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REVIEW OF THE TRANSEND TRANSMISSION NETWORK REVENUE PROPOSAL 2009 - 2014

An Independent Review Prepared for the Australian Energy Regulator

VOLUME 2 - APPENDICES

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APPENDIX 1: DETAILED DISSECTION OF OPEX COSTS

	Nominal Dollars $M					2008-09 $M											
Inflation factors to = June 2009 dollars						1.179	1.179	1.149	1.118	1.083	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	2003-04 2nf hlf yr	2003-04	2004-05	2005-06	2006-07	2003-04 2nf hlf yr	2003-04	2004-05	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14
Field operations & maintenance	6.04	10.39	12.80	12.32	14.05	7.12	12.25	14.70	13.77	15.21	16.48	16.44	16.54	17.66	17.99	18.45	19.48
Transmission services	1.80	3.52	4.54	6.14	6.02	2.12	4.15	5.22	6.86	6.52	6.69	7.39	7.80	8.17	8.42	8.74	9.05
Transmission operations	0.83	2.04	2.43	5.78	4.35	0.97	2.40	2.79	6.46	4.71	4.83	4.96	5.11	5.35	5.51	5.72	5.92
Asset management	1.51	2.73	3.62	3.90	5.02	1.79	3.22	4.16	4.36	5.43	8.38	8.30	6.64	6.90	8.58	10.56	9.72
Corporate	2.85	5.00	5.64	7.48	7.53	3.36	5.90	6.48	8.37	8.15	8.34	9.51	9.77	9.93	10.08	10.47	10.87
Total	**13.03**	**23.68**	**29.03**	**35.63**	**36.97**	**15.36**	**27.92**	**33.36**	**39.82**	**40.02**	**44.72**	**46.59**	**45.86**	**48.01**	**50.58**	**53.95**	**55.03**
Subs	2.60	4.26	5.30	4.18	5.63	3.06	5.02	6.09	4.67	6.10	5.34	5.72	5.65	6.24	6.50	6.44	6.67
Lines	1.21	1.45	2.72	2.57	2.63	1.43	1.71	3.12	2.88	2.85	5.05	4.20	4.31	4.67	4.39	4.66	5.32
P&C	0.57	1.15	0.97	1.13	1.30	0.67	1.36	1.12	1.27	1.40	1.23	1.09	1.09	1.03	1.24	1.26	1.33
Easements	0.73	1.55	1.89	1.89	2.02	0.86	1.83	2.17	2.12	2.19	2.00	2.38	2.27	2.32	2.36	2.41	2.47
Comms	0.92	1.98	1.92	2.54	2.48	1.09	2.33	2.20	2.84	2.68	2.87	3.05	3.22	3.41	3.50	3.69	3.69
Field operations & maintenance	**6.04**	**10.39**	**12.80**	**12.32**	**14.05**	**7.12**	**12.25**	**14.70**	**13.77**	**15.21**	**16.48**	**16.44**	**16.54**	**17.66**	**17.99**	**18.45**	**19.48**
Subs	0.36	0.72	0.74	1.43	1.02	0.42	0.85	0.86	1.60	1.11	1.16	1.28	1.33	1.42	1.45	1.51	1.57
Lines	0.47	0.85	1.27	1.33	1.17	0.55	1.01	1.46	1.49	1.27	1.29	1.42	1.44	1.48	1.53	1.58	1.63
P&C	0.15	0.32	0.50	0.62	0.71	0.18	0.38	0.57	0.69	0.77	0.79	0.81	0.83	0.87	0.90	0.93	0.97
GM Transmission Services	0.20	0.46	0.35	0.58	0.60	0.23	0.55	0.40	0.64	0.65	0.66	0.68	0.70	0.73	0.76	0.79	0.81
Assets Group Administration	0.17	0.31	0.56	0.53	0.57	0.20	0.37	0.64	0.59	0.62	0.63	0.65	0.67	0.70	0.72	0.75	0.78
	1.34	2.67	3.42	4.48	4.07	1.58	3.15	3.93	5.01	4.41	4.52	4.85	4.97	5.20	5.36	5.57	5.76
Projects	0.13	0.26	0.40	0.43	0.62	0.15	0.31	0.45	0.48	0.67	0.70	0.79	0.93	0.96	0.99	1.03	1.06
Outage Management	0.16	0.25	0.43	0.74	0.80	0.19	0.29	0.49	0.83	0.87	0.91	1.11	1.18	1.25	1.29	1.34	1.39
Contract Services	0.00	0.00	0.00	-	-	0.00	0.00	0.00	-	-	0.12	0.14	0.17	0.18	0.18	0.19	0.20
Environment & safety	0.17	0.34	0.29	0.49	0.52	0.20	0.40	0.33	0.54	0.57	0.44	0.50	0.56	0.58	0.59	0.62	0.65
	0.45	0.85	1.12	1.66	1.95	0.54	1.00	1.28	1.85	2.11	2.16	2.54	2.84	2.97	3.06	3.18	3.29
Transmission services	**1.80**	**3.52**	**4.54**	**6.14**	**6.02**	**2.12**	**4.15**	**5.22**	**6.86**	**6.52**	**6.69**	**7.39**	**7.80**	**8.17**	**8.42**	**8.74**	**9.05**
Customer & Asset management	1.10	2.00	2.87	3.08	3.56	1.30	2.35	3.29	3.44	3.86							
GM Customer and asset management											0.28	0.33	0.35	0.37	0.38	0.39	0.40
Strategic grid planning											0.18	0.75	0.87	0.86	0.85	0.76	0.83
Asset strategy & planning											1.90	2.32	2.39	2.48	2.54	2.65	2.74
System development											1.15	1.40	1.43	1.51	1.57	1.62	1.67
Connections											0.63	0.77	0.80	0.83	0.86	0.89	0.92
	1.10	2.00	2.87	3.08	3.56	1.30	2.35	3.29	3.44	3.86	4.14	5.57	5.83	6.06	6.20	6.31	6.57
Regulation & Compliance	0.41	0.73	0.76	0.82	1.45	0.49	0.87	0.87	0.92	1.57	4.24	2.72	0.81	0.85	2.38	4.25	3.15
Asset management	**1.51**	**2.73**	**3.62**	**3.90**	**5.02**	**1.79**	**3.22**	**4.16**	**4.36**	**5.43**	**8.38**	**8.30**	**6.64**	**6.90**	**8.58**	**10.56**	**9.72**
Business services	1.97	3.33	3.93	5.21	5.37	2.32	3.92	4.52	5.82	5.82	5.96	6.42	7.22	7.23	7.24	7.47	7.70
Corporate Governance & Planning	0.45	0.79	0.84	1.44	1.37	0.53	0.93	0.96	1.61	1.49	1.52	2.20	1.60	1.65	1.69	1.75	1.80
Insurance	0.43	0.89	0.88	0.84	0.78	0.51	1.05	1.01	0.94	0.85	0.86	0.89	0.95	1.05	1.15	1.26	1.37
Corporate	**2.85**	**5.00**	**5.64**	**7.48**	**7.53**	**3.36**	**5.90**	**6.48**	**8.37**	**8.15**	**8.34**	**9.51**	**9.77**	**9.93**	**10.08**	**10.47**	**10.87**
Transmission operations						-	-	-	-								
GM Transmission operations	0.25	0.34	0.33	0.35	0.38	0.29	0.40	0.38	0.39	0.41	0.41	0.43	0.44	0.46	0.48	0.50	0.51
Network operations	0.08	0.16	0.88	2.61	2.83	0.09	0.19	1.02	2.92	3.06	3.13	3.20	3.30	3.45	3.55	3.69	3.82
Operational planning	-	-	0.04	0.83	0.88	-	-	0.05	0.93	0.96	0.96	1.00	1.03	1.07	1.11	1.16	1.19
Strategic operations	-	-	0.00	0.14	0.27	-	-	0.00	0.16	0.29	0.32	0.33	0.34	0.36	0.37	0.38	0.40
NEM entry	0.50	1.54	1.17	1.84	-	0.59	1.82	1.34	2.06	-	-	-	-	-	-	-	-
Transmission operations	**0.83**	**2.04**	**2.43**	**5.78**	**4.35**	**0.97**	**2.40**	**2.79**	**6.46**	**4.71**	**4.83**	**4.96**	**5.11**	**5.35**	**5.51**	**5.72**	**5.92**
Total Controllable Opex	**13.03**	**23.68**	**29.03**	**35.63**	**36.97**	**15.35**	**27.92**	**33.36**	**39.82**	**40.02**	**44.72**	**46.59**	**45.86**	**48.01**	**50.58**	**53.95**	**55.03**
Network Support	-	-	0.22	1.25	0.62	-	-	0.25	1.39	0.67	3.01	3.64	3.93	2.64			
Self insurance	-	-	-	-	0.08	-	-	-	-	0.08	0.33	1.02	0.79	0.79	0.79	0.79	0.79
Debt Raising Costs *	-	-	-	-	-	-	-	-	-	-	-	-	0.89	1.00	1.12	1.17	1.23
Equity Raising costs	-	-	-	-	-	-	-	-	-	-	-	-	2.41	2.41	2.41	2.41	2.41
TOTAL OPERATING EXPENDITURE	**13.03**	**23.68**	**29.25**	**36.87**	**37.66**	**15.35**	**27.92**	**33.61**	**41.21**	**40.77**	**48.07**	**51.26**	**53.89**	**54.85**	**54.90**	**58.33**	**59.47**

*** Actual debt raising costs are included in interest expense (as a margin to the borrowing rate)**

APPENDIX 2: OPEX CALCULATIONS FOR NEXT REGULATORY CONTROL PERIOD

Table 6.2 Audited base year ($m, 2008-09)

Category	2006–07
Field operations and maintenance	15.2
Transmission services	6.5
Transmission operations	4.7
Asset management	5.4
Corporate	8.1
Total controllable	**40.0**
Network support	0.7
Debt raising costs	0.0
Equity raising costs	0.0
Self insurance	0.1
Total Operating expenditure	**40.7**

Table 6.3 Adjusted audited base year ($m, 2008-09)

Category	2006–07	Adjusted	Comments
Field operations and maintenance	15.2	0.0	Zero based
Transmission services	6.5	6.5	no change
Transmission operations	4.7	4.7	no change
Asset management	5.4	4.4	Remove one-off costs
Corporate	8.1	7.3	Remove insurance
Total controllable	**40.0**	**22.9**	
Network support	0.7	0.0	Remove zero base cost
Debt raising costs	0.0	0.0	no change
Equity raising costs	0.0	0.0	no change
Self insurance	0.1	0.0	Remove zero base cost
Total Operating expenditure	**40.7**	**22.9**	

Table 6.4 Scope changes excluding asset growth and wage growth factors ($m, 2008-09)

	Item	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	5 year Totals
	Separation costs	0.0	0.6	0.0	0.0	0.0	0.0	0.0	0.0
Table 6.11	Works program support	0.2	2.1	3.0	2.7	2.5	2.4	2.5	13.1
Table 6.12	Skills development and training		0.2	0.2	0.2	0.2	0.2	0.2	1.1
	Total Operating expenditure	**0.2**	**3.0**	**3.2**	**2.9**	**2.7**	**2.6**	**2.7**	**14.1**

Scope changes applied to expenditure category ($m, 2008-09)

Category	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	5 year Totals
Field operations and maintenance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Transmission services	6.5	7.0	7.2	7.2	7.2	7.2	7.2	36.1
Transmission operations	4.7	4.7	4.7	4.7	4.7	4.7	4.7	23.6
Asset management	4.6	5.9	6.0	5.9	5.9	5.8	5.8	29.4
Corporate	7.3	8.3	8.2	8.0	7.9	7.9	7.9	39.8
Total Operating expenditure	**23.1**	**25.9**	**26.1**	**25.9**	**25.7**	**25.6**	**25.6**	**128.8**

Asset growth

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Asset growth	**0.0%**	**1.5%**	**0.4%**	**8.1%**	**2.5%**	**3.8%**	**0.7%**

Table 6.9 Efficiency factors

Scale factors	%
Field operations and maintenance	n/a
Transmission services	25
Transmission operations	25
Asset management	25
Corporate	10

Table 6.9a Expenditure categories with asset growth ($m, 2008-09)

Category	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	5 year Totals
Field operations and maintenance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Transmission services	6.5	7.1	7.3	7.4	7.5	7.6	7.6	37.3
Transmission operations	4.7	4.7	4.7	4.8	4.9	4.9	5.0	24.4
Asset management	4.6	5.9	6.0	6.1	6.1	6.1	6.1	30.3
Corporate	7.3	8.3	8.2	8.1	8.0	8.0	8.0	40.3
Total Operating expenditure	**23.1**	**26.0**	**26.2**	**26.4**	**26.4**	**26.6**	**26.7**	**132.3**

Field operations and maintenance ($m, 2008-09)

Category	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	5 year Totals
Substations	5.3	5.6	5.4	5.9	6.0	5.8	5.8	28.9
Secondary systems	1.2	1.1	1.0	1.0	1.1	1.1	1.1	5.4
Operational communications	2.9	3.1	3.2	3.4	3.5	3.7	3.7	17.5
Transmission lines	5.0	4.1	4.1	4.4	4.0	4.2	4.6	21.3
Easements	2.0	2.3	2.2	2.2	2.2	2.2	2.2	10.9
Total Operating expenditure	**16.5**	**16.2**	**16.0**	**16.8**	**16.8**	**16.9**	**17.5**	**84.0**

Table 6.5 Zero based costs excluding wage growth ($m, 2008-09)

	Item	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	5 year Totals
	Field operating and maintenance	16.5	16.2	16.0	16.8	16.8	16.9	17.5	84.0
Table 6.14	Insurance premiums	0.9	0.9	0.9	1.0	1.1	1.3	1.4	5.8
	Revenue regulation	3.7	2.1	0.2	0.2	1.6	3.2	2.1	7.3
	Total Operating expenditure	**21.0**	**19.2**	**17.2**	**18.0**	**19.6**	**21.4**	**21.0**	**97.1**

Operating expenditure with scope changes and zero based forecasts ($m, 2008-09)

Category	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	5 year Totals
Field operations and maintenance	16.5	16.2	16.0	16.8	16.8	16.9	17.5	84.0
Transmission services	6.5	7.1	7.3	7.4	7.5	7.6	7.6	37.3
Transmission operations	4.7	4.7	4.7	4.8	4.9	4.9	5.0	24.4
Asset management	8.3	8.0	6.2	6.3	7.7	9.2	8.2	37.6
Corporate	8.2	9.2	9.2	9.1	9.1	9.3	9.4	46.1
Total Operating expenditure	**44.1**	**45.2**	**43.4**	**44.5**	**46.0**	**47.9**	**47.6**	**229.4**

Table 6.10 Wage growth

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Wage growth	**3.2%**	**2.7%**	**3.6%**	**3.3%**	**2.9%**	**3.5%**	**3.9%**

Table 6.6 &
Table 6.17 Expenditure categories with wage escalation ($m, 2008-09)

	Category	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	5 year Totals
Table 6.13	Field operations and maintenance	16.5	16.4	16.5	17.7	18.0	18.5	19.5	90.1
	Transmission services	6.7	7.4	7.8	8.2	8.4	8.7	9.0	42.2
	Transmission operations	4.8	5.0	5.1	5.3	5.5	5.7	5.9	27.6
	Asset management	8.4	8.3	6.6	6.9	8.6	10.6	9.7	42.4
	Corporate	8.3	9.5	9.8	9.9	10.1	10.5	10.9	51.1
	Total Operating expenditure	**44.7**	**46.6**	**45.9**	**48.0**	**50.6**	**54.0**	**55.0**	**253.4**

Table 6.21 Other operating categories ($m, 2008-09)

	Category	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	5 year Totals
Table 6.17	Network support	3.0	3.6	3.9	2.6	0.0	0.0	0.0	6.6
Table 6.18	Debt raising	0.0	0.0	0.9	1.0	1.1	1.2	1.2	5.4
Table 6.19	Equity raising	0.0	0.0	2.4	2.4	2.4	2.4	2.4	12.1
Table 6.20	Self Insurance	0.3	1.0	0.8	0.8	0.8	0.8	0.8	4.0
	Total Operating expenditure	**3.3**	**4.7**	**8.0**	**6.8**	**4.3**	**4.4**	**4.4**	**28.0**

Table 6.22 Total forecast operating expenditure ($m, 2008-09)

Category	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	5 year Totals
Field operations and maintenance	16.5	16.4	16.5	17.7	18.0	18.5	19.5	90.1
Transmission services	6.7	7.4	7.8	8.2	8.4	8.7	9.0	42.2
Transmission operations	4.8	5.0	5.1	5.3	5.5	5.7	5.9	27.6
Asset management	8.4	8.3	6.6	6.9	8.6	10.6	9.7	42.4
Corporate	8.3	9.5	9.8	9.9	10.1	10.5	10.9	51.1
Total controllable expenditure	**44.7**	**46.6**	**45.9**	**48.0**	**50.6**	**54.0**	**55.0**	**253.4**
Network support	3.0	3.6	3.9	2.6	0.0	0.0	0.0	6.6
Debt raising	0.0	0.0	0.9	1.0	1.1	1.2	1.2	5.4
Equity raising	0.0	0.0	2.4	2.4	2.4	2.4	2.4	12.1
Self Insurance	0.3	1.0	0.8	0.8	0.8	0.8	0.8	4.0
Total Operating expenditure	**48.1**	**51.3**	**53.9**	**54.9**	**54.9**	**58.3**	**59.5**	**281.4**

Table 6.24 5 year comparison of historical and forecast operating categories ($m, 2008-09)

Category	Historic	Forecast	Difference
Field operations and maintenance	75.8	90.1	14.4
Transmission services	31.5	42.2	10.7
Transmission operations	22.4	27.6	5.2
Asset management	29.4	42.4	13.1
Corporate	40.0	51.1	11.1
Total controllable expenditure	**199.0**	**253.4**	**54.4**

Table 6.15 Revenue Regulation ($m, 2008-09)

Revenue Regulation (with Wage Growth)			0.2	0.2	1.7	3.6	2.5	8.2

APPENDIX 3: EX-POST PROJECT REVIEW

DESCRIPTION	CATEGORY	TOTAL COST ($m)
North East Transmission Line – Norwood-Scottsdale-Derby 110kV Transmission Line	Augmentation	34.1
Mowbray Substation	Augmentation	10.3
Upgrade of Creek Road-Risdon 110kV Transmission Line	Augmentation	0.3
Establishment of a 33kV Connection Point at Risdon Substation	Connection	6.8
Wesley Vale Substation: Additional 11kV circuit breaker installation	Connection	0.2
Asset Management Information system Phase 2	Operational Support System	4.8
Secondary Equipment Store (construction)	Inventory/ Spares	3.0
Substation Security Upgrade	Physical security / compliance	30.3
Strategic Accommodation South	Business Support	6.8
IT and business applications	Information Technology	2.6

NORWOOD-SCOTTSDALE-DERBY 110 kV TRANSMISSION LINE

1 PROJECT DESCRIPTION

1.1 Project Identification

ND0519

1.2 CAPEX Category

Augmentation

1.3 Brief Overview

The scope of this project was to address those issues related to the 88 kV transmission line. The project involved the design and construction of a new double circuit 110 kV transmission line from Norwood Substation to Scottsdale Substation and a single 110 kV circuit from Scottsdale Tee to Derby Substation.

New optical ground wire (OPGW) was installed along the Norwood–Scottsdale–Derby transmission line.

1.4 Background

At the time this project was proposed, the north-east region of Tasmania was supplied from Norwood Substation by the last remaining 88 kV transmission line in Tasmania. This remaining portion of the 88 kV transmission system had been in service since 1936. The main issues related to this 88 kV supply system were:

- Security of supply;
- Reliability of supply;
- Compliance with the Tasmanian Electricity Code (TEC), technical standards, transmission licence;
- Operational issues; and
- Safety and environmental issues.

To resolve these issues Transend developed an overall strategy for north-east Tasmania electricity supply that was endorsed by Transend's board in August 2002. The strategy aimed to resolve asset management and operational issues at Norwood, Scottsdale and Derby substations. Business cases for these substation upgrades have subsequently been approved by Transend's board.

The strategy also addressed the suitability of the 88 kV supply system to satisfy Aurora Energy's long-term demand forecast for the north-east region.

In particular, issues relating to the transmission line to be addressed by this project included inadequate conductor rating, substandard conductor-to-ground clearances and the suitability of the existing towers for future requirements.

On 14 June 2002, Hydro Tasmania submitted a connection application to Transend for its proposed wind farm development at Musselroe Bay and a preliminary connection enquiry for Rushy Lagoon wind farm. Hydro Tasmania's wind farm development proposal contemplated a 110 kV connection to Transend's Derby Substation and required larger conductor than that required to meet the forecast demand in the north-east region.

On 26th February 2004 the Transend Board approved expenditure of up to $18.0 m for the project. Subsequent tender submissions, quotations received for the associated substation interface works and the requirement for a capacity deed with Hydro Tasmania, identified significant cost increases and on 24th February 2005 the Transend Board approved revised expenditure of up to $33.04 m.

On 25th January 2007 additional funding of $7.2 m was approved by the Transend Board to complete the project. These additional costs were due to:

- Increased pole foundation works;
- Additional works identified during the construction of the transmission line;
- Additional project risk mitigation requirements (associated with temporary deviations and interim system availability configurations); and
- Increased internal project management costs.

The transmission line was commissioned in June 2007.

2 PROJECT NEED

2.1 Drivers

The investment drivers for this project were regulatory and business risk issues:

- Security of supply;
- Reliability of supply;
- Compliance with the Tasmanian Electricity Code (TEC), technical standards and the transmission licence;
- The connection agreement with Aurora Energy (Aurora);
- Asset condition; and
- Operational, safety and environmental issues.

2.2 Timing

The condition of the existing transmission line, and regulatory and business risk issues that would persist until this transmission line was replaced drove the timing requirement for investment in this project.

To delay the investment meant Transend would remain exposed to unacceptable business risk and compliance issues.

2.3 Strategic Alignment

Transend is engaged in developing its transmission system to cost effectively meet its obligations under the National Electricity Rules. At the time this project was proposed, Transend was subject to the obligations imposed by the TEC, which closely mirrored the National Electricity Code at that time.

The TEC set out the general principles for maintaining power system security and related matters. Under the TEC Transend is required to analyse the expected and future operations of the transmission network over a 15 year planning period and to identify development projects. These development projects are then subject to a regulatory test, as was the case with the Norwood–Scottsdale–Derby transmission line project.

Transend developed the north-east Tasmania power system security strategy to address the system security and reliability issues in the area. This project and the upgrade works at each of the substations represent the implementation of that strategy.

The following table summarises the alignment of elements of Transend's business plan with the project objectives:

Criterion	Business Objective	Project Objective
Safety	Ensure a safe working environment for employees, contractors and the public.	The existing 88 kV line had 47 substandard conductor to ground clearances. A new 100kV line resolved this issue.
Supply Reliability	Provide a continuous supply of electricity to consumers ensuring the transmission system is available almost 100% of the time.	The 110 kV transmission line was designed for higher operating temperature and higher supply capacity. The project also allowed the old 88 kV assets to be retired.
System Security	Maintain the power system in a secure operating state as defined in the Tasmanian Electricity Code.	The Norwood to Scottsdale line was double circuit construction and the circuit from Scottsdale Tee to Derby Substation was single circuit construction.
Return	Achieve appropriate and sustainable returns on shareholders' equity.	The Energy Regulator determination for this project was received in July 2003
Costs	Minimise costs of operating the business.	The old 88 kV assets were decommissioned and the available assets, particularly the Scottsdale Substation transformers, were fully utilised.

3 ALTERNATIVES

3.1 Options

Transend presented its approach, methodology, assumptions, development options and scenarios for the Regulatory Test application to the RNPP in November 2002.

The following five development options were agreed with the Panel to be analysed to determine the preferred option:

Option Description	
Option 0 – Double Circuit 88 kV **This option evaluated maintaining and bringing the existing 88 kV line up to a Code compliant condition and adding a second circuit to increase security of supply to the region.**	**Option 1 – Hybrid Option** **This option evaluated a 110 kV single circuit supply plus embedded generation (25 MW wood-fired) to provide security of supply to the region**
Option 2 – Double Circuit 110 kV **This option evaluated a double circuit 110 kV line from Norwood to Scottsdale, with a single circuit 110 kV line from the Scottsdale tee to Derby.**	**Option 3 – Single Circuit 110 kV** **This option evaluated a single circuit 110 kV line from Norwood to Scottsdale and Derby.**
Option 4 – Distribution & Generation **This option evaluated dispersed generation (5 x 5 MW wood fired units) located in Bridport, Scottsdale and Derby areas plus distribution network reinforcement. No new capital investments in the transmission system were included.**	

3.2 Options Analysis

Each option was assessed across the eight scenarios of:

1) Base demand forecast;
2) High demand forecast;
3) Low demand forecast;
4) High discount rate;
5) Low discount rate;
6) 20 per cent increase in capital costs;
7) 10 per cent decrease in capital costs; and
8) Low VoLL.

The results for each option (subtracted from the base option) for each scenario are as follows (2003 $m):

Options	Market Development Scenarios							
	1)	2)	3)	4)	5)	6)	7)	8)
0 - Double 88kV	-	-	-	-	-	-	-	-
1 – Hybrid	-146.72	-184.16	-124.62	-123.84	-180.27	-156.32	-141.92	-146.72
2 - Double 110kV	**11.61**	**22.06**	**6.69**	**9.30**	**14.92**	**12.53**	**11.14**	11.61
3 – Single 110kV	10.28	20.20	6.44	8.45	12.89	11.45	9.70	**12.15**
4 - Distrib/Gener'n	-86.97	-119.50	-67.22	-71.91	-109.49	-93.69	-83.60	-86.97

The double circuit 110 kV option provided the greatest market benefit over seven of the eight selected scenarios.

3.3 Consideration of Non Network Solutions

Options 1 and 4 were the non-network (semi) solutions considered. Both these options did not compete favourably with the transmission options due to high construction and operating costs associated with embedded generation.

3.4 Capex/Opex Trade-offs

No evidence could be found in the documentation of explicit Capex/Opex trade-off considerations during the development of the project. Given the age and condition of the 88 kV assets that were replaced, WorleyParsons considers that it is highly likely the project resulted in some level of reduction in transmission line and substation operating and maintenance costs, however nothing was observed in the document to substantiate this.

Evidence was presented showing the marked improvement in reliability performance to downstream customers since the new lines were commissioned.

4 REGULATORY CONSIDERATIONS

4.1 Alignment with NER Capital Expenditure Objectives

Transend considers that the capital expenditure was required to meet the following capital expenditure objectives identified in clause 6A.6.7(a) of the NER:

- Meet the expected demand for prescribed transmission services;
- Comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services; and
- Maintain the reliability, safety, and security of the transmission system through the supply of prescribed transmission services.

4.2 Regulatory Test

Transend applied the Regulatory Test and market benefit analysis to determine the preferred development option for this line. An open consultation process was undertaken and non-network development proposals were considered. The approach for the Regulatory Test application for this project justification was agreed with the RNPP in November 2002.

Five development options were considered over eight market development scenarios for replacement of the existing assets (which were at the end of their physical operational life) and provision of the long term supply need for Aurora, to determine the best option.

Transend presented this project to the RNPP in February 2003. The RNPP endorsed the recommendation to upgrade supply to 110 kV and establish a new double circuit 110 kV transmission line between Norwood and Scottsdale substations and a single circuit line to Derby Substation in March 2003.

The Tasmanian Energy Regulator in his determination in July 2003 confirmed that this project was justified.

Transend became aware that the original cost estimate was insufficient for the eventual scope of the project. Thus Transend was obliged to re-evaluate the project, which it did using the same approach as previously undertaken.

Using the same set of options and market scenarios and the same method for calculating the market benefit, the evaluation showed that the preferred option still provided the greatest market benefit.

The proposal was again presented to the RNPP on 18 February 2005 and was endorsed by the RNPP on 23 February 2005.

5 GOVERNANCE

5.1 Business Case Approvals

Investment for this project was approved by the Transend Board as follows:

Business Case		Total Approved Value	Date of Approval
BC4331	Norwood-Scottsdale-Derby 110 kV Line	$18.00 m	26/02/2004
BC4331	Norwood-Scottsdale-Derby 110 kV Line: Extra Funds	$31.00 m	24/02/2005
BC4331/1	Norwood-Scottsdale-Derby 110 kV Line: Capacity Deed	$33.04 m	24/02/2005
BC4331/2	Norwood-Scottsdale-Derby 110 kV Line: Extra Funds #2	$41.24 m	25/01/2007

At no stage did the expenditure incurred for this project exceed that approved by the Board. The Norwood–Scottsdale–Derby 110 kV transmission line: extra funds #2 was endorsed by the Capital Review Team (CRT) in January 2007. All other business cases relating to this project were submitted prior to the establishment of the CRT.

During construction of the project, the Transend Board received monthly updates on progress. Steering committee meetings were also held on a regular basis to ensure adequate project governance.

5.2 Variations

Business cases were presented to the Transend Board to outline new information and the impact on cost as this information came to light. At no stage did the project expenditure exceed board approved limits.

On 24 February 2005 the Board approved increased funding due to additional expenditure requirements following the tender process which identified costs at 77 per cent greater than originally estimated due to:

- Transmission line construction re-scoping and external factors as outlined at section 6.1;
- Delays due to receiving planning approval;
- Interface work at Norwood, Scottsdale and Derby substations; and
- Increased internal project management costs.

On 25 January 2007 additional funding was approved to complete the project which had encountered additional costs due to:

- Increased pole foundation works;
- Additional works identified during the construction of the transmission line;
- Additional project risk mitigation requirements (associated with temporary deviations and interim system availability configurations); and
- Increased internal project management costs.

5.3 Assumptions

The basic assumptions used in the comparative evaluation of options and scenarios were:

- The study period was set to be 25 years (i.e. 2003-2028),
- Residual value of assets was calculated on a further 25 year period (i.e. 2029-2054),
- The base load forecast would be the one submitted by Aurora, with 2 MW subtracted to adjust for the loss of Simplot,
- Estimated capital and operating costs on wood fired power stations are from SEDA and National Power Partners.

In addition to the basic assumptions above, the following assumptions were used in the model:

Variable	Minimum Value	Likely Value	Max Value	Issues and Comment
Discount rate for transmission (real)	6%	7.5%	9%	
Forecast load growth	0.9%	2.9%	4.9%	The "likely value" is set at the Aurora forecast of 2.9% for the region.
Value of lost load (VoLL)	$1,000 per MWh	$10,000 per MWh	$20,000 per MWh	Work done on the industries in the area have confirmed that these figures are appropriate although on the low side of the range.
Capital costs of transmission equipment	Base - 10%	Base cost estimates	Base +20%	
Operating and maintenance costs for transmission equipment	1%	2%	3%	Percent of capital cost
Renewable Energy Certificates	$29/kWh	$37/kWh	$45/kWh	In the DPL model there is also included a 10% chance that RECS will be $0 to include the possibility that this class of scheme may be excluded from the RECS system.
Wood fired power station fuel costs	$20/t	$30/t	$40/t	In the DPL model there is also included a 10% chance that fuel could be sourced for $0. Although this may be viable for small scale plants located at mills, it is not likely for a large scale plant. It was included to see the effect on sensitivities.
Value of losses	3.5 cents/kWh	4.5 cents/kWh	5.5 cents/kWh	

5.4 Project Risks

Business risks associated with entering into a capacity deed with Hydro Tasmania for the Musselroe Wind Farm connection were identified. These risks included:

Risk Issue	Likelihood	Consequence	Net Risk
Risk of diversion from core business	Rare	Moderate	Moderate
Not maximising business growth opportunities	Likely	Moderate	High
Sub-optimal capital expenditure (augmentation & replacement)	Unlikely	Minor	Low
(Text removed)	Rare	Moderate	Moderate
Lack of flexibility in dealing with customers	Unlikely	Minor	Low
Ineffective management of the connection of large scale wind farms on the Tasmanian power system	Moderate	Moderate	High

(Text has been removed due to its commercial-in-confidence nature)

(Text has been removed due to its commercial-in-confidence nature)

There was also mention of how the construction of the new transmission lines would mitigate the risks associated with the 88 kV transmission lines that were to be replaced. These risks included:

- Major bushfire attributable to Transend;
- Contributing to adverse public safety outcomes (electrocution/falling off towers);
- Inadequate safety of employees/contractors; and
- Damage to third party (not customers) property/public liability (excluding fire or loss of life).

5.5 Conformance with Policies & Procedures

No non-conformance issues associated with Transend policies and procedures, of the time, were observed.

5.6 Post Implementation Review

A post implementation review document was sighted and a capital project investment review was developed in June 2008 which summarised the key elements of the project.

6 EFFICIENCY

6.1 Estimating Basis

The estimate that formed the basis for the original business case that was approved by the Board in February 2004 was prepared by Sinclair Knight Merz (SKM) and was based on "unit rates" and adjustment factors that were developed for the Transend asset valuation carried out in 2002.

Transend relied on the estimate provided by SKM, but the estimating methodology and assumptions used by SKM for this project did not accurately reflect the market prices to undertake this type of work. At that time Transend did not have a robust and mature project estimating process in place.

Following receipt of tenders for the majority of the work through a competitive tendering process, it was clear that the approved funding for this project was insufficient to successfully complete the identified works.

Subsequently, a revised business case for funding of up to $31 million to complete the project was approved by the Board in February 2005.

Further funding to complete this project was approved by the Board in January 2007. The additional funding was required to address issues encountered during the implementation of the project.

In summary, the basis for the original estimate was not sound and did not accurately reflect the market prices for this type of work at that time. Notwithstanding the significant difference between the tender price received and the original estimate, the project was completed at a price consistent with market prices at that time through a competitive tendering process. The tender prices received for this project varied in the range of approximately $21 million to $30 million. The significant variation indicates that even the experienced transmission line contracting market was unsure as to how to accurately cost this project.

6.2 Costs

The capitalised cost of the project was $34.1 million (exclusive of IDC and inclusive of FDC). This was made up of transmission line construction component of $30.5 million and land acquisition of $3.6 million.

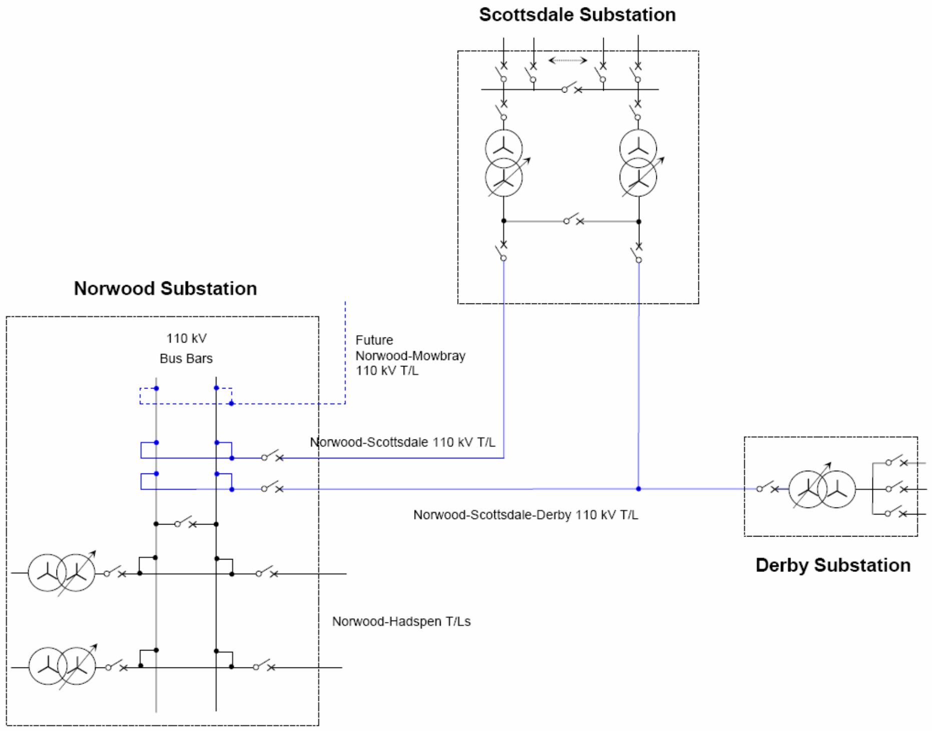
All assets (excluding the portion which relates to the capacity deed entered into with Hydro Tasmania) are included in the Regulated Asset Base.

The fall of "as commissioned expenditure" as detailed in Appendix 3 of Transend's submission was:

Jan-Jun 2004	2004-05	2005-06	2006-07	2007-08	2008-09	Total
Line			$30.5 m			$30.5 m
Land			$3.6 m			$3.6 m
						$34.1 m

6.3 Design Considerations

The project was for the design, procurement, construction and commissioning of one double circuit transmission pole-line from Norwood to Scottsdale substations consisting of 48 km of compact double-circuit overhead line on tubular steel structures, with a further 25 km of single circuit 110 kV spur continuing from the Scottsdale Tee to Derby Substation (that is, from the existing tee off point). The pole design from the Scottsdale Tee to Derby Substation was also to be of double circuit tubular steel structure design, with only one circuit strung (so that a second circuit could be strung in the future).



The project also called for the design, procurement, construction, testing and commissioning of an Optical Ground Wire (OPGW) along the entire length of the Norwood – Scottsdale – Derby transmission line.

