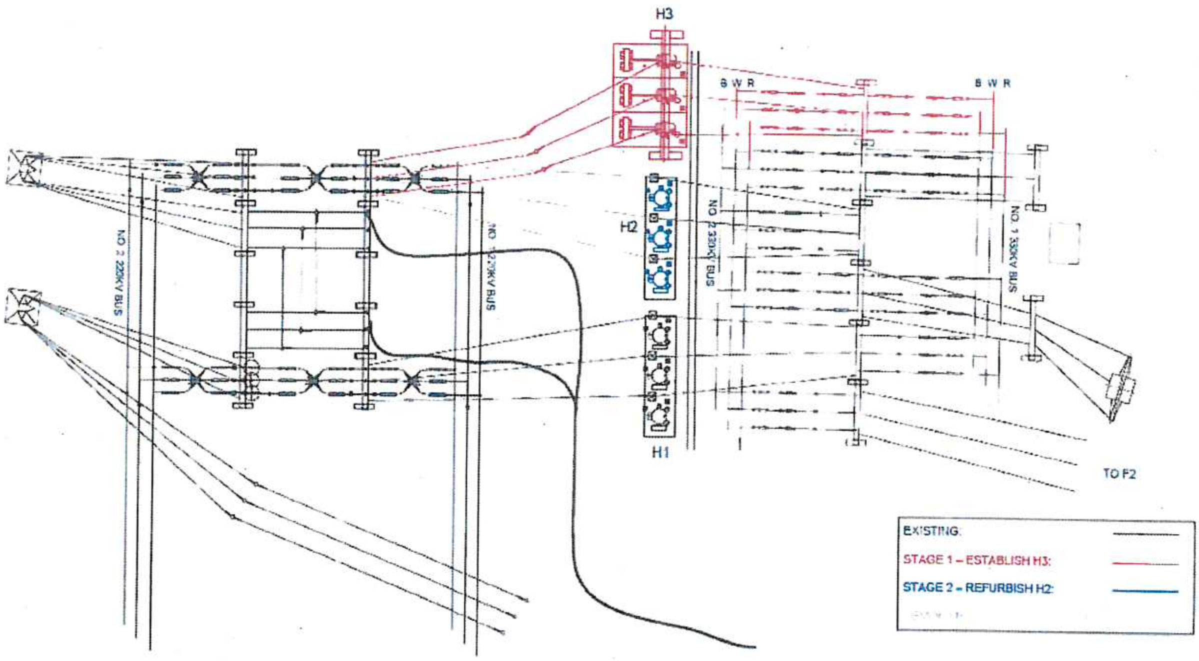
9. OPTIONS CONSIDERED

The options considered for the H1 and H2 transformer replacement at SMTS are:

- Staged replacement with single-phase transformers (preferred)
- Integrated replacement with single-phase transformers
- Integrated replacement with three-phase transformers
- Contingency spare transformer phase
- Do Nothing

The option analysis considers key aspects such as security of supply risk during the construction phase of the project, economic merits of an integrated versus staged replacement and AEMO and the distributor's future augmentation plans for SMTS.

Outage constraints as a result of high market impact costs prevent in-situ replacement of the 330/220 kV transformers at SMTS. Outages and supply risks can be minimised by establishing a new H3 transformer on a vacant location directly North West of the existing H2 units as shown below.



9.1. OPTION 1 - STAGED REPLACEMENT WITH SINGLE-PHASE TRANSFORMERS (PREFERRED)

This option involves replacing the existing H1 and H2 700 MVA 330/220 kV transformer banks with two 700 MVA transformer banks made up with single-phase transformers in two separate projects. This approach allows deferral of capital expenditure for Stage 2 for approximately ten years by using the old transformer as an emergency spare to mitigate the risk of a long transformer outage following a major transformer failure.

As 330/220 kV transformers are not widely used in the Victorian transmission network, a spare transformer of this type is not currently available and a major failure of an H transformer could result in a 24 month outage. Under this option, the supply risk is managed by retaining the existing H2 transformer as a temporary cold spare in stage 1 of the project. A new single-phase cold spare unit will be installed in stage 2 when both old [C-I-C] transformers are being retired.