These design arrangements are in line with standard industry practice and there was no evidence of significant over-design of the transmission line.

6.4 Project Delivery

This project was the first transmission line replacement project that Transend had undertaken. In addition, it was the largest project undertaken by Transend at the time and its successful implementation was dependent on working through a number of complexities of design, construction, cut-over, contract management, landowner issues and way-leave procurement, geotechnical results as well as adverse weather conditions, a limited contractor pool and increasing steel prices.

The project was let as a design and construct contract under a competitive tender process. The Principal's Project Requirements defined the requirements for the work and outlined the responsibilities of the contractor and principal.

There were a number of issues which impacted adversely on the cost and timing of the project. These included:

- Estimating practices did not reflect market conditions at that time;
- The contracting strategy may not have been the most appropriate for this type of project;
- Landowners restricted access to parts of the transmission line route;
- Timing of gaining planning approvals and, in some cases, onerous planning conditions placed on the project;
- Delays with the transmission line design were encountered;
- The market demand for materials, including the increased price of steel, aluminium and other commodities critical to the project;
- Complexities involved with integrating the transmission line and the substation works;
- Complexities encountered during project implementation (originally anticipated to be resolved through contractor-led innovation);
- The amount of risk mitigation activities that needed to be undertaken during project implementation was underestimated;
- Significant latent conditions were encountered (in particular, encountering rock when excavating for tower foundations); and
- Subcontractor availability was adversely impacted because of delays to the project.

The impact of these issues on cost was an increase from the original $18 million to $31 million and subsequently to the likely end of project cost of $36.7 million (including the Hydro component). The impact on time was to delay practical completion until 20 February 2007.

7 ASSESSMENT

WorleyParsons considers that Transend has demonstrated that there was a justifiable need for this project. Project drivers included security and reliability of supply, compliance with the TEC, overcoming safety issues and the condition of the old 88kV transmission line. The project was an integral part of the strategy to improve the various supply issues that related to the north east region of Tasmania.

WorleyParsons considers that the investment was efficient. The design arrangements adopted for the project are in line with standard industry practice and the final cost of $34.1 million was reasonable when compared with estimates prepared by WorleyParsons based on similar projects. The project was let as a design and construct contract under a competitive tender process. Although the final costs exceeded the original estimate, the project was completed consistent with market prices at the time. The project was one phase of a multi phase program to address network issues in the north east area over an extended time frame.

The investment processes and procedures adopted by Transend for this project appear to have ensured that prudent capital expenditure was undertaken. The four business cases were appropriately authorised and at no stage did the expenditure exceed the approved level. Five options were considered by Transend, including a distribution and generation option, and the project was endorsed to the RNNP and approved by the Tasmanian Energy Regulator. The project risks were also assessed and considered and a post implementation review was conducted.

WorleyParsons considers that the project was required to be completed during the Current Regulatory Control Period. The project timing was driven by the condition of the existing transmission line and the regulatory and business risks issues faced until the line was replaced.

8 CONCLUSION

This project appears to have been prudently planned, scoped and executed. Appropriate levels of project governance were also in place. WorleyParsons is of the opinion that the project passes a prudency test assessment.

MOWBRAY SUBSTATION DEVELOPMENT AND 110kV TRANSMISSION LINE FROM TREVALLYN SUBSTATION

1 PROJECT DESCRIPTION

1.1 Project Identification

ND0036

1.2 CAPEX Category

Augmentation

1.3 Brief Overview

This project comprised the establishment of a substation at Mowbray in north-east Launceston with an initial capacity of 40 MVA. The substation is supplied by a single 110 kV transmission line from Trevallyn Substation and firm capacity is provided via two dedicated 22 kV feeders, also emanating from Trevallyn Substation.

The initial installation comprises one 30/50 MVA 110/22 kV transformer and a 22 kV switchboard with ten 22 kV distribution feeders. Provision was made in the substation design for an additional transmission line bay, a second transformer and a further six 22 kV distribution feeders.

The 110 kV transmission line construction involved crossing the Tamar River and two sections of underground cable.

1.4 Background

This project was the first stage of the establishment of a 110/22 kV substation to address poor feeder performance in the Launceston area and capacity limitations at Trevallyn and Norwood Substations. The project was the fourth of four key elements of a major Launceston Area Supply Upgrade Program.

Launceston Area Supply Upgrade Elements		Construction Commenced	Completed
1	New Hadspen 220/110 kV Substation	1997	1999
2	Trevallyn Substation redevelopment	1997	2001
3	CBD 6.6 kV distribution conversion to 22 kV	1995	2000
4	New 110/22 kV Mowbray Substation	2004	2006

The original business case was presented to the Transend Board on the 24th May 1999 and at that time the Board approved an expenditure of up to $5.8m (1999 dollars).

Transend's original development application to the Launceston City Council in December 2000 for the project was rejected. Following an appeal by Transend to the Supreme Court, the Resource Management and Planning Appeals Tribunal granted conditional approval in

March 2002. The condition was that more of the transmission line should be installed as underground cable than had originally been proposed.

A revised business case was presented to the Transend Board on the 21st November 2002 and at that time the Board approved an expenditure of up to $8.2m (plus GST).

Land was then purchased, specifications prepared, and tenders invited for the design and installation of the transmission line and substation. Further cost escalations occurred however due to complications and delays arising from increases in load from 2002, the need for more extensive footing solutions, and underestimation of the design and installation costs.

A further revised business case was presented to the Transend Board on the 25th March 2004 and at that time the Board approved an expenditure of up to $10.9m (plus GST).

2 PROJECT NEED

2.1 Drivers

The main drivers for the project were the unsatisfactory reliability, security and capacity of the transmission and distribution systems in the greater Launceston area. The drivers listed in their order of importance are:

- Reliability of the urban and rural distribution feeders;
- Security of the CBD and urban feeders;
- Capability of the distribution feeders to transfer capacity between the Trevallyn and Norwood Substations;
- Capacity of the Trevallyn and Norwood Substations; and
- Future demand growth requirements

2.2 Reliability data

2.2.1 TEC Performance Standards

Supply Area Category	Average Reliability Annual Total Interruption Time (minutes)	Lower Bound of Reliability Annual Total Interruption Time (minutes)
CBD	30	60
Urban	120	240
Rural	480	720

2.2.2 CBD Feeders

The Launceston CBD is supplied from Trevallyn substation via four dedicated underground feeders.

Graphical data was presented for four quarters ending 09/2001, 12/2001, 03/2002 & 06/2002 respectively.

On an annual basis, feeders 1 and 3 appear to perform above average (<30 minutes pa), feeder 2 appears to perform slightly below average (>30 minutes pa) and feeder 4 appears to perform slightly above the TEC lower bound of reliability (>60 minutes pa).

2.2.3 Urban Feeders

Trevallyn substation supplies eight urban feeders and Norwood substation supplies six urban feeders.

Graphical data was presented for four quarters ending 09/2000, 12/2000, 03/2001 & 06/2001 respectively

On an annual basis, all feeders except 65062 (ex Norwood) appear to perform below the TEC lower bound of reliability (>240 minutes pa), and feeder 65062 appears to perform below average (>120 minutes pa).

2.2.4 Rural Feeders

Trevallyn substation supplies five rural feeders and Norwood substation supplies two rural feeders.

Graphical data was presented for four quarters ending 09/2001, 12/2001, 03/2002 & 06/2002 respectively

On an annual basis, all seven rural feeders appear to perform below the TEC lower bound of reliability (>720 minutes pa).

2.3 Substation Capacity

2.3.1 Norwood

Norwood Substation has a firm capacity cyclic of 60 MVA (2 x 50 MVA Units installed) and the 2002 winter peak load was 65 MVA.

2.3.2 Trevallyn

Trevallyn Substation has a firm capacity cyclic of 120 MVA (3 x 50 MVA Units installed) and the 2002 winter peak load was 141 MVA.

2.3.3 Distribution Transfer Capability

Norwood Substation to Trevallyn Substation – 10.3 MVA.

Trevallyn Substation to Norwood Substation – 9.5 MVA.

2.3.4 Security of Supply

The sustained loss of either of the Trevallyn or Norwood substations would have serious consequences for the entire Launceston area.

2.4 Timing

At the time of the submission to the RNPP in October 2002, only two 22 kV injection points (Norwood and Trevallyn substations) supplied the greater Launceston area. Loadings on both substations had exceeded their cyclic firm capacity.

Aurora's distribution feeder network was also heavily loaded, without a secure back-up electricity supply. Reliability of some feeders exceeded the TEC lower boundary of reliability. This situation was being managed at that time by transferring load to adjacent feeders.

In the submission to the RNPP, a new 22 kV connection point at Mowbray Substation was needed by the winter of 2004, otherwise distribution contingency plans would be necessary to manage reliability and security of supply issues for the CBD. For the winters of 2003, 2004 and 2005, such plans were invoked.

The optimum timing for this project was for it to proceed as soon as practicable. Subsequent delays in commencement and in construction meant that the substation was not commissioned on time. The expected commissioning date was June 2005; however the substation was not commissioned until 25 May 2006.

2.5 Strategic Alignment

The following table summarises the alignment of elements of Transend's business plan with the project objectives:

Business Objective	Project Objective
Provide infrastructure to enable State economic growth.	Strengthen the capacity of the transmission system in the north east Launceston area to meet Aurora Energy's connection point requirements.
Prudently manage business risk exposures.	Remove risks associated with asset overloading.
Meet customer expectations.	Improve customer service through increasing the security, reliability, availability and quality of supply to Aurora Energy.
Establish credibility with public/stakeholders.	Minimise the potential for serious adverse public opinion.

3 ALTERNATIVES

3.1 Options

Transend and Aurora presented a joint submission to the RNPP in October 2002 which considered the developed options.

Prior to the submission many transmission and distribution options were evaluated. The option to develop Mowbray Substation as a 66/22 kV substation was rejected on the basis of technical and security issues. Another option considered was the establishment of a 110/22 kV connection point at Hadspen Substation. While this option would have addressed the issue of secure electricity supply to the south-west area of greater Launceston, it did not address electricity supply issues in the north-east area of Launceston.

Transend and Aurora jointly investigated options that would utilise the existing infrastructure as much as possible and provide maximum market benefits. Consequently, three options were analysed in detail, and compared over nine likely scenarios for regional development, to determine the option which provided the greatest market benefit. The options analysed are summarised below.

Option Description	NPV	Reason for selection/rejection
Do Nothing		Option not progressed on the basis that it would have resulted in excessive amounts of lost load and would place the existing load and assets at risk
Distribution Option Reinforcement and reconfiguration of the distribution feeder network and installation of additional transformers at Trevallyn and Norwood Substations.	$0	Option relied on the two existing connection points at Norwood and Trevallyn substations. The distribution reinforcement option envisaged the installation of a third transformer at Norwood substation and a fourth at Trevallyn substation. Option also involved expansion of the already congested distribution network.
Distribution Reinforcement plus Demand Side Management & Local Co-generation Hot water ripple control system to control peak demand, up to 35 MVA, plus embedded co-generation as required.	$55m	Option did not take into account the issues associated with changes in tariffs for the introduction of demand side management and prospective co-generation establishment. In this option, the capacity of the network would be capped at the total cyclic firm capacity of the combined Trevallyn and Norwood substations with any expected load growth reduced by use of demand side management or catered for by the installation of co-generation.
Transmission Option Establishment of the Mowbray 110/22kV connection point initially supplied radially from Trevallyn Substation. Additional supply from Norwood Substation to be installed later with a second transformer installed when required.	$72m	Option focussed on the establishment of a third injection point in the greater Launceston area. Option provided opportunity for distribution network re-configuration and consequently improve the distribution feeder reliability and increase the supply to the region.

3.2 Options Analysis

The basis of the comparison was the net change in market benefit, which included capital expenditure, the net cost of demand side management (DSM) and co-generation schemes, operations and maintenance, network losses and customer costs.

Customer costs are those incurred due to the loss of electricity supply and were determined in accordance with the ESAA Guidelines for Reliability Assessment Planning, 1997. This process accounted for the differences in reliability of supply between each option. It required the use of a detailed risk analysis model of the entire greater Launceston area as load could be transferred, to a limited extent, between Trevallyn and Norwood substations, via the 22kV feeder network.

The evaluation of options and scenarios was described at section 5 of the joint submission to the RNPP and concluded that the transmission option, the development of Mowbray Substation as a new 110/22 kV substation, delivered the highest net market benefits for all of the scenarios considered.

The development of Mowbray Substation would reduce the reliance on the existing 22 kV injection points at Trevallyn and Norwood substations, providing improved reliability and security of supply to the Launceston central business district and suburbs.

3.3 Consideration of Non Network Solutions

The introduction of DSM and the establishment of a generation station, associated 22kV substation and associated distribution works were considered.

3.4 Capex/Opex Trade-offs

No evidence could be found in the documentation of explicit Capex/Opex trade-off considerations during the development of the project.

Evidence was presented showing the marked improvement in reliability performance to downstream customers since the new line and substation was commissioned.

4 REGULATORY CONSIDERATIONS

4.1 Alignment with NER Capital Expenditure Objectives

Transend considers that the capital expenditure was required to meet the following capital expenditure objectives identified in clause 6A.6.7(a) of the NER:

- Comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services; and
- Maintain the reliability, safety, and security of the transmission system through the supply of prescribed transmission services.

4.2 Regulatory Test

On 10 August 2001, Transend and Aurora sought endorsement from the RNPP to the options for the LASU program and the methodology, scenarios and metrics to determine the option that best met the regulatory test, by maximising the market benefit.

This submission was the precursor to the final submission to the RNPP in October 2002 presenting the market benefit test analysis and findings.

Transend and Aurora made a submission to the RNPP in October 2002 which included the application of the market benefits limb of the regulatory test.

The market benefit analysis considered a number of options in detail, taking into account issues such as the:

- Impact of gas supply to electricity consumption;
- Impact of the buy-back scheme for replacement of wood heaters in the region; and

- Viability of non-regulated development options such as demand side management and embedded generation in comparison to development options.

The RNPP submission outlined the outcome of the public consultation process undertaken during January and February 2001. There were no viable alternatives to those proposed in the published consultation paper. On 4 November 2002, the RNPP advised Transend that "the panel was satisfied that the Mowbray substation proposal meets the requirements of the regulatory test".

Subsequent to the submission to the RNPP which had assumed a capital cost to Transend of $10.3 million, the Board approved an increase in funding for the project to $10.9 million. The regulatory test was not recalculated on the revised cost estimate. In the original analysis the margin between the preferred option and the next best option was $11 million in NPV terms. The costs of the preferred option would need to have been increased to $11 million before it would no longer have been the preferred option.

5 GOVERNANCE

5.1 Business Case Approvals

The Transend Board approved expenditure of $5.8 million on 24 May 1999 to establish the required assets for a new network substation connection point at Mowbray.

The Transend Board approved expenditure of $8.2 million on 21 November 2002 to develop a new substation at Mowbray and an associated 110 kV transmission line.

The Transend Board approved expenditure of $10.9 million on 25 March 2004 for the Mowbray Substation development.

It should be noted that at no stage did the project expenditure exceed approved expenditure limits.

During construction of the project, Transend's Board received monthly updates on progress. Steering committee meetings were also held to ensure adequate project governance.

5.2 Variations

No variation approvals were required beyond the authority of the project manager.

5.3 Assumptions

The network related costs associated with each option were obtained from:

- Previous reports from Hydro Consulting unit;
- The most recent Hydro Consulting report on Regulatory Test application; and
- Likely construction costs as given by Transend.

Other basic assumptions were:

- The study period was set to be approx 25 years (that is, 2003-2028);
- Residual value of assets was calculated on a further 25 year period (that is, 2029-2054);
- Energy loss costs were taken as 4.0 c/kWh and assumed constant for the entire study period;

- The full cost of establishing the Mowbray Substation includes the terminal substation, the transmission connection and associated alterations to the distribution system; and

- The load duration curve is modelled as a 7-step load curve, based on that provided in the planning statement.

Assumptions relating to the distribution system included:

- The forecast system load was referenced from Aurora Energy 's Terminal Load Forecasts 2000;

- Power can be switched to adjacent substations through the 22 kV network according to the MVA transfer matrix, in a switching time of two hours;

- There is a very limited alternate supply capability associated with the security of the Launceston CBD from either Norwood or Trevallyn substations;

- A 40MW distribution link between Trevallyn and Mowbray substations is utilised as a backup for the single circuit 110kV transmission connection;

- The power factor of the distribution network was taken to be 0.95 lagging; and

- All distribution feeders were assumed to be 19/3.25AAC or equivalent cable.

Assumptions relating to substations included:

- The life expectancy of each transformer in the network is modelled as a normal distribution with a mean of 50 years and a standard deviation of 10 years;

- The individual cost of terminal substation maintenance has been explicitly modelled and is assumed to increase with the square of the age and equal the total cost of the substation over the 50-year life of the substation;

- In addition to this ageing component, interruptions due to minor faults and maintenance are taken into consideration; and

- The magnetising losses for new transformers are only 20% of those for old transformers in the network, due to changes in the technology.

The "ESAA guidelines for Reliability Assessment Planning, April 1995" gives the Value of Lost Load (VoLL) for various customers, by market segment, as shown below:

Market Segment	Upper $ / kWh	Lower $ / kWh
Residential	10	2
Commercial	25	15
Central Business District	25	15
Industrial	10	6

These values are in line with those produced by Monash University.

These were combined using the following proportions, and an assumed frequency of failure of one interruption in every two years, to given a "composite" value for VoLL for each substation as shown below:

Substation	SUB MIX OF CUSTOMER (%)				Demand $/kVA	Energy $/kVAh	Composite $/kVAh
	Domestic	Commercial	CBD	Industrial			
Norwood (22 kV)	50	20	20	10	2.3	16	18.3
Trevallyn (22 kV)	35	20	30	15	3.3	17.5	20.8
Mowbray	30	30	30	10	3.3	19	22.3

The reliability of the power supply is to be modelled stochastically, that is, the expected frequency and duration of interruptions of each component in the power system is to be taken into account, together with restoration practices in the distribution feeder network.

For this purpose:

- The existing 110kV network is to be considered firm;
- The 110/22kV transformers are assumed to have a normally distributed life expectancy of 50 years and a standard deviation of 10 years;
- The reliability of the distribution feeders is to be based on their previously recorded performance; and
- Planned maintenance interruptions on the distribution feeders are to be accounted for by adjusting the operating costs for the effects of consequential switching operations. Operating costs associated with these feeders will be increased because of the additional switching required to isolate equipment.

5.4 Project Risks

No specific business risks associated with the project were observed in the documentation.

5.5 Conformance with Policies & Procedures

No non-conformance issues associated with Transend policies and procedures, of the time, were observed.

5.6 Post Implementation Review

A post implementation review document was sighted and a capital project investment review was developed in February 2008 which summarised the key elements of the project.

6 EFFICIENCY

6.1 Estimating Basis

High level estimates of the project costs which made up the revised sum of $8.2 million which the Board approved in November 2002 are summarised below:

Estimate 2002

Major equipment item description	**Length**	**Cost**
Mowbray Substation establishment		$4.76 m
Trevallyn Substation to river crossing (underground)	150 metres	$0.32 m
River crossing (overhead)		$0.05 m
Gilmore Street (overhead)	750 metres	$0.20 m
Directional drill under east Tamar highway		$0.06 m
East Tamar highway (underground) and two transitions: U/G to O/H and O/H to U/G	1050 metres	$1.90 m
McKenzie and Derby streets (underground)	550 metres	$0.91 m
	Project total	**$8.20 m**

Subsequently Transend received tenders for the project works which provided greater certainty of the cost of the project. The revised estimate is summarised below:

Estimate 2004

Cost item	**Cost**
Contract sum	$7.75 m
Expenditure incurred (preparation and planning)	$0.78 m
Engineering support services including design reviews (Hydro and other consultancies)	$0.45 m
Trevallyn end modifications for protection and communications interfacing (Hydro)	$0.32 m
River crossing towers (estimate of tower strengthening and foundation replacement required following detailed modelling)	$0.25 m
Principal’s project management costs	$0.39 m
IDC (interest during construction)	$0.50 m
Project contingency (approximately 5%)	$0.46 m
TOTAL	$10.90 m

6.2 Costs

The total cost of the Mowbray Substation Development project, including interest during construction (IDC), was $10.49 million at June 2007. This was the figure provided in the Capital Project Investment Review. There are some outstanding issues and a small amount is yet to be capitalised – the exact amount remains uncertain but will be in the order of $200,000.

Currently, the capitalised value of Mowbray is $10.44m and this includes IDC of $682,000. Of this amount, $301,000 was capitalised prior to the Current Regulatory Control Period along with IDC of $78,000.

The amount reported in Appendix 3 of Transend's submission reflects the amount capitalised in the current regulatory control period, less IDC for the same period, plus an adjustment for regulatory finance during construction (FDC) of 7.54%.

All assets are included in the Regulated Asset Base.

The fall of "as commissioned expenditure" as detailed in Appendix 3 of Transend's submission was:

Jan-Jun 2004	2004-05	2005-06	2006-07	2007-08	2008-09	Total
		$8.0m	$2.2m			$10.3m

6.3 Design Considerations

Mowbray substation was to be developed in two stages. This project was stage one and its objective was to provide an additional 22 kV connection point to the northeast Launceston area.

This was a low cost solution because stage 1 comprised only a single 110 kV transmission line and single 110/22 kV transformer. Firm capacity was provided by 2 x 20 MVA 22 kV interconnectors operating in parallel between Trevallyn substation and Mowbray substation.

A key element of the development was the provision of eight new 22 kV feeders which would have provided some capacity relief to the 22 kV system. This would have had the effect of reducing the number of customers on the existing feeders, thus reducing the number of customers affected due to a feeder outage. This would also have provided improved transfer capability between 22 kV feeders, so that in the event of a feeder outage, some portion of customers on that feeder could be transferred to another feeder so that supply could be maintained whilst repair works were undertaken.

Reducing the number of customers on a particular feeder and improved transfer between feeders would have contributed to improved reliability performance on the 22 kV network.

Transend considered both the Transmission and Distribution network in the design of the project. This is evident from the fact that firm capacity for the substation was achieved by utilising the 22 kV system. Had Transend only considered the Transmission system, the project would have been more expensive as firm capacity would have been achieved by the installation of an extra 110 kV transmission line and another 110/22 kV transformer.

6.4 Project Delivery

Transend's original development application to the Launceston City Council in December 2000 for the Mowbray Substation development project was rejected. Following an appeal by Transend to the Supreme Court, the Resource Management and Planning Appeals Tribunal (RMPAT), in March 2002, gave planning approval. However, a condition of that approval was that more of the transmission line should be installed as underground cable than had originally been proposed, thus changing the scope of the project and delaying its commencement.

Following Transend Board's approval of the revised scope, cost and timing in November 2002, Transend purchased the land for the substation site, developed the functional and technical specifications and invited tenders for the design and installation of the transmission circuit and substation. The project was implemented using a "design and construct" contracting approach.

Requests for tender were issued to seven companies. Four tenders were received, of which three conformed to the specifications. The tender evaluation team selected the lowest cost conforming tender as the preferred tenderer (Aurora Energy's Contract Services). An explanation of the tender process and a summary of tenders received were included in the business case to the Board of 25 March 2004.

Because Transend let the contract as a design and construct project, it was able to closely manage the project through a direct relationship with the lead contractor. Project management was overseen by the Steering Committee assigned to the project by Transend management. Project review meetings were held fortnightly as well as site meetings (at least weekly). An issues register was used to log and manage ongoing project issues.

Commissioning was subsequently delayed by eleven months due to a number of engineering challenges that were encountered during the construction period. These included:

- Additional need to underground the 110 kV transmission line due to street clearance restrictions;
- Removal of asbestos contaminated soil uncovered during trenching;
- Microwave communications could not be economically established to the site so it was deferred to Stage 3;
- The stage 2 transformer plinth and transformer cables were installed during stage 1 due to future site access constraints; and
- Earthing issues at the site resulted in extra costs to install a masonry fence around the substation.

Although these variations resulted in additional expenditure and time delays, the project remained within the March 2004 business case estimate. Liquidated damages were recovered from the contractor for the period of delay.

Mowbray Substation and the transmission line were commissioned 25 May 2006.

7 ASSESSMENT

WorleyParsons considers that Transend has demonstrated that there was a justifiable need for this project as there was a need to remedy the unsatisfactory reliability, security and capacity of the transmission and distribution systems in the greater Launceston area. All of the rural feeders and most of the urban feeders supplied by Trevallyn Substation were less reliable than the lower bounds of the TEC requirements, and both Norwood and Trevallyn substations were exceeding their firm capacity with limited distribution transfer capacity available.

WorleyParsons considers that the investment was efficient. The design approach was a low cost solution, as stage 1 comprised only a single 100 kV line and a single 110/22 kV transformer, with firm capacity provided by a distribution interconnection. The project was subjected to a competitive tender and the contract was awarded to the lowest cost conforming tenderer. The project was one phase of a multi phase program to address network issues over an extended time frame, and this phase was a low cost solution consistent with good industry practice. The final cost of $10.49 million is reasonable when compared with estimates prepared by WorleyParsons based on similar projects.

The investment processes and procedures adopted by Transend for this project appear to have ensured that prudent capital expenditure was undertaken. The three business cases were appropriately authorised and at no stage did the expenditure exceed the approved level. Four options were considered by Transend, including a distribution option and a DSM/distribution option, and the project was endorsed to the RNNP. The project risks were also assessed and considered and a post implementation review was conducted.

Documentation from Aurora showing markedly improved 22kV feeder reliability levels in 2007 when compared to 2001/02 is consistent with the expectations of this project.

WorleyParsons considers that the project was required to be completed during the Current Regulatory Control Period. The new connection point was needed by winter 2004, whereas the substation was not commissioned until May 2006.

8 CONCLUSION

This project appears to have been prudently planned, scoped and executed. Appropriate levels of project governance were also in place. WorleyParsons is of the opinion that the project passes a prudency test assessment.

UPGRADE OF THE CREEK ROAD-RISDON AND CHAPEL STREET-RISDON 110 kV TRANSMISSION LINES

1 PROJECT DESCRIPTION

1.1 Project Identification

ND0573

1.2 CAPEX Category

Augmentation

1.3 Brief Overview

This scope of this project was to increase the capacity of the Creek Road–Risdon and Chapel Street–Risdon 110 kV transmission lines to 800 amps, thereby reducing the amount of load at risk by 23 MW and reducing the duration that the transmission lines are operated non-firm.

The project involved the modification of the conductor attachment levels on some structures to achieve increased conductor-to-ground clearance and increase the maximum conductor operating temperature from 75°C to 90°C.

1.4 Background

The Creek Road–Risdon and Chapel Street–Risdon 110 kV transmission lines are single circuits installed on the same structures in the corridor between Creek Road and Risdon substations. The previous copper conductor in the section of line between Creek Road and Risdon substations was installed in 1955.

Risdon Substation is a key substation in the southern Tasmanian transmission network supplying large loads and has a significant base load at all times.

Prior to this project being undertaken, the thermal rating and capacity of the Creek Road–Risdon and Chapel Street–Risdon 110 kV transmission lines was limited to 680 amps under an outage condition.

O'Donnell Griffin (ODG) was commissioned in October 2003 to conduct a feasibility study to upgrade these transmission lines. ODG considered two stages for the upgrade:

- Stage 1 included upgrading the two lines from 75°C to 90°C with minimal expenditure; and
- Stage 2 included replacing the existing copper conductor with a new, high temperature conductor.

This project comprised Stage 1.

2 PROJECT NEED

2.1 Drivers

The investment drivers for this upgrade were to mitigate business risk and to increase the capacity of the Chapel Street–Risdon and Creek Road–Risdon 110 kV transmission lines. This project contributed to the mitigation of a number of business risks identified in Transend's 2002 Business Risk Review.

The Chapel Street–Risdon and Creek Road–Risdon 110 kV transmission lines were rated for a firm 680 amps in summer. Under a forced outage situation, there was a potential to shed up to 75 MW load at the nearby zinc smelter, Nyrstar (previously Zinifex and before that Pasminco). This project increased the firm capacity of the Creek Road–Risdon corridor to a minimum of 800 amps (the rating of substation bay equipment), thereby reducing the load at risk by 23 MW. A short term rating of 880 amps was assigned during certain outages based on risk assessment.

The increased capacity of the Chapel Street–Risdon and Creek Road–Risdon 110 kV transmission lines was critical to enable these transmission lines to be removed from service at a later date to complete the stage 2 project without load shedding.

2.2 Timing

This project aligned with a project to modify disconnectors at Chapel Street Substation to increase the capacity of the Chapel Street–Risdon 110 kV transmission circuit 2.

Outages for the work in both projects were coordinated to deliver an efficient outcome.

This project was stage 1 in the process to upgrade the Creek Road–Risdon and Chapel Street–Risdon 110 kV transmission lines and was required to be completed before the progression of stage 2. The second stage included replacing the existing copper conductor between Creek Road and Risdon substations with high temperature conductor. The development of the Chapel Street–Creek Road–Risdon transmission line was part of the Southern Power System Security program.

This project investment was programmed for completion in the 2003–04 financial year.

2.3 Strategic Alignment

The following table summarises the relationship between the business and project objectives:

Criterion	Business Objective	Project Objective
Safety	Ensure a safe working environment for employees, contractors and the public.	Avoid the potential for low clearances and thermal damage to the conductor from increased electrical loads.
Supply Availability	Provide a reliable supply of electricity to Transend's customers.	Remove potential for outages to customers by increasing capacity under everyday and short-term conditions.
System Security	Maintain the power system in a secure operating state as defined in the Tasmanian Electricity Code.	Upgrade the Creek Road–Risdon and Chapel Street–Risdon 110 kV transmission lines thereby improving the security of supply to Risdon Substation
Costs	Minimise costs of operating the business.	Reduce the risks of supply outages, litigation and compensation.

3 ALTERNATIVES

3.1 Options

The options considered for this project were as follows:

Option Description	Reason for selection/rejection
Do Nothing	Option did not address the capacity and risk issues identified
Upgrade the Creek Road–Risdon and Chapel Street–Risdon 110 kV transmission lines to a maximum operating temperature of 90°C.	Option addressed the capacity and risk issues identified in and was therefore selected and implemented.

3.2 Options Analysis

The option to Upgrade the Creek Road–Risdon and Chapel Street–Risdon 110 kV transmission lines to a maximum operating temperature of 90°C was the preferred option because it achieved the increase in line capacity with a low estimated budget cost.

The preferred option also addressed the issues highlighted in Section 2.1 – Drivers.

3.3 Consideration of Non Network Solutions

No specific consideration of a non-network solution was mentioned; however this solution would have been difficult as establishing a generation capability at a mid point along these urban area installed overhead lines would be very difficult.

Load shedding was not seen as a viable long-term solution.

3.4 Capex/Opex Trade-offs

No Capex/Opex trade-offs were considered for this project. WorleyParsons consider that Capex/Opex trade-offs were not a significant issue for this project.

4 REGULATORY CONSIDERATIONS

4.1 Alignment with NER Capital Expenditure Objectives

Transend considers that the capital expenditure was required to meet the following capital expenditure objectives identified in clause 6A.6.7(a) of the NER:

- Meet the expected demand for prescribed transmission services;
- Comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services; and
- Maintain the reliability, safety, and security of the transmission system through the supply of prescribed transmission services.

4.2 Regulatory Test

This project was not specifically identified in Transend's revenue cap application to the ACCC in 2004. It was however an integral part of the southern power system security project because it facilitated the implementation of the Creek Road–Risdon and Chapel Street–Risdon 110 kV transmission lines conductor replacement project (stage 2).

The project was not specifically identified in the TSMP July 2004 to June 2009.

5 GOVERNANCE

5.1 Business Case Approvals

The business case for this project was approved by the Chief Executive Officer on 6th February 2004.

The business case recommended:

- Capital expenditure of up to $325,000 (plus GST) during the 2003-04 financial year to upgrade the Creek Road-Risdon and Chapel Street-Risdon 110 kV transmission lines.

5.2 Variations

Variations to the original business case were not required.

5.3 Assumptions

See Section 5.4 – Project Risks

5.4 Project Risks

A key assumption of the project was that the use of live and dead line work methods by skilled personnel would deliver the project within normal operational levels and without undue safety risk to personnel, system reliability and operation.

Safety risks were minimised by:

- Maximising the use of any planned outage;
- Designing the components of the work, where possible, for live line installation; and
- Carrying out the work in a manner to minimise the time for restoration of any de-energised circuit.

5.5 Conformance with Policies & Procedures

No non-conformance issues associated with Transend policies and procedures, of the time, were observed.

5.6 Post Implementation Review

Given the small size of this project and the fact that the project was completed within budget, a separate finalisation report was not prepared. Project finalisation was facilitated through normal reporting processes. A capital project investment review was developed in June 2008 which summarised the key elements of the project.

6 EFFICIENCY

6.1 Estimating Basis

The original business case estimate for the project was as follows:

Cost Estimate Item	Estimate
Construction	$120,000
Project Development	$80,000
Project Management (by External Contractor)	$40,000
Design	$20,000
Supervision (by Transend)	$10,000
Outage Co-ordination	$10,000
Contingency	$45,000
TOTAL	**$325,000**

6.2 Costs

The capitalised cost of the project was $273,000 (inclusive of FDC) and all assets resulting from this project have been included in the Regulated Asset Base.

The fall of "as commissioned expenditure" as detailed in Appendix 3 of Transend's submission was:

Jan-Jun 2004	2004-05	2005-06	2006-07	2007-08	2008-09	Total
$0.2 m	$0.1 m					$0.3 m

6.3 Design Considerations

WorleyParsons is of the opinion that it was prudent of Transend to engage the services of ODG for this project as they had had experience in:

- The application of risk assessment techniques and the identification of high risk zones;
- The application of ESAA C(b)1 in Tasmania;
- The assessment of transmission and communication structures for increased loads;
- The preparation of work instructions for upgrading requiring member replacement and secondary reinforcement on energised transmission lines;
- The assessment, design, specification and supervision of foundation upgrading on loaded towers;

- The preparation of costings for upgrading work in complex situations;
- The upgrading required for additional maintenance points on ageing transmission lines and for the stringing requirements of OPGW; and
- The inspection of ageing transmission lines for the requirements of upgrading.

6.4 Project Delivery

Transend contracted ODG to provide design and program management services for this project.

Tower strengthening which was to be undertaken by Aurora Energy under the existing TranAur04 contract was not required.

The remaining works were tendered out to a selected number of pre-qualified contractors and managed under existing compliance program contracts. The conductor attachment modifications work was completed by Electrix Pty Ltd.

The objectives of this project were met in that the capacity of the Creek Road–Risdon and Chapel Street–Risdon 110 kV transmission lines was increased to 800 amps (with an assigned short term rating of 880 amps under certain circumstances).

This increased capacity allowed the Creek Road–Risdon and Chapel Street–Risdon 110 kV transmission lines conductor replacement project to be undertaken without load shedding.

The project was commissioned in March 2004.

7 ASSESSMENT

WorleyParsons considers that Transend has demonstrated that there was a justifiable need for this project. Project drivers included the need to mitigate business risk and to increase the capacity of the Chapel Street–Risdon and Creek Road–Risdon 110 kV transmission lines. Risdon Substation is a key substation in the southern Tasmanian transmission system, and a forced outage would have resulted in significant load shedding.

WorleyParsons considers that the investment was efficient. The design and program management was undertaken by O'Donnel Griffin and the final cost of $273,000 is reasonable when compared with estimates prepared by WorleyParsons based on similar projects. The construction elements were tendered out to a selected number of pre-qualified contractors. Although the final costs exceeded the original estimate, the project was completed consistent with market prices at the time. The project was one phase of a multi phase program to address network issues in the north east area over an extended time frame.

The investment processes and procedures adopted by Transend for this project appear to have ensured that prudent capital expenditure was undertaken. There were no variations to the original business case submitted for the project and at no stage did the expenditure exceed the approved level. Only two options were considered in detail by Transend (the "do nothing" option and the preferred option). WorleyParsons was not able to identify other viable options. The project risks were also considered and a post implementation review was not conducted, given the relatively small size of the project and its completion within budget.

WorleyParsons considers that the project was required to be completed during the Current Regulatory Control Period. The project was needed early in the period, and was coordinated with outages for another project.

8 CONCLUSION

This project appears to have been prudently planned, scoped and executed. Appropriate levels of project governance were also in place. WorleyParsons is of the opinion that the project passes a prudency test assessment.

RISDON SUBSTATION: ESTABLISHMENT OF A 33 kV CONNECTION POINT

1 PROJECT DESCRIPTION

1.1 Project Identification

ND0511

1.2 CAPEX Category

Connection

1.3 Brief Overview

The project scope was to provide Aurora with a 33 kV connection point with a firm capacity of 120 MVA and to decommission the existing 22 kV infrastructure.

The scope included:

- Redevelopment of the existing 11 kV switchroom area for the new 33 kV switchboard, two station service transformers, wholesale metering, AC and DC supplies, protection and control, supervisory control and data acquisition and communication;
- Two new 110/33 kV transformers, and an existing transformer reconfigured for 33 kV output; and
- Removal from site existing switchroom asbestos roofing material and all 22 kV and associated equipment.

All the necessary control, protection and metering for the new and modified primary equipment was also included in the scope.