Stage 1 includes installation of three 330/220 kV single phase transformers (700 MVA bank) directly north-west of the existing H2 transformer and establishing the associated double switched 330 kV bay for the transformer connection. The existing H2 transformer will be de-energized and retained in its present location as a temporary cold spare. Stage 2 includes an in-situ replacement of the existing H1 transformer, retirement of the H1 and temporary spare H2 transformer and installation of a new single phase transformer as a cold spare phase. The combined nominal capital cost for Stage 1 and 2 is higher than the nominal cost of an integrated project as it does not achieve the same efficiency savings of a single integrated project due to increased project management in establishing and managing separate projects.

However, the staged replacement delivers the best economic outcome with the lowest PV cost ($55.4 M) of all technically feasible options. That is, $55.4M PV cost for Stage 1 (this business case) or $65.4M PV cost for the combined stage approach (stages 1 & 2, as shown in Appendix A).

9.2. *OPTION 2 - INTEGRATED REPLACEMENT WITH SINGLE-PHASE TRANSFORMERS*

This option is a like for like replacement, which involves replacing the existing 700 MVA 330/220 kV H1 and H2 transformer banks with two 700MVA transformer banks made up of single-phase transformers. This option is similar to option 1, but replaces both H1 and H2 transformers in a single integrated project. It has the highest initial cost of all the options considered.

This option involves replacement of the H2 transformer at the vacant position directly north-west of the existing H2 transformer, establishment of a double switched 330 kV bay and in-situ replacement of the existing H1 transformer. It also includes the installation of a cold spare single-phase transformer to manage the supply risk following a major transformer failure.

This option will effectively mitigate the transformer failure risk and hence avoid the consequential community cost due to a transformer failure. The PV cost for this option is $76.8 M, which is higher than the staged replacement option (option 1). It is hence not further considered.

9.3. *OPTION 3 – INTEGRATED REPLACEMENT WITH THREE-PHASE TRANSFORMERS*

This option involves replacing the H1 and H2 700 MVA 330/220 kV transformer banks with two 700MVA three-phase transformers. No spare is included for this option.

This option will mitigate the 330/220 kV transformer failure risks at SMTS. However, replacement with three-phase transformers does not provide the flexibility of covering major transformer failure risk with a spare single-phase unit. This means a major failure of an H transformer under this option could result in a 24 months outage due to the long lead time for transformer replacement. During this period, the system is susceptible to a total loss of both H transformers in a second contingency event. The PV cost for this option is $116.2 M and it is hence not further considered.

9.4. *OPTION 4 – CONTINGENCY SPARE TRANSFORMER PHASE*

This option involves procuring and installing a single-phase transformer at SMTS to be used as an emergency cold spare transformer. It defers the replacement of the H1 and H2 700 MVA 330/220 kV transformers as it limits the market impact cost exposure following a failure of one of the existing 330/220 kV single phase transformers as explained below.

A major failure of an H transformer could result in a 24 month outage due to the long lead time to replace a transformer of this size and voltage ratio. With a spare phase available on site, the supply risk is reduced as the transformation can be restored within a month or less.

The economic evaluation shows that this option has a high PV cost ($181.5 M). The residual supply risk is substantial even with a spare phase on site because of the time it takes to move the spare phase and to replace a failed unit compared with Option 1, which only takes a couple of days to divert the 220 kV connections to the spare transformer bank. Failure of multiple single phase transformers will also result in long outages for this option. This option is not preferred.

9.5. *OPTION 5 – DO NOTHING *MANDATORY*

The 'Do Nothing' option quantifies the base line risk (primarily supply risk) at SMTS. It is only used for modelling purposes in the economic cost-benefit analysis to determine the economical time for the option with the lowest PV cost to proceed. The 'Do Nothing' option does not address the following SP AusNet obligations:

- under the National Electricity Rules to maintain the quality, reliability and security of supply of prescribed transmission services

- under the requirements of the Electricity Safety Act to operate, maintain and decommission its supply network to minimise as far as practicable the hazards and risks to the safety of any person arising from the supply network

10. BENEFITS

Business Driver	Strengthen	Regulated Network Reliability and Resilience	Strong
Benefit & Measure	▪ Network reliability and availability will be enhanced by replacing a transformer that is in a poor condition		

Business Driver	Strengthen	Compliance	Moderate
Benefit & Measure	▪ The proposed transformer replacement project will ensure continued compliance with the network performance and reliability requirements defined in the NER ▪ Reduced safety risk to personnel. ▪ Compliance with the Electricity Safety Act and ESMS		

Business Driver	Transform	Customer and Community	Strong
Benefit & Measure	▪ Customer service is improved by reducing the risk of their supply being adversely impacted.		