1.4 Background

Transend and Aurora Energy (Aurora) jointly developed the Hobart Area Supply Upgrade Strategy (HASU) to convert the existing 22 kV subtransmission network to 33 kV.

The strategy was presented to the Reliability and Network Planning Panel (RNPP) in February 2000 and this was followed by an Information Paper to the RNPP in April 2000.

As part of the strategy, a development program was agreed between Transend and Aurora for the stages and timing for the supply upgrade of Aurora's substations to 33 kV. The upgrade of Risdon substation was the fourth stage in this program which allowed Aurora to upgrade its remaining substations, New Town, Derwent Park and Claremont, to 33 kV.

Upgrades at Creek Road, West and East Hobart and Sandy Bay substations preceded the Risdon substation development.

Aurora formalised its project intent by submitting a Connection Application to Transend on 4th July 2002 for the establishment of a 33 kV connection point at Risdon Substation.

2 PROJECT NEED

2.1 Drivers

This project was the fourth stage of the Hobart Area Supply Upgrade (HASU) strategy; a program jointly developed by Transend and Aurora to convert the existing 22 kV Hobart area subtransmission network to 33 kV. The strategy was presented to the RNPP in February and April 2000.

The HASU was required to cater for the projected demand growth in the greater Hobart Area. Under the Energy Supply Industry (ESI) Act 1995, Transend and Aurora have an obligation to ensure that electricity demand is met under normal circumstances. Also under the Tasmanian Electricity Code (TEC), S5.1.2.2, Transend is required to provide the necessary level of power transfer capability with the power system in a satisfactory operating state for electricity demand to be met.

The previous stages of the HASU demonstrated that conversion to a 33 kV subtransmission system was the preferred option to address the demand issues.

2.2 Timing

The timing of the project was governed by the wider HASU strategy governed mainly by Aurora requirements. Hence the timing of the Risdon substation upgrade was agreed with Aurora to enable the East Hobart and Sandy Bay 33 kV supply connections to be available when required. Also, establishment of a 33 kV connection site at Risdon Substation enabled Aurora to complete the remaining stages of the HASU program.

The remaining stages of the program included upgrading of Derwent Park, Claremont and New Town substations to 33 kV. To utilise the full benefits of this development the following timing was agreed with Aurora:

- January 2004 - Cutover East Hobart to Creek Road 33 kV board;
- March 2004 – Cutover remaining 33 kV feeders;
- Winter 2004 – Upgrade Risdon substation to 33 kV;
- October 2004 – January 2005 – Transfer East Hobart to Risdon 33 kV;
- March 2005 – connect Derwent Park and New Town to Risdon 33 kV; and
- December 2005 – connect Claremont to Risdon 33 kV and decommission 22 kV supply at Creek Road substation.

2.3 Strategic Alignment

In 2000, Transend completed a HASU strategy review. The joint Transend/Aurora process of review and analysis of alternative development strategies for the HASU considered strategic options structured around major central business district substations supplied at either 110 kV or 33 kV.

The selected option was to upgrade the Hobart area 22 kV system to 33 kV and establish capacity for transformation at 110/33 kV at both Risdon and Creek Road substations.

This project aligned with the HASU strategy.

The following table summarises the alignment of elements of Transend's 2003 business plan with the project objectives:

Criterion	Business Objective	Project Objective
Safety	Ensure a safe working environment for employees, contractors and the public.	Replace equipment that presents a greater safety risk to employees, contractors and the public
Supply Availability	Provide a reliable supply of electricity to Transend's customers.	Provide a new 33 kV injection point in the greater Hobart area.
System Security	Maintain the power system in a secure operating state as defined in the Tasmanian Electricity Code.	Minimise the risk of outages to the Hobart central business district and surrounding areas.
Returns	Achieve appropriate and sustainable returns on shareholders' equity.	Minimise the risk of customer load shedding.
Costs	Minimise costs of operating the business.	Decommission the old 22 kV assets at Risdon and Creek Road substations and fully utilise the available 33 kV assets at Creek Road Substation.

3 ALTERNATIVES

3.1 Options

The economic need for the project was established at the RNPP in April 2000 prior to stages 1, 2 and 3 being approved. Transend has applied the cost effectiveness analysis for this fourth stage of the HASU program rather than a market benefit analysis because all previous stages of the program have demonstrated that 33 kV development option is the preferred option. Also, after stage one of the program, a new 33 kV connection point at Creek Road Substation was established and new 33 kV assets became available for stages two and three of the program.

The options considered for this project were as follows:

Option	Option Description	Cost ($m)	Reason for selection/rejection
1	Upgrade Risdon Substation to 33 kV with a firm capacity of 120 MVA	9.0	Selected because it is the least cost option.
2	Establish a new 110/33 kV substation at McRobies Gully. This would reduce demand at Creek Road and Risdon Substation so that a 33 kV 60 MVA connection point could be established at Risdon without purchasing new transformers.	20.0	Rejected because not the least cost option.
3	Establish a new 33 kV connection point at North Hobart Substation. This would reduce demand at Risdon to 60 MVA firm, so that only one transformer would need to be purchased.	15.5	Rejected because not the least cost option.
4	Establish a new 110/33 kV substation at Mt. Nelson. This would reduce demand at Risdon substation to 60 MVA firm, so that only one transformer would need to be purchased.	16.8	Rejected because not the least cost option.
5	Establish a new 33 kV connection point at Chapel St Substation. This would reduce demand at Risdon substation to 60 MVA firm, so that only one transformer would need to be purchased.	14.6	Rejected because not the least cost option.

3.2 Options Analysis

Five different development options were costed to provide a 33 kV connection site for Aurora's East Hobart and Sandy Bay substations. The HASU strategy and development program also envisaged redevelopment of Aurora's New Town, Derwent Park and Claremont substations to 33 kV.

Aurora's intention was to decommission 22 kV subtransmission voltage and upgrade these substations to 33 kV supply before the end 2005. To facilitate this request Risdon substation had to be redeveloped as a part of any development option. A minor difference was the scope of the required upgrade at Risdon substation for different development options.

Some of the development options did have an impact on the already established Creek Road Substation 33 kV connection site by a reduction in the loading of this substation or a reduction in the number of 33 kV feeders required.

The following table represents the summary comparison of the costed options:

Development Option Details	Option1 Risdon	Option 2		Option 3		Option 4		Option 5	
		Mc-Robies	Risdon	Nth Hobart	Risdon	Mt Nelson	Risdon	Chapel St	Risdon
Number 0f 110/33kV Tx's	3	3	2	2	2	2	2	2	2
Number of 33kV Feeders	12	9	11	6	11	6	12	6	12
Cost ($m)		15,451	4,509	9,602	5,900	10,555	6,197	8,392	6,204
	8,988	19,960		15,502		16,752		14,596	

From the above table it is evident that option one, the upgrade of the existing 22 kV Risdon Substation to 33 kV, is the most cost effective solution to provide a 33 kV supply to East Hobart and Sandy Bay substations.

This upgrade provided the necessary 33 kV connection assets for the future upgrade of the remaining New Town, Derwent Park and Claremont substations. It also facilitated the establishment of 33 kV interconnectors between Creek Road, Risdon and Lindisfarne substations.

3.3 Consideration of Non Network Solutions

No specific non-network solutions were considered; however this project was only one stage of an overall 22kV to 33kV conversion of the Hobart supply area.

3.4 Capex/Opex Trade-offs

No Capex/Opex trade-offs were considered for this project. WorleyParsons considers that Capex/Opex trade-offs were not a significant issue for this project.

4 REGULATORY CONSIDERATIONS

4.1 Alignment with NER Capital Expenditure Objectives

Transend considers that the capital expenditure was required to meet the following capital expenditure objectives identified in clause 6A.6.7(a) of the NER:

- Comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services;
- Maintain the quality, reliability and security of supply of prescribed transmission services; and

- Maintain the reliability, safety, and security of the transmission system through the supply of prescribed transmission services.

4.2 Regulatory Test

Transend applied the cost effectiveness analysis for this fourth stage of the HASU program rather than a market benefit analysis because all previous stages of the program have demonstrated that 33 kV development option was the preferred option. Also, after stage one of the program, a new 33 kV connection point at Creek Road Substation was established and new 33kV assets became available for the following stages.

This project is specifically identified in the 2003-2009 Revenue Cap Application (RCA) and was specifically included in the TSMP 2003 Edition.

5 GOVERNANCE

5.1 Business Case Approvals

The business case for this project was approved by the Transend Board on 27th February 2003.

The Transend Board resolved to authorise expenditure of up to $9.0 million (plus GST) during 2003-04, 2004-05 and 2005-06 to establish a 33 kV connection point at Risdon Substation.

5.2 Variations

There were a number of contract variations that arose during the course of the project, mostly initiated by Transend as a result of the state of the infrastructure found on site, in order to improve the quality of the final installation.

The variations were within the general scope of the project, within the authority of the project manager to approve, and did not take the project beyond the project estimate approved by the board.

5.3 Assumptions

Key assumptions were identified for the overall Hobart Area Supply Upgrade Program of which this project formed part.

These assumptions were concerned with the 33 kV subtransmission option and related to Aurora Networks rather than Transend. The assumptions were based the success of 33 kV as a long term substransmission voltage.

5.4 Project Risks

Business risks were identified for the overall Hobart Area Supply Upgrade Program of which this project formed part.

These risks were also concerned with the 33 kV subtransmission option and related to Aurora Networks rather than Transend. The risks related to greater requirement for 33 kV underground cable than originally planned, embedded generation scenarios, changes in load forecasts and cost and schedule overruns.

5.5 Conformance with Policies & Procedures

No non-conformance issues associated with Transend policies and procedures, of the time, were observed.

5.6 Post Implementation Review

A post implementation review document was sighted and a capital project investment review was developed in March 2008 which summarised the key elements of the project.

6 EFFICIENCY

6.1 Estimating Basis

The original business case estimate for the project was as follows:

Cost Estimate Item	Estimate
Civil Works	**$0.447 m**
Building Works	$0.322 m
Other	$0.125 m
Electrical Works	**$6.172 m**
Design	$0.415 m
Transformers	$2.550 m
Switchboards	$0.523 m
Circuit Breakers	$1.394 m
Protection Equipment	$1.119 m
Station 415V AC Supply	$0.076 m
Station DC Supply	$0.075 m
Cabling, etc.	$0.020 m
Installation	**$0.598 m**
Circuit Breakers	$0.096 m
Switchboards	$0.061 m
Transformers	$0.027 m
Control & Protection Equipment	$0.060 m
AC & DC Supplies	$0.039 m
Other	$0.315 m
General	**$0.945 m**
Project Initiation/Concept Design	$0.050 m
Project Development	$0.130 m
Design Reviews & Project Management	$0.225 m
Commissioning & Training	$0.049 m
As Built Drawings & Manuals	$0.021 m
Project Finalisation	$0.038 m
Interest During Construction	$0.441 m
Contingency @ 10% on all works	**$0.817 m**
TOTAL	**$8.988 m**

6.2 Costs

The capitalised cost of the project was $6.8 million (exclusive of IDC and inclusive of FDC) and all assets resulting from this project have been included in the Regulated Asset Base.

The fall of “as commissioned expenditure” as detailed in Appendix 3 of Transend’s submission was:

Jan-Jun 2004	2004-05	2005-06	2006-07	2007-08	2008-09	Total
		$3.9 m	$2.9 m			$6.8 m

6.3 Design Considerations

The Risdon substation is one of the few under Transend’s control where the transformation is from a transmission voltage (110kV) to a subtransmission voltage (33kV).

On the 110 kV side, a double bus, single breaker arrangement has been utilised. This arrangement permits some flexibility as it has two operating busses and either bus can be isolated for maintenance; however there is a high exposure to bus faults. The arrangement is not as flexible as the double bus, double breaker or breaker-and-a-half arrangement; however it is less expensive.

On the 33 kV side, a simple three transformer, three bus arrangement has been utilised.

The arrangements utilised are not the most expensive and are of a standard design. There is no evidence of significant over-design of the substation.

6.4 Project Delivery

The project was implemented under AS 4300, General Conditions of Contract for Design and Construct. The site design and installation contract was awarded to Aurora Contract Services following a competitive tender process.

The contract was monitored and controlled through regular project meetings as well as project control group meetings. Key project milestones were aligned to Aurora’s 33 kV zone substation and 33 kV sub-transmission upgrade program, providing a smooth transition from 22 kV to 33 kV supply.

Transend procured the 110/33 kV transformers for this project. The two transformers purchased for this project (one to be used at Risdon Substation and the other to replace the system spare which was transferred to Risdon Substation for this project) were bundled with a number of transformers required for other projects and were supplied by Wilson Transformers Pty Ltd.

The objectives of the project were to provide a 33 kV connection point for Aurora Energy and to provide sufficient capacity to meet the connected demand over the planning period. The successful implementation of this project allowed these objectives to be achieved.

This project was commissioned in stages to align with Aurora’s upgrade program and the revised schedules as agreed with Aurora.

- Transformer T6 and the new 33 kV switchboard were commissioned on 23 May 2006;

- Transformer T5 was commissioned on 3 November 2006; and
- Transformer T4 was commissioned on 15 January 2007.

Practical completion was achieved on 21 January 2007 and the commissioning certificate issued in February 2007.

7 ASSESSMENT

WorleyParsons considers that Transend has demonstrated that there was a justifiable need for this project. Project drivers were a connection request from Aurora Energy and the need to meet projected demand in the Hobart area. The project was the fourth stage of the HASU strategy, a program to convert the existing 22 kV subtransmission to 33 kV.

WorleyParsons considers that the investment was efficient. The design approach on the 110 kV side (double bus, single breaker arrangement) is a relatively cheap arrangement, as is the simple three transformer, three bus arrangement adopted for the 33 kV side. The final cost of $6.8 million is reasonable when compared with estimates prepared by WorleyParsons based on similar projects. The project was tendered as a design and construct contract, with Transend providing the transformers.

The investment processes and procedures adopted by Transend for this project appear to have ensured that prudent capital expenditure was undertaken. There were no variations to the original business case submitted for the project and at no stage did the expenditure exceed the approved level. Five development options were considered in detail by Transend including economic evaluations, and the lowest cost solution was adopted. The project risks were also considered and a post implementation review was conducted.

WorleyParsons considers that the project was required to be completed during the Current Regulatory Control Period. The project timing was governed by the wider HASU strategy, with timing driven by Aurora Energy.

8 CONCLUSION

This project appears to have been prudently planned, scoped and executed. Appropriate levels of project governance were also in place. WorleyParsons is of the opinion that the project passes a prudency test assessment.

WESLEY VALE CIRCUIT BREAKER INSTALLATION

1 PROJECT DESCRIPTION

1.1 Project Identification

ND0705

1.2 CAPEX Category

Connection

1.3 Brief Overview

The scope of this project was to install one additional 11 kV circuit breaker and associated protection, control and metering equipment at Wesley Vale Substation.

1.4 Background

Wesley Vale Substation provides electricity supply at 11 kV directly to the Paper Australia (PA) Mill at Wesley Vale. At the time this project was proposed, Tasmanian Wood Panels (TWP) was supplied from PA Mill under an electricity supply connection agreement between the two companies.

Transend received an application from Aurora Energy for an additional 11 kV connection point at Wesley Vale Substation to provide electricity supply directly to TWP.

2 PROJECT NEED

2.1 Drivers

The main investment driver for this project was Aurora Energy's application for an additional 11 kV connection point at Wesley Vale Substation. The purpose was to establish separation of the electricity supply for PA Mill and TWP and provide electricity supply directly to TWP from Wesley Vale Substation.

Transend suggested that there was also a business risk reduction driver as Transend's 2005 business risk review highlighted a number of risks directly related to this project. The installation of an additional circuit breaker contributed to the mitigation of the those risks, as follows:

- Non compliance with transmission laws and regulations; and
- Lack of flexibility in dealing with customers.

2.2 Timing

This project was implemented in response to Aurora Energy's request for an additional 11 kV feeder connection at Wesley Vale Substation. Aurora Energy submitted its request in July 2006 for completion by September 2006.

2.3 Strategic Alignment

Transend's 2006-07 to 2010-11 Strategic Plan, which was approved by the Transend Board in May 2006, included a number of strategic performance objectives that were relevant to this project. This project contributed to Transend's strategic performance objectives as follows:

Strategic Performance Objective	Measure	Project Objective
Involve customer in decisions that affect them.	More than 80% of projects where affected customers are consulted.	Meet the stated requirements of Aurora Energy at Wesley Vale Substation.
Maintain transmission connection site performance.	Aurora Networks distribution connection assets.	Install assets that are able to meet customer's expectations at connection sites.
Fulfil operating licence obligations.	Compliance with conditions of transmission licence.	Comply with relevant rules, standards and guidelines, particularly. with regard to the intent of customer connection obligations.
Provide appropriate and sustainable returns to shareholders.	Return on revenue-capped assets.	Undertake prudent investments to ensure appropriate returns. Include proposed expenditure in Transend's regulated asset base.

3 ALTERNATIVES

3.1 Options

The options considered for this project were as follows:

Option Description	Reason for selection/rejection
Do Nothing	This option would not address Aurora Energy's request for one additional 11 kV feeder connection point at Wesley Vale Substation to supply electricity directly to TWP via the distribution system. Transend is obliged under the National Electricity Rules to respond to a customer enquiry and negotiate the services requested by the customer. In addition, this option would not support Transend's strategic performance objectives.
Install one additional 11 kV circuit breaker at Wesley Vale Substation	This option addressed Aurora Energy's request for an additional 11 kV connection point at Wesley Vale Substation. It also supported Transend's strategic performance objectives.

3.2 Options Analysis

The option to Install one additional 11 kV circuit breaker at Wesley Vale Substation was selected because it addressed Aurora Energy's connection request and aligned with Transend's strategic performance objectives.

3.3 Consideration of Non Network Solutions

No non network solutions were considered for this project. WorleyParsons considers that non network solutions were not a significant issue for this project.

3.4 Capex/Opex Trade-offs

No Capex/Opex trade-offs were considered for this project. WorleyParsons considers that Capex/Opex trade-offs were not a significant issue for this project.

4 REGULATORY CONSIDERATIONS

4.1 Alignment with NER Capital Expenditure Objectives

Transend considers that the capital expenditure was required to meet the following capital expenditure objective identified in clause 6A.6.7(a) of the NER:

- Comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services.

5 GOVERNANCE

5.1 Business Case Approvals

The business case for this project was approved by the Acting Chief Executive Officer on 21st September 2006.

The business case recommended:

- Capital expenditure of up to $235,000 in nominal dollars (plus GST) to complete the project;
- Conditional expenditure of up to $40,000 for provisional contingency events to be used only if the contingencies arise; and
- The engagement of AREVA T&D Australia Ltd under the existing contract 1196 as the principal contractor to complete the scope of works.

5.2 Variations

Variations to the original business case were not required.

5.3 Assumptions

The only key assumption identified was that the project would have no material impact on other systems.

5.4 Project Risks

The only business risk identified for the project was an increased likelihood of interruption to electricity supply during the installation of the additional 11 kV circuit breaker and its associated equipment.

A project plan was developed to minimise the risk exposure and the following actions were undertaken:

- Appropriate on-site supervision was provided to ensure compliance with the project plan and the relevant Transend power system safety rules;
- As far as practicable, adequate preparatory work was undertaken in terms of the laying of control cables and site pre-commissioning of the new circuit breaker and associated protection, control and metering prior to cut-over;
- The new 11 kV circuit breaker and associated protection and control equipment was identical to those that were also installed at Wesley Vale Substation. This reduced the risks associated with design error and/or operator error; and
- The design, installation and commissioning contractor already utilised at Wesley Vale Substation under contract 1196 was engaged to implement this project.

5.5 Conformance with Policies & Procedures

No non-conformance issues associated with Transend policies and procedures of the time, were observed.

5.6 Post Implementation Review

Given the small size of this project and the fact that the project was completed within budget, a separate finalisation report was not prepared. Project finalisation was facilitated through normal reporting processes. A capital project investment review was developed in June 2008 which summarised the key elements of the project.

6 EFFICIENCY

6.1 Estimating Basis

The original estimate for the project included in the business case indicated the investment funding requirement was for $235 000 plus a contingency of $40 000. The estimate was subsequently refined as follows:

Estimate Cost Item	Estimate
Circuit breaker panel complete with bus section, circuit breaker, current transformer and voltage transformer	$59,500
Protection relays	$21,325
Supervisory control and data acquisition	$8,500
Design and engineering	$37,500
Installation (order placed after designs and work started)	$45,000
Commissioning	$25,000
Contingency to allow for outages & working in live environment	$49,206
TOTAL	**$246,031**

6.2 Costs

The capitalised cost of the project was $230,911 (exclusive of FDC and IDC) and all assets resulting from this project have been included in Regulated Asset Base.

The fall of “as commissioned expenditure” as detailed in Appendix 3 of Transend’s submission was:

Jan-Jun 2004	2004-05	2005-06	2006-07	2007-08	2008-09	Total
			$0.2 m			$0.2 m

6.3 Design Considerations

The scope called for the installation of a standard 11kV circuit breaker and associated protection and control equipment that was identical to other units already installed at Wesley Vale Substation. This standardised equipment approach alleviated the need for any special design considerations and facilitated standard operating procedures within the substation.

6.4 Project Delivery

Transend engaged AREVA to implement this project. At the time this project was proposed, AREVA had recently completed a package of work including high voltage switchgear replacement at Wesley Vale Substation. AREVA was engaged for this project as a variation to its existing contract with Transend, which had been established following a competitive tender process.

This approach facilitated the timely and cost effective implementation of the project and minimised Transend's risk of an unplanned interruption to power supply during its execution. The additional panel was successfully installed and commissioned ready for connection to Aurora Energy's feeder for TWP. This project therefore satisfactorily met the investment needs and the objectives of the project.

The project was commissioned in November 2006.

7 ASSESSMENT

WorleyParsons considers that Transend has demonstrated that there was a justifiable need for this project. The main driver for the project was a connection request from Aurora Energy in line with the provisions of clause C5.3.3 (b) of the NER.

WorleyParsons considers that the investment was efficient. Standardised designs were implemented and the installation required only a variation to an existing construction contract (established through competitive tender), thus eliminating any contract start-up costs. The final cost of $231,000 is reasonable when compared with estimates prepared by WorleyParsons based on similar projects.

The investment processes and procedures adopted by Transend for this project appear to have ensured that prudent capital expenditure was undertaken. There were no variations to the original business case submitted for the project and at no stage did the expenditure exceed the approved level. Only the "do nothing" option and the preferred option were considered in detail by Transend. WorleyParsons was not able to identify any other viable options. The project risks were also considered but a post implementation review was not conducted, due to the relatively small size of the project and its completion within budget.

WorleyParsons considers that the project was required to be completed during the Current Regulatory Control Period, with the project timing driven by Aurora Energy.

8 CONCLUSION

WorleyParsons is of the opinion that the project passes a prudency test assessment.

ASSET MANAGEMENT INFORMATION SYSTEM (AMIS)

1 PROJECT DESCRIPTION

1.1 Project Identification

ND0614

1.2 CAPEX Category

Operational Support Systems

1.3 Brief Overview

The AMIS project consolidates primary asset management functions and information on the WASP Asset Management System. The project also provides integration between WASP and ancillary asset management systems and other core Transend systems. This system integration allows information from disparate databases to be synchronised, cross-related and provided to users in composite views. This eliminates uncertainty about definitive sources of information and allows for more informed decision making.

The project has established data integrity standards and business processes for asset management and is providing comprehensive reporting for all aspects of asset management and system performance.

1.4 Background

An asset management information system (AMIS) is a combination of people, processes and technology applied to provide the essential outputs for effective asset management such as reduced risk, enhanced transmission system performance, enhanced compliance, effective knowledge management, effective resource utilisation and optimum infrastructure investment. It is a tool that interlinks asset management processes through the entire asset life cycle (cradle to grave) and provides a robust platform for extraction of relevant asset information for various purposes.

Transend's AMIS strategy has the objectives of managing asset related information to:

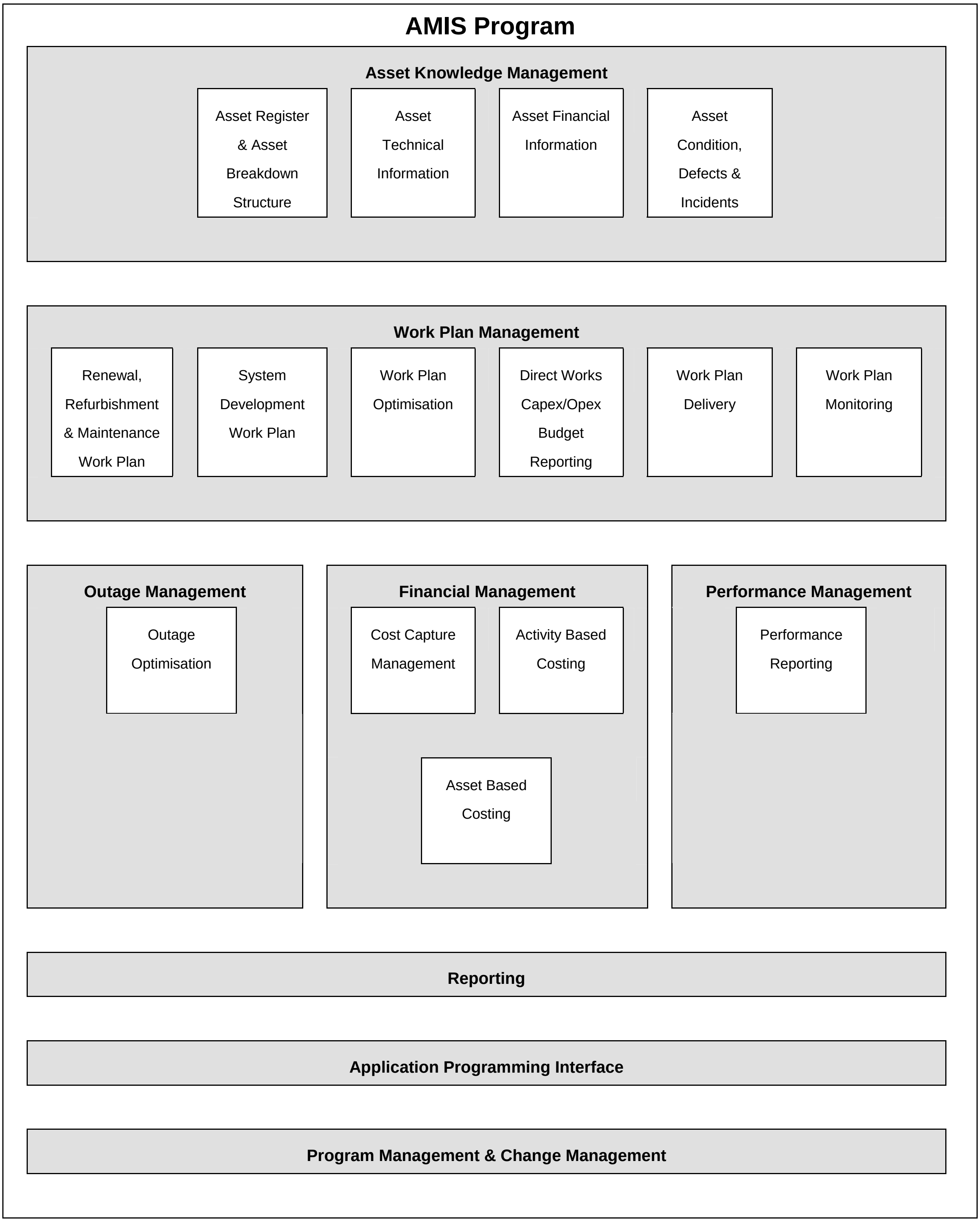
- Improve the management of assets;
- Enhance productivity by the provision of appropriate tools;
- Ensure the timeliness, accuracy, integrity and credibility of asset data;
- Meet statutory, regulatory and customer requirements and expectations;
- Ensure the appropriate ownership, custodianship and management of the data;
- Provide easy maintainability of data; and
- Provide an open access to asset data and performance information to Transend staff.

In 2003 Transend commenced a program to implement an AMIS. The program has been highly successful and has implemented many of the components of the AMIS strategy. AMIS is now directly supporting the following business processes:

- Asset information management;
- Network performance monitoring;

- Rating management;
- Long-term work plan management;
- Work plan publishing to contractors;
- Outage scheduling;
- Incident and audit management;
- Defect management;
- Power transformer condition monitoring;
- Project prioritisation;
- Circuit and customer pricing management; and
- Transmission lines easement property management.

As depicted below, AMIS is structured around five key areas of asset information, work plan management, outage management, financial management and performance reporting.


AMIS Program
Asset Knowledge Management
Asset Register & Asset Breakdown Structure
Asset Technical Information
Asset Financial Information
Asset Condition, Defects & Incidents
Work Plan Management
Renewal, Refurbishment & Maintenance Work Plan
System Development Work Plan
Work Plan Optimisation
Direct Works Capex/Opex Budget Reporting
Work Plan Delivery
Work Plan Monitoring
Outage Management
Outage Optimisation
Financial Management
Cost Capture Management
Activity Based Costing
Asset Based Costing
Performance Management
Performance Reporting
Reporting
Application Programming Interface
Program Management & Change Management

2 PROJECT NEED

2.1 Drivers

The key investment driver for this project was (and remains) to facilitate the development of an asset management system to support improved asset management and the asset life cycle management process.

This is highlighted in the Transend Strategic Plan 2008, section 8.8 Business processes. (Attachment Referenced Document 7).

Transend's asset management business goals are efficient asset management, effective asset operation and effective regulatory management. These goals drive the need for integrated access to consistent, accurate and up-to-date asset information and for integrated business processes. A summary is provided below:

Driver	Explanation
Efficient asset management	▪ Maintenance efficiency – requires information about the asset's condition and maintenance/performance history. ▪ Maintenance productivity – requires information on maintenance costs and performance to support improvement and refinement of strategy. ▪ Investment decision making – replacement/refurbishment/renewal decisions require data on condition, maintenance costs, performance history to facilitate option modelling. ▪ Asset and system performance monitoring and measurement – requires system, asset and asset group performance history. ▪ Benchmarking – depends on reliable asset related data.
Effective asset operation	▪ Information on asset capability (ratings) must be accurate and current for effective asset operation and performance. ▪ Power system modelling – is dependent on accurate and consistent asset data.
Effective regulatory management	▪ Regulatory and statutory reporting – consistency and accuracy require standardised processes and systems. ▪ Connection and network services agreements – Transend is obliged to maintain a current set of technical information related to connection assets.

Specific investment drivers are identified in each business case.

2.2 Timing

The initial project was approved on 16 January 2002 with expenditure to be incurred during the financial years 2001/02 and 2002/03, during the Previous Regulatory Control Period. This was stage one of a broad project to implement the strategy for asset management information system, which was later approved by Transend's Board for implementation over the Current Regulatory Control Period.

2.3 Strategic Alignment

The continued development of AMIS is recognised as an element of Transend's strategic focus. The following is an extract from Transend's Strategic Plan 2008:

> *Transend aims to strengthen its focus on process improvement opportunities across the business. The continual improvement of key business processes will enable Transend to:*
>
> - *satisfy stakeholder needs more efficiently;*

- *provide services more effectively;*
- *improve productivity; and*
- *deliver the capital works program.*

Transend is committed to the continual development of an asset management information system. This system is linking Transend's extensive asset database with various business processes throughout the entire asset life cycle. The new system is helping to:

- *improve asset management;*
- *enhance productivity; and*
- *allow Transend to meet regulatory requirements.*

The continued development and enhancement of the AMIS is also explicitly described as an organisational initiative within Transend's Strategic Performance Objectives 2008/09.

This project was included in Transend's revenue cap application to the ACCC in 2004 and was also included in the annual Transmission System Management Plans from 2003 through to 2008 inclusive.

3 ALTERNATIVES

3.1 Options

Each initiative is undertaken in the context of an approved business case. The economic analysis for each of these is embedded in the business case.

Generically, the basic options for the AMIS project were:

Option No.	Option description	Reason for selection/rejection
1	**Do nothing**	Without AMIS, asset management systems would remain fragmented, information would reside in silos, be duplicated without any synchronisation resulting in poor information about assets and necessitating time-consuming process to compile and correlate information. There would be an inability to monitor and measure asset management performance and the ability to implement sophisticated asset management strategies would be compromised.
2	**Proceed with AMIS as fully defined in the Project Management Plan.**	AMIS progressively establishes 'databases of record' for all key asset and related information, integrates and streamlines business processes and information flows between systems. It provides comprehensive reporting and business intelligence to enable business performance to be readily seen and analysed.

4 REGULATORY CONSIDERATIONS

4.1 Alignment with NER Capital Expenditure Objectives

Transend considers that the capital expenditure was required to meet the following capital expenditure objectives identified in clause 6A.6.7(a) of the NER:

- Comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services;
- Maintain the quality, reliability and security of supply of prescribed transmission services; and,
- Maintain the reliability, safety, and security of the transmission system through the supply of prescribed transmission services.

4.2 Regulatory Test

Not applicable for this non-network project.

5 GOVERNANCE

5.1 Business Case Approvals

Each initiative of the AMIS project is supported by an individual business case; hence there are multiple business cases. Further business cases will be undertaken as work progresses for the remainder of the project.

This method provides appropriate levels of financial and scope control by ensuring that:

- The cost benefit or each initiative can be assessed on its particular merits and equated directly to the AMIS sub-project scope and objectives;
- The initiative is aligned with current Transend asset management priorities and strategies;
- Funds are only made available at the required time;
- Business analysis occurs close to the time of system development;
- The deliverables from each piece of work are clearly identified; and
- Business benefits and efficiencies are clearly identified and delivered.

This approach has been noted and endorsed in the KPMG AMIS Project Quality Assurance Review Visit #4 Internal Audit Report November 2005.

The approved AMIS business cases for the Current Regulatory Control Period are listed below:

Business Case	Title	Approval Date	Approved Value	Approval Sighted
4505	Incident & Auditing Management Tool	14/12/2004	$10,000	✓
4507	Static Rating Information System	12/12/2004	$95,000	

Business Case	Title	Approval Date	Approved Value	Approval Sighted
4508	Works Plan Technical Specification	17/12/2004	$42,000	✓
4508	Works Plan Technical Specification - Variation	04/02/2005	40,000	✓
4509	Substation Assets Register	17/12/2004	$59,000	✓
4510	Telecoms Circuits	04/02/2005	$67,500	✓
4521	Transformer Test Results	17/03/06	$100,000	✓
4522	Combined Voltage Current Transformer	01/02/2005	$20,000	✓
4525	AM Tools & System Enhancement	04/02/2005	$72,000	✓
4525	AM Tools & System Enhancement - Variation	31/07/2005	$28,000	✓
4526	WASP 4.0 Upgrade	04/02/2005	$60,000	✓
4527	Secondary Systems Schemes & Relays	04/02/2005	$100,000	
4572	Network Performance Reporting	06/06/2005	$100,000	✓
4574	WASP Performance Reporting Source	24/04/2004	$100,000	✓
4576	Incident Investigation & Audit Database	20/07/2005	$100,000	✓
4582	Aurora Site Data Sheets in WASP	13/07/2005	$100,000	✓
4601	ILOG Software Purchase	28/09/2005	$36,500	✓
4602	WASP Asset Loader Program	17/03/2006	$100,000	✓
4603	WASP Rating Data Enhancements	17/03/2006	$100,000	✓
4604	WASP Works Plan Mgt Implementation	07/02/2006	$100,000	✓
4606	Earthing Assets in WASP	07/02/2006	$50,000	✓
4609	Asset Defect Management in WASP	17/11/2005	$10,000	✓
4610	Business Process Definition - WASP	16/11/2005	$70,000	✓
4616	Trans Lines AR Enhancements	07/02/2006	$50,000	✓
4626	WASP Works Plan Mgt Software Lic.	07/02/2006	$100,000	✓
4657	Secondary System WASP Audit	29/03/2006	$100,000	✓

Business Case	Title	Approval Date	Approved Value	Approval Sighted
4658	WASP Application Program'g Interface	17/03/2006	$100,000	✓
4666	System & Fault Outage Trends - WASP	09/05/2006	$25,000	✓
4670	WASP-PROMS-NOS AR Rationalisation	09/05/2006	$100,000	✓
4671	AMIS Program Management & Planning	09/05/2006	$100,000	✓
4678	AMIS System Security Plan	10/07/2006	$80,000	✓
4683	AMIS PMP NormanDisneyYoung Audit	16/06/2006	$100,000	✓
4684	Subs and P&C Defect Mgt in WASP	09/11/2006	$80,000	✓
4690	Works Prioritisation System	05/12/2006	$250,000	✓
4757	WASP Asset Reg to support SUN Asset Reg	05/08/2007	$54,000	✓
4758	Revenue Cap Capex/Opex Reporting	16/06/2006	$100,000	✓
4760	Works Plan Technology Enhancement	27/06/2007	$95,000	✓
4761	Mapping Maintenance Procedures	13/06/2007	$20,000	✓
4774	Asset Mgt Process Manual	28/05/2007	$90,000	✓
4775	TL Work Task Registration in WASP	16/07/2007	$40,000	✓
4779	Streamline Fault Outage Registration	12/06/2007	$10,000	✓
4785	Weather Station Assets in WASP	23/05/2007	$10,000	✓
4787	Program of Work Reconfiguration	11/05/2007	$10,000	✓
4827	WASP Asset Register OLAP Reporting	30/10/2007	$46,000	✓
4835	Tagging Pres/Neg/Unreg Assets WASP	20/03/2008	$20,000	✓
4836	Import 08/09 P Work Plan into WASP	26/03/2008	$15,000	✓
4842	PerfRep Enhancements for Service Std's Reporting	21/01/2008	$100,000	✓
4851	Business Intelligence for Fault Outages	16/04/2008	$30,000	✓
4854	Transmission Line Defect Registration in WASP	30/04/2008	$77,700	✓
4855	AMIS Business Intelligence Analysis & Design	23/05/2008	$73,000	✓

Business Case	Title	Approval Date	Approved Value	Approval Sighted
4858	WASP Program Work Implementation	06/05/2008	$10,000	✓
	TOTAL	**$3,445,700**		

5.2 Variations

There have been no changes to the project scope. As part of scope reviews and priority reviews, minor refinements (for example, in light of technology improvements and resultant opportunities) have been identified and reflected in relevant business cases.