Business Driver	Transform	Sustainability	Strong
Benefit & Measure	• The new transformers will have lower losses than the existing transformers, allowing power to be transmitted more efficiently. ▪ Safety risk will be minimised ▪ Lower operation and maintenance cost		

11. RISK OF PROJECT NOT BEING APPROVED

Business Driver	Strengthen	Regulated Network Reliability and Resilience	Strong
Benefit & Measure	▪ Community impact due to increasing frequency and duration of service disruptions ▪ Additional costs associated with emergency replacement ▪ Potential transmission incentive scheme penalties associated with transformer outages		

Business Driver	Strengthen	Compliance	Moderate
Benefit & Measure	▪ Non-compliance with the network performance and reliability requirements stated in the National Electricity Rules. ▪ Non-compliance with the accepted Electricity Safety Management Scheme.		

Business Driver	Transform	Customer and Community	Strong
Benefit & Measure	▪ Customer supply is impacted due to asset failure		

Business Driver	Transform	Sustainability	Strong
Benefit & Measure	• Operation and maintenance cost escalating to inefficient levels		

12. DELIVERY PROJECT RISKS (KNOWN)

Risk	What could occur
▪ Failure of existing H1 or H2 transformer prior to replacement	▪ Emergency replacement resulting in project scope changes and likely cost increases
▪ Delays in project delivery	▪ It would increase the risk of a transformer failure

13. FINANCIAL IMPACTS

13.1. EXPEND CAT /WORK CODE:

CI20

13.2. ECONOMIC EVALUATION OPTIONS

For the full Economic and Financial Evaluation of the options and supporting financial details refer to Appendix A and the SMTS H2 Transformer Replacement Project NPV Model V0.10 saved in PET.

TABLE: Financial Analysis of Preferred Option

Financial Forecasts ($'000s)	2012 / 13	2013 / 14	2014 / 15	2015 / 16	2016 / 17	Total
Revenue			[C-I-C] [redacted]			
Expenses						
Capital						
Savings						
Working Capital						
Residual Revenue						
Tax						
Net Cash Flow (excludes financing)						
NOPAT (EVA, excludes interest)						
Capital Charge						
EBITDA						
EBIT						
NPAT						
Earnings / (Loss) per Share, cents						
NPV						[C-I-C] [redacted]
WACC (Post Tax Nominal)						

All figures are in $000's unless otherwise stated. (nominal)

TABLE: Economic Analysis of Options

Economic Analysis of Options ($'000s)	PV Capital Cost	PV Opex Costs	PV Community Benefits	PV Proceeds From Sales	Total PV Cost	NPV including Reg Return
Do Nothing	-	(57)	(1,834,078)	-	(1,834,135)	(2,624)
Staged replacement with 700MVA single-phase transformers *(Stage 1 only)	(26,387)	(57)	(28,954)	-	(55,398)	146
Integrated replacement with 700MVA single-phase transformers	(47,964)	(20)	(28,792)	-	(76,777)	404
Integrated replacement with 700MVA three-phase transformers	(33,812)	(20)	(82,347)	-	(116,179)	220
Contingency spare transformer phase	(3,164)	(57)	(178,290)	-	(181,511)	(341)

All figures are in $000's unless otherwise stated.
(nominal and discounted)

*Note, the 'Staged Replacement' option shown in the table above is for stage 1 only. A supplementary NPV analysis was done to confirm that the PV cost of the Staged Replacement Option is lower than the Integrated Replacement Option and the results are presented in Appendix A.