Given the duration of AMIS (six years) and the pace of change in the information technology industry, where opportunities occur for more effective solutions based on improved and proven technology, then these are applied within the constraints of business objectives and scope. An example of this is where current "Business Intelligence" (BI) technology and tools have allowed for a holistic and effective solution to meet AMIS Performance Reporting requirements and to also provide a framework for whole of business BI.

5.3 Assumptions

The key assumptions of the project include:

- Transend has process experts (internally or externally) with the key skills sets necessary to direct the AMIS project team in terms of the desired deliverables from the AMIS elements;
- The internal/ external resources are available to assist the project team as desired (times when available);
- Transend has the capacity to provide operational and administrative support of the new AMIS business systems and applications;
- The core WASP (Asset Management) and SUN (Financial Management) systems will not be replaced; and
- The finance system (SUN), incident management system (RIMSys), Outage Management System (PROMS), transmission operation control system (NOCS) and semi manual electronic tracking system (SMELT) will not be replaced.

Specific Information Technology assumptions include:

- WASP remains the Transend asset management and works management business system;
- SUN Financials remains the Transend financial management business system;
- PROMS remains the Transend outage scheduling business system – rationalisation of PROMS and related functions is feasible during the project; and
- SMELT remains the logging tool used by Transmission Operations Group.

Assumptions in relation to each of the AMIS sub-projects are listed as follows:

Sub Project Description		Assumptions
1.1	Asset Register & ABS	▪ None
1.2	Asset Technical Information	▪ Manual data-entry will be employed to migrate technical attribute data into WASP from remote systems. ▪ DigSilent application supports a native, standard file-format import\export mechanism for P&C devices which requires no customisation or enhancement
1.3	Asset Financial Information	▪ SUN will be the Database of Record for data-entry and calculation of all asset financial attributes. ▪ Microsoft Reporting Services will be used to generate on-demand consolidated asset financial reporting from WASP and SUN, precluding the need to physically store asset financial information within assets in WASP. ▪ Accounting Unit of Property and Regulatory Unit of Property map to asset category\specification items in WASP and do not need to be mapped to individual assets. ▪ Transmission Pricing data extracts will leverage the near-completed (at November 06) WASP customer site data and completed WASP circuit-circuit topology model and will not require any additional data model developments.
1.4	Incident, Defect & Condition	▪ Manual data-entry will be used to load historical test condition information prior to development of the automated Test Template loader program.
2.1	Maintenance Plan	▪ WASP Asset Register will not require custom development\enhancement to support requirements. ▪ Major additional development or enhancement of the new WASP Works Planning system will not be required.
2.2	System Development Work Plan	▪ WASP Asset Register will not require custom development\enhancement to support requirements. ▪ WASP Works Management module will not require custom development\enhancement to support requirements.
2.3	Work Plan Optimisation	▪ The ILOG Gantt-Chart development toolkit product will be used to custom-build all calendar-style work plan optimisation applications within AMIS. ▪ EMS Solutions deliver a system interface that allow AMIS developers to update items within the underlying Works Plans in WASP. ▪ AMIS will custom-build a work prioritisation system specific to Transend requirements. ▪ The project prioritisation system will not be integrated with the WASP works planning system – the volume\volatility of project prioritisation functions does not justify automatic refreshes within the works planning system. ▪ The project prioritisation system will not support the prioritisation of operational maintenance tasks (ie individual instances of work on assets). Instead, Asset Management Strategies will identify the relative priority of task types (eg Class 1 circuit breaker maintenance as a whole) and these will be used as a reference guide in optimising the individual tasks within the works plans
2.4	Direct Works Capex/Opex Budget Reporting	▪ None

Sub Project Description	Assumptions
2.5 Works Plan Delivery	▪ The WASP work packaging, work issuing and work closeout screens within the Works Management module will be used and do not require any custom enhancement
2.6 Works Plan Monitoring	▪ None
3.1 Outage Optimisation	▪ The ILOG Gantt Chart development toolkit product will be used to custom build Gantt Chart applications within AMIS.
4.1 Cost Capture Management	▪ SUN Financials will remain as the corporate financial system. ▪ Existing Chart of Accounts will not need to be modified. Requirements will be supported by implementing additional "T" and "A" codes within SUN Financials only ▪ Existing WASP-SUN integration for registering "jobs" (eg 2145/001 or 3245/004) in SUN will be suitable but additional "Task Code" objects within each job will be sent as a system interface enhancement.
4.2 Activity Based Costing	▪ None
4.3 Asset Based Costing	▪ None
5.1 Performance Reporting	▪ None
6.0 Reporting	▪ MS-Reporting Services will be used to generate all AMIS Reports.
7.0 Application Programming Interface	▪ None

5.4 Project Risks

A risk and issues management system is identified in the AMIS Program Management Plan and this system details the approach and process relating to risk management.

5.4.1 Risk Management Process Objectives

The specific objectives and benefits of the AMIS risk management procedure is to:

- Identify and qualify risks as soon as possible, quantify their likely impact on a workstream or the overall AMIS program, the probability of occurrence and identify possible risk mitigating actions;
- Allocate the risk to the person or group that has the expertise or responsibility to resolve it;
- Develop a "Risk Register" that will enable risks to be viewed and categorised. This will allow knowledge sharing and improve risk management efficiency on the AMIS Program; and
- Develop continuous reporting and monitoring measures to ensure that risks are being proactively managed.

5.4.2 Risk Management Definitions

In the context of the AMIS program, a risk is defined as a potential event, such that if it occurs, could have a material effect on the successful delivery of the program objectives, if not resolved or controlled appropriately. A risk:

- Is a situation, which if it were to occur, could have significant adverse impact on the Program timeline, cost or quality;
- Can occur at the overall program level, at individual program element, at individual project stream or individual activity level;
- Has an associated probability and impact that may point to the need for current and/or future action – avoidance, mitigation, contingency; or
- May be a one-off event, repeated events or a progressive continuum.

A risk can either be:

- One which the Program has the capacity to identify, manage and monitor itself; or
- One involving a third party (external to the AMIS program), e.g. other Transend projects, acquisitions, etc, but with impact on the critical path to a successful outcome.

5.4.3 Risk Management Approach

Risk Management will be undertaken throughout the lifecycle of the Program, with the risks being reviewed and reassessed on a periodic basis. It is an iterative process requiring careful monitoring and review to capture new risks and remove old risks that no longer require active monitoring.

Project Managers and the Program Manager must review the “Risk Register” weekly to evaluate the need for urgent actions to prevent risks materialising. All major risks that could adversely affect the successful achievement of the Program objectives must be highlighted for subsequent consideration by the Program Manager and if necessary escalated to the AMIS Program Committee.

To ensure focus is maintained on high impact and high priority risks, the risk register will assign each risk with an impact and consequence rating and generate an overall risk rating using the matrix below.

IMPACT				
	HIGH	Significant Risk	Major Risk	Maximum Risk
	MEDIUM	Minor Risk	Significant Risk	Major Risk
	LOW	Minor Risk	Minor Risk	Significant Risk
		LOW	MEDIUM	HIGH
			PROBABILITY	

Consider risks in this area first

Consider risks in this area next

Then here, and so on until all diagonals have been considered

The following table outlines consequences and action indicated for the Risk Matrix:

	Consequences	Action Indicated
Maximum Risk	**Drastic** This could result in the failure of the program	▪ Requires essential allocation of resources within the program to constantly monitor the risk and mitigate the risk ▪ Establish plans and counter-measures
Major Risk	**Noticeable** This will impact the program by delaying completion or requiring investment of additional resources with the consequential increase in costs or the need to re-plan the work.	▪ Requires priority allocation of resources within the program to mitigate the risk and monitor the risk at intervals. ▪ Establish plans and counter measures.
Significant Risk	**Some** The risk is one that may have an impact on the program's time and budget, and will need tapping into contingencies factored into the plan. Such risks are ones whose consequences may be accepted – even with a negative impact on the time and budget.	▪ Allocation of resources for study of the risk are available. ▪ Nominated person monitors the risk periodically.
Minor Risk	**Minor** There is sufficient contingency built into the Program, and the project management team has the tools, techniques, resources, skills, finances, research facilities and network of contacts to contain the risk.	▪ Risk identified and included in Risk Register. ▪ Risk reviewed periodically for any changes.

5.4.4 Risk Management Process

The steps in the risk management process are as follows:

- The risk is identified by the originator;
- The risk is identified through daily activities or during routine project management review and raised;
- The risk is assessed for its implications, probability and importance and preventative actions are identified. The risk is logged in the risk register and a resolution of the risk is formulated;

- The risk is then assessed and prioritised in the risk register;
- If the risk is considered of significant priority or higher, it is escalated to the Program Manager for review;
- The Program Manager reviews the risk and provides recommendations to the project Managers to mitigate the risk;
- If the risks are considered to be of major or maximum priority, they are consolidated in the Program Management risk register and escalated to the AMIS Program Committee for review;
- The AMIS Program Committee reviews the risks escalated to them and provides direction and guidance on the recommended actions to mitigate the risk;
- Mitigating actions are assigned to the personnel (designated as risk managers) as appropriate; and
- The risks are monitored on an ongoing basis. All “major” or “maximum” risks will be monitored at each Steering Group meeting. All risks will be reviewed at least monthly at the Program Management meeting and reported to the AMIS Program Committee in routine meetings.

5.4.5 Risk Register

A single, integrated risk register is used to track all risks across the entire program.

5.5 Conformance with Policies & Procedures

No non-conformance issues associated with Transend policies and procedures, of the time, were observed.

5.6 Post Implementation Review

A formal post implementation review has not been completed as this project is currently in progress, however a capital project investment review was developed in July 2008 which summarised the key elements of the project to date.

6 EFFICIENCY

6.1 Costs

The following table links business case numbers to project component and itemises expenditure to-date by project component with estimates to complete and forecast total expenditure. These figures are for the Current Regulatory Control Period. Further business cases will be prepared as the project proceeds.

Project Component		Expenditure to 22/06/08	Estimate to complete	Forecast Total Expenditure
1.1	Asset Register & ABS	$0.742 m	$0.122 m	$0.865 m
1.2	Asset Technical Information	$0.381 m	$0.045 m	$0.426 m
1.3	Asset Financial Information	$0.121 m	$0.011 m	$0.132 m
1.4	Incident, Defect & Condition	$0.253 m	$0.269 m	$0.522 m
2.1	Maintenance Plan	$0.446 m	$0.001	$0.448 m
2.2	System Development Work Plan	-	$0.70 m	$0.070 m
2.3	Work Plan Optimisation	$0.182 m	$0.255	$0.437 m
2.4	Direct Works Capex/Opex Budg Report'g	$0.100 m	-	$0.100 m
2.5	Works Plan Delivery	$0.020 m	$0.020 m	$0.040 m
2.6	Works Plan Monitoring	-	$0.035 m	$0.035 m
3.1	Outage Optimisation	-		$0.325 m
4.1	Cost Capture Management	-	$0.150 m	$0.150 m
4.2	Activity Based Costing	$0.022 m	$0.030	$0.051 m
4.3	Asset Based Costing	-	$0.030	$0.030 m
5.1	Performance Reporting	$0.483 m	$0.311	$0.794 m
6.0	Reporting	$0.035 m	$0.054	$0.089 m
7.0	Application Programming Interface	$0.178 m	$0.113 m	$0.291 m
Project Total		**$2.963 m**	**$1.842 m**	**$4.806 m**

Expenditure of $1.249 million occurred during the Previous Regulatory Control Period. Total project expenditure to 22 Jun 2008 including both the previous and Current Regulatory Control Periods is $4.212 million; with total forecast project expenditure of $6.055 million.

6.2 Project Delivery

Project delivery is in accordance with the Project Management Plan (PMP) Section 6, Program Delivery methodology and in Appendix H of the PMP.

There are two key service providers for AMIS:

- EMS the authors and owners of the WASP and basix packages and which is based in the ACT; and
- Synateq Pty Ltd which specialises in consulting, project management and system development and which is based in Hobart.

EMS's core services are the provision and maintenance of asset management packages and these services are sourced as and when appropriate by Transend.

Transend's relationship with Synateq is long-standing and based on mutual business benefit. Synateq provides resources and competency for project management and system development. The nature of the relationship ensures there is continuity for knowledge retention and knowledge transfer throughout the lifetime of AMIS.

7 ASSESSMENT

WorleyParsons considers that Transend has demonstrated that there was a justifiable need for this project as efficient asset management, effective asset operation and effective regulatory management all require access to consistent, accurate and up-to-date asset information supported by integrated business processes.

WorleyParsons considers that the investment was efficient. The project was broken up into components with separate business cases, in accordance with an overall Project Management Plan. Two key service providers were used – one providing and maintaining the asset management packages and the other providing project management and system development resources. The forecast expenditure of $6.1 million to the end of the Current Regulatory Control Period (including $1.2 million during the Previous Regulatory Control Period) is consistent with WorleyParsons' experience with similar asset management projects.

The investment processes and procedures adopted by Transend for this project appear to have ensured that prudent capital expenditure was undertaken. Fifty-one business cases have been approved in relation to this project as packages of work were identified and scoped. This approach provided appropriate levels of financial and scope control. All of the project components were consistent with an over-arching AMIS strategy.

In WorleyParsons' experience, a key issue with IT projects is the effective management of risk. WorleyParsons notes that a rigorous risk management system was included as a significant component within the AMIS Project Management Plan. Risks have been reviewed and reassessed on a regular basis, including a weekly review of the risk register by Project Managers and the Program Manager. Each identified risk is assigned an impact and consequence rating and is included in an integrated risk register. Based on the rigour of the process applied, WorleyParsons considers that Transend has been effectively managing the project risks.

A formal post implementation review has not yet been conducted as the project is still in progress.

WorleyParsons considers that the project was required during the Current Regulatory Control Period. Work commenced on the project during the Previous Regulatory Control Period, and the need for an integrated asset information system has increased over the Current Regulatory Control Period with Tasmania's inclusion in the NEM and the requirement for increased regulatory reporting, together with increasing pressure for business efficiencies.

8 CONCLUSION

This project appears to have been prudently planned, scoped and executed. Appropriate levels of project governance were also in place. WorleyParsons is of the opinion that the project passes a prudency test assessment.

SECONDARY SYSTEM EQUIPMENT STORE

1 PROJECT DESCRIPTION

1.1 Project Identification

ND0765

1.2 CAPEX Category

Non Transmission

1.3 Brief Overview

The project comprised the redevelopment of the former Main Transmission Line (MTL) building and included:

- The engagement of Stanton Management Group (SMG) to project manage the redevelopment;
- The development of purpose-built storage facilities for protection and control equipment;
- provision of a test bench area for testing and maintaining protection and control equipment;
- Relocation of the information technology configuration and storage area from the Operations building;
- Facility storage space (e.g. office furniture) which is presently incorporated in the MTL building;
- A meeting room; and
- Space that could be utilised as alternative accommodation in a contingency situation.

1.4 Background

In early 2006 Transend developed a Facilities Management Plan (FMP) to review current facilities and identify future demand. In December 2006 a further plan was developed for the primary and secondary equipment stores.

Transend's current location for storing critical system spares is leased premises in Moonah which provides storage for both primary and secondary systems equipment, critical spares for substations, transmission lines and protection and control and some specific project equipment. Transend's current lease on these premises expires in June 2010 and the building owner, Aurora Energy, has indicated that it will not offer an extension or renewal of the existing lease past this date as it is planning to sell the site.

The current store is inadequate for housing secondary systems equipment. There is a requirement that a controlled environment for critical spares be provided as well as a test bench facility. To ensure efficiency of operations, it is essential that the facility is located close to the Maria Street campus.

The former Main Transmission Line (MTL) building situated on the Maria Street campus was underutilised and was identified by the Facilities Project Group (FPG) as having potential for redevelopment as a secondary systems equipment store.

2 PROJECT NEED

2.1 Drivers

The current store houses both primary and secondary systems equipment and the lease with Aurora Energy expires on 30 June 2010 with no extension possible. This store is considered inadequate for the storage of protection and control secondary systems equipment.

A number of issues have been identified with the current spares location:

- Access to the store is via a long steep stairway presenting an occupational health and safety (OH&S) handling risk;
- The secondary systems equipment is housed within a wooden framed and clad building within the main store presenting a significant risk that in the event of a fire all spares would be lost;
- Secondary systems equipment is exposed to dust due to poor sealing from the main primary equipment store. Excessive dust can contribute to premature equipment failure;
- Due to a lack of temperature control and insulation there are large temperature changes. This can have a detrimental effect due to overheating and moisture ingress;
- There is insufficient space for the current spares holdings resulting in equipment being stored on the floor;
- The current test facilities are inadequate due to a lack of space, dust, and poor earthing. The test area is unable to accommodate standard panel testing; panels are currently located within the primary store. Test facilities are required to regularly test spares and evaluate new products;
- Risk of damage associated with shared use of panel testing space;
- Unsuitable storage environment potentially impacting upon manufacturers' warranties and increasing risk of spares being inoperable or damaged; and
- Remoteness from Transend's Maria Street Campus.

Other issues will also be addressed with this investment:

- Underutilisation of the MTL building and risks associated with the existing asbestos roofing;
- Lack of an additional meeting room and limited contingency space;
- Cost of direct connection to Transend data and voice networks; and
- Security concerns with information technology configuration workspace being contained within an open plan office environment.

2.2 Timing

The project was approved on 22 November 2007 for implementation during 2007–08 and 2008–09. There has been a strong building tender market during the past three to four years. However, there has been a softening over recent months which is likely to continue for some months. Market analysis indicated that going to tender was likely to prompt a lower cost outcome.

Investment in this project is timed to realise the business benefits as soon as practicable.

The schedule identifies project completion in September 2008.

2.3 Strategic Alignment

The following table shows the alignment of elements of Transend's Business Plan in effect in 2007 with the project objectives:

Criterion	Business Objective	Project Objective
Maintain transmission system performance	Transmission system performance	Timely access to protection and control spares will contribute to reducing power system equipment outage durations.
Comprehensive business continuity planning practices	Organisational efficiency and effectiveness	Strengthen business continuity by increased redundancy for Maria Street campus Operations building
Continuous improvement of key business processes	Organisational efficiency and effectiveness	Establishing appropriate facilities to support the achievement of Transend's business objectives and demand for adequate facilities

This project was not specifically included in Transend's revenue cap application to the ACCC in 2004; however it was included in the Facilities Management Plan, Transend Strategy Paper, August 2006.

3 ALTERNATIVES

3.1 Options

A summary of the options considered and analysed for this project is tabled below:

Option Description	NPV	Reason for selection/rejection
Do nothing	-	This option does not address the current storage issues nor the risks associated with the asbestos roofing and leaves the MTL building under-utilised.
Incorporate secondary systems store into Transend's new primary systems equipment store at Bridgewater	-$2.96m	This option would not address the current storage issues for an extended period. It would not satisfy the preference for a facility on or within close proximity of Transend's Maria Street campus and would also leave the MTL building under-utilised.
Lease property elsewhere	-$3.50m	This option would create less flexibility to undertake alterations and currently there is no suitable premises in close proximity to the Maria Street There would be high rental and fit-out costs and would also leave the MTL building under-utilised;
Redevelop existing MTL building on Transend's Maria Street site to incorporate a secondary systems equipment store.	-$2.21m	This option addresses the issues identified in the most cost effective way. Additional benefits include: ▪ development can occur in a timely fashion allowing a smooth transition to the new store prior to relocation of the primary store; ▪ 24 hour presence is provided by security guards and control room staff; ▪ value adds to an existing underutilised asset that demonstrates good environmental practice through reuse of an existing facility; ▪ property ownership remains with Transend which provides maximum future potential; ▪ operations are consolidated within the Maria street campus reducing travel requirements, communications and IT support costs; ▪ provision of a small scale on-campus business continuity location for key personnel; ▪ access to essential services; ▪ a reduced timeline, as the building is available now and ready for construction; and ▪ the development has planning approval.

3.2 Options Analysis

The analysis indicated that redeveloping the existing MTL building was the least cost option. The net present value of costs was calculated using a discount rate equal to the Transend regulated WACC (weighted average cost of capital).

4 REGULATORY CONSIDERATIONS

4.1 Alignment with NER Capital Expenditure Objectives

Transend considers that the capital expenditure was required to meet the following capital expenditure objectives identified in clause 6A.6.7(a) of the NER:

- Maintain the quality, reliability and security of supply of prescribed transmission services; and
- Maintain the reliability, safety, and security of the transmission system through the supply of prescribed transmission services.

4.2 Regulatory Test

Not applicable for this non-network project.

5 GOVERNANCE

5.1 Business Case Approvals

A summary of the business cases relevant to this project is listed below:

Business case	Business case title	Approval date	Approved value ($M)
BC4797	Transend's Secondary Equipment Store	12 June 2007	0.160
BC4986	Secondary System Equipment Store	22 November 2007	2.730

5.2 Variations

No variation approvals have been required beyond the authority of the Project Manager.

5.3 Assumptions

The only specific assumption associated with the project that was observed in the documentation was:

- Transend's WACC (Weighted Average Cost of Capital) was adopted for NPV calculations.

5.4 Project Risks

The average net risk rating for this preferred option was deemed to be low. The key risks for this project are summarised as follows:

Risk	Likelihood	Consequence	Gross Risk Rating	Mitigation	Net Risk Rating
Capital cost overrun	Possible	Moderate	Moderate	Maintain appropriate project controls	Low
Unable to meet redevelopment in identified timeframe	Possible	Moderate	Moderate	Maintain appropriate project controls	Low

5.5 Conformance with Policies & Procedures

No non-conformance issues associated with Transend policies and procedures of the time, were observed.

5.6 Post Implementation Review

A formal post implementation review has not been completed as this project is currently in progress, however a capital project investment review was developed in July 2008 which summarised the key elements of the project to date.

6 EFFICIENCY

6.1 Estimating Basis

The following summarises the project estimate provided to the Transend Board in November 2007:

Estimate Cost Item	Estimate
Building shell	$1.380 m
Fit out	$0.520 m
Communications	$0.330 m
Transend internal costs	$0.100 m
Accuracy (15%)	$0.300 m
TOTAL	**$2.630 m**

6.2 Contingency

The following summarises the contingency allowances for the project provided to the Transend Board in November 2007:

Provisional Contingency	Estimate
Contractor Delay Claims	$0.030 m
Delays Impact on Principal	$0.040 m
Latent Conditions	$0.040 m
TOTAL	**$0.100 m**

6.3 Costs

As at 25 June 2008, two progress payments totalling $315,930 have been paid to the contractor.

It is expected the project will be completed in September 2008 on time and within budget and it is expected that all assets will be included in the Regulated Asset Base.

The fall of “as commissioned expenditure” as detailed in Appendix 3 of Transend’s submission was:

Jan-Jun 2004	2004-05	2005-06	2006-07	2007-08	2008-09	Total
					$3.0 m	**$3.0 m**

6.4 Project Delivery

The contract for the re-development and fit-out of the building was let to Fairbrother Pty Ltd for the contract sum of $1 593 925. Stanton Management Group (SMG) Pty Ltd has been appointed as project manager.

7 ASSESSMENT

WorleyParsons considers that Transend has demonstrated that there was a justifiable need for this project. The main project driver was the need to find alternative accommodation due to the expiry of the current lease, which could not be extended. Further, the current storage facilities are not suitable from a range of perspectives, as discussed in Section 2.1, and Transend expects to derive business benefits from moving to more appropriate premises.

WorleyParsons considers that the investment was efficient. The project was tendered out and project management has been assigned to a service provider experienced in the building industry. The project is proceeding on time and is expected to be completed within budget

The investment processes and procedures adopted by Transend for this project appear to have ensured that prudent capital expenditure was undertaken. There have been no variations to the original business case submitted for the project and at no stage has the expenditure exceeded the approved level. Four options were considered in detail by Transend and economic analysis undertaken for options other than the “do nothing”. The project risks were also considered with the risks assessed as low. A formal post implementation review has not been conducted as the project is still in progress.

WorleyParsons considers that the project was required to be completed during the Current Regulatory Control Period. The project has been timed to realise the business benefits as soon as practicable.

8 CONCLUSION

This project appears to have been prudently planned, scoped and executed. Appropriate levels of project governance were also in place. WorleyParsons is of the opinion that the project passes a prudency test assessment.

ASSET SECURITY STRATEGY

1 PROJECT DESCRIPTION

1.1 Project Identification

ND0437 & ND0827

1.2 CAPEX Category

Physical Security/Compliance

1.3 Brief Overview

The project is a comprehensive program of integrated asset management activities designed to reduce the risks associated with unauthorised access to Transend's electricity transmission infrastructure. The major components are:

- Security fencing upgrades;
- Security fencing replacements;
- Substation building upgrades;
- Provision of access control systems;
- Provision of intruder detection systems (including powered fencing); and
- Installation of visual monitoring systems.

1.4 Background

Transend developed an asset security strategy to address the issue of asset security and commensurate business risk exposure. The successful implementation of the asset security strategy is expected to reduce business risk by minimising the exposure to litigation and negative publicity as a consequence of an unauthorised intrusion and by reducing the likelihood of interruption to electricity supply due to malicious intent.

In December 2005, Transend's Board approved capital expenditure of up to $22 million to implement the asset security strategy. The strategy provided a comprehensive and integrated approach to effectively manage the risks associated with asset security and to ensure that Transend's assets comply with the applicable Australian standards and the Energy Networks Association (ENA) guidelines.

The asset security strategy was endorsed by the Director of the State Security Unit.

In addition to addressing risks associated with asset security, the strategy proposal provides operational benefits as remote visual monitoring facilities are being established at critical and remote substations.

Significant progress has been made with the implementation of the asset security strategy to date, focussing on the security fencing replacement and upgrade components to ensure primary security measures are in place. It is expected that the various fencing projects included in the strategy will be completed by December 2009.

The provision of systems for access control, intruder detection and visual monitoring has been combined into the electronic asset security upgrade project as part of the overall strategy.

2 PROJECT NEED

2.1 Drivers

The investment driver for this project is to mitigate business risk by;

- Ensuring the safety of the public, employees and contractors;
- Adequately protecting transmission assets from physical damage, thereby sustaining the availability and reliability of electricity supply;
- Complying with the relevant acts, codes, standards and guidelines;
- Meeting the requirements of good electricity industry practice;
- Addressing recommendations and opportunities for improvement by auditors and insurers; and
- Enhancing remote asset monitoring capability.

An assessment of the financial risk associated with malicious damage at major substations was in the order of $30 million to $100 million. Transend's insurance brokers advised that Transend's financial exposure could exceed $20 million in the event of serious injury or fatality of a member of the public.

2.2 Timing

This project will have capital expenditure and commissioning across both the Current and Next Regulatory Control Periods. Based on the investment need and good electricity industry practice, Transend considers that the project timing is appropriate and reflects prudent financial management. Project implementation is being staged over a reasonable timeframe. Deferment of any part of the investment would reduce Transend's mitigation of the identified risks and would not be consistent with prudent asset management and good industry practice.

2.3 Strategic Alignment

Transend's 2005 strategic plan included a number of strategic performance objectives of relevance to the asset security strategy. The following table summarises the alignment of this project with Transend's strategic objectives.

Strategic Performance Objective	Measure	Proposal Objective
Maintain transmission system performance	Supply Reliability	Reduce the likelihood of unplanned outages due to unauthorised intrusion. Enhance remote asset monitoring capability.
Operate Safely	Reportable Incidents	Reduce the likelihood of intrusion by the public and the potential for injury or fatality.
Demonstrate good corporate citizenship	Legal and regulatory compliance	Comply with relevant standards and guidelines, particularly with regard to safety and security.

3 ALTERNATIVES

3.1 Options

The asset security strategy approved by the Board in December 2005 recommended a comprehensive, integrated approach to address the business risks presented by the existing physical security arrangements at Transend's substations. The alternatives to such a comprehensive approach were:

- Do nothing – would not address the security issues identified and would leave Transend exposed to significant business risk;
- Undertake a range of separate projects to address individual components of the asset security strategy – this approach would require Transend to implement the components of the security strategy on a piecemeal basis rather than as an integrated program. This option would not provide the optimum and most cost effective outcome; and
- Undertake a comprehensive, integrated approach – this option allows Transend to address the investment needs in a cost-effective and efficient manner. Integrating the security components delivers a more effective outcome through leveraging the security solutions according to the specific requirements at each substation. In addition it provides a more cost effective approach to project delivery through economies of scale for contractors and more effective contract management by Transend.

In March 2008, the Board considered a proposal to provide additional funds to complete the security project. The reasons for the increased funding requirement are discussed in Section 11 of that document. Transend considered a number of options to most cost effectively complete the project.

A summary of the options considered and analysed is shown below.

Option	Option Description	Reason for rejection/Selection
1	**Do not proceed with the electronic asset security project**	This option would not address the business risks identified in the asset security strategy paper which align with Transend's strategic risk review and would not align with good industry practice.
2	**Remove components of the electronic asset security project at each site**	This option would reduce the effectiveness and cost efficiency of the security strategy because the highly integrated system as proposed achieves leveraging of effectiveness of the components through integration. This option would only partially mitigate the risks identified in the asset security strategy.
3	**Remove sites from the scope of the electronic asset security project**	This option would not address the identified business risks for those sites removed from the scope of the project and would not align with good industry practice.
4	**Consolidated, reduced scope approach to implementing the electronic security project**	This option would substantially address the business risks identified in the asset security strategy, retain an integrated approach to asset security and provide a cost effective approach to reduce the risks associated with unauthorised access to Transend's substations. In addition, it would facilitate compliance with the ENA guidelines and align with good industry practice.
5	**Continue to implement the original scope of the electronic asset security project**	This option would address all of the business risks identified in the asset security strategy. This option would provide the most comprehensive mitigation of those risks identified, however it would cost an additional $7.8 million compared with option 4.

3.2 Options Analysis

Option 4 was selected because it ensures that the proposed works are cost effectively coordinated with the capital program for the Next Regulatory Control Period. In addition, it substantially addresses the business risks identified in the asset security strategy, retains an integrated approach to asset security and provides a cost effective approach to reduce the risks associated with unauthorised access to Transend's electricity transmission infrastructure.

Option 4 will also facilitate compliance with the ENA guidelines and is consistent with contemporary industry practice.

The reduced scope for the visual monitoring system and intruder detection components of the project does not preclude their future reinstatement should periodic site-specific reviews identify the need. The security system infrastructure included in option 4 will enable integration of additional visual monitoring system and intruder detection components in the future.

4 REGULATORY CONSIDERATIONS

4.1 Alignment with NER Capital Expenditure Objectives

Transend considers that the capital expenditure was required to meet the following capital expenditure objectives identified in clause 6A.6.7(a) of the NER:

- Comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services;
- Maintain the quality, reliability and security of supply of prescribed transmission services; and
- Maintain the reliability, safety, and security of the transmission system through the supply of prescribed transmission services.

4.2 Regulatory Test

In Transend's 2003–2009 Revenue Cap Application, reference was made at Section 6.3 Renewal expenditure as follows:

> *Additional expenditure of renewal capital is needed over the regulatory period to continue to meet Transend's compliance obligations pursuant to the relevant legislation and codes, including those relating to environmental and safety aspects*.

Reference was specifically made at Section 6.3.2 Requirements for renewal capital expenditure – Items targeted for renewal:

> *Substation security and surveillance systems.*

This project was included in the Transmission System Management Plan July 2003 to June 2009 at Section 8.23 Substation Security Systems:

> *Transend has a program in place to ensure that the security fences and gates at all sites meet applicable Australian standards, provide appropriate levels of protection for the public and are secure enough to maintain Transend's risk exposure within acceptable limits.*

5 GOVERNANCE

5.1 Business Case Approvals

Details of the business cases relevant to this project are summarised below:

Business case number	Business case title	Approval date	Approved value ($m)
BC4617	Asset security strategy	16 December 2005	22.0
BC 4617/1	Asset security strategy: extra funds	27 March 2008	6.6

5.2 Variations

No variation approvals have been required beyond the authority of the Project Manager.

5.3 Assumptions

No specific assumptions associated with the project were observed in the documentation.

5.4 Project Risks

Transend's 2007 Strategic Business Risk Review highlighted a number of risks that directly related to asset security. The following table provides details of the relevant business risks:

Risk Name	Risk Description	Main Cause of Risk	Potential Consequences	Consequence	Likelihood	Risk Rating
Asset Management	Transend is responsible for an asset relate event that results in personal injury, equipment damage or loss of electricity supply	▪ Vandalism ▪ Inappropriate contractor or staff action/negligence	▪ Loss of electricity supply ▪ Personal safety/injury to personnel ▪ Business disruption ▪ Property damage ▪ Loss of life ▪ Litigation ▪ Negative publicity	Moderate	Moderate	**High**
Safety	Transend is responsible for or contributes to an incident or condition that place the safety of employees, contractors or the public at risk.	▪ Unauthorised access to electricity infrastructure ▪ Inadequate substation security fencing ▪ Inadequate signage/warnings	▪ Death ▪ Personal injury ▪ Litigation ▪ Property damage ▪ Financial loss ▪ Negative public image/ reputation damage	Major	Unlikely	**High**
Security	Failure to put in place appropriate security arrangements and compliance with Transend's TSNP Licence as an owner/operator of critical infrastructure.	▪ Unauthorised access to transmission assets/facilities relating to theft ▪ Unauthorised access to transmission assets/facilities relating to sabotage, vandalism or terrorism ▪ Intentional damage inflicted by disgruntled employee/contractor	▪ Non-compliance with Licence/Critical infrastructure obligations ▪ Major blackout/ considerable customer disturbance ▪ Injury/loss of life to staff/public ▪ Diversion of management effort ▪ Financial loss to Transend ▪ Loss of shareholder confidence/loss of reputation	Catastrophic	Rare	**High**

5.5 Conformance with Policies & Procedures

No non-conformance issues associated with Transend policies and procedures, of the time, were observed.

5.6 Post Implementation Review

A formal post implementation review has not been completed as this project is currently in progress; however a capital project investment review was developed in July 2008 which summarised the key elements of the project to date.

6 EFFICIENCY

6.1 Estimating Basis

A summary of the estimate of costs which was developed for the business case which was presented to the Board in December 2005 is provided below:

Major equipment item description	Cost ($m)
Security fencing and gates	9.5
Building upgrades	1.2
Access control systems	1.4
Intruder detection systems	5.0
Visual monitoring systems	2.2
Procedure and standard development, drawings, training	1.2
Internal costs	1.5
Project total	**22.0**

By March 2008, substantial progress had been made on the implementation of the asset security strategy with a focus on the security fencing replacements to ensure primary security measures were in place. The tender process which Transend undertook to progress the electronic asset security upgrade component of the asset security strategy indicated that the funding provision for this component was inadequate to complete the project.

Following the tender process, Tenix Systems was contracted to progress the electronic component of the asset security strategy.

The increased costs above the original budget estimate for the electronic substation security upgrade project are primarily attributed to the:

- Logistical complexity of the project - this project includes a large number of interfaces that require extensive project co-ordination;
- Technical complexity of the project - this project includes a number of high technology, leading-edge components that require seamless integration between 47 substations;
- Lack of previous estimating and costing history and experience in delivering a similar project;

- Increase in the cost of materials since 2005, particularly for the powered fencing component of the project;
- Increase in labour rates since 2005; and
- Increased demand for security related services throughout Australia.

A number of safety incidents caused by contractors undertaking civil works associated with fencing replacements in substations has also occurred since the asset security strategy commenced. The increased site supervision required to mitigate the likelihood of further incidents has also resulted in increased internal project costs.

Additional capital expenditure of up to $7.8 million (excluding internal costs and provisional contingencies) would be required to complete the full scope of the electronic asset security component of the electronic security project. This additional expenditure includes the preferred contractor costs, provision of communication facilities, interface and other design costs, powered fencing for Sheffield and George Town substations, and an estimate accuracy allowance.

Contractor Tenix Systems provided indicative project scope variations which informed Transend's revised scope, as outlined in Section 3 Options analysis. The following table summarises the revised costs for the asset security strategy.

Strategy component	Approved funding ($m)	Revised estimate ($m)
Security fencing and gates (including replacements and upgrades)	9.5	9.5
Building upgrades	1.2	1.2
Electronic asset security upgrade (Note: the revised costs include preferred contractor costs, communication facilities, interface works, other design costs, powered fencing for Sheffield and George Town substations, and an estimate accuracy allowance)	8.6	13.4
Procedure and standard development, drawings, training	1.2	1.2
Internal costs	1.5	1.7
Total	**22.0**	**27.0**

6.2 Costs

Expenditure of $5.141 Million has been incurred to June 2008.