TABLE: Project Expenditure Forecasts

Project Expenditure Forecasts ($'000s)	2012 / 13	2013 / 14	2014 / 15	2015 / 16	2016 / 17	Total
Design			[C-I-C] [redacted]			
Internal Labour						
Materials						
Plant & Equipment						
Contracts						
Meter Costs						
Other						
Project Direct Expenditure (P50)	59	3,491	17,409	9,390	384	30,732
Delivery Risk Adjustment =(P90-P50)			[C-I-C] [redacted]			
Project Direct Expenditure plus risk (P90)						
Overheads						
Finance Charges						
Operating Costs / (Savings)						
WDV (Written Down Value) of Assets to be retired						
Total Estimated Expenditure for Approval	65	3,954	20,078	10,781	468	35,346
NPV						[C-I-C] [redacted]
Corporate WACC (Post Tax Nominal)						

TABLE: Contribution of Projects to Key Business Metrics

Contribution of Projects to Key Business Metrics	2012 / 13	2013 / 14	2014 / 15	2015 / 16	2016 / 17	Post 2016 / 17
Opex (Costs) / Savings	-	-	-	-	-	-
OH&S	-	-	-	-	$22	$1,240
System Capacity	-	-	-	-	$36,815	$7,491,967
Environmental Risk	-	-	-	-	-	-
Regulatory Compliance	-	-	-	-	-	-
Bushfire Mitigation	-	-	-	-	-	-
Corporate Image	-	-	-	-	-	-
GSL Benefits	-	-	-	-	-	-
Transmission Incentive Revenue	-	-	-	-	$29	$6,557
Asset Failure Risk						
Gas Mains Renewal						

All figures are in $000's unless otherwise stated.
(nominal)

TABLE: Capitalised Finance Charges (Interest during Construction)

Financial Year ($'000s)		Month	Project Direct Expenditure: Project Direct Expenditure $Real	Project Direct Expenditure: Project Direct Expenditure $Nominal	Project Direct Expenditure: Overheads	Totals	Net Monthly Expenditure	Cummulative WIP Balance	Transferred Into RAB (Sarcoded)	Customer Contribution Receipted Into Trust	Finance Charges	Total Finance Charges	Cumulative Finance Charges
	2012 / 2013	Apr-12	-	-	-		-	-	-		-		-
		May-12	-	-	-		-	-	-		-		-
For A to P:		Jun-12	-	-	-		-	-	-		-		-
Direct	59	Jul-12	-	-	-		-	-	-		-		-
Overheads	4	Aug-12	-	-	-		-	-	-		-		-
Finance Charges	-	Sep-12	-	-	-		-	-	-		-		-
	63	Oct-12	-	-	-		-	-	-		-		-
Error checks		Nov-12	17	17	1		18	18	-		-		-
($Real)		Dec-12	17	17	1		18	36	-		-		-
Direct	-	Jan-13	8	8	1		9	45	-		-		-
Overheads	-	Feb-13	8	8	1		9	54	-		-		-
		Mar-13	8	8	1	63	9	63	-		-	-	-
	2013 / 2014	Apr-13	8	9	1		9	72	-		-		-
		May-13	4	4	0		5	77	-		-		-
For A to P:		Jun-13	17	17	1		18	95	-		-		-
Direct	3,491	Jul-13	17	17	1		16	115	-		1		1
Overheads	244	Aug-13	131	134	9		144	260	-		2		3
Finance Charges	123	Sep-13	34	35	2		37	299	-		2		5
	3,858	Oct-13	197	202	14		217	519	-		4		8
Error checks		Nov-13	2,108	2,163	151		2,314	2,853	-		19		28
($Real)		Dec-13	197	202	14		217	3,090	-		21		49
Direct	-	Jan-14	197	202	14		217	3,329	-		23		71
Overheads	-	Feb-14	294	302	21		323	3,678	-		25		96
		Mar-14	197	202	14	3,735	217	3,921	-		27	123	123
	2014 / 2015	Apr-14	197	208	15		222	4,172	-		28		152
		May-14	3,791	3,991	279		4,271	8,500	-		58		210
For A to P:		Jun-14	34	35	2		38	8,597	-		59		268
Direct	17,409	Jul-14	34	35	2		38	8,694	-		59		328
Overheads	1,219	Aug-14	34	35	2		38	8,792	-		60		388
Finance Charges	975	Sep-14	34	35	2		38	8,891	-		61		449
	19,602	Oct-14	67	71	5		76	9,028	-		62		510
Error checks		Nov-14	67	71	5		76	9,167	-		63		573
($Real)		Dec-14	3,924	4,131	289		4,420	13,680	-		93		666
Direct	-	Jan-15	4,111	4,328	303		4,631	18,437	-		126		792
Overheads	-	Feb-15	2,485	2,616	183		2,799	21,381	-		146		938
		Mar-15	1,759	1,852	130	18,627	1,982	23,524	-		161	975	1,099
	2015 / 2016	Apr-15	2,531	2,734	191		2,925	26,631	-		182		1,280
		May-15	718	775	54		830	1	27,461		1		1,282
For A to P:		Jun-15	624	674	47		722	728	-		5		1,287
Direct	9,390	Jul-15	1,341	1,449	101		1,550	2,294	-		16		1,302
Overheads	657	Aug-15	599	647	45		693	3,007	-		21		1,323
Finance Charges	477	Sep-15	591	638	45		683	3,715	-		25		1,348
	10,525	Oct-15	582	629	44		673	4,418	-		30		1,378
Error checks		Nov-15	442	478	33		511	4,963	-		34		1,412
($Real)		Dec-15	328	354	25		379	5,378	-		37		1,449
Direct	-	Jan-16	328	354	25		379	5,797	-		40		1,488
Overheads	-	Feb-16	328	354	25		379	6,218	-		42		1,531
		Mar-16	281	303	21	10,047	325	6,587	-		45	477	1,576
	2016 / 2017	Apr-16	212	235	16		251	6,886	-		47		1,623
		May-16	135	149	10		160	-	7,045		-		-
For A to P:		Jun-16	-	-	-		-	-	-		-		-
Direct	384	Jul-16	-	-	-		-	-	-		-		-
Overheads	27	Aug-16	-	-	-		-	-	-		-		-
Finance Charges	47	Sep-16	-	-	-		-	-	-		-		-
	458	Oct-16	-	-	-		-	-	-		-		-
Error checks		Nov-16	-	-	-		-	-	-		-		-
($Real)		Dec-16	-	-	-		-	-	-		-		-
Direct	-	Jan-17	-	-	-		-	-	-		-		-
Overheads	-	Feb-17	-	-	-		-	-	-		-		-
		Mar-17	-	-	-	411	-	-	-		-	47	-
Total						32,883					1,623	1,623	
Cash flow amount should equal the total directs as shown on page 1 of the A to P							Total Including Finance Charges				34,506		