The fall of "as commissioned expenditure" as detailed in Appendix 3 of Transend's submission was:

Jan-Jun 2004	2004-05	2005-06	2006-07	2007-08	2008-09	Total
				$7.8 m	$22.5 m	$30.3 m

6.3 Project Delivery

The implementation of the asset security strategy has been undertaken as an integrated program of asset management activities. All major components have been competitively tendered.

Substantial progress has been made with the implementation of the asset security strategy with a focus on the security fencing replacement and upgrade components to ensure primary security measures are in place. It is expected that the various fencing projects included in the strategy will be completed by December 2009.

The contract for the electronic asset security project was awarded to Tenix Systems in May 2008.

To date, progress on the electronic asset security project has included the design and implementation of communications network facilities at each site. The facilities provide a secure communications system over which the access control, intruder detection and visual monitoring systems will communicate.

In March 2008, Transend conducted a detailed review of the electronic component of the asset security strategy. As an outcome, a site-specific risk assessment template was developed to ensure that the implementation of the asset security strategy at each Transend site remained prudent and efficient. Transend commissioned an independent review of the revised risk assessment template to ensure compliance with the ENA guidelines and to determine the extent to which the template aligned with good industry practice.

Parsons Brinckerhoff Associates Pty Ltd (PBA) indicated that the template was in accordance with the principles of the ENA guideline, and provided feedback to Transend regarding the extent to which the template and its intended use aligned with good industry practice.

Transend subsequently undertook risk assessments of all substations and completed templates for each site. These templates formed the basis for the revised implementation of the asset security strategy.

7 ASSESSMENT

WorleyParsons considers that Transend has demonstrated that there was a justifiable need for this project. The investment driver for this project was the need to mitigate business risk by ensuring safety of employees, the public and contractors; protecting transmission assets from damage and complying with regulatory requirements.

WorleyParsons considers that the investment was efficient. The project is part of an overall risk mitigation strategy which provides a comprehensive, integrated approach to effectively manage the risks associated with asset security and to ensure that Transend's assets comply with the applicable Australian standards and the ENA guidelines. Work for the project has been tendered out.

The investment processes and procedures adopted by Transend for this project appear to have ensured that prudent capital expenditure was undertaken. The original business case for $22m was approved; the tender process for the electronic asset security component of the project indicated that the costs for this component had been significantly underestimated, and a business case for an additional $6.6m (with a slightly reduce scope of work) was subsequently approved. At no stage has the expenditure exceeded the approved level. Three options were considered in detail by Transend, with the integrated approach being preferred ahead of the piecemeal approach and the "do nothing" option. Transend's 2007 Strategic Business Risk Review identified a range of risks that directly related to this project. A formal post implementation review has not been conducted as the project has not been completed.

This project will have capital expenditure in both the Current and Next Regulatory Control Periods. WorleyParsons considers that the project timing is appropriate to mitigate the identified risks over a reasonable timeframe.

8 CONCLUSION

This project appears to have been prudently planned, scoped and executed. Appropriate levels of project governance were also in place. WorleyParsons is of the opinion that the project passes a prudency test assessment.

STRATEGIC ACCOMMODATION SOUTH

1 PROJECT DESCRIPTION

1.1 Project Identification

ND0393

1.2 CAPEX Category

Non Transmission

1.3 Brief Overview

This project comprised the development of a fit for purpose building to accommodate (co-locate) Transend southern-based staff.

1.4 Background

Prior to this project being completed, Transend's southern-based accommodation comprised offices at Bowen Road, Moonah and Creek Road, Lenah Valley.

Transend had leased the Bowen Road offices since 1999 and this was a short-term strategy as Transend was potentially being sold. The lease expired in December 2001; however Transend had options under the lease beyond that time.

The Creek Road offices were transferred to ownership by Transend as a result of the system controller and network operations translation from the Hydro in July 2000. This is a strategic site that houses the network operations centre, which controls Tasmania's power system.

Southern based staff were therefore based across two sites, which led to a number of business inefficiencies. Neither building was capable of accommodating all southern based staff without substantial development. An issues management team and a strategic accommodation study group were established to consider Transend's medium to long term strategy and options. The strategic accommodation study group comprised internal representation as well as expert external advice.

On 21st May 2001 a Strategic Accommodation South paper was presented to the Transend Board. This paper recommended that:

- The preferred site for the development of Transend's office accommodation be an area off Maria Street, Lenah Valley and adjoining Transend's "Creek Road" site; and
- Transend legally secure under option or conditionally, an area of land of approximately 11,000 sqm off Maria Street, Lenah Valley to further explore this option.

On the 28th February 2002 the Transend Board approved expenditure of up to $4.45 m to purchase land and construct the office facility.

A further paper based on schematic design was submitted to the Board on 27th June 2002 detailing extra costs associated with construction of the new office facility. The additional cost of $1.27m was mainly attributable to air-conditioning the whole building. The Board agreed that the Maria Street site was the best option for the development of office accommodation and resolved to proceed with the purchase of the land. However, it was agreed that an external consultant should be engaged to conduct a review of the proposed design to ensure Transend was building a facility that was fit for purpose. The Board reaffirmed its decision to approve expenditure of up to $4.45 m.

On the 27th March 2003 the Transend Board resolved to endorse the March 2003 accommodation proposal, engage project managers, and to proceed with detailed design development and documentation for the development

On the 28th August 2003 the Transend Board approved expenditure of up to $6.48 m to construct the office facility. Tenders were called and evaluated.

On the 3rd September 2003 the CEO approved expenditure of up to $45,000 for the purchase of land for the office facility.

On the 18th December 2003 the Transend Board approved expenditure of up to $5.549 m to construct the office facility.

In September 2004 the A/CEO approved capital expenditure of $220,000 to carry out civil works to complete the project. The Southern Accommodation Project Control Group had identified civil works that were needed to finalise the project. These civil works included:

- An additional car park;
- A road connecting the southern end of car park No.2 to the Telstra Tower on Transend property; and
- A road connecting the northern end of car park No.2 to a paved layover area.

Following a tender and post tender negotiation process, a revised cost of $232,000 was identified.

On 11th July 2005, the CEO approved $232,000 to finalise the project.

2 PROJECT NEED

2.1 Drivers

Co-location was the primary objective of the accommodation project. Transend was working from multiple sites, which resulted in duplication and general unintended business inefficiencies. Co-location of Transend's business operation on to the one site was seen as a way to maximise operational efficiencies and capitalise on a united workforce.

2.2 Timing

The driver for this investment was co-location of Transend's southern business operations to generate business efficiency. It was viewed that the sooner co-location could be achieved, the sooner the business efficiencies would be achieved.

2.3 Strategic Alignment

This project was aligned to the Transend Business Plan 2001-2004. Under Transend's performance objectives, a key objective is to minimise costs of operating the business. The driver for this project was to minimise costs of operating the business by co-locating to one site for southern based staff.

The business plan also refers to the plan to consolidate accommodation. In part it states:

Office Accomodation

Transend is working towards consolidating its office accommodation at both ends of the state. In the north of the State, the company has centralised its base in newly developed offices at Trevallyn Substation in Launceston. The Burnie Office, which housed two employees, has been closed and both employees moved to Launceston.

The company is now looking towards a similar situation in Hobart, where Transend currently maintains two offices – one in Lenah Valley, the other in Moonah. The company has established a strategic accommodation review with the aim of accommodating all the Hobart based staff in one location.

This project was included in the RCA, but not included in the Transmission System Management Plan as it was a non-transmission system project.

3 ALTERNATIVES

3.1 Options

A summary of the options considered and analysed in 2001 is tabled below:

Option	Option description	NPV ($m)	Issues
1.1	Creek Road – develop site, add two additional levels, lease some area to Hydro Tasmania for income	1.889	▪ overcapitalises site; ▪ compounds existing problems and constraints; ▪ limited options long term for future development; ▪ unacceptable wayleave provision; and ▪ disruption to existing operation of Creek Road during construction.
1.2	Creek Road – develop vacant land area fronting corner at Creek Road and Maria Street	1.747	▪ limited footprint; ▪ steep site increases development costs; ▪ pedestrian link between buildings over sloping ground; and ▪ unacceptable wayleave.
1.3.1	Creek Road – purchase adjoining land from Salvation Army for development	1.518	▪ co-location to one site achieved; ▪ presence achieved via separate modern administration building; ▪ statement of corporate activity adjoining substation; ▪ good on site parking existing and scope for further development if needed; ▪ favourable contours minimising construction costs; and ▪ existing service and good visual amenity.
2.1	Greenfield site and maintain part of Creek Road site – freehold	2.017	Advantages: ▪ utilises existing facility and avoids duplication; and

Option	Option description	NPV ($m)	Issues
2.2	Greenfield site and maintain part of Creek Road site – leasehold	3.276	▪ may be able to exploit oversupplied office space market. Disadvantages: ▪ fail to achieve co-location; ▪ fragmented business culture; ▪ lack of long term flexibility if leased; and ▪ car parking difficult to provide in city.
3.1	City or Greenfield – freehold	2.655	Advantages: ▪ • co-location achieved; and ▪ • enhanced corporate presence and profile. Disadvantages: ▪ cost; ▪ Creek Road assets underutilised; ▪ lack of long term flexibility if leased; and ▪ car parking difficult to provide in city.
3.2	City or Greenfield – leasehold	4.463	
4.1	Freehold purchase and expand into further 1,050 square metres	2.037	Advantages: ▪ Timing; ▪ Least cost option; and ▪ Limited disruption to current business. Disadvantages: ▪ Fail to achieve co-location; ▪ Fragmented business culture; and ▪ Lack of long term flexibility.
4.2	Leasehold purchase and expand into further 715 square metres	1.171	

At the time, the option to purchase adjacent land at Creek Road was preferred because it was the least cost option which achieved the project objective of co-location.

A summary of the options considered in 2002 is tabled below:

Option	Option description	NPV ($m)	Issues
0	Do nothing	N/A	This option did not address the investment needs identified in section 4.
1	Maria Street (Creek Road development)	2.236	This option addresses the investment need, achieves the co-location objective and provides for future development.
2a	Bowen Road – buy the property, expand occupancy and refurbish	3.385	This option was not preferred because it was not the least cost option which achieved the investment objective. Car parking was also inadequate.
2b	Bowen Road – establish long term lease, expand occupancy and refurbish	3.168	

The option to purchase adjacent land at Creek Road/Maria Street was preferred because it was the least cost option which achieved the project objective of co-location.

3.2 Options Analysis

The selected option provided the least cost (in net present value terms over ten years) solution which addressed the investment need and achieved the project objective. This option also delivered the following benefits:

- Achieved co-location of southern Transend personnel on one site with level access between new and existing buildings;
- Provided a corporate presence and statement;
- Achieved workgroup synergies with increased morale and unified team environment;
- Maintained current system security and network operations functionality;
- Potential for consolidation, growth and rationalisation of activities and facilities;
- Communications and power infrastructure were able to be cost-effectively expanded, and security could readily be enhanced;
- Provided a tradeable asset for the future which is central and accessible; and
- Enhanced the staff amenity.

4 REGULATORY CONSIDERATIONS

4.1 Alignment with NER Capital Expenditure Objectives

Transend considers that the capital expenditure was required to meet the following capital expenditure objectives identified in clause 6A.6.7(a) of the NER:

- Maintain the quality, reliability and security of supply of prescribed transmission services; and
- Maintain the reliability, safety, and security of the transmission system through the supply of prescribed transmission services.

4.2 Regulatory Test

Not applicable for this non-network project.

5 GOVERNANCE

5.1 Business Case Approvals

A summary of the business cases relevant to this project is listed below:

Business case	Business case title	Approval date	Approved value ($m)
BC4173	Strategic Accommodation (South)	21 May 2001	N/A
BC4173	Strategic Accommodation: South	28 February 2002	4.450
BC4173	Southern Accommodation	27 March 2003	6.030
BC4377	Purchase by Transend of a portion of Kemp & Denning (K&D) land.	18 August 2003	0.045
BC4173	Southern Accommodation	28 August 2003	6.480
BC4173	Southern Accommodation – award contract	5 December 2003	5.780
BC4408	Additional works Maria St Campus	29 November 2004	0.210
BC4479/1	Civil works Maria St campus: additional funds	1 July 2005	0.232

5.2 Variations

During the course of the project, it was agreed to provide an additional car parking area which was the subject of a separate business case. This development, which required the relocation of the main water pipeline, was to be the only significant variation from the original project scope.

At no stage did the project expenditure exceed approved expenditure limits.

5.3 Assumptions

The following key assumptions were made in the analysis of options:

- Transend's WACC (Weighted Average Cost of Capital) was adopted at 7.5%;
- Growth factors based on "Access Economics" forecasts for CPI growth over the following 10-year period;
- Allowance for receipt of $120,000 per annum rent from Hydro Tasmania in all options;
- Income tax benefit based on rate of 30%; and
- Depreciation allowance of 2.5% on building + communications and 13% on fit-out component.

5.4 Project Risks

No specific business risks associated with the project were observed in the documentation.

5.5 Conformance with Policies & Procedures

No non-conformance issues associated with Transend policies and procedures, of the time, were observed.

5.6 Post Implementation Review

A post implementation review document dated December 2004 was sighted and a capital project investment review was developed in June 2008 which summarised the key elements of the project.

6 EFFICIENCY

6.1 Estimating Basis

The following summarises the project estimate provided to the Transend Board in August 2003 and the additional works approved by the Chief Executive Officer in July 2005:

Cost Item	Cost
Building Structure	$1.765 m
Services	$1.570 m
Civil	$0.610 m
Fitout	$1.135 m
Furniture	$0.300 m
Design Development	$0.400 m
Land Acquisition	$0.350 m
Project Management	$0.160 m
Interest During Construction (IDC)	$0.140 m
Security	$0.050 m
Additional Building Works	$0.023 m
Additional Site Works	$0.080 m
Landscaping	$0.095 m
Contingency	$0.012 m
Additional Car Park	$0.232 m
TOTAL	**$6.922 m**

6.2 Costs

The capitalised cost of the project was $6.841 million (exclusive of IDC and FDC).

This cost includes capital expenditure prior to the Current Regulatory Control Period.

All assets are included in the Regulated Asset Base.

The fall of "as commissioned expenditure" as detailed in Appendix 3 of Transend's submission was:

Jan-Jun 2004	2004-05	2005-06	2006-07	2007-08	2008-09	Total
	$6.4m					**$6.4m**

6.3 Project Delivery

Project management was provided by Stanton Management Group (SMG). SMG coordinated the activities and input of the architect, contractors and other service providers.

The project was overseen by a project control group (PCG) made up of Transend internal representatives, SMG and Heffernan, Button and Voss (architects).

The design brief which was developed by the PCG incorporated the criteria outlined in the "Key Building Principles" report which allowed for the number of workspaces to be accommodated, the type of work station (in accordance with a prototype) and the provision of sufficient meeting rooms and auxiliary areas. This report was developed in close consultation with Transend staff.

Construction works were competitively tendered, with the tender process managed by the PCG. Regular site meetings were held with the building contractor, Hansen and Yuncken Pty Ltd, to review progress.

The project progressed according to program and budget and the building was commissioned on 10 December 2004.

7 ASSESSMENT

WorleyParsons considers that Transend has demonstrated that there was a justifiable need for this project. The project driver was the need to co-locate Transend's Southern-based business operation onto the one site to maximise business efficiencies and capitalise on a united workforce.

WorleyParsons considers that the investment was efficient. Project management was undertaken by Stanton Management Group (SMG) who coordinated the activities of the architect, contractors and other service providers. The project was overseen by a project control group, consisting of Transend, SMG and the architect. The design brief was developed by the Project Control Group who also managed the competitive tender process for the construction works.

The investment processes and procedures adopted by Transend for this project appear to have ensured that prudent capital expenditure was undertaken. Several business cases were submitted for this project, with increases due to air conditioning the complete the building, the purchase of additional land and extensions to civil works. All business cases were approved at the appropriate level and at no stage did the expenditure exceed the approved level. Nine options were considered in detail by Transend and economic evaluations were conducted. The option selected was the least cost option other than the "do nothing" option, which did not address the investment needs. A formal post implementation review was conducted. WorleyParsons notes that already accommodation shortage issues have returned as staff are currently being accommodated at sites at both Lenah Valley and Moonah.

WorleyParsons considers that the project was required to be completed during the Current Regulatory Control Period, in order to achieve the busness efficiencies as soon as practicable.

8 CONCLUSION

This project appears to have been prudently planned, scoped and executed. Appropriate levels of project governance were also in place. WorleyParsons is of the opinion that the project passes a prudency test assessment.

IT & BUSINESS APPLICATIONS

1 PROJECT DESCRIPTION

1.1 Project Identification

Various

1.2 CAPEX Category

Information technology

1.3 Brief Overview

The IT and business application investment comprises a reasonably large number of projects that relate to IT and other business applications. Each project has a total nominal cost of less than $1 million. The bundling of capital projects provides for the efficient capture of project expenditure into Transend's capital works program to facilitate more efficient reporting of these smaller projects.

While each project is broadly categorised as IT and business application, each project has its own investment driver/s which are addressed in each individual business case.

1.4 Background

Prior to 2003, Transend owned very little IT infrastructure. The majority of IT services and requirements were provided under the Hydro Electric Corporation (now Hydro Tasmania) disaggregation agreement. Under the agreement, Transend was able to utilise infrastructure and applications owned by Hydro Tasmania and Aurora Energy to operate its business. Under this arrangement, the operation and support of the shared infrastructure were performed by LogicaCMG, for which Transend paid a monthly service fee.

The structure of the agreement provided Transend with significantly lower costs than if Transend owned its own infrastructure. This was mainly due to:

- Economies of scale were achieved through operating all three electricity companies using shared infrastructure and a single service provider; and
- A favourable percentage was attributed to Transend based on its staffing levels (compared with the other entities) under contract arrangements with the service provider (LogicaCMG).

Transend's shareholders made the decision to enter the National Electricity Market and Transend was required to sever ties with Hydro Tasmania and Aurora Energy and had to establish its own IT capability.

Over the period 2003-04 to 2007-08, the major drivers for Corporate IT activities were:

- Disaggregation of the IT infrastructure from Hydro Tasmania and Aurora Energy;
- Preparation for entry into the National Electricity Market;
- Operating in the National Electricity Market and regulatory environment; and
- Catering for business growth.

Transend maintains ongoing investment in information technology (IT) necessary to support operational and business applications.

Transend has a diverse range of IT applications which are constantly monitored and improved where necessary to ensure their ongoing performance. IT systems and applications are regularly acquired, upgraded or replaced depending on business needs.

Separate business cases have been prepared for approval in each instance. The projects included in this review comprise all of the IT business applications projects that were either partly or totally commissioned in 2007–08. The ongoing procurement of minor assets including computers, screens, video cards etc are also included within the IT and business applications group.

2 PROJECT NEED

2.1 Drivers

Investment in IT and business applications is required to satisfy a range of business needs, including the following:

- Enhance the efficiency of business operations;
- Address compliance matters associated with operation in the National Electricity Market;
- Satisfy regulatory and licence obligations;
- Ensure appropriate IT security and capacity;
- Facilitate efficient business operations in the Tasmanian power industry;
- Efficiently undertake power system operations, modelling and analysis; and
- Adequately protect critical infrastructure.

Specific investment drivers are identified in each business case.

2.2 Timing

The timing of each project is programmed to efficiently address the business needs identified in each business case.

2.3 Strategic Alignment

Transend's Strategic Plan 2008 identifies the strategic performance objectives that are relevant to this project. These are summarised below:

Strategic result area	Strategic performance objective	Project objective
Safety and Work environment	Recognition as an employer of choice	Foster a positive culture that contributes to the achievement of organisational objectives
Organisational efficiency and effectiveness	Fundamental business support systems re-engineered for business advantage	Upgrade or replacement of IT packaged systems as appropriate is fundamental to sustaining or enhancing organisational efficiency and effectiveness
Organisational efficiency and effectiveness	Continuously improve key business processes	Upgrade or replacement of IT packaged systems as appropriate a fundamental component of the continual improvement process
Organisational efficiency and effectiveness	Continuously improve commercial focus within the business	Contemporary IT packaged systems are vital to ensuring financial performance is monitored and optimised
Good corporate citizenship	Compliance with legal obligations	Ensure that the tools are available to monitor and control compliance with the law, regulations and industry codes of practice

Linkages to Transend's strategic performance objectives are identified in each business case as appropriate.

3 ALTERNATIVES

3.1 Options

The options considered were:

- Do nothing – would result in software that does not support business requirements or becomes increasingly difficult to support and maintain, and it would also generate security issues when application integrity is compromised and application upgrades are not performed, maintenance costs increase and ultimately vendor support is removed;
- Replace software after it fails or becomes unsupportable – would cause reduction in support of business requirements, a large increase in management and maintenance costs would also occur and business productivity would decrease; and
- Manage software replacement cycles – provides the greatest level of support for business requirements and minimises management and maintenance costs, planned replacement increases business productivity and leverages opportunities for systems integration.

Specific project options considered are discussed in each business case as appropriate.

4 REGULATORY CONSIDERATIONS

4.1 Alignment with NER Capital Expenditure Objectives

Transend considers that the capital expenditure was required to meet the following capital expenditure objectives identified in clause 6A.6.7(a) of the NER:

- Comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services;
- Maintain the quality, reliability and security of supply of prescribed transmission services; and,
- Maintain the reliability, safety, and security of the transmission system through the supply of prescribed transmission services.

4.2 Regulatory Test

Not applicable for this non-network project.

5 GOVERNANCE

5.1 Business Case Approvals

A summary of each of the business cases that comprise the IT and business applications capital investment group of projects are summarised below.

Business case	Title	Approved by	Approval date	($m)	Sighted
BC 4046/1 BC4046/2A BC4046/2 BC 4046/3 BC 4763	Phase 3 Interface between PROMS & NEMMCO's outage scheduler (NOS)	Mgr EGM CEO CEO EGM	20 Nov 01 3 Jan 03 16 Jul 03 21 May 04 1 Mar 07	0.010 0.060 0.185 0.200 0.025	✓ ✓ ✓ ✓ ✓
BC 4402	Installation and commission of Internet Connection Service	CEO	22 Dec 03	0.057	✓
BC 4456	Accommodation Building LAN Infrastructure	CEO	2 Aug 04	0.304	✓
BC 4500	Operator Training simulator	EGM1	24 Dec 04	0.098	✓
BC 4570	3 phase Electromagnetic Transient Software	CEO	29 Apr 05	0.100	✓
BC 4596	Remote Access Security	CEO	21 Apr 08	0.048	✓
(Text removed)	(Text has been removed due to its commercial-in-confidence nature)	CEO	5 Dec 05 8 Feb 06	0.135 0.230	✓ ✓
BC 4620, BC 4620/1	Human Resource Management Information System	CEO	15 Aug 06 24 Apr 07	0.500	✓ ✓

Business case	Title	Approved by	Approval date	($m)	Sighted
BC 4620/2			11 Jun 08		✓
BC 4637	IT Infrastructure Capacity Upgrade + (Variation request approval $160k)	CEO	3 Mar 06 25 Oct 06	0.513 0.160	✓ ✓
BC 4656	Compliance Management Tool Acquisition	CEO	1 May 06	0.274	✓
BC 4437 BC 4729	Internet Security Appliance Upgrade	CEO	31 May 04 25 Oct 06	0.590 0.029	✓ ✓
BC 4744 Variation BC 4744/2	Budget reporting Tool + (approval for extra funds)	CEO EGM	22 Dec 06 22 Jul 08	0.472	✓ ✓ ✓
BC 4764	Purchase and Implementation of Automatic Generation Control application for NOCS	CEO	17 May 07	0.288	✓
BC 4765	Purchase and Implementation of Short Circuit Analysis application for NOCS	CEO	30 May 08	0.136	✓
BC 4766	Purchase and Implementation of Disturbance Data Collection application for NOCS	CEO	2 Jun 08	0.032	✓
BC 4780	Purchase of NEO software	EGM	27 Mar 07	0.062	✓
BC 4788	CNVA Rectification	CEO	28 Jun 07	0.298	✓
BC 4848	Corporate IT Network Management System	CEO	19 Feb 08	0.016	✓
BC 4856	NOCS Base Software upgrade	CEO	29 May 08	0.312	✓
BC 4860	Wise Application Packaging	GM	6 May 08	0.014	✓
BC 4861	Intrusion Prevention Appliance Replacement	EGM	29 May 08	0.136	✓
BC 4903	Network Operator console & voice recording system project	CEO	8 Oct 07	0.440	✓
ND0303	Purchase of Minor Assets	These two line items are not subject to business case requirements because they are a consolidation of minor asset expenditure. Expenditure is approved according to the delegation manual via authorised purchase requisitions.			
ND0797	Purchase of computers/ screens/video cards				

5.2 Variations

Where there have been variations to the scope or cost of a project, additional funds have been requested via a resubmitted business case.

5.3 Assumptions

Any specific assumptions associated with a project are identified in each business case as appropriate.

5.4 Project Risks

Transend's 2007 Business Risk Review identifies a number of risks that are directly related to this project. The implementation of this project will contribute to the mitigation of these risks, which are summarised below:

Risk Name	Risk Description	Revised consequence	Revised likelihood	Revised rating
IT operation and development	Operating and developing the Corporate It infrastructure and associated services	Moderate	Moderate	High
Financial management	Risk of compromised reporting of financial information and/or financial losses	Moderate	Unlikely	Moderate
Fraud	Risk that fraudulent activities are not detected in a timely manner resulting in loss of revenue and reputation	Minor	Unlikely	Low
Compliance	Non-compliance with statutory obligations and regulations and/or failure of compliance monitoring systems	Moderate	Unlikely	Moderate
Security	Failure to put in place appropriate security arrangements and compliance with Transend's TNSP licence and as an owner/operator of critical infrastructure	Catastrophic	Rare	High

Linkages to Transend's business risk review and project specific business risks are identified in each business case as appropriate.

5.5 Conformance with Policies & Procedures

No non-conformance issues associated with Transend policies and procedures of the time were observed.

5.6 Post Implementation Review

A formal post implementation review has not been completed as this project is currently in progress; however a capital project investment review was developed in July 2008 which summarised the key elements of the project to date.

6 EFFICIENCY

6.1 Asset Management Framework

An asset management framework has been developed that provides details of the planning and management practices for assets owned by Corporate IT within Transend. The majority of those assets are installed at the Maria street campus and the co-primary site at Chapel Street. Downstream infrastructure, such as routers, other WAN equipment and local workstations, are deployed throughout the state.

The framework and the supporting Asset Management Plans act as tools to support the ability of the Corporate IT department to deliver appropriate maintenance and operation services for Transend.

For management purposes, Corporate IT assets are assigned to an asset category which groups like assets together. Each asset category has an individual Asset Management Plan with a defined scope.

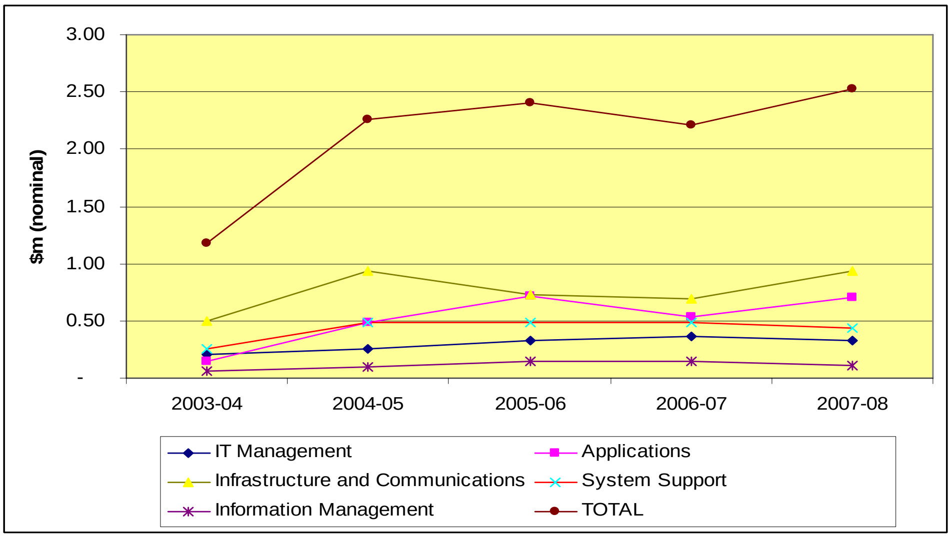
6.2 Costs

The preliminary projected commissioned costs for 2007–08 and preliminary projected total project commissioned costs for the IT business applications group of projects are summarised below:

Major equipment item description	Preliminary projected commissioned costs ($)	
	2007–08	Total project
Phase 3 (Interface between PROMS & NEMMCO's outage scheduler (NOS)	39,780	465,682
Installation and commission of Internet Connection Service	11,201	44,064
Internet Security Appliance Upgrade	24,073	597,132
Accommodation Building LAN Infrastructure	655	224,715
Operator Training simulator	2,074	77,075
3 phase Electromagnetic Transient Software	34,872	37,936
Remote Access Security	32,689	32,581
(Text has been removed due to its commercial-in-confidence nature)	13,468	136,307
Human Resource Management Information System (HRMIS)	461,557	461,557
IT Infrastructure Capacity Upgrade + (Variation request approval $160k)	0	665,530
Compliance Management Tool Acquisition	274,000	274,000
Budget reporting Tool + (approval for extra funds)	353,445	353,445
Purchase & Implementation of Automatic Generation Control application for NOCS	184,404	184,404
Purchase & Implementation of Short Circuit Analysis application for NOCS	1,276	2,052
Purchase & Implementation of Disturbance Data Collection application for NOCS	957	1,596
Purchase of NEO software	45,000	45,000
CNVA Rectification	230,330	234,129
Network Operator console & voice recording system project	360,627	362,815
Corporate IT Network Management System	4,643	4,643
NOCS Base Software upgrade	74,539	74,566
Wise Application Packaging	10,650	10,650
Intrusion Prevention Appliance Replacement	105,521	105,521
Purchase of Minor Assets	25,396	
Purchase of computers/screens/video cards	315,204	
Investment total	**2,606,362**	**4,395,400**

6.3 Historical Costs

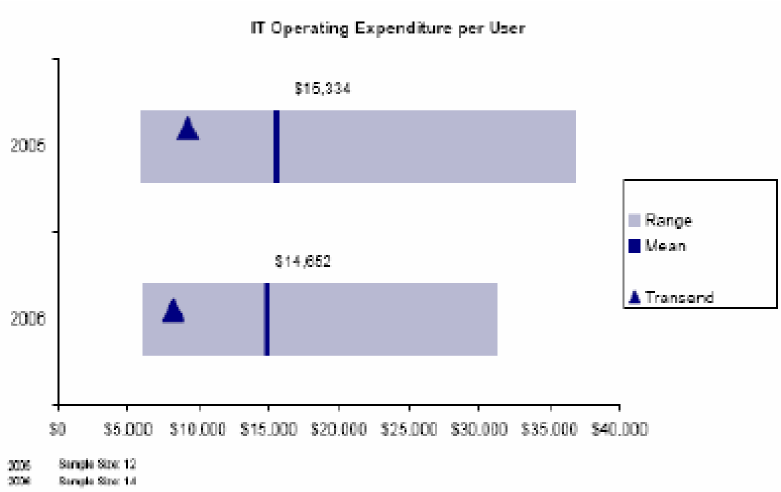
The historical operating expenditure for delivering and managing Transend's Corporate IT services is shown below:



Over the same period Transend's employee and contractor numbers have grown. This has driven growth in all areas of IT including IT business systems, IT operations, service delivery, information management, and data communications. Over the 2003-04 to 2007-08 period the number of audited IT user accounts increased from 125 to 300.

6.4 Benchmarking

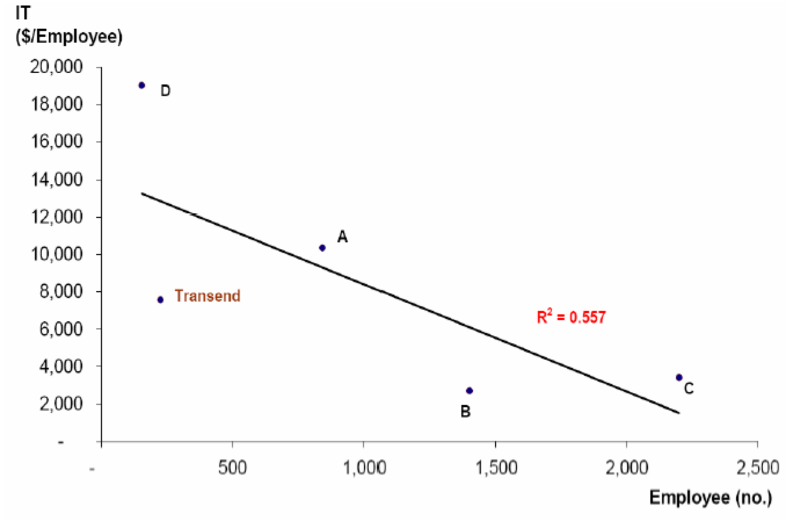
In 2006, Transend participated in a benchmarking study conducted by KPMG in order to assess the appropriateness of its IT expenditure for the size of its business. The results of the study revealed that Transend's IT expenditure per user at $9,755 was efficient when compared to other Australasian TNSP's. Transend's expenditure level remains well below the 2006 mean of $15,974.



All Participants

- IT operating expenditure per user ranged from $5,895 to $31,239 across the survey participants in 2006. The mean was $15,974.
- This is a slight increase on the mean of $15,257 in 2005
- Adjusted IT operating expenditure per user ranged from $3,159 to $24,918 across the survey participants in 2006, with a mean of $11,243
- One participant nearly doubled its IT operating expenditure per user. Another six participants had their IT operating expenditure increased

Transend engaged PBA in 2007 to review its operating expenditure for its Corporate support functions. The following shows Transend's Corporate IT spend per employee and indicates that Transend benchmarks favourably against other TNSP's.



6.5 Project Delivery

The majority of Corporate IT package systems comprise the purchase of equipment or services from preferred suppliers or vendors for IT package systems.

7 ASSESSMENT

WorleyParsons considers that Transend has demonstrated that there was a justifiable need for this program which was made up of a range of IT and business applications, each with its own investment drivers, as discussed in Section 2.1. WorleyParsons assessed the need for each application and has made the assessment that all of them were justified.

WorleyParsons considers that the investment was efficient. The program was broken up into a range of applications, each with a separate business case. All of the applications were consistent with an over-arching asset management framework and Asset Management Plans. The asset management framework provides details of the planning and management processes for corporate IT assets. Transend's Corporate IT spend per employee benchmarks favourably against other TNSP's

The investment processes and procedures adopted by Transend for this project appear to have ensured that prudent capital expenditure was undertaken. Thirty-two business cases have been approved in relation to this program as applications were identified and scoped. This approach provided appropriate levels of financial and scope control. At a high level, three options for the program were considered, including the "do nothing" option. Transend elected to take the approach of managing software replacement cycles, which WorleyParsons supports on the basis that it provides the lowest business risk and is likely to result in lower costs.

Transend’s 2007 Business Risk Review identified a number of risks that are directly related to the program. Linkages to the Business Risk Review and project specific risks are identified in each business case.

Each project within the program is timed to efficiently address the business needs identified in the project business case. WorleyParsons reviewed the timing at the project level and did not identify any timing issues.

8 CONCLUSION

This program of work appears to have been prudently planned, scoped and executed. Appropriate levels of project governance were also in place. WorleyParsons is of the opinion that the project passes a prudency test assessment.

APPENDIX 4: EX-ANTE PROJECT REVIEW

DESCRIPTION	CATEGORY	TOTAL COST (June 09 $m)
Waddamana - Lindisfarne 220kV Transmission line & Substation	Augmentation	119.9
Strategic Easement Acquisition	Land and easements	21.2
Newstead Substation new 110/22kV connection point	Connection	20.8
George Town Substation 220kV security upgrade	Augmentation	18.4
Asset Management Information Systems	Operational support systems	7.2
(Text removed) Control Centre Backup	Business support	6.3
Substation Asset Condition Monitoring Enhancement Program	Physical security / compliance	4.5
Corporate IT – Package Systems	Information technology	4.2
Electrona Substation Stage 2 Development	Augmentation	1.5
New Norfolk Substation HV Protection Upgrade	Connection	0.9

WADDAMANA-LINDISFARNE 220 kV TRANSMISSION LINE

1 PROJECT DESCRIPTION

1.1 Project Identification

ND0575

1.2 CAPEX Category

Augmentation

1.3 Brief Overview

The project involves the construction of approximately 100 km of new double-circuit 220 kV transmission line (strung initially on one side) between Waddamana and Lindisfarne, the establishment of a new 220 kV substation at Waddamana and the extension of Lindisfarne Substation.

This project accounts for 17.5% of Transend's proposed Capex for the Next Regulatory Control Period.

1.4 Background

The project was originally submitted to the RNPP in December 2002 (under the market benefit limb of the regulatory test), and the panel recommended approval of the establishment of a 220 kV supply point at Lindisfarne Substation. The Regulator approved the project but required Transend to resubmit if conditions changed. Transend was also required to test the market on the cost of a network support option. Transend proceeded with the 110 kV works as approved by the Regulator.

In January 2004, Transend called for Expressions of Interest for a gas-fired power station at Bridgewater, as a network support alternative to constructing the 220 kV transmission line. The network augmentation option provided a lower present value cost than network support, over a range of scenarios.

Transend released a Final Report on the proposed large network augmentation for Southern Tasmania in August 2004. The report was distributed to interested parties for consultation. Although some responses were received, no party disputed or objected to the findings in the report.

At the request of the RNPP, Transend provided a supplementary report to the RNPP in February 2005, to provide an updated quantitative analysis of five options:

- Augmentation of the 110 kV network;
- Single circuit 220 kV on double circuit towers;
- Double circuit 220 kV; and
- Two network support options.

Of these, the option of a single circuit 220 kV line on double circuit towers had the highest NPV benefit – the cost for the project was estimated to be $55m. The Regulator made a Determination in favour of this option in March 2005.

Planning permission for the project was obtained in January 2007, following appeals to the Waddamana to Risdon Valley Electricity Transmission Line Combined Planning Authority. The process to gain planning approval has lead to significant project delays, contributed to by the appeals involved and the conditions imposed, particularly the requirement for approval by the planning authority for detailed tower locations and heights.

As additional information came to hand regarding the costs of constructing the project, Transend substantially increased the project cost estimate. Tasmania also entered the National Electricity Market and became subject to the National Electricity Rules in May 2005. In the light of these changes, Transend re-ran the regulatory test, issued an Application Notice and called for submissions from interested parties, but no submissions were received. In August 2007, Transend issued a Final Report in relation to its application to establish a large transmission network asset.

1.5 Project Description

The project involves the provision of a second 220 kV injection point for the Southern region, at Lindisfarne Substation. The work is proposed in two stages:

- Stage 1 (to be completed in the Next Regulatory Control Period) – installation of one auto-transformer at Lindisfarne Substation and the construction of a new 220 kV double circuit line strung on one side only; and
- Stage 2 (presently expected to commence after the end of the Next Regulatory Control Period) – installation of a second auto-transformer at Lindisfarne Substation and stringing of the second 220 kV circuit.

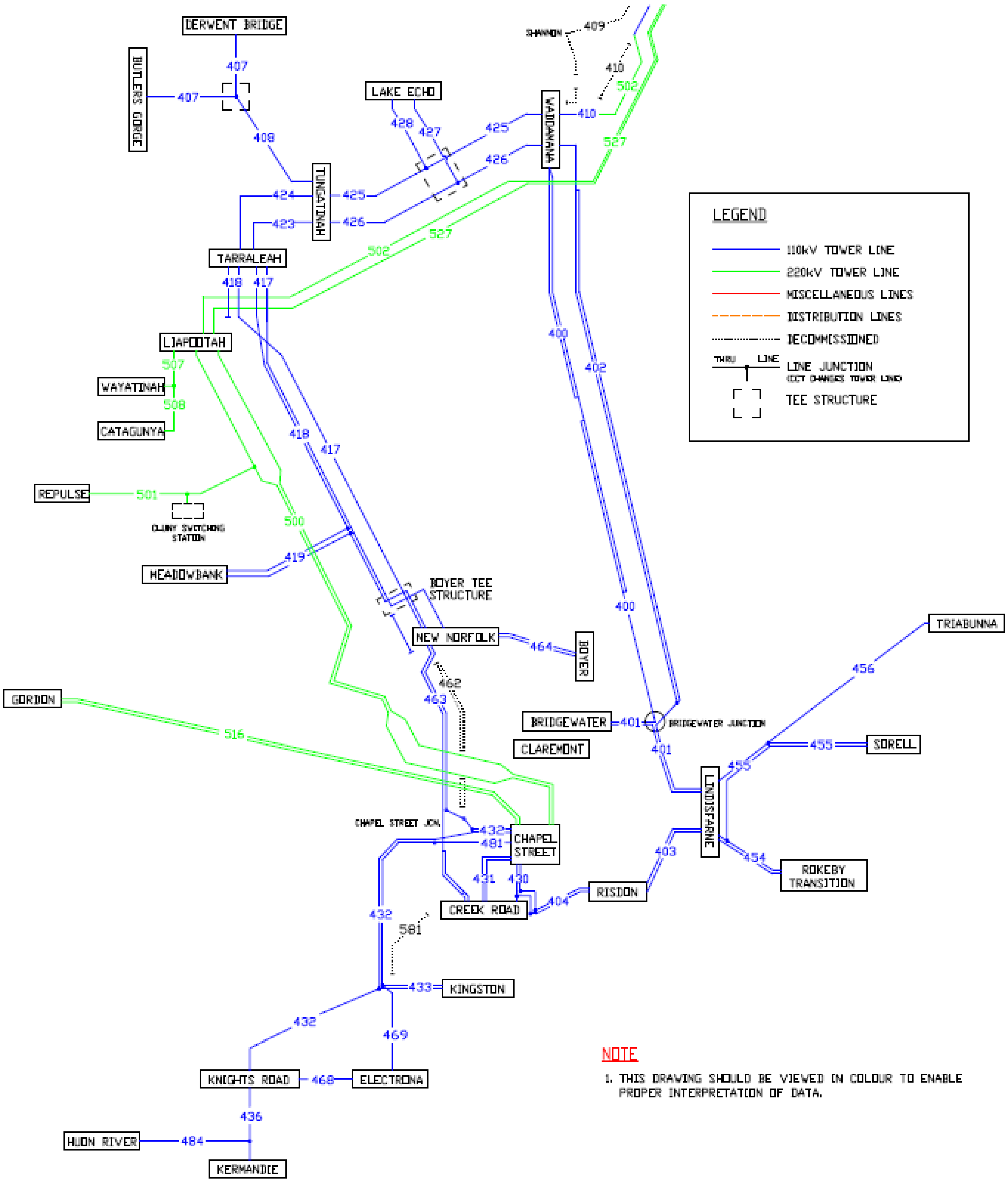
Stage 1 (covered by this project) involves the following works:

- Construction of a new 220 kV switchyard at Waddamana Substation in the vicinity of the existing Waddamana Substation with a tee into each of the two existing Liapootah-Palmerston 220 kV transmission lines;
- Construction of a new 220 kV switchyard at Lindisfarne Substation, adjacent to the existing 110 kV switchyard, comprising one 220/110 kV 200 MVA auto-transformer with associated 220 kV and 110 kV switch bays and associated protection, control and metering equipment; and
- Decommissioning of the existing Waddamana-Lindisfarne 110 kV transmission line and the construction in the existing easement of a new 220 kV transmission line from Waddamana to Lindisfarne, on double circuit towers strung on one side only.

2 PROJECT NEED

The electricity supply to Southern Tasmania is via a series of 110 kV transmission lines from the Upper Derwent region and 220 kV transmission lines from Liapootah and Gordon Power Station into Chapel Street Substation. Additional supply is from Palmerston via the Liapootah-Palmerston 220 kV transmission lines and the Waddamana-Palmerston transmission line, as shown in Figure 1.

Figure 1: Single Line Diagram of Southern Transmission System



It can be seen that the supply of electricity to the southern area (including Hobart) is highly reliant on Chapel Street Substation as the sole 220 kV injection point in the area.

The southern Tasmanian transmission network currently has insufficient capacity to supply all customer load under certain network conditions. The network can supply up to 640 MW of electricity during cold periods; however, the southern system maximum demand already exceeds this limit. The network is unable to effectively deliver enough power to meet peak demand without overloading transmission lines or risking voltage collapse.

To minimise the risk of supply interruptions in Southern Tasmania, Transend has a network supply agreement with Hydro Tasmania, with the costs of the agreement subject to pass-through arrangements. Under the agreement, the shortfall in Transmission capacity is mitigated by constraining-on generation from Gordon Power Station and, to a lesser extent, power stations on the lower Derwent. The network support agreement provides a solution that alleviates some, but not all, of the network constraints in southern Tasmania, and in particular, the generation from Gordon Power Station does not address all load at risk on Hobart's eastern shore.

As well as load at risk, there are issues with substandard ground clearances and condition of aged transmission lines which would be addressed by the project. The line was constructed in the 1920s to operate at 88 kV and there are problems with towers. As well, the conductor is in a bad condition. There have been a number of failures of the overhead earth wire, causing damage to the transmission line conductors.

2.1 Drivers

The main drivers for the project (in decreasing order of importance) are:

- Provide adequate capacity to meet the southern region demand;
- Improve the security of supply to the southern region by reducing reliance on the 220 kV transmission lines that connect to Chapel Street Substation; and
- Replace assets that are at the end of their useful lives.

2.2 Timing

As discussed under Section 4.2, MMA concluded that net market benefits for the project are achievable from 2010 onwards. Key implementation dates identified in MMA's original report are as follows:

Milestone	Date
Dismantling of Waddamana-Lindisfarne 110 kV transmission line between Waddamana and Bridgwater complete	June 2008
220 kV line construction starts	July 2008
Substation construction starts	February 2008
Project practical completion	December 2010

Interim milestones have subsequently been revised but commissioning is still forecast for December 2010.

3.1 Strategic Alignment

Transend has identified the alignment of this project to the organisation's Strategic Plan, as shown in the following table:

Strategic Result Area	Strategic Performance Objective/outcome	Proposal Objectives
Shareholders' value	Provide appropriate and sustainable returns to shareholders	Invest in assets that provide a prescribed service and generate a regulated income for the life of the assets
Market & regulatory framework	Fulfil transmission licence obligations and other ESI obligations	Fulfil Transend's transmission licence obligation to procure all transmission system augmentations or other works or services on mainland Tasmania that are shown to satisfy the regulatory test
Transmission system development & performance	Maintain transmission performance	Maintain an economically optimum level of supply security and reliability to electricity consumers in the south of Tasmania
Customer relationship	Involve customers in decisions that affect them	Follow the regulatory consultation requirements of the NER to allow industry participants to comment on the assumptions and analysis
Achieve environmental excellence	Appropriate consideration of Transend's impact on the natural and built environment	Minimise the impact on aboriginal heritage and the environment (eg. Transend has modified the location of a number of towers)

3 ALTERNATIVES

3.1 Options

The original 2002 submission to the RNPP considered the following options:

Option	Brief Description
Option 0	"Do nothing" (ie. no transmission development). Involves the permanent removal from service of 8 x 110 kV lines on the grounds of public safety.
Option 1	Restore non-compliant lines to their design rating, install a 5th transformer at Chapel Street and install a second circuit from Creek Road to Risdon.
Option 2	As for Option 1 except that 110 kV transmission lines are upgraded to 75^{o}C.
Option 2a	As for Option 2 except that the 5th autotransformer at Chapel Street is not included.
Option 2b	As for Option 2 except that the second circuit from Creek Road to Risdon is not included.
Option 3	Establish a new 220 kV substation at Lindisfarne, supplied by a new double circuit 220 kV line strung initially on one side. Remove substandard lines and upgrade two circuits to 75^{o}C.
Option 4	Same as Option 3 but with new double circuit 220 kV line strung both sides.
OCGT100	As for Option 1, but with a 100 MW open cycle gas turbine generator connected at Risdon, operating only as required; no 5th transformer at Chapel Street; and no cable from Creek Road to Risdon.
CCGT100	As for Option OCGT100 except for a 100 MW combined cycle gas turbine generator operating as base load in lieu of the OCGT.
OCGT200	As for Option OCGT100, except for 200 MW generator in lieu of 100 MW.
CCGT200	As for Option CCGT100, except for 200 MW generator in lieu of 100 MW.
	Demand side management.

The conclusion reached from the analysis of the options at that time was that a new 220 kV supply point at Lindisfarne Substation maximised the market benefit and was consistent with good electricity industry practice.

Subsequent reviews reduced the options to three generic approaches (based on the findings from the earlier review):

- Do nothing, under which there is no investment in generation or transmission assets;
- Network augmentation – investment in a new double circuit 220 kV transmission line between the existing Waddamana and Lindisfarne substations (developed either complete or in two stages) and related substation upgrades; and
- Gas fired generation – involving the staged installation of open-cycle gas turbines and/or a combined-cycle gas turbine located at Bridgewater.

3.2 Consideration of Non Network Solutions

Transend engaged Energex to assess Demand Side Management (DSM) options in four key areas – ripple control of water heating load, load curtailment, co-generation and gas substitution. Based on Energex's report (tabled in 2001), Transend concluded that the options in the four key areas did not present themselves as significant enough to impact on the fundamental issues facing the southern power system. Transend concluded that hot water control, if implemented, could take 10 years to achieve significant demand benefit, perhaps offering up to 66 MW of emergency load shedding, but was beyond the timeframe for addressing the system issues. Curtailable load of 300 kW was insignificant, as was co-generation of less than 3 MW.

Transend concluded that it was reasonable to rule out DSM as an alternative option, and did not include DSM as an option in further reviews. WorleyParsons concurs with this approach.

3.3 Capex/Opex Trade-offs

Although there would be some reduction in Opex following the replacement of the existing aged Waddamana-Lindisfarne transmission line, this has not been explicitly considered by Transend. WorleyParsons considers that Opex/Capex trade-offs are not a significant issue for this project.

4 REGULATORY CONSIDERATIONS

4.1 Alignment with NER Capital Expenditure Objectives

The project expenditure is required in order to meet the following capital expenditure objectives identified in clause 6A.6.7(a) of the NER:

- Meet the expected demand for prescribed transmission services over that period;
- Comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services; and
- Maintain the reliability, safety and security of the transmission system through the supply of prescribed transmission services.

5.3 Regulatory Test

The NER require TNSPs to apply the regulatory test to new network investments (augmentations) estimated to require a total capitalised expenditure in excess of $1m. Proposed new network investments or non-network alternative options may satisfy the test via one of its two limbs – the "reliability" limb or the "market benefit" limb. For this project, Transend has applied the 'market benefit' limb, which is satisfied if, having regard to a number of alternative options, timings and market development scenarios, it maximises the net economic benefit to all those who produce, consume and transport electricity in the market.

Transend conducted internal assessments of the net market benefits of augmenting the southern transmission network and network support options. Monte Carlo simulation software was used to evaluate the various options under a number of scenarios. Under the approach taken to assess the net benefit and optimal timing of investments, Transend concluded that, the generation supply system could not be modelled in detail, and as a result, the supply capability may have been over-estimated under some market conditions.

Transend engaged McLennan Magasanik Associates (MMA) to conduct an assessment of the market benefits from grid reinforcement in southern Tasmania. MMA presented its initial report in June 2007. MMA determined the market benefits of:

- Two network augmentation options:
  - The installation of a complete double circuit line from Waddamana to Lindisfarne; or
  - The staged installation of separate circuits of the same line; and
- A thermal generation investment alternative : up to four 75 MW open-cycle gas turbines (OCGT) and/or a 225 MW combined-cycle gas turbine (CCGT), located at Bridgewater.

Three economic growth scenarios were analysed in the study by varying the projected load growth in the market simulations. Total life cycle costs were considered in the analysis. Sensitivity analysis was also undertaken to test the sensitivity of the results to variations in the assumed value of customer reliability.

MMA concluded that in all scenarios, one or other of the network augmentation options yielded higher market benefits than the generation alternative. The staged double circuit option was recommended by MMA, as it provided the highest net market benefit under most scenarios and provided flexibility to increase capacity if and when required. MMA also recommended that the project proceed as soon as possible, with net market benefits achievable from 2009 under most scenarios.

In the light of significant increases in project cost estimates, MMA were engaged later in 2007 to reassess the market benefits using the updated cost estimates. MMA concluded that the net market benefits of network augmentation still exceeded the net market benefits of generation investment, under the majority of scenarios. MMA concluded that there was little difference in net market benefits between the two network augmentation options, but recommended the staged approach due to the increased flexibility offered. MMA also concluded that the optimal timing would be delayed one year, with net market benefits achievable from 2010 onwards under most scenarios.

5 GOVERNANCE

5.1 Business Case Approvals

Five business cases have been submitted, covering various aspects of the project. Details are summarised in the following table:

Business Case Title	Approved By	Approval Date	Approved Value ($m)
Waddamana-Lindisfarne 220 kV Project Establishment	Board	24/03/05	3.50
Tower Testing: Waddamana-Lindisfarne 220 kV Transmission Line	CEO	22/11/06	0.48[1]
Southern Power System Development	Board	26/04/07	3.91
Waddamana-Lindisfarne 220 kV Transmission Line Land Acquisition	CEO	06/08/07	0.35
Waddamana-Lindisfarne 220 kV	Board	20/12/07	157.2

Note: 1 Amended to $0.50m on 13/05/08

5.2 Variations

An Expenditure Approval Variation Request was approved by the CEO on 13 May 2008 for an additional $18,317 for tower testing (approved expenditure of $570k). The cost over-run has been attributed to an additional cost of $57,000 in the tower tester's costs. WorleyParsons considers the level of detail for this variation to be in keeping with the comparatively small size of the variation.

5.3 Assumptions

Although a number of detailed assumptions were made by MMA in its review of market benefits, Transend does not appear to have made assumptions that would impact on establishing a need for the project or the project costs.

5.4 Project Risk

The key risks for the project were assessed by Transend as shown in the following table:

Risk	Likelihood	CONSEQUENCE	Gross Risk Rating	Mitigation	Net Risk Rating
Environment & Planning: • Line • Substations	Moderate	Moderate	High	Minimise changes and provide comprehensive submission to CPA	High
	Unlikely	Moderate	Moderate	Minimise changes and provide comprehensive submission to CPA	Moderate
Regulatory: costs not recovered	Unlikely	Moderate	High	Provide comprehensive submission to the AER as part of 2008 revenue proposal including referencing the regulatory consultations already done	Moderate
Construction: • Cost overrun	Likely	Moderate	High	Go to tender and use market prices as the basis for the 2008 revenue proposal forecast	Moderate
• Delay in commissioning project	Moderate	Moderate	High	Implement good project management	Moderate

5.5 Conformance with Policies & Procedures

As stated in Section 5.1, five business cases have been approved for this project. In every case, the project was authorised at the appropriate level in line with delegations of authority. One project variation was required and authorised at the appropriate level, when it was realised that expenditure would exceed the approved limits for the tower testing.

There is evidence that this project has been reviewed by the Capital Review Team (extracts of minutes) and that there is a Steering Committee for the project (business cases and extracts of minutes). The Steering Committee is chaired by the CEO Richard Bevan and the members include two General Managers. The Capital Working Team has not been actively involved in this project, as the Steering Committee has been directly taking responsibility for project governance.

WorleyParsons concludes that the project has been developed in conformance with Transend’s policies and procedures, particularly the Investment Process Governance Framework and the Project Initiation and Development Procedure.

6 EFFICIENCY

6.1 Estimating Basis

The estimates for this project comprise Level 1 estimates, for both the transmission line and substation components of the project. WorleyParsons noted that Level 3A estimates were available for the transmission line components and that these had been used to support the business case approved in December 2007. There is close alignment between the Level 1 and Level 3A estimates. Transend has advised that it has utilised the Level 1 estimates to maintain consistency in approach.

Although it could be argued that Level 3A estimates should be more accurate than Level 1 estimates, the Level 1 estimates for this project were prepared in March 2008 and reflect some minor scope refinements and price adjustments. WorleyParsons is satisfied that the Level 1 estimates used for the revenue proposal provide a reasonable basis for forecasting the expenditure for this project.

6.2 Costs

Excluding cost escalators and risk factor, the estimated expenditure in the Next Regulatory Control Period (June 09, $m) is $97.266m.

Including cost escalators and risk factor, Transend's proposed fall of expenditure is shown in the following table:

2009/10	2010/11	2011/12	2012/13	2013/14	TOTAL
64.262	55.646				119.908

6.3 Design Considerations

A consideration in assessing the efficiency of the project is whether Transend has selected the appropriate voltage for the line. Transend did consider the construction of a 110 kV line but rejected this on the basis that, although the construction costs would be much the same as a 220 kV line, a 110 kV line would not solve the capacity and voltage issues to the same extent as the 220 kV option.

Transend could also select a higher voltage for the new transmission line (eg. 275 kV or 330 kV) or plan for a higher voltage by insulating to a higher voltage and operating the line initially at 220 kV. Transend is developing a vision for the long-term development of the network, which includes voltage levels for the network backbone. Should a decision be made to increase the voltage level of the transmission backbone, the Waddamana-Lindisfarne corridor would be a low priority, as 220 kV would meet the needs of the corridor for at least several decades. Transend has considered insulating to a higher voltage but rejected this approach on the basis that the line could readily be reinsulated to a higher voltage at a later date if need be.

A second consideration in assessing the efficiency of the project is the design selected by Transend. For the initial stage, Transend proposes to install the following:

- At Lindisfarne – a single transformer and two circuit breakers, as shown in Figure 1; and
- At Waddamana – two circuit breakers as shown in Figure 2.

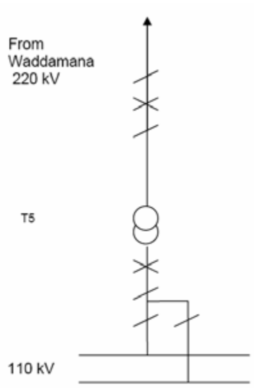


Figure 1

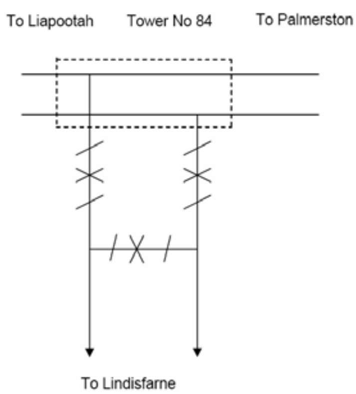


Figure 2

Transend proposes to install a single 220/110 kV 200 MVA autotransformer at Lindisfarne with on load tap changer and automatic voltage control relay. For the transmission line, Transend has selected Sulphur AAAC 1120, 61/3.75 mm conductor designed for 75oC, with a new Optical Ground Wire (OPGW) installed between Waddamana and Lindisfarne substations. The transmission line elements has been designed according to relevant standards and ESAA HB C(b)1 guidelines.

WorleyParsons notes that there is a difference of less than 1% in the NPV of the two network options (ie. staged double circuit augmentation versus straight double circuit augmentation) under the majority of scenarios.

A further approach could be to string both circuits initially but construct the substation works for a single circuit. This would avoid the difficulties associated with stringing the second circuit with the first circuit alive, obtaining outages on the first line for portions that could not be strung with the first circuit alive and with obtaining access from landowners to string the second circuit.

Transend is currently seeking prices for stringing the line with both single and double circuits, as part of the tender process for the proposed line. At this point, the second circuit and associated substation works have been included in Transend's Revenue Proposal as a contingent project.

WorleyParsons considers the design selected by Transend to be appropriate for the circumstances and in accordance with good industry practice.

6.4 Project Delivery

The transmission line component of this project will be delivered as a separate design and construct approach to mitigate the risks that have been encountered on other similar projects. The transmission line design component was competitively sourced and the design is now complete. The transmission line construction will be competitively sourced in the near future.

The substation construction component of this project will be competitively sourced with Hydro Tasmania nominated to undertake the substation design.

7 ASSESSMENT

WorleyParsons considers that Transend has demonstrated that there is a justifiable need for the project, to provide adequate capacity to meet the southern region demand and to improve the security of supply to the southern region, as discussed in Section 2. It is also relevant to note that in effect, the project has twice gone through the regulatory test process, requiring extensive project justification each time.

WorleyParsons notes that Transend considered 12 options in its initial studies, including DSM and network support options. The range of options was narrowed down in later studies, but network support options were still included and actively pursued. WorleyParsons considers that Transend has considered a reasonable range of options.

Market benefit analysis has been undertaken and the proposed option provided the highest market NPV under the majority of scenarios. On this basis, WorleyParsons considers that Transend has selected the most efficient project.

WorleyParsons notes that the estimated cost for this project has significantly increased over earlier estimates, as further information has come to hand. In spite of the significant cost increases, there is no evidence to suggest that Transend has over-estimated the cost of the project; rather, it highlights previous issues in regard to the estimating process applied at the time. WorleyParsons is satisfied that the forecast costs are reasonable for the work proposed.

The project timing aligns with MMA's recommendation that the project proceed as soon as possible, with net market benefits achievable from 2010 under most scenarios.

WorleyParsons considers that the project aligns with Transend's strategic plans, governance arrangements and Capex policies and procedures, as discussed in Section 5.

WorleyParsons has not identified any inaccuracies in the information provided in relation to this project.

8 CONCLUSION

WorleyParsons considers that the proposed project cost and timing as proposed by Transend are reasonable and should be included in the ex-ante cap as proposed by Transend.

STRATEGIC EASEMENT ACQUISITION

1 PROJECT DESCRIPTION

1.1 Project Identification

ND1001

1.2 CAPEX Category

Land and Easements

1.3 Background

The purpose of this project is to undertake the necessary investigations and, where prudent, procure transmission line easements and substation land for planned transmission system augmentations or new connections.

Transend's recent experience with transmission system augmentation or new connection projects has identified difficulties in widening existing easements and obtaining development approvals. These difficulties have largely resulted due to the lack of proactive planned land and easement acquisitions for planned prescribed transmission system augmentations or new connections.

Strategic acquisition of easement and land will ensure that planned transmission system augmentations or connection projects:

- Prudently avoid the cost escalation associated with easement widening in developed areas;
- Obtain the necessary planning approvals to allow projects to proceed in a timely manner;
- Efficiently provide the expected demand for prescribed transmission services;
- Meet connection requirements as required by connection customers; and
- Ensure that the transmission system is developed in a manner that complies with the National Electricity Rules (Rules) and the Electricity Supply Industry (Network Performance Requirements) Regulations 2007.

The strategic easement and land acquisitions included in this project relate to those identified in Transend's preliminary grid vision work and regional development plans. Undertaking early route analysis and selection will allow Transend to carefully consider the land and easement acquisition impacts on project options, and strategically pre-purchase land and obtain easements where prudent in a timely manner.

2 Project Description

The purpose of this project is to complete high level investigations of options to assist with determining the location of transmission line easements and substations, to facilitate future prescribed transmission system augmentation or connection and, where it is a prudent purchase, land and easements.

This project considers projects in the capital works program where the extent, cost and impact of the acquisition of additional land or easement has a material influence on the manner in which future prescribed transmission system augmentations or connections are implemented, and hence, strategic investigations and land or easement acquisition is required.

It is proposed to undertake this project in stages and on individual projects. The stages of this project are:

- Investigation of the current easement situation and detailed estimation of the costs of land or easement acquisition;
- Completion of strategic studies to determine suitability of easements and land; and
- Actual acquisition of easements and land if prudent to do so.

Strategic investigations will be completed to determine the preferred route and location for transmission line easements and substation sites within Tasmania, to allow for planned prescribed transmission system augmentations or connections. The strategic investigations must consider the following:

- The ability to extend easements may be constrained by adjacent developments;
- Existing encroachments into the easements may already have occurred further constraining augmentation;
- Timely acquisition of additional land or easements may be required to prevent encroachment, or further encroachment; and
- Cost of land and easement is increasing, so timely acquisition may reduce Transend's exposure to increased cost of land if expenditure is deferred.

The strategic investigations will include an assessment of the existing way-leaves (where relevant) and high level environmental impact assessments supported by studies in the following areas:

- Vegetation communities;
- Threatened flora & fauna;
- Aboriginal heritage and European heritage;
- Agricultural land;
- Surface geology;
- Acid sulphate soils;
- Land systems;
- Land use (zoning) and planning schemes;
- Cadastre (including tenure information if possible);
- Digital terrain model (or contours);
- Infrastructure – gas pipeline, electricity infrastructure, roads, rail;
- Aerial photography; and;
- Planned and existing infrastructure.

Information sources that will be utilised during the investigation process include the Herbarium and Museum databases, aerial photographs, planning schemes, relevant state planning policies, soil, geological, vegetation, good quality agricultural land and topographical mapping for the defined study areas. This information will be produced in geographical information systems format to allow comparison and constraints mapping of route options.

The information collected for the detailed transmission line route and substation site options analysis process will be utilised to map the key constraints for the proposed transmission line route alignments and possible substation locations.

The environmental studies typically comprise the following activities:

- Assessment of the visual impact of the options will be conducted on site;
- Study of predicted electric and magnetic fields (EMF);
- Preliminary geotechnical studies; and
- Identification of the number of land use planning zones.

The easement investigation and acquisition project that will be undertaken in the Next Regulatory Control Period is the Sheffield–Burnie new transmission line project, identified in section 4 of the Tasmanian Regional Plan – North-west area.

Investigations that will be undertaken for transmission line projects in the Next Regulatory Control Period are:

- Liapootah–Chapel St corridor investigation;
- Alternative 110 kV supply to Devonport/Wesley Vale area; and
- Tasman Peninsula transmission line.

Investigations that will be undertaken for substations in the Next Regulatory Control Period are:

- 110 kV supply to Exeter/Devonport;
- Staverton Switchyard; and
- Dunalley Substation.

The benefits realised through the implementation of this project include:

- Timely acquisitions ensure that preferred or better options are not eliminated as a result of adjacent developments making acquisitions prohibitively expensive, or impossible;
- Minimised cost of land or easement acquisition component for transmission augmentation or connection projects and thus the cost of the transmission services component of the cost of electricity;
- Reduced time for completion and approval of Development Applications;
- Improved deliverability of identified projects as far as landowner negotiations are concerned;
- Mitigate planning approval and project delivery risk by having an easement already in place;
- the options analysis for identified transmission augmentation or connection projects includes all the relevant issues, and is based upon considered risks;
- Enhanced likelihood that overhead transmission line options will obtain planning approval;
- Improved deliverability of the capital works program; and
- Project planning is improved through early, thorough examination of the existing easement situation and prior planning of the acquisition processes and timing.

It is noted that the Sheffield-Burnie transmission line has been included as a contingent project, with the trigger event hinging on either load growth or the connection of generation. Transend has split this into two parts, with the easement acquisition being part of the Strategic Easement Acquisition project in the ex-ante cap and the other costs included in the Sheffield-Burnie contingent project. WorleyParsons supports this approach, on the basis that there is a case for the acquisition of the easements, regardless of whether the contingent project proceeds in the Next Regulatory Control Period or not.

2 PROJECT NEED

The purpose of this project is to undertake high level investigations of options to assist with determining the location of transmission line easements and substations, to facilitate planned prescribed transmission system augmentations or connections, and where prudent to do so, purchase land and easements.

2.1 Drivers

The main drivers for the project are to:

- Ensure the efficient delivery of the capital works program;
- Allow the timely completion and approval of Development Applications;
- Minimise the costs associated with land acquisition component of transmission augmentation or connection projects;
- Enhance the likelihood that overhead transmission line options will obtain planning approval; and
- Complete acquisition of suitable easements and land to minimise barriers to the delivery or implementation of planned prescribed transmission system augmentations or connections.

2.2 Timing

Most of the expenditure relates to the procurement of easements for the new Sheffield-Burnie 220 kV transmission line. Transend has based its proposed timing on the easements being procured eight years prior to the line being required under a medium growth scenario. This results in significant expenditure in 2012-13 and 2013-14. The issue of timing is further discussed in Section 7.

2.3 Strategic Alignment

Transend has identified the alignment of this project to the organisation’s Strategic Plan, as shown in the following table:

Strategic Result Area	Strategic Performance Objective/outcome	Proposal Objectives
Market & regulatory framework	Fulfil transmission licence obligations and other ESI obligations	Augment the transmission network to comply with transmission licence obligations and other ESI obligations at the least cost
Asset management	Compliance with transmission planning criteria	Augment the transmission network to comply with the transmission planning criteria (network performance requirements)
Asset management	Identify medium term augmentation options in a timely manner	Ensure medium term transmission network augmentations are implemented at the right time at the least cost
Asset management	Gain approvals for capital projects in a timely manner	Ensure transmission network augmentation projects are approved at the right time at the least cost
Good corporate citizenship	Compliance with legal obligations	Comply with the law, regulations and industry codes of practice when planning transmission network augmentation projects

3 ALTERNATIVES

3.1 Options

Option 1 – Do nothing

Recent industry feedback has indicated that obtaining planning approval for overhead transmission lines and substations within highly populated areas throughout Australia has become increasingly more difficult, time consuming and expensive. The same can also be said for areas that have high environmental or heritage significance, like large areas of Tasmania, which are protected from electricity infrastructure development, through legislative provisions and the application of planning schemes. Due to the increased time required to obtain planning approval, this approach will reduce Transend's ability to deliver the future capital works program and to ensure that the Tasmanian transmission system is compliant with the Rules and the network performance requirements.

This option is not preferred because it would not allow Transend to achieve the capital expenditure objectives identified in the Rules.

Option 2 – Only acquire or investigate the acquisition of easements immediately prior to the need for transmission system augmentations or new connections

Historically this is the approach that Transend has applied in relation to planned augmentation and connection projects. This has resulted in a number of adverse effects to the delivery of projects; increased costs associated with land and easement acquisition, increased compensation costs, increased costs to the electricity customers, delays to the implementation of projects and decreased reliability and security of supply until the projects are completed. Similar to option 1, this option will also detract from Transend's ability to deliver the future capital works program and to ensure that the

Tasmanian transmission system is compliant with the Rules and the network performance requirements.

This option is not preferred because it would not allow Transend to achieve the capital expenditure objectives identified in the Rules.

Option 3 – Strategic easement acquisition

This option will result in Transend undertaking high level investigations of options to assist with determining the location of transmission line easements and substations, to align with planned prescribed transmission system augmentations or new connections and, where prudent, purchase land and easements. Given the complexity of achieving planning approval for transmission system augmentation and connection projects, it is prudent to complete strategic investigations to determine the preferred route and location for transmission line easements and substation sites within Tasmania, to allow for planned prescribed transmission system augmentations or connections. It is proposed that by undertaking the works outlined in this project Transend will:

- Minimise the costs associated with land acquisition component of augmentation or connection projects and thus the cost of the transmission services component of the cost of electricity;
- Ensure efficient delivery of the capital works program;
- Completion and approval of Development Applications;
- Enhance the likelihood that overhead transmission line options will obtain planning approval;
- Complete acquisition of suitable easements and land to support the delivery or implementation of future prescribed transmission system augmentations or connections; and
- Ensure that the transmission system is compliant with the NER and the network performance objectives.

This option will allow Transend to achieve the capital expenditure objectives identified in the NER.

Option 3 is Transend's preferred option.

3.2 Options Analysis

WorleyParsons supports the approach embodied in Option 3, recognising the increasing difficulties and costs in obtaining easements over time.

3.3 Consideration of Non Network Solutions

Not applicable to this project.

3.4 Capex/Opex Trade-offs

Not applicable to this project.

4 REGULATORY CONSIDERATIONS

4.1 Alignment with NER Capital Expenditure Objectives

The project expenditure is required in order to meet the following capital expenditure objectives identified in clause 6A.6.7(a) of the NER:

- Meet the expected demand for prescribed transmission services over that period;
- Comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services;
- Maintain the quality, reliability, and security of supply of prescribed transmission services; and
- Maintain the reliability, safety and security of the transmission system through the supply of prescribed transmission services.

4.2 Regulatory Test

The NER require TNSPs to apply the regulatory test to new network investments (augmentations) estimated to require a total capitalised expenditure in excess of $1m. Proposed new network investments or non-network alternative options may satisfy the test via one of its two limbs – the “reliability” limb or the “market benefit” limb. It is not clear at this stage which limb of the regulatory test Transend would apply to this project.

This project is classified as a large network asset, and as such, the project is subject to the consultation process under clause 5.6.6 of the NER.

5 GOVERNANCE

5.1 Business Case Approvals

A business case has not been submitted for this project at this time because the project has not been developed to a stage sufficient for business case submittal.

5.2 Assumptions

No key assumptions have been identified at this point.

5.3 Project Risk

Transend’s 2007 Business Risk Review identifies a number of risks that directly relate to this project. The implementation of this project will contribute to the mitigation of these risks, which are summarised in the following table. Project specific risks will be identified during the project initiation process and included in the business case.

Risk Description	Revised consequence	Revised Likelihood	Revised rating
The risk of inadequate strategic system planning and development leads to poor systems performance and/or inefficient system investment	Moderate	Moderate	High
Non-compliance with Electricity Supply Industry statutory obligations and regulations and/or failure of compliance monitoring systems	Moderate	Unlikely	Moderate

Other risks associated with the project include:

- If the acquisition of land or easement is not implemented in advance, project costs may be greater as a result of the cost of land increasing;
- If the acquisition of land or easement is not implemented in advance, project options that are currently efficient and cost effective may become cost-prohibitive;
- Land owners impacted by the acquisition may be unnecessarily disrupted, or compensated.

Further project specific risks will be identified during the project initiation process.

5.4 Conformance with Policies & Procedures

This project is at a very early stage. An initial Project Definition form has been completed, together with a Capital Project Investment Review and Level 1 estimates.

WorleyParsons concludes that the project has been developed in conformance with Transend's policies and procedures, particularly the Investment Process Governance Framework and the Project Initiation and Development Procedure.

6 EFFICIENCY

6.1 Estimating Basis

The average $/km price for easements and investigation work has been based on recent studies completed by external consultants for Transend for the Norwood-Scottsdale-Derby project.

6.2 Costs

Excluding cost escalators and risk factor, the estimated expenditure in the Next Regulatory Control Period (June 09, $m) is $15.297M.

Including cost escalators and risk factor, Transend's proposed fall of expenditure is shown in the following table:

2009/10	2010/11	2011/12	2012/13	2013/14	TOTAL
	0.024	0.013	10.697	10.458	21.192

6.3 Design Considerations

Not relevant to this project.

6.4 Project Delivery

A project management plan, deliverables and methodology will be developed for each identified project when the project is initiated and progressed to the development phase.

This project will be primarily undertaken by contracted resources.

7 ASSESSMENT

WorleyParsons considers that Transend has demonstrated that there is a justifiable need for the project, to ensure the efficient delivery of the capital works program, as discussed in Section 2. The project will assist in the timely completion and approval of development applications, minimise the cost of land acquisition, increase the likelihood of obtaining planning approval and minimise the barriers to transmission line works.

As discussed in Section 3, WorleyParsons considers the option proposed by Transend as being reasonable, recognising the increasing difficulties and costs in obtaining easements over time.

Transend's cost estimates are based on Level 1 estimates. The average unit price for easements and investigation work has been based on recent studies completed by external consultants for the a major transmission line project. WorleyParsons is satisfied that the forecast costs are reasonable for the work proposed.

Transend has based its proposed timing on the easements being procured eight years prior to the line being required under a medium growth scenario. This results in significant expenditure in 2012-13 and 2013-14. In support of the proposed timing, Transend carried out a Net Present Value (NPV) comparison of six options, covering a range of load growth and timing scenarios. As a further comparison, WorleyParsons has calculated the NPV for two further options – keeping the medium demand growth, but deferring the easement acquisitions by one and two years. A comparison of the Net Present Value over 20 years is shown in the following table:

No.	Option	NPV ($m real 09)
1	Medium growth, procure easement in 2012-14	-16.3
2	Medium growth, procure easement in 2013-15	-17.2
3	Medium growth, procure easement in 2014-16	-17.6

It can be seen that the procurement of the easements in the final two years of the Next Regulatory Control Period (that is, Option 1) presents the lowest cost.

WorleyParsons considers that the project aligns with Transend's strategic plans, governance arrangements and Capex policies and procedures, as discussed in Section 2.3 and Section 5.

WorleyParsons has not identified any inaccuracies in the information provided in relation to this project.

8 CONCLUSION

WorleyParsons considers that the proposed project cost and timing as proposed by Transend are reasonable and should be included in the ex-ante cap as proposed by Transend.

NEWSTEAD SUBSTATION NEW 110/22 kV CONNECTION SITE

1 PROJECT DESCRIPTION

1.1 Project Identification

ND0931

1.2 CAPEX Category

Connection

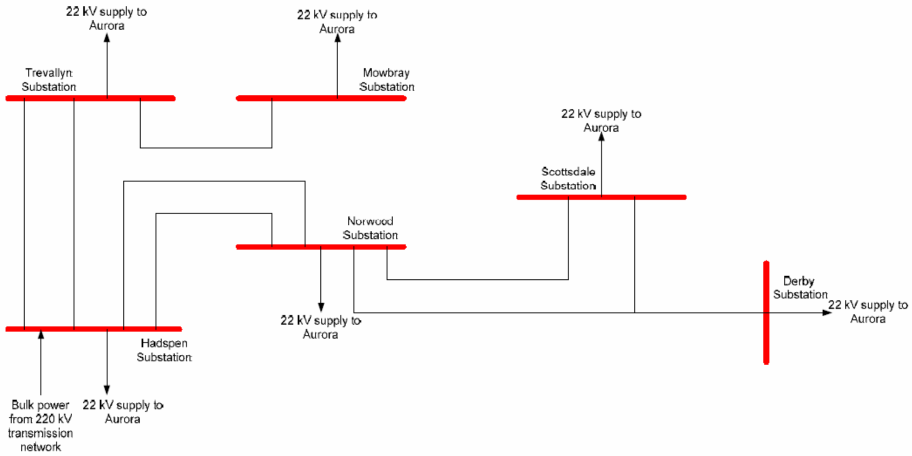
1.3 Brief Overview

The project involves the establishment of a new 110/22 kV substation in the Newstead area. This will require the following works:

- Termination of the new Mowbray-Norwood 110 kV transmission line on two termination towers at the Newstead substation;
- Installation of 2 x 60 MVA 110/22 kV transformers and associated switchgear;
- Development of the substation site (including perimeter fence, roadways, earth mat, lighting, control building, lightning protection); and
- Associated protection and control schemes.

1.4 Background

The existing supply to the Launceston area is shown in the following single line diagram:

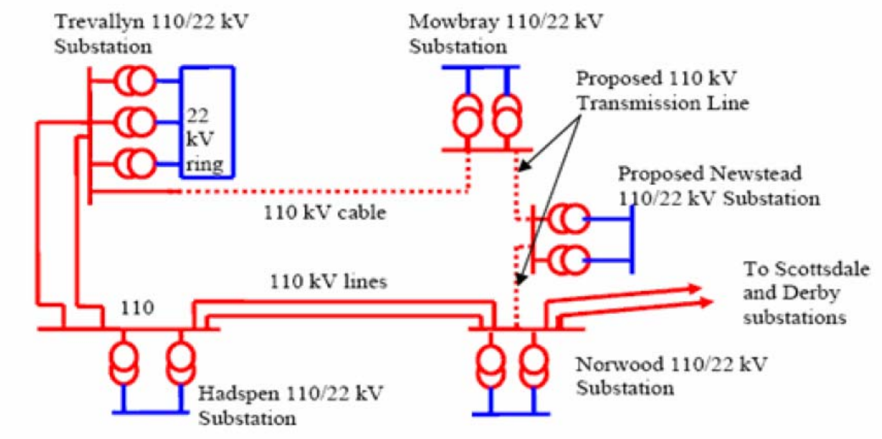


Transend and Aurora have identified existing constraints in the electricity transmission and distribution networks that supply the Launceston Area. This area includes the major suburbs and surrounding areas of Trevallyn, Hadspen, Mowbray, Norwood and the Launceston Central Business District (CBD). Technical studies and demand forecasts have identified that there are a number of limitations with the current electricity supply in the Launceston Area. In the event that a credible contingency occurs there are a number of areas that will result in overloads of the transmission network and loss of supply to distribution customers. Action is required to overcome these limitations to allow Transend and Aurora to meet their obligations under the local jurisdictional requirements and technical standards in the NER.

In addition, Transend currently has received two separate connection applications from Aurora. One of the connection applications is requesting a firm supply capability of 50 MVA at Mowbray Substation by winter 2009. To achieve this firm supply, Transend is required to provide a second 110 kV transmission line to Mowbray Substation. Transend has determined that the best solution to ensure reliability and security of supply for the Launceston area and to meet Aurora's requirements is to provide a new 110 kV transmission line between Norwood and Mowbray substations. The other connection application received from Aurora is requesting the establishment of a new 22 kV connection site at Newstead. This new substation will provide a new 22 kV injection point for delivery of supply to the loads in the Newstead area and facilitate load transfer from the existing substations in the Launceston area.

The Newstead area is currently supplied from Mowbray and Norwood substations via heavily loaded 22 kV distribution feeders. The 22 kV supply from Norwood Substation is currently non-firm and the 22 kV supply from Mowbray Substation will be non-firm by 2011 based on the 2008 demand forecast.

The new 22 kV connection site at Newstead area will be implemented with the Norwood-Mowbray 110 kV transmission line project to demonstrate efficiency in the works delivery. The combination of the 110 kV transmission line between Norwood and Mowbray and a new connection site at Newstead area has been identified as the preferred option through joint planning between Transend and Aurora. The combined projects are shown in the following single line diagram:



2 PROJECT NEED

The current arrangement at Norwood Substation does not comply with clause 5.(1)(a)(iv) of the Electricity Supply Industry (Network Performance Requirements) Regulations 2007 in that "the unserved energy to load that is interrupted consequent on damage to a network element resulting from a credible contingency event is not capable of exceeding 300 MWh at any time". The 22kV supply from Mowbray Substation is expected to become non-firm in 2011.

Aurora has submitted a connection application for a new 22 kV connection site in the Newstead area to cater for demand growth. The connection site is required to have a firm capacity of 60 MVA.

2.1 Drivers

The main drivers for the project (in decreasing order of importance) are:

- Improve security and reliability of supply to the Launceston area to comply with the minimum network performance levels under the ESI Regulations; and

- To cater for forecast demand growth in the Launceston CBD and surrounding areas.

Transend and Aurora conducted joint planning studies to determine the best solution for the Launceston area to address both the security of supply and reliability issues.

2.2 Timing

The new connection site in the Newstead area is required as soon as practicable, and is planned to be completed by 2012. The project has been coordinated with the Norwood–Mowbray 110 kV transmission line project.

2.3 Strategic Alignment

Transend has identified the alignment of this project to the organisation's Strategic Plan, as shown in the following table:

Strategic Result Area	Strategic Performance Objective/outcome	Proposal Objectives
Market & regulatory framework	Fulfil transmission licence obligations and other ESI obligations	Augment the transmission network to comply with transmission licence obligations and other ESI obligations at the least cost.
Customer relationship	Involve customers in decisions that affect them	Consult with Aurora Energy and other stakeholders as appropriate to ensure that the project outcomes meet customer and stakeholder expectations
Transmission system performance	Maintain transmission performance	Augment the transmission system to maintain or improve transmission network performance as appropriate. Augment the transmission system to maintain or improve connection site performance.
Asset management	Compliance with transmission planning criteria	Augment the transmission network to comply with the transmission planning criteria (network performance requirements).

3 ALTERNATIVES

3.1 Options

Transend considered a range of alternative options:

Option	Brief Description	Comments
Option 0	Do nothing	This option would not provide the additional capacity requirements or allow Transend to comply with the network performance requirements, would not meet the requirements of Aurora's connection application and would not allow Transend to achieve the capital expenditure objectives
Option 1	Distribution reinforcement	This option would require additional transformers and would also involve the expansion of an already congested distribution system.
Option 2	Distribution reinforcement plus demand side management with local co-generation schemes	No viable solution identified, would require additional planning approvals and would involve issues associated with tariff changes.
Option 3	Install a third transformer at Norwood Substation	Would reduce reliability and security of supply at the distribution level and is limited by physical constraints when running distribution feeders out of Norwood Substation.

3.2 Consideration of Non Network Solutions

Transend, in conjunction with Aurora, has considered distribution reinforcement and non-network options, but has concluded that they do not resolve the outstanding issues.

3.3 Options Analysis

Transend and Aurora have jointly determined that the best solution to ensure reliability and security of supply to the Newstead area and to meet Aurora's requirements is to establish a new 110/22 kV substation in the Newstead area. WorleyParsons concurs with this assessment, given the physical constraints in running additional distribution feeders from Norwood Substation.

Any alternative solutions identified from the public consultation process will be considered during the project initiation process.

3.4 Capex/Opex Trade-offs

Not applicable to this project.

4 REGULATORY CONSIDERATIONS

4.1 Alignment with NER Capital Expenditure Objectives

The project expenditure is required in order to meet the following capital expenditure objectives identified in clause 6A.6.7(a) of the NER:

- Meet the expected demand for prescribed transmission services over that period;
- Comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services; and
- Maintain the reliability, safety and security of the transmission system through the supply of prescribed transmission services.

The current arrangement at Norwood Substation does not comply with clause 5.(1)(a)(iv) of the Electricity Supply Industry (Network Performance Requirements) Regulations 2007 in that “the unserved energy to load that is interrupted consequent on damage to a network element resulting from a credible contingency event is not capable of exceeding 300 MWh at any time”.

4.2 Regulatory Test

The NER require TNSPs to apply the regulatory test to new network investments (augmentations) estimated to require a total capitalised expenditure in excess of $1m. Proposed new network investments or non-network alternative options may satisfy the test via one of its two limbs – the “reliability” limb or the “market benefit” limb. For this project, Transend has applied the “reliability benefit” limb, which is satisfied if, having regard to a number of alternative options, timings and market development scenarios, it maximises the net economic benefit to all those who produce, consume and transport electricity in the market.

This project is classified as a large network asset, and as such, the project is subject to the consultation process under clause 5.6.6 of the NER.

5 GOVERNANCE

5.1 Business Case Approvals

A business case has not yet been submitted for the project.

5.2 Assumptions

Key assumptions made are:

- That the project will be constructed in association with the Mowbray-Norwood 110 kV transmission line;
- That an approved development application will be obtained; and
- Regulatory approval will be obtained from the AER.

5.3 Project Risk

Transend’s 2007 Business Risk Review identifies a number of risks that directly relate to this project. The implementation of this project will contribute to the mitigation of these risks, which are summarised in the following table. Project specific risks will be identified during the project initiation process and included in the business case.

Risk Description	Revised Consequence	Revised likelihood	Revised risk rating
The risk of inadequate strategic system planning and development leads to poor system performance and/or inefficient system investment	Moderate	Moderate	High
Failure to operate the power system in accordance with Legislative and Contractual obligations	Major	Rare	High
Risk of inadequate customer management leads to reduced profitability, disgruntled customers and/or loss of customers	Moderate	Unlikely	Moderate
Risk that Transend is responsible for inappropriate asset management that results in equipment failure, a major bushfire or damage to third party property impacting on operations of the power system and/or resulting in property damage or loss of life	Moderate	Moderate	High
Does not comply with the power system requirement under NER	Moderate	Unlikely	Moderate

5.4 Conformance with Policies & Procedures

WorleyParsons notes that this project is at an early stage of development, but found that the project has been developed in conformance with Transend's policies and procedures, particularly the Investment Process Governance Framework.

6 EFFICIENCY

6.1 Estimating Basis

The estimates for this project comprise Level 1 estimates and align with the values contained in Transend's Capital Accumulation Model used for the submission.

6.2 Costs

Excluding cost escalators and risk factor, the estimated expenditure in the Next Regulatory Control Period (June 09, $) is $16.701m.

Including cost escalators and risk factor, Transend's proposed fall of expenditure (June 09, $m) is shown in the following table:

2009/10	2010/11	2011/12	2012/13	2013/14	TOTAL
0.909	11.999	7.911			20.820

6.3 Design Considerations

Transend proposes to install two 60 MVA 110/22 kV transformers at the new substation, in a standard 'H' configuration. The size of the transformers is appropriate to meet Aurora's request for 60 MVA firm capacity.

The 'H' configuration proposed by Transend for this substation is common throughout the industry and is appropriate for this installation.

6.4 Project Delivery

At this stage it is envisaged that this project will be implemented using a design and construct approach. Preferred contractors experienced in this type of work will be engaged to undertake the works to complete this project.

7 ASSESSMENT

WorleyParsons considers that Transend has demonstrated that there is a justifiable need for the project, to improve security and reliability of supply to the Launceston area to comply with the ESI Regulations and cater for forecast demand growth, as discussed in Section 2.

As discussed in Section 3, WorleyParsons considers the option proposed by Transend is reasonable. Transend, in conjunction with Aurora, considered distribution reinforcement, and a combination of DSM and distribution reinforcement, as well as the installation of a third transformer at Norwood Substation. None of these alternative options adequately addressed the project drivers.

Transend's cost estimates are based on Level 1 estimates. WorleyParsons is satisfied that the design for this project is appropriate, as the proposed 'H' configuration is an industry standard, and that the forecast costs are reasonable for the work proposed.

The project is required now to overcome existing constraints and has been timed to align with the construction of the Norwood-Mowbray transmission line, which is also scheduled for completion in 2012.

WorleyParsons considers that the project aligns with Transend's strategic plans, governance arrangements and Capex policies and procedures, as discussed in Section 5.

WorleyParsons has not identified any inaccuracies in the information provided in relation to this project.

8 CONCLUSION

WorleyParsons considers that the proposed project cost and timing as proposed by Transend are reasonable and should be included in the ex-ante cap as proposed by Transend.

GEORGE TOWN SUBSTATION 220 kV SECURITY UPGRADE

1 PROJECT DESCRIPTION

1.1 Project Identification

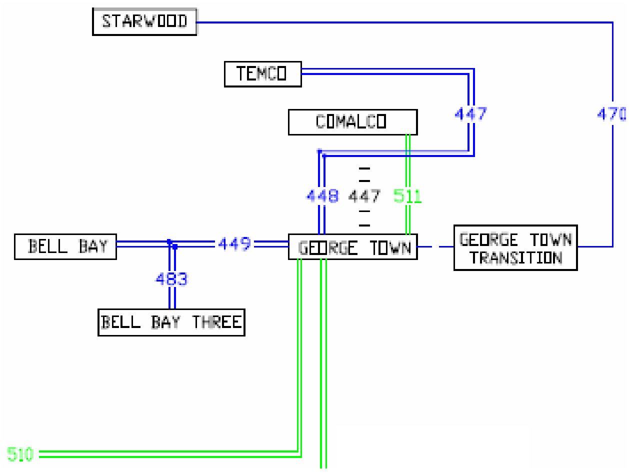
ND0657

1.2 APEX Category

Augmentation

1.3 Brief Overview

George Town Substation is supplied from Hadspen and Sheffield substations. It provides connection points for Basslink, Bell Bay Power Station, direct connect customers and Aurora Energy's customers in the George Town area. George Town Substation is a critical node on the transmission system and it is vital to sustaining a reliable and secure electricity supply in Tasmania – refer to the following single line diagram.



George Town Substation 220 kV currently does not meet the network performance requirements and certain assets need to be replaced due to condition and performance issues.

The key objectives of the George Town Substation 220 kV security upgrade project are to sustain the reliability and security of the transmission network and to comply with regulatory obligations.

1.4 Project Description

The George Town Substation 220 kV security upgrade project comprises the redevelopment of the George Town Substation 220kV switchyard from the existing double busbar arrangement, to a circuit breaker and a half arrangement. The redevelopment will also include a number of asset replacements, and building of a second control building.

This redevelopment project will include the completion of the following major tasks:

- Submission of a development application for the substation to the George Town Council, to cover the works associated with this project;

- Completion of additional land purchase from Rio Tinto to secure suitable land to allow this redevelopment project to continue;
- Construction of a new 220kV solid busbar (busbar E);
- Removal of the existing 220kV busbar (busbar A);
- Extend the existing substation to accommodate the new 220kV switchyard arrangement;
- Construction of a second control building, next to the existing 220 kV capacitor bank;
- Modification of the existing GT-HD 220 kV transmission line No.2 bay and the Auto Transformer T3 bay to a circuit breaker and a half arrangement;
- Modification of the existing GT-HD 220 kV transmission line No.1 bay and the Auto Transformer T2 bay to a circuit breaker and a half arrangement;
- Modification of the existing GT-SH 220 kV transmission line No.1 bay and the Auto Transformer T1 bay to a circuit breaker and a half arrangement;
- Modification of the existing GT-SH 220 kV transmission line No.2 bay to a double circuit breaker arrangement. This arrangement will allow easy conversion to circuit breaker and a half if a new 220kV bay is installed opposite this transmission line;
- Relocation of CT's on A752, B752, C752 and D752;
- Relocation of the protection schemes associated with GT-HD 220 kV transmission line No.2, GT-SH 220 kV transmission line No.2, Auto Transformer T1 and T3 to the new control building. Relocation of the Rio Tinto No.5 protection scheme is also included;
- Installation of new protection schemes to facilitate the redevelopment works;
- Installation of second AC, DC, SCADA and communications systems to minimise the impact of the substation if a catastrophic failure occurs in one control building;
- Substation infrastructure and ancillary works at George Town substation; and
- Infrastructure construction, testing and commissioning.

2 PROJECT NEED

George Town Substation is a critical node of the 220 kV transmission system in the Northern region of Tasmania. It is the termination node for the Basslink DC transmission link, and it supplies Aurora Energy customers and major industrial customers in the George Town area. The operation of Basslink was a key consideration in completing the reliability study for George Town Substation. The total loss of George Town Substation during times of large power export or import via the Basslink DC transmission link, could lead to a large system disturbance in Tasmania.

Transend currently has two major industrial customers connected to George Town Substation, along with Aurora Energy. These customers have the following load requirements:

- Rio Tinto (Comalco) – 311 MW supplied from the 220 kV busbar;
- TEMCO – 88 MW supplied from the 110 kV busbar; and
- Aurora Energy – 25 MW supplied from the 22 kV busbar.

Transend is concerned that the current George Town Substation 220 kV layout and the condition of numerous assets at this substation are not suitable to provide reliable and secure supply to these customers. Also, there is business risk exposure of non-compliance to NER, local jurisdictional planning criteria and transmission licence requirements. Therefore, Transend has undertaken a detailed reliability evaluation of several options for George Town Substation 220 kV development to determine a compliant arrangement of the 220 kV switchyard.

In addition, Transend currently has received two separate connection applications from customers for connections at George Town 220 kV switchyard, as follows:

- Alinta Pty Ltd / Babcock & Brown
  - Combined cycle plant – 210 MW connected to the 220 kV busbar at George Town Substation; and
  - Open cycle plant up to 180 MW. This includes the existing 3*35 MW Twin Pac machines and a new 76 MW Open Cycle Gas Turbine manufactured by Rolls Royce/Trent. This plant is connected to the 110 kV busbars at George Town Substation.

(WorleyParsons notes that at the time of writing this report, Alinta / Babcock & Brown is in the process of selling their entire assets at Bell Bay Power Station).

- Gunns:
  - Generator – 215 MW connected to the 220 kV busbar at George Town Substation; and
  - Plant load – 96 MW (120 MW exported to Tasmanian transmission system).

These connection applications were also considered when analysing the options for the George Town Substation development, to ensure that the preferred development option does not cause impediments for the addition of these two connection points.

Due to the significance of George Town Substation as both a supply point and generation connection point, it is vital that the integrity of the substation be maintained as much as possible and the consequences of unplanned outages minimised to prevent possible widespread system disturbances.

Transend has identified that there are multiple business risks related to the existing George Town 220 kV substation arrangement. The existing arrangement presents a compliance issue under the NER and the local jurisdiction applied by the Reliability Network Planning Panel (RNPP). The specific RNPP planning and security criteria to which George Town Substation is currently non-compliant is 3,000 MWh for a single asset failure (eg. bus coupler failure, failure of an instrument transformer connected to the bus or bus coupler circuits). Consequently, Transend published the George Town Substation 220 kV security upgrade project in Transend's 2006 Annual Planning Report as a small network augmentation project. The project was also published in Transend's 2003 Revenue Cap Application and the 2006 Transmission System Management Plan.

2.1 Drivers

The main drivers for the project (in decreasing order of importance) are to:

- Improve security and reliability of supply at the George Town Substation;
- Comply with the minimum network performance levels under the ESI Regulations; and
- Replace assets that are at the end of their useful lives (eg. gantry structures supporting the bus).

2.2 Timing

This project is required now, as Transend does not meet the performance requirements of the ESI Regulations. The project has been coordinated with other projects currently being implemented at George Town Substation and is scheduled for completion in 2013.

2.3 Strategic Alignment

Transend has identified the alignment of this project to the organisation's Strategic Plan, as shown in the following table:

Strategic Result Area	Strategic Performance Objective/outcome	Proposal Objectives
Market & regulatory framework	Fulfil transmission licence obligations and other ESI obligations	Augment the transmission network to comply with transmission licence obligations and other ESI obligations at the least cost.
Customer relationship	Involve customers in decisions that affect them	Consult with Aurora Energy and other stakeholders as appropriate to ensure that the project outcomes meet customer and stakeholder expectations
Transmission system performance	Maintain transmission performance	Augment the transmission system to maintain or improve transmission network performance as appropriate.
Asset management	Compliance with transmission planning criteria	Augment the transmission network to comply with the transmission planning criteria (network performance requirements).

3 ALTERNATIVES

3.1 Options

The Reliability Modelling and Analysis Study undertaken in July 2007 considered twelve development options, and recommended that five of these be further assessed. The options considered were:

Option	Brief Description
Option 1	Do nothing
Option 2	Two circuit breaker and a half diameters on shared network, Alinta connected in double circuit breaker arrangement and Gunns connected in circuit breaker and a half
Option 3	Three circuit breaker and a half diameters on shared network, Alinta connected in double breaker arrangement and Gunns connected in circuit breaker and a half
Option 4	Triple busbar arrangement
Option 5	Improving Rio Tinto reliability plus two circuit breaker and a half diameters on shared network
Option 6	Improving Rio Tinto reliability plus one circuit breaker and a half diameters on shared network
Option 7	Alinta and Gunns connected opposite to Rio Tinto circuits in circuit breaker and a half connections plus two circuit breaker and a half diameters on shared network circuits
Option 8	Alinta and Gunns connected opposite to Rio Tinto circuits in disconnector and a half connections plus two circuit breaker and a half diameters on shared network circuits
Option 9	Alinta and Gunns connected opposite to Rio Tinto circuits in disconnector and a half connections plus three circuit breaker and a half diameters on shared network circuits
Option 10	Relocation of George Town-Hadspen No. 1 and No. 2 and George Town-Sheffield No. 1 and No. 2 transmission lines and disconnector and a half arrangement for Alinta and Gunns
Option 11	Circuit breaker and a half for Alinta and Gunns connections and three circuit breaker and a half on shared network circuits
Option 12	Triple busbar arrangement, with relocated Alinta termination bay.

3.2 Options Analysis

The options were modelled using the SUBREL computer software to calculate reliability indices under two scenarios (import and export), analysing all credible outage events. Using this approach, the options were narrowed down to Options 7, 8, 9, 10 and 11. Option 1 did not meet the identified project needs. After further analysis, Transend selected Option 7, taking into account meeting the project objectives and costs. WorleyParsons is satisfied with this selection, based on the information provided.

3.3 Consideration of Non Network Solutions

Not applicable to this project.

3.4 Capex/Opex Trade-offs

Although some savings in Opex could be expected, Transend considers that these are not material.

4 REGULATORY CONSIDERATIONS

4.1 Alignment with NER Capital Expenditure Objectives

The project expenditure is required in order to meet the following capital expenditure objectives identified in clause 6A.6.7(a) of the NER:

- Comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services;
- Maintain the quality, reliability and security of supply of prescribed transmission services; and
- Maintain the reliability, safety and security of the transmission system through the supply of prescribed transmission services.

4.2 Regulatory Test

This project is now classified as a large network augmentation, due to changes in scope and costs. The NER require TNSPs to apply the regulatory test to new network investments (augmentations) estimated to require a total capitalised expenditure in excess of $1m. Proposed new network investments or non-network alternative options may satisfy the test via one of its two limbs – the "reliability" limb or the "market benefit" limb. For this project, Transend will apply the "reliability benefit" limb, which is satisfied if, having regard to a number of alternative options, timings and market development scenarios, it maximises the net economic benefit to all those who produce, consume and transport electricity in the market. The project will be subject to the consultation process under clause 5.6.6 of the NER.

5 GOVERNANCE

5.1 Business Case Approvals

A business case has not yet been submitted for this project.

5.2 Assumptions

Not considered at this stage.

5.4 Project Risk

Transend's 2007 Business Risk Review identifies a number of risks that directly relate to this project. The implementation of this project will contribute to the mitigation of these risks, which are summarised in the following table. Project specific risks will be identified during the project initiation process and included in the business case.

Risk Description	Revised Consequence	Revised likelihood	Revised risk rating
Failure to operate the power system in accordance with Legislative and Contractual obligations	Major	Rare	High
Risk that Transend is responsible for inappropriate asset management that results in equipment failure, a major bushfire or damage to third party property impacting on operations of the power system and/or resulting in property damage or loss of life	Moderate	Moderate	High
Non- compliance with ESI obligations and regulations and/or failure of compliance monitoring systems	Moderate	Unlikely	Moderate

5.4 Conformance with Policies & Procedures

WorleyParsons notes that this project is at an early stage of development, but found that the project has been developed in conformance with Transend's policies and procedures, particularly the Investment Process Governance Framework.

6 EFFICIENCY

6.1 Estimating Basis

The estimates for this project comprise Level 1 estimates and align with the values contained in Transend's Capital Accumulation Model used for the submission.

6.2 Costs

Excluding cost escalators and risk factor, the estimated expenditure in the Next Regulatory Control Period (June 09, $m) is $14.497m.

Including cost escalators and risk factor, Transend's proposed fall of expenditure (June 09, $m) is shown in the following table:

2009/10	2010/11	2011/12	2012/13	2013/14	TOTAL
	2.431	10.979	4.951		18.361

6.3 Design Considerations

Transend proposes to redevelop the George Town Substation from a double busbar arrangement to a circuit breaker and a half arrangement. This configuration is common throughout the industry for use at 220 kV and is appropriate for this installation.

6.4 Project Delivery

At this stage it is envisaged that this project will be implemented using a design and construct approach. Preferred contractors experienced in this type of work will be engaged to undertake the works to complete this project.

7 ASSESSMENT

WorleyParsons considers that Transend has demonstrated that there is a justifiable need for the project, to sustain the reliability and security of a critical node in the transmission network, to comply with regulatory obligations and to replace assets that are at the end of their useful lives, as discussed in Section 2.

As discussed in Section 3, WorleyParsons considers the option proposed by Transend as being reasonable. Twelve options were modelled using sophisticated computer software to analyse all credible outage events under two scenarios. The preferred option was selected after further detailed analysis, taking into account estimated costs and addressing the project drivers.

Transend's cost estimates are based on Level 1 estimates. WorleyParsons is satisfied that the design for this project is appropriate, with the use of a breaker and a half arrangement common throughout the industry, and that the forecast costs are reasonable for the work proposed.

The project is required now, as Transend currently breaches the performance requirements of the ESI Regulations, and has been timed to align with other work at George Town Substation.

WorleyParsons considers that the project aligns with Transend's strategic plans, governance arrangements and Capex policies and procedures, as discussed in Section 2.3 and Section 5.

WorleyParsons has not identified any inaccuracies in the information provided in relation to this project.

8 CONCLUSION

WorleyParsons considers that the proposed project cost and timing as proposed by Transend are reasonable and should be included in the ex-ante cap as proposed by Transend.

ASSET MANAGEMENT INFORMATION SYSTEM

1 PROJECT DESCRIPTION

1.1 Project Identification

ND1043

1.2 CAPEX Category

Operational Support Systems

1.3 Background

The AMIS represents the following:

- An integration of people, processes and technology supporting Transend's asset management functions;
- A set of philosophies and guiding principles for information management; and
- A capital development program.

The AMIS supports the various business processes concerned with asset management including asset records management, works management, works planning, performance reporting, and others. Major system improvements and developments of the AMIS are currently being performed by the AMIS project team.

Transend's strategic plan states that Transend is committed to the continual development of an asset management information system. This system is a tool that interlinks asset management processes through the entire asset life cycle and provides a robust platform for extraction of relevant asset information for various purposes.

Transend's AMIS strategy has the objectives of managing asset related information so as to:

- Improve the management of assets;
- Enhance productivity by the provision of appropriate tools and systems;
- Ensure the timeliness, accuracy, integrity and credibility of asset data;
- Meet statutory, regulatory and customer requirements and expectations;
- Ensure the appropriate ownership, custodianship and management of the data;
- Provide easy maintainability of data; and
- Provide an open access to asset data and performance information to Transend staff.

Transend commenced implementation of the AMIS system in 2003. The program has been extremely successful and Transend has implemented many of the components of the AMIS strategy. AMIS is now directly supporting a wide range of business processes. The purpose of this project is to continue the development and enhancement of Transend's AMIS.

1.4 Project Description

The AMIS project continues the development and enhancement of Transend's AMIS. The project maintains the program of recent investments in system integration and process improvements. This project will see additional asset management initiatives delivered in a manner and magnitude consistent with the recent investments in AMIS activities.

Transend proposes to enhance this core asset management system by developing and implementing many components of an advanced asset management system. The project will build on the information systems that currently constitute Transend's AMIS and will deliver enhancements to further integrate business systems and business processes supporting the management of transmission system assets.

The project will investigate, analyse and implement (as appropriate) initiatives such as:

- Operational information management;
- Asset information management;
- Asset risk management;
- Geographical information systems;
- Mobile solutions;
- Project management/delivery integration;
- Outage management integration;
- Integration of environment, safety and training considerations into the AMIS;
- Power system modelling integration; and
- Inventory control / stores optimisation.

The project will also actively consider change management and the business' capacity to adopt the significant change expected to be delivered by this project.

2 PROJECT NEED

Transend considers that continued development of the AMIS is essential to ensure that asset management strategies can be effectively and efficiently implemented. Development of AMIS will assist converting asset management strategies into implementable activities. AMIS directly supports the achievement of Transend's strategic performance objectives for improvements within asset management. AMIS is a critical tool that complements Transend's asset management policies and strategies. The continued investment in AMIS will be crucial to support the management of transmission system assets in accordance with the AMIS Program Management Plan, asset management plans, the Strategic Asset Management framework and the Asset Management Policy.

2.1 Drivers

The main drivers for the project (in decreasing order of importance) are:

- Improve asset management; and
- Enhance productivity.

2.2 Timing

This project will consist of separate additional asset management initiatives, implemented over the full five years of the Next Regulatory Control Period.

The investment timing is scheduled to facilitate the delivery of asset management strategies. The investment timing identified in the Program Management Plan and the Asset Management Systems

Team Plan will ensure that the asset management information systems are developed in a timely fashion and do not constrain the implementation of asset management strategies. The timing also takes into consideration the organisation's ability to focus on, and commit resources to, the development of AMIS initiatives.

2.3 Strategic Alignment

Transend has identified the alignment of this project to the organisation's Strategic Plan, as shown in the following table:

Strategic Result Area	Strategic Performance Objective/outcome	Proposal Objectives
Asset management	Achieve excellence in asset management	Continued development and enhancement of the AMIS to further improve asset management
Organisational efficiency and effectiveness	Continuously improve key business processes	Gain additional productivity improvements through the enhancement of asset management processes

Transend's commitment to the further development of the AMIS as a strategic initiative is demonstrated by the following extract from Section 8.8 of Transend's Strategic Plan 2008:

> Transend is committed to the continual development of an asset management information system. This system is linking Transend's extensive asset database with various business processes throughout the entire asset life cycle. The new system is helping to:
>
> - Improve asset management;
> - Enhance productivity; and
> - Allow Transend to meet regulatory requirements.

3 ALTERNATIVES

3.1 Options

Transend has considered the following options:

Option	Brief Description
Option 1	Do nothing – This will result in Transend being unable to further improve its asset management practices beyond the "foundation" levels of the current AMIS. The concurrent implementation of asset management strategies and frameworks (such as the Strategic Asset Management framework) will be hindered because of the inability of the AMIS to support process improvements.
Option 2	Continue to develop asset management information systems capacity – This will result in the continued improvement of Transend's ability to meet many of its strategic performance objectives. It will also facilitate the implementation of asset management strategies and projects concerned with improvements in asset management practices.

Further options analysis will be undertaken for each initiative.

3.2 Consideration of Non Network Solutions

Not applicable for this non-network project.

3.3 Capex/Opex Trade-offs

It is noted that Transend proposes to increase the number of support people, with a resulting increase in Opex.

4 REGULATORY CONSIDERATIONS

4.1 Alignment with NER Capital Expenditure Objectives

The activities included in the AMIS project are required to achieve the following capital expenditure objectives identified in clause 6A.6.7(a) of the National Electricity Rules (Rules):

- Comply with all applicable regulatory obligations associated with the provision of prescribed transmission services;
- Maintain the quality, reliability and security of supply of prescribed transmission services; and
- Maintain the reliability, safety and security of the transmission system through the supply of prescribed transmission services.

4.2 Regulatory Test

Not applicable for this non-network project.

5 GOVERNANCE

5.1 Business Case Approvals

An individual business case will be developed for each AMIS initiative. The aim of this approach is to provide appropriate levels of financial and scope control by ensuring that:

- The cost benefit or each initiative can be assessed on its particular merits and equated directly to the AMIS sub-project scope and objectives;
- The initiative is aligned with current Transend asset management priorities and strategies;
- Funds are only made available at the required time;
- Business analysis occurs close to the time of system development;
- The deliverables from each piece of work are clearly identified; and
- Business benefits and efficiencies are clearly identified and delivered.

5.2 Assumptions

None identified at this point.

5.3 Project Risk

Transend's 2007 Business Risk Review identifies a number of risks that directly relate to this project. The implementation of this project will contribute to the mitigation of these risks, which are summarised in the following table. Project specific risks will be identified during the project initiation process for each initiative and included in each business case.

Description	Likelihood	Impact	Risk Rating
Business develops silo solutions for managing asset information without using AMIS	M	H	H
Core AMIS systems do not support business requirements	L	H	M
Business is too stretched to leverage AMIS business benefits	M	H	H
AMIS project team does not have sufficient capacity to complete the AMIS project in a timely manner	M	M	M
Asset register data integrity is poor, causing user community not to trust the system	M	H	H
Users do not follow business procedures	M	H	H
Lack of a non-compliance mechanism means Transend is not aware of breaches of ratified business procedures	M	M	M

5.4 Conformance with Policies & Procedures

WorleyParsons notes that the project is at a very early stage and concludes that the project has been developed in conformance with Transend's policies and procedures.

6 EFFICIENCY

6.1 Estimating Basis

The AMIS project will continue to deliver enhanced asset management initiatives in a manner similar to recent AMIS project activities. Using these recent project outputs as a basis, cost estimates for the project have been developed by experienced staff using the following labour rates and resource profile (based on 7.5 hours per day and 48 working weeks per year). These rates are reflective of current competitive market rates and have been benchmarked against labour rates obtained from service providers capable of providing such services.

Details are shown in the following tables:

Role	Hourly rate $
Project Manager	132.50
Senior Business Analyst (SBA)	145.00
Business Analyst (BA)	127.50
Developer	74.50
Senior Developer	100.00
Subject Matter Expert (SME)	60.00

	2009/10		2010/11		2011/12		2012/13		2013/14	
	No	$m	No	$m	No	$m	No	$m	No	$m
Project Manager	1.00	0.24	1.00	0.24	1.00	0.24	1.00	0.24	1.00	0.24
SBA	1.00	0.26	0.10	0.03	0.10	0.03	0.10	0.03	0.00	0.00
BA	2.00	0.46	1.00	0.23	0.85	0.20	0.60	0.14	0.60	0.14
Developer	3.75	0.50	2.00	0.27	1.00	0.13	1.00	0.13	1.00	0.13
Senior Developer	2.00	0.36	2.00	0.36	1.00	0.18	0.90	0.16	0.75	0.14
SME	2.60	0.28	1.60	0.17	1.60	0.17	1.40	0.15	1.40	0.15
Total		2.10		1.30		0.95		0.85		0.80

Note – all financial data is presented in June 2007 dollars.

6.2 Costs

Excluding cost escalators and risk factor, the estimated expenditure in the Next Regulatory Control Period (June 09, $m) is $6.0m

Including cost escalators and risk factor, Transend's proposed fall of expenditure is shown in the following table:

2009/10	2010/11	2011/12	2012/13	2013/14	TOTAL
2.496	1.558	1.147	1.042	0.996	7.238

6.3 Project Delivery

This project will see additional asset management initiatives delivered in a manner and magnitude consistent with the recent investments in AMIS activities. There is not expected to be any fundamental change to the manner in which the project is delivered.

The project will continue to be guided by a Program Management Plan. This document will be revised and updated (as necessary) throughout the life of the project. It is also expected that the current partnership arrangement with Synateq will continue. Transend's relationship with Synateq is long-standing and based on mutual business benefit. Synateq provides resources and competency for project management and system development. The nature of the relationship ensures there is continuity for knowledge retention and knowledge transfer throughout the lifetime of AMIS.

7 ASSESSMENT

WorleyParsons considers that Transend has demonstrated that there is a justifiable need for the project, to improve asset management and enhance productivity, as discussed in Section 2. A further driver for the project is to assist in meeting regulatory requirements.

Given the successful track record for the development and implementation of AMIS to date, and Transend's strong drive to improve asset management and enhance productivity, WorleyParsons supports the option of further developing AMIS rather than the "do nothing" option.

Transend's cost estimates are based on extensive experience with the project to date, with expected hours and hourly rates identified and assessed by experienced staff. WorleyParsons has no evidence to suggest that these estimates are unreasonable.

WorleyParsons considers that it is reasonable for Transend to continue to develop AMIS over the Next Regulatory Control Period, to support improving asset management and enhance productivity. Although there will be flexibility as to the timing of individual initiatives within this program, WorleyParsons supports the ongoing development of AMIS over the Next Regulatory Control Period.

WorleyParsons considers that the project aligns with Transend's strategic plans, governance arrangements and Capex policies and procedures, as discussed in Section 2.3 and Section 5. Transend's Strategic Plan 2008 clearly demonstrates Transend's strong commitment to the onmgong development of AMIS.

WorleyParsons identified a minor discrepancy in the information provided in relation to this project – some inconsistent costing information – but this has since been clarified (the matter was not material).

8 CONCLUSION

WorleyParsons considers that the proposed project cost and timing as proposed by Transend are reasonable and should be included in the ex-ante cap as proposed by Transend.

(Text removed) **CONTROL CENTRE BACKUP**

1 PROJECT DESCRIPTION

1.1 Project Identification

(Text removed)

1.2 CAPEX Category

Business Support (Non-Network)

1.3 Background

In addition to substation equipment, the (Text removed) Substation building is used (Text removed) to house their backup control centre and co-primary infrastructure, respectively. The building also serves as a backup facility under Transend's Business Continuity Management Plan.

(Text removed) Substation was reaffirmed by the (Text removed) in 1997 as the backup site for the Energy Control Centre, primarily because of its position in the communications network and the ease of implementing a backup centre there. Since then, the increased focus on business continuity, and the increased dependence on information technology for network operations and for core business systems, has resulted in an increased use of (Text removed) as the backup site for a range of functions. The support infrastructure and assets at (Text removed)Substation require significant development to accommodate the increasing demands for the site.

1.4 Project Description

Transend proposes to upgrade the current back-up facilities, either by developing the existing (Text removed) Substation site or by relocating to an alternative site.

Transend proposes to conduct an initial review to determine the most appropriate and cost effective way to address the developing business requirements prior to committing to the replacement of assets and further modifications to the site. The review process will include:

- Identifying current and future business requirements;
- Determining what is needed to upgrade the existing facility to meet business requirements;
- Investigating and analysing alternative options; and
- Recommending a preferred option.

The analysis of the existing (Text removed) Substation site will consider:

- Its close proximity to the primary site at (Text removed);
- Its classification by ASIO as a medium security risk site;
- The increased reliance on the backup site to accommodate facilities in addition to the backup control centre; and
- The lack of suitable accommodation and facilities for use in emergencies involving the wider electricity or state emergency response.

2 PROJECT NEED

The following issues with the existing facilities have been identified

Aspect	Key concerns

Communications Room	• Communications room is a key dependency but is exposed in that:
	  o Many companies have access to it;
	  o It has external access and access controlled only by keys;
	  o Equipment it contains is not segregated and accessible by anyone who accesses the room; and
	  o Satisfactory operation is dependent on air-conditioners which have little security

Computer Room	• The one room houses 3 functions:
	  o Corporate IT;
	  o Backup SPS; and
	  o Backup NOCS.
	• Limited space and access for normal maintenance functions and for personnel
	• External entrance door (security implications)
	• Air conditioners require external air for make up air

Back-up Control Room	• An internal audit carried out by Ernst Young to assess Transend's business continuity and IT disaster recovery capability identified a high risk inherent in the current siting of the back-up control centre. It recommended 'undertake a risk assessment to determine whether it is acceptable to have an alternative location that is not in close proximity to the (Text removed) (Primary site) and finalise the backup site business case ',(Audit report section 2.3.1, D08/42288) • Not set-up for long-term occupancy
Training / Emergency Response Room	• Adjacent to control room and inadequate in size and fit-out for use in a full scale emergency
Facilities for Staff	• Non-compliant with BCA and DDA requirements • Inadequate mess room • Not set up for continuous manning • Has no disaster plan in terms of water or sewerage
Inherent risk within a major substation	• Transmission substations are classified by the ASIO in the Electricity Risk Context statement, as a medium risk in the ranking of infrastructure • Vulnerable to any action that is aimed at causing major disruption to society
Risk of Bush Fire	• Bushland comes to the boundary of the substation
Site physical access	• Access through narrow single entry residential street • Further building on the site would require relocation of a critical, high copping water main
Location	• Within the greater Hobart residential area

2.1 Drivers

The main drivers for the project (in decreasing order of importance) are:

- Mitigation of business risk (business continuity); and
- Compliance with the requirements of NEMMCO and the State Emergency Plan.

2.2 Timing

The project is currently timed for the period July 2009 to March 2012. Transend proposes to commence the project early in the Next Regulatory Control Period, consistent with other priorities.

2.3 Strategic Alignment

Transend has identified the alignment of this project to the organisation's Strategic Plan, as shown in the following table:

Strategic Result Area	Strategic Performance Objective/outcome	Proposal Objectives
Safety and work environment	Provide a healthy and safe work environment	Provide adequate backup control room space and facilities
Organisational efficiency and effectiveness	Comprehensive business continuity planning practices	Provide appropriate backup control facilities Provide appropriate response team facilities Provide adequate site security
Market & regulatory framework	Fulfil transmission licence obligations and other ESI obligations	Fulfil Transend's transmission licence obligation to develop, maintain and implement an emergency management plan

This proposal is considered within the Internal Audit report "Business Continuity Management and IT Disaster Recovery" Ernst & Young 14 May 2008. In this report, Ernst & Young made the following observations and recommendations (amongst many others):

Observation	Recommendation
The current Disaster Recovery location – (Text removed), is less than (Text removed) kilometres away from the primary site which is not ideal.	Undertake a risk assessment to determine whether it is acceptable to have the alternative location that is in close proximity to the (Text removed) (Primary site) and finalise the backup site business case.
Several single points of failure in the current network topology have been identified. There are no Internet connections, Internet email connectivity or network routers including DMZ infrastructure available in the secondary site.	Undertake a design review of all the key Internet links and DMZ architecture in the (Text removed) Disaster Recovery site and implement Internet connection to the Disaster Recovery site.
Remote access connectivity is not available in the Disaster Recovery site for Transend users to access their business applications and data.	Review the current remote access infrastructure and implement remote access capabilities in the Disaster Recovery site. Confirm where the staff will be accommodated and how the IT facilities will be provided to them.
The current telecommunications capabilities in the (Text removed) site may not be sufficient to accommodate all business and IT communication requirements for Transend's business.	Undertake design review of voice and data links and provide more telecommunication capabilities in the Disaster Recovery site.

3 ALTERNATIVES

3.1 Options

Transend is currently considering the following options:

Option	Brief Description	Considerations
Option 1	Redevelop (Text removed) Substation to accommodate the increased demands	• Limited available additional space; functional planning constrained by extension of existing building • Extensive disruption of present backup facilities during infrastructure upgrades • Close proximity to (Text removed) site
Option 2	Construct a new facility to host backup functions at (Text removed) Substation	• Limited available space for new building • Likely opposition from (Text removed) City Council to grant planning approval • Close proximity to (Text removed) site
Option 3	Investigate an alternative site for a new backup control and business continuity rooms only – retain equipment at (Text removed) Substation	• Personnel to be located remote from data/communications equipment • Reliable communications links required • Option to share with another organisation
Option 4	Investigate an alternative site for a backup control centre, including co-primary corporate IT, business continuity functions	• Option to co-locate with another Transend facility (eg. new primary store) • Diversified high capacity data/communication paths required from (Text removed) site
Option 5	Investigate sharing a backup site with a similar organistion	• (Text removed) share (Text removed) site with Transend for energy control system backup • Potential for coincident need for backup facilities in major regional or statewide emergency • Diversified high capacity data/communication paths required from (Text removed) site

3.2 Consideration of Non Network Solutions

Not applicable to this project.

3.3 Capex/Opex Trade-offs

Not applicable to this project.

4 REGULATORY CONSIDERATIONS

4.1 Alignment with NER Capital Expenditure Objectives

The project expenditure is required in order to meet the following capital expenditure objective identified in clause 6A.6.7(a) of the NER:

- Comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services.

4.2 Regulatory Test

The Regulatory Test is not applicable to this project, as it is not augmenting the network.

5 GOVERNANCE

5.1 Business Case Approvals

A business case is currently being prepared, seeking approval to investigate the options, at a proposed cost of $40,000. Approval of the business case will allow the following to be addressed:

- Quantify the expected functional and infrastructure requirements for a current industry standard backup control centre, corporate IT and business continuity facility;
- Proceed with a detailed evaluation of the options for redevelopment of the existing (Text removed) facilities or relocation to a new facility;
- Quantify redevelopment or relocation costs; and
- Consider and recommend a preferred option.

Once the options have been investigated, a further business case will be prepared and submitted to the Board for approval.

5.2 Assumptions

Not applicable at this early stage of the project.

5.3 Project Risk

A wide range of risks for the project were assessed by Transend, with the key risks identified as follows:

- Bushfire – this risk is considered as significant. Bush fires in the (Text removed) have created heat and smoke problems at both (Text removed) and (Text removed) sites. Modifications could be made to seal off areas that would otherwise be contaminated as external air intakes contaminate with smoke;
- Security risk – under the Federal ASIO ranking of major infrastructure risks, (Text removed), as a major transmission substation, has been assessed as a medium security risk. This ranking rates it alongside the only other medium risk site in Hobart, the oil storage facility at (Text removed); and
- Planning requirements – Further development at the (Text removed) site is contrary to (Text removed) City Council Planning Scheme requirements. It is likely that the Council will oppose an application for approval of an industrial infrastructure development in the residential area at (Text removed).

5.4 Conformance with Policies & Procedures

WorleyParsons notes that the project is at a very early stage and concludes that the project has been developed in conformance with Transend's policies and procedures.

6 EFFICIENCY

6.1 Estimating Basis

The estimates for this project comprise initial high-level estimates based on preliminary estimates obtained from (Text removed) . The preliminary estimates from (Text removed) were based on:

- Recent project experience involving data centres, other ITC based facilities and supporting infrastructure;
- Prior knowledge of (Text removed) Substation IT, communications, electrical and mechanical services; and
- Current industry standard costing rates.

6.2 Costs

Excluding cost escalators and risk factor, the estimated expenditure in the Next Regulatory Control Period (June 09, $m) is $5.070m.

Including cost escalators and risk factor, Transend's proposed fall of expenditure is shown in the following table:

2009/10	2010/11	2011/12	2012/13	2013/14	TOTAL
0.369	2.872	3.098			6.340

6.3 Project Delivery

Not considered at this stage.

7 ASSESSMENT

WorleyParsons considers that Transend has demonstrated that there is a justifiable need for the project, to mitigate business risk associated with loss of key systems, as discussed in Section 2. WorleyParsons considers that effective back-up facilities for network operations and corporate IT functions are essential for an electricity transmission business.

As discussed in Section 3, Transend is currently considering a range of options. The proposed initial review will determine the most appropriate option to address the issues with the current arrangements.

Transend's cost estimates are founded on preliminary estimates provided by a firm of Engineers and Planners, based on recent experience, prior knowledge of the site and current standard costing rates. WorleyParsons has no evidence to suggest that the forecast costs are not reasonable for the work proposed.

The project has been timed to commence early in the Next Regulatory Control Period, consistent with other priorities. Although there may be some flexibility with regard to timing, WorleyParsons is satisfied that the need is such that the project should be completed during the Next Regulatory Control Period.

WorleyParsons considers that the project aligns with Transend's strategic plans, governance arrangements and Capex policies and procedures, as discussed in Section 2.3 and Section 5. The proposal was considered within a recent Internal Audit report, and the proposed project will address the relevant recommendations.

WorleyParsons has not identified any inaccuracies in the information provided in relation to this project.

8 CONCLUSION

WorleyParsons considers that the proposed project cost and timing as proposed by Transend are reasonable and should be included in the ex-ante cap as proposed by Transend.

SUBSTATION ASSET CONDITION MONITORING ENHANCEMENT PROGRAM

1 PROJECT DESCRIPTION

1.1 Project Identification

ND1002

1.2 CAPEX Category

Physical security/compliance

1.3 Background

Transend has undertaken a review of its asset management strategies for substation assets. The review has identified a number of condition monitoring initiatives that will enhance the reliability and availability of substation assets, thereby improving transmission system performance. The initiatives include a number of innovative condition monitoring and assessment techniques that will enable Transend to realise a number of key benefits, including:

- Early detection and possible prevention of asset failure resulting in reduced costs associated with a major or catastrophic failure;
- Enhanced fault response capability, including reduced response time and improved decision making;
- Improved monitoring of the safety of personnel working in remote locations;
- Improved maintenance practices, resulting in reduced maintenance effort and cost, fewer scheduled outages and outages of shorter duration;
- Greater effectiveness of real-time decision making, including potential dynamic loading of transformers and asset utilisation reviews; and
- Provision of long-term data, improved knowledge and understanding about equipment performance, including a more detailed history of asset condition when compared with traditional condition assessment and diagnostics.

1.4 Project Description

The substation asset condition monitoring enhancement program involves the following initiatives:

- Power transformer condition monitoring programs;
- Instrument transformer condition monitoring programs;
- Circuit breaker remote condition monitoring;
- Substation asset visual monitoring equipment; and
- Purchase of test equipment.

1.4.1 Power Transformers

The power transformer condition monitoring programs are in line with Transend's asset management plans for power transformers. The programs consist of the installation of:

- On-line temperature monitoring systems;
- On-line insulating oil analysis systems;

- Tap changer oil sampling facilities; and
- On-line transformer moisture removal systems.

1.4.1.1 On-Line Temperature Monitoring Systems

Excess heat within a power transformer can degrade the transformer's paper insulation and subsequently reduce the service life of the unit. The reduction in a transformer's service life can be calculated and modelled using measured values of winding and oil temperatures. While the majority of new transformers are installed with the capability of remote monitoring of winding and oil temperature, there are a number of critical, highly-loaded units installed in the transmission system that would benefit from remote monitoring of winding and oil temperature indicators to ensure optimal loading levels are achieved. Twenty-one units at ten substations have been selected for the installation of electronic on-line winding temperature indicators (WTIs) and oil temperature indicators (OTIs). All of these transformers are heavily loaded and most of them are past the midway point in their respective lives.

The system has been successfully trialled at Chapel Street Substation, and based on this experience, the average estimated cost is $30,000 per unit. Transend proposes 21 installations at a total cost of $630,000 (June 07, $). The timing of the installation program will be co-ordinated with scheduled maintenance activities or other planned capital works where practicable, commencing in 2009/10.

Expected benefits from the program include the following:

- Improved end-of-life decision making by monitoring and profiling thermal performance of transformer loading;
- Enable Transend to accurately model and determine the thermal degradation of the identified units and ensure optimal loading levels are achieved;
- Facilitate planned transformer outages by applying dynamic ratings for non-firm transformers; and
- Reduced number of inadvertent trips associated with mechanical OTI and WTI indicators (five recorded incidents since 1996).

1.4.1.2 On-Line Insulating Oil Analysis Systems

Analysis of the condition of a transformer's insulating oil enables accurate assessment of the electrical condition of the unit. On-line oil analysis systems (eg on-line dissolved gas analysis units) enable continuous monitoring of oil condition, thereby giving the earliest possible indication of potential fault activity within a transformer. The "Supply Transformer Asset Management Plan" has identified seven supply transformers that would benefit from the installation of on-line insulating oil analysis systems. The units have been identified as being unique to the transmission system (that is, having no available spare) and/or highly loaded, and are not due for replacement within the mid to long-term.

The estimated cost for the equipment procurement and installation is $60,000 per unit, giving a total cost for the program of $420,000 (June 07, $). The timing of the installation program will be co-ordinated with scheduled maintenance activities or other planned capital works where practicable, commencing in 2010/11.

The implementation of the on-line insulating oil analysis systems installation program will enable the continuous monitoring of the condition of unique and/or highly loaded transformers installed in the transmission system. It will also enable early detection and possible prevention of asset failure resulting in reduced costs associated with a major or catastrophic failure.

1.4.1.3 Tap Changer Oil Sampling Facilities

On-load tap changers (OLTCs) account for 25 per cent of all transformer failures according to a CIGRE survey. The dissolved gas analysis (DGA) method can be applied to OLTCs to determine condition and detect incipient internal faults, such as overheating of transition resistors or diverter contacts. While a significant number of Transend's population of OLTCs have oil sampling facilities fitted, 52 units have been identified as requiring a retrofit of appropriate sampling valves. This initiative will enable Transend to review its current time-based tap changer maintenance strategy with the view to adopting a condition-based maintenance regime.

The estimated cost of installing sampling valves on the identified OLTCs is $104,000 based on an average cost of $2,000 per unit. The proposed implementation methodology includes the fitting of valves in conjunction with planned maintenance over a six-year period commencing in 2009/10.

The implementation of the program to install tap changer oil sampling facilities will enhance the condition assessment process and enable detection of incipient internal faults. In addition, it will enable Transend to consider the implementation of a condition-based tap changer maintenance strategy.

1.4.1.4 On-Line Transformer Moisture Removal Systems

Moisture within a transformer is a natural by-product of the ageing of paper insulation. In addition, moisture within a transformer can be a result of leaking gaskets or poor oil-handling techniques. Moisture within a power transformer accelerates the ageing of a unit and results in a number of destructive effects, including partial discharge, flashover failure on the insulation surfaces or to earth, expansion of cellulose insulation, loss of insulation integrity and reduced mechanical pressure of a transformer's clamping system.

This proposal includes the purchase of two on-line moisture removal systems that provide on-line dehydration, degassing and filtration of transformer insulating oil. The estimated cost is $150,000 per system (June 07, $) and procurement of the units is planned for 2010/11 and 2011/12. The two systems will be deployed on a rotational basis and connected to transformers identified during the condition assessment process as being suitable for moisture removal to sustain asset performance and reliability. In particular, the on-line moisture removal systems will be used on targeted transformers that would traditionally be candidates for mid-life refurbishment or life extension. The use of on-line systems will reduce the need to undertake mid-life refurbishments, which are costly and require extended outage duration to undertake the works.

This program will provide the following benefits:

- Reduce the need to undertake mid-life refurbishments, which are costly and require extended outage duration to undertake the works;
- The transformer remains in-service during the treatment process;
- Restores the dielectric strength of the insulating oil; and

- Remote monitoring and control functionality for dehydration efficiency (measured by volumetric of the separated water), which ensures that the transformer's insulation system is not over-dried.

The estimated costs to purchase two trailer-mounted on-line moisture removal systems is $150,000 (June 07, $). Procurement of the units is planned for 2010/11 and 2011/12. The two systems will be deployed on a rotational basis and connected to units identified during the condition assessment process as being suitable for moisture removal to sustain asset performance and reliability. In particular, the on-line moisture removal systems will be used on targeted units that would traditionally be candidates for mid-life refurbishment or life extension.

1.4.2 Instrument Transformer Condition Monitoring Programs

The instrument transformer monitoring program accords with Transend's asset management plans for EHV current and voltage transformers. Strategies to address identified performance, condition and design issues are:

- Insulating oil sampling facilities; and
- On-line monitoring of capacitive voltage transformers.

1.4.2.1 Insulating Oil Sampling Facilities

For oil-filled instrument transformers, analysis of the insulating oil can be used to determine the condition of the units. In particular, the DGA method can be used to identify evolving faults within an instrument transformer. As the oil-paper insulating systems deteriorate, gases are produced. Analysis of the types and quantities of the gases dissolved in the insulating oil can be used to determine the type and severity of the fault causing the production of gas. The DGA method is typically not applied to Capacitive Voltage Transformers (CVTs) due to the relatively low oil volume of CVT units and the separation of the capacitor divider and intermediate voltage transformer sections.

In addition to the DGA method, measuring the water content within the insulating oil of an instrument transformer can be used as an indicator of electrical condition. The amount of water present in the insulating oil can indicate the ingress of moisture from the atmosphere or deterioration of the paper insulation within a unit. High water content also accelerates the chemical deterioration of the paper insulation.

Historically, condition monitoring practices included performing electrical testing of instrument transformers on a six yearly basis. As the electrical testing process is sensitive to the prevailing ambient conditions at the time of test, other assessment methods (such as the insulating oil analysis method) are preferred to determine instrument transformer electrical condition. Insulating oil analysis is less expensive than electrical testing and requires a reduced outage duration to undertake the condition assessment process. The average cost of electrical testing for a three-phase set of instrument transformers is $5,500. In comparison, the average cost of undertaking insulating oil sampling and analysis per three-phase set is $1,250. In addition, the outage duration required to complete electrical testing of a set of instrument transformers is approximately six hours. In comparison, it takes less than one hour to undertake the insulating oil sampling process for an equivalent set of units.

The substation asset condition monitoring enhancement program includes the installation of oil sampling facilities for the following instrument transformers:

- Inductive voltage transformers – 199 units; and
- Current transformers – 280 units.

The estimated cost to complete the installation of insulating oil sampling facilities on the identified instrument transformers is $290,000 based on an average cost of $1,800 per three-phase set (June 07, $). The proposed implementation methodology includes the fitting of oil sampling valves in conjunction with planned maintenance over a six year period.

The major benefit of adopting the insulating oil analysis approach for instrument transformer condition monitoring is the significant reduction in life-cycle operating costs. The reduced operating costs have been factored into Transend's forecast Opex.

1.4.2.2 On-Line Monitoring of Capacitive Voltage Transformers

For CVTs, on-line monitoring and comparison of secondary voltages of each phase can be used to determine the likelihood of failure of the capacitive element. Deterioration of capacitor elements causes the secondary voltage to progressively decrease as they approach failure. By continually monitoring the difference in secondary voltages between each phase in a three-phase set, a likely failure can be detected. If the secondary voltage of a CVT deviates by more than five per cent from the other two phases for an extended period, it is likely that the capacitive element is deteriorated or damaged.

The continuous monitoring of CVT secondary voltages can be performed by using modern protection relays, which can be configured to generate a voltage imbalance alarm both locally via the substation supervisory control and data acquisition (SCADA) system and remotely via the Network Operations Control System (NOCS). In addition, transducers can be retrofitted to CVT installations without modern relays to initiate a voltage imbalance alarm.

The application of on-line monitoring for the population of CVTs will result in the discontinuation of electrical testing for CVTs, which will contribute to a reduction in operating expenditure for instrument transformers. The reduced operating costs have been factored into Transend's forecast Opex. The estimated cost of implementing the on-line monitoring program for the CVT population is $240,000 (June 07, $), made up as follows:

- Detailed analysis and system design (including trial) $40,000;
- SCADA modification $60,000;
- Installation and testing of transducers (at sites without SCADA) $90,000; and
- Programming of RTUs and testing of alarms to NOCS $50,000.

The timeframe for the implementation of the program is 2009/10 and 2010/11 in order to maximise the cost-benefits associated with the discontinuation of electrical testing for CVTs.

1.4.3 Circuit Breaker Remote Condition Monitoring

The circuit breaker remote condition monitoring program is in line with Transend's Circuit Breaker Asset Management Plan. This initiative involves the establishment of systems and procedures for remotely interrogating protection relays to obtain data on circuit breaker operations, operating times and fault currents, to enhance the assessment of circuit breaker condition. The initiative also includes the integration of the system within the AMIS.

The expected program benefits include:

- Reduction in life-cycle operating costs. The use of circuit breaker data (eg opening and closing times) obtained from protection and control relays will result in a reduction in the number of comprehensive off-line timing tests undertaken for the circuit breaker population;
- Improved knowledge and understanding of circuit breaker performance, including a more detailed history of asset condition when compared with traditional circuit breaker condition assessment and diagnostics; and
- The implementation of this program will improve transmission system performance by reducing the number and duration of planned outages that are required to undertake circuit breaker timing tests.

The program is estimated to cost $130,000 (June 07, $), made up as follows:

- Detailed analysis and system design (including trial) $30,000;
- AMIS integration $20,000;
- Site configuration and testing of relays $50,000; and
- Program management $30,000.

The timing of the implementation of this program is 2009-10 and 2010-11, which has been selected in order to maximise the cost-benefits associated with the reduction in the number of circuit breaker timing tests undertaken.

1.4.4 Substation Asset Visual Monitoring

The substation asset visual monitoring equipment initiative involves the installation of visual monitoring facilities at substations, with an average of ten cameras being installed per year over four years.

The benefits of visual monitoring systems include:

- Unauthorised entry alarms can be immediately verified at critical or remote sites;
- The safety of personnel working at remote locations can be monitored;
- Enhanced emergency response effectiveness as the presence and severity of faults can be verified, potentially reducing outage duration;
- Emergency response personnel can be immediately deployed as necessary; and
- The condition and status of substation assets can be monitored remotely.

The installation of additional visual monitoring facilities has been included in the substation asset condition monitoring enhancement program to provide enhanced security, operational and asset monitoring functionality. The program includes the installation of an average of ten cameras per year from 2010/11 to 2013/14 at an estimated total cost of $200,000 per annum (June 07, $), based on tender information.

In addition to the benefits listed above, the installation of visual monitoring systems at substations will enable Transend to review its current frequency of inspections at less critical substations. Substation inspections are currently undertaken on a monthly basis with the primary driver for inspection frequency being ensuring the integrity of the security fence. The installation of visual monitoring systems at selected substations will enable Transend to monitor the integrity of the security fence and potentially reduce the frequency of inspections at less critical substations. The expected average annual reduction in operating expenditure associated with a reduced inspection frequency is approximately $2,000 per site following the installation of visual monitoring systems (based on a reduced inspection frequency of three months for less critical sites).

1.4.5 Condition Monitoring Test Equipment

The condition monitoring test equipment initiative involves procurement of the following test equipment:

- SF6 gas analyser and leakage detector;
- Partial discharge detection equipment;
- Portable dissolved gas analysis unit; and
- High voltage test unit.

1.4.5.1 SF6 Gas Analyser and Leakage Detector

Transend's has a number of assets that use sulphur hexafluoride (SF6) gas as an insulating medium. For SF6 gas-insulated equipment, gas sampling and analysis is used to determine the condition of the assets. In particular, measurement of the water present within the gas can provide evidence of moisture ingress or internal deterioration of the insulation. The presence of water within SF6 gas impedes the natural recombination process of decomposition products back to SF6. Instead, decomposition products combine with water to form hydrogen fluoride, which is a highly corrosive electrolyte. The water content within SF6 gas can be obtained via a dew-point measurement. Dew-point limits for in-service circuit breakers and instrument transformers are typically specified by the manufacturer.

SF6 analysis can also be used as a diagnostic tool in the event of an equipment failure. Internal problems within SF6 gas-insulated equipment such as sparking, arcing or overheating in the presence of other contaminants generate specific by-products, which can be identified through SF6 gas analysis.

The assessment of SF6 gas is important in the prevention of failures in SF6 gas-insulated circuit breakers. SF6 gas is widely used as an insulating material for EHV equipment due to its arc quenching and self-regenerative properties. Under ideal conditions, when a SF6 gas circuit breaker operates, a discharge occurs, causing each fluorine atom to disassociate from the sulphur by capturing an electron. Once the discharge is complete, the fluorine atoms release the extra electrons, and rejoin with the sulphur atoms, reforming SF6. However under less than ideal circumstances, contamination can occur (eg. oxygen and moisture from the atmosphere) and this regeneration process is impaired, causing the SF6 gas to deteriorate. Periodic analysis of the SF6 gas can detect the presence of such contaminants prior to a failure, enabling the circuit breaker to be refurbished rather than replaced, and potentially extending its operational life.

The “Circuit Breaker Asset Management Plan” recommends dew-point testing of SF6 gas as part of the condition monitoring and preventive maintenance plan. This initiative includes the procurement of a SF6 gas analyser at an estimated cost of $50,000 to be utilised for planned and unplanned circuit breaker condition monitoring activities. The substation asset condition monitoring enhancement program also includes the purchase of a SF6 gas leakage detector at an estimated cost of $90,000. While the gas pressure in Transend’s SF6 gas-filled equipment is continuously monitored and alarmed, Transend currently does not have the necessary equipment that can confirm and locate the source of any SF6 gas leaks. The current practice is to contract a Victorian service provider to survey assets with a specialised SF6 gas leakage camera, which means that timely testing and confirmation of a gas leak is not possible. In addition, the current arrangement is not cost effective as it requires the mobilisation of equipment and personnel from Victoria. This initiative includes the purchase of a gas imaging and analysis video camera, which will provide a timely and cost-effective approach to the detection and location of SF6 gas leaks.

The proposed timeframe for the purchase of SF6 gas test equipment is 2009/10 and 2010/11.

1.4.5.2 Partial Discharge Detection Equipment

Partial discharges within high voltage (HV) metal-clad switchgear can result in catastrophic failure of individual switchgear bays or, in some cases, the entire switchboard. Transend has a population 495 HV switchgear bays associated with indoor metal-clad switchboards installed within the transmission system. This switchgear is critical in ensuring the reliability and availability of electricity supply to the distribution network and major industrial customers. The consequence of a failure of a metal-clad switchboard is major and would result in considerable customer disturbance.

Partial discharge within high voltage equipment generally occurs within voids, cracks, at conductor-dielectric interfaces within a solid insulation system, or in bubbles within liquid dielectrics. Partial discharge can also occur along the boundary between different insulating materials. Once it commences, partial discharge causes progressive deterioration of insulating materials, ultimately leading to electrical breakdown. The integrity of the insulation of high voltage equipment can be confirmed using partial discharge detection equipment during the manufacturing stage as well as periodically through the equipment’s service life. Partial discharge prevention and detection are essential to ensuring reliable, long-term operation of high voltage equipment.

Transend’s “High Voltage Switchgear Asset Management Plan” recommends the commencement of partial discharge monitoring program for the population of high voltage switchgear. In addition, the “Power Cables Asset Management Plan” recommends the investigation of applying the partial discharge monitoring method to monitor the condition of power cables.

This initiative includes the purchase of two partial discharge detection devices in 2010-11 and 2011-12 at an estimated cost of $120, 000 (June 07, $).

1.4.5.3 Portable Dissolved Gas Analysis Unit

Transend’s primary method of condition assessment and fault diagnosis for power transformers is based on analysis of insulating oil test results. In particular, DGA of transformer insulating oil is essential in determining the presence and nature of an internal transformer fault condition. As a fault develops, key gases are generated within the transformer’s insulating oil, providing an accurate indication of the possible fault condition through DGA.

In the event of a protection operation that trips a transformer out of service, Transend's current fault response process involves sampling the transformer's insulating oil and gas obtained from the Buchholz relay and transporting the samples to a mainland laboratory for testing. Depending on the nature of the protection operation, the transformer will remain out of service until the results of laboratory tests are obtained and an appropriate informed decision can be made regarding the likely cause of the protection operation. The period between sampling and analysis can range from 24 to 72 hours, which significantly delays the decision to return a transformer to service or otherwise.

Transend purchased a portable DGA unit in 2005 to enhance its emergency response capability by enabling timely on-site testing and analysis of insulating oil and Buchholz gas immediately after an event. The unit has been utilised extensively in performing post-fault analysis of transformer fault incidents, which has resulted in reduced response times and an improved decision making process. In addition, the unit has been used for regular analysis of the insulating oil of transformers with suspected fault conditions and/or units that are approaching the end of their service lives. The procurement of an additional portable DGA unit will further enhance Transend's emergency response processes by ensuring that a test unit is available to provide a timely, state-wide response capability to a transformer fault.

1.4.5.3 High Voltage Test Equipment

Transend currently outsources planned and unplanned high voltage testing of the circuit breakers to Hydro Tasmania Consulting (HTC), but Transend has experienced difficulties in obtaining the resources when required for unplanned testing. This proposal includes the purchase of high voltage test equipment to enable "in-house" testing of circuit breakers and other primary equipment in the event HTC is unavailable to undertake the testing or it no longer offers this service. As an outcome of Transend's recent resourcing review project, a number of protection and control functions will be in-sourced which will result in suitably qualified personnel available in-house to potentially undertake the high voltage testing function.

The benefits of procuring high voltage test equipment include:

- Maximises availability of test equipment for fault response activities; and
- Provides a cost-effective approach to testing system spare assets to confirm suitability for service.

The estimated cost of purchasing high voltage testing equipment is $200 000 (June 07, $). The proposed timeframe for the purchase of appropriate high voltage testing equipment is 2012-2013.

2 PROJECT NEED

2.1 Drivers

The main drivers for the project (in decreasing order of importance) are:

- Improve asset management;
- Enhance productivity; and
- Health and safety of employees.

2.2 Timing

This program will consist of a number of separate initiatives, implemented over the full five years of the Next Regulatory Control Period.

The timing of the initiatives has been determined based on the following factors:

- System risk, including the potential impact of an asset failure on the security and availability of electricity supply;
- Potential operating expenditure savings associated with the implementation of the initiatives; and
- Co-ordination of the initiatives with other planned maintenance or capital works to optimise the implementation process.

2.3 Strategic Alignment

Transend has identified the alignment of this project to the organisation's Strategic Plan, as shown in the following table:

Strategic Result Area	Strategic Performance Objective/outcome	Proposal Objectives
Transmission system performance	Maintain transmission system performance	Provide improved reliability of electricity supply through early detection and possible prevention of asset failure resulting in reduced impact and costs associated with asset failure. Provide improved availability of electricity supply by adopting innovative asset condition monitoring techniques that minimise planned and unplanned maintenance duration.
Transmission system performance	Maintain transmission connection site performance	Provide improved reliability and availability of electricity supply to customers though the application of proven condition monitoring techniques.
Safety & work environment	Provide a healthy and safe work environment	Improved monitoring of the safety of personnel working in remote locations.
Shareholders' value	Provide appropriate and sustainable returns to shareholders	Undertake prudent asset investments to ensure appropriate returns

3 ALTERNATIVES

3.1 Options

The various initiatives included in the program have been developed following a comprehensive review of Transend's asset management strategies and condition monitoring techniques. As part of the review process, various condition monitoring techniques were identified, evaluated and, in some cases, trialled to ensure the most cost-effective solution has been selected. In addition, the initiatives included in the program will be subject to a final options analysis process, which will be undertaken as part of the preparation and approval of each individual business case.

3.2 Consideration of Non Network Solutions

Not applicable for this program.

3.3 Capex/Opex Trade-offs

The expected savings in Opex due to these initiatives have been quantified and included in Transend's Opex forecasts.

4 REGULATORY CONSIDERATIONS

4.1 Alignment with NER Capital Expenditure Objectives

Transend considers that the project expenditure is required in order to meet the following capital expenditure objectives identified in clause 6A.6.7(a) of the NER:

- Maintain the quality, reliability and security of supply of prescribed