13.3. BUDGET PROVISION

The project has budget allocation (CAPEX) in the Transmission Company Funded allowance for each of the financial years from 2012/13 through to 2016/2017.

13.4. REVENUE

It is reasonable to assume that all costs incurred in this project will be included in the RAB and generate revenue accordingly for the following reasons:

NER Schedule 6A.2.1 "Establishment of opening regulatory asset base for a regulatory control period" Clause (f) (1) requires that:

> *"The previous value of the regulatory asset base* ***must be increased by the amount of all capital expenditure incurred*** *during the previous control period, including any capital expenditure determined for that period under clause 6A.8.2(e)(1)(i) in relation to contingent projects where the revenue determination has been amended by the AER in accordance with clause 6A.8.2(h)* ***(regardless of whether such capital expenditure is above or below the forecast capital expenditure for the period*** *that is adopted for the purposes of the transmission determination (if any) for that period)."* ***(Emphasis added)***

Furthermore, the AER recognises that it does not approve individual projects. For example, in the January 2008 SP AusNet Revenue Determination:

> *"... the AER reiterates that the total forecast capex approved is an allowance only, and is not tied to a fixed, project specific, work program. Within the approved allowance, SP AusNet retains the discretion regarding the allocation and expenditure of capex, and is expected to be responsive to changing conditions in order to meet the prescribed capex objectives."*

13.5. FINANCIAL RISKS

The majority of the project will be completed in the next regulatory control period and will be subject to approval of the capital expenditure allowance set at the next Transmission Revenue Reset (TRR) by the Australian Energy Regulator (AER). Noting that the AER does not approve individual capital projects and SP AusNet has the ability to prioritise works within the period, it is unlikely SP AusNet would be required to fund a capital shortfall due to the SMTS H2 transformer replacement. Any shortfall in funding would at worst be limited to the financing cost incurred until the end of the period, as the National Electricity Rules (NER) require that "the value of the regulatory asset base must be increased by the amount of all capital expenditure incurred regardless of whether such capital expenditure is above or below the forecast capital expenditure for the period".

The AER will most likely consider the associated capital expenditure forecast reasonable, and so approve it in SP AusNet's allowance, if an approved business case is available at the next regulatory review, funding is committed and the project is underway.

The new assets will roll into the Regulatory Asset Base (RAB) at the end of the next regulatory period at their depreciated constructed value.

The financial risks are being treated as follows:

- AEMO has confirmed the ongoing need of the SMTS facilities in accordance with the proposed redevelopment,
- A detailed Project Execution Plan will minimise the number and duration of outages, limiting the associated rebate cost;
- The project has been carefully estimated to cover the additional cost that may arise because this is a brown field development, and
- Capital efficiency will be targeted by a combination of foreign exchange hedging, period order purchasing, fixed-price subcontracts and in-house project execution processes.

13.6. ASSET RETIREMENTS, CONTRIBUTED (GIFTED) ASSETS, CUSTOMER CONTRIBUTION REVENUE

The written down value for this project is zero as the old H2 transformer will not be retired but retained on site as a temporary cold spare.

13.7. CORPORATE ACCOUNTING AND TAX ADVICE

The project is a usual business transaction and does not require any special corporate accounting, tax advice, or sign off.

Appendix A – Supplementary NPV Analysis

The following tables are contained in the NPV model SMTS H2 Transformer Replacement Project NPV Model V0.10 in PET - Please select 'show Stage 1 & 2' in the 'Bus_Case_BO' tab.

The written down value due to assets retirements for stage 2 of the project is excluded from the supplementary NPV analysis, if any.

TABLE: Financial Analysis of Preferred Option

Financial Forecasts ($'000s)	2012 / 13	2013 / 14	2014 / 15	2015 / 16	2016 / 17	Total
Revenue	[C-I-C] [redacted]					
Expenses						
Capital						
Savings						
Working Capital						
Residual Revenue						
Tax						
Net Cash Flow (excludes financing)						
NOPAT (EVA, excludes interest)						
Capital Charge						
EBITDA						
EBIT						
NPAT						
Earnings / (Loss) per Share, cents						[C-I-C] [redacted]
NPV						
WACC (Post Tax Nominal)						

All figures are in $000's unless otherwise stated. (nominal)

TABLE: Economic Analysis of Options

Economic Analysis of Options ($'000s)	PV Capital Cost	PV Opex Costs	PV Community Benefits	PV Proceeds From Sales	Total PV Cost	NPV including Reg Return
Do Nothing	-	(57)	(1,834,078)	-	(1,834,135)	(2,624)
Staged replacement with 700MVA single-phase transformers *(Stage 1 & 2)	(37,158)	(45)	(28,186)	-	(65,389)	521
Integrated replacement with 700MVA single-phase transformers	(47,964)	(20)	(28,792)	-	(76,777)	404
Integrated replacement with 700MVA three-phase transformers	(33,812)	(20)	(82,347)	-	(116,179)	220
Contingency spare transformer phase *(Incl. the	(36,624)	(31)	(31,623)	-	(68,278)	519

All figures are in $000's unless otherwise stated.
(nominal and discounted)

The analysis shown in the table above confirms that the Staged Replacement option is justified, as it provides the least cost option with a total PV cost of $65.4 M. This option also has an overall NPV of $521 k.

TABLE: Contribution of Projects to Key Business Metrics

Contribution of Projects to Key Business Metrics	2012 / 13	2013 / 14	2014 / 15	2015 / 16	2016 / 17	Post 2016 / 17
Opex (Costs) / Savings	-	-	-	-	-	$68
OH&S	-	-	-	-	$22	$2,055
System Capacity	-	-	-	-	$36,815	$7,495,571
Environmental Risk	-	-	-	-	-	-
Regulatory Compliance	-	-	-	-	-	-
Bushfire Mitigation	-	-	-	-	-	-
Corporate Image	-	-	-	-	-	-
GSL Benefits	-	-	-	-	-	-
Transmission Incentive Revenue	-	-	-	-	$29	$6,457
Asset Failure Risk						
Gas Mains Renewal						

All figures are in $000's unless otherwise stated.
(nominal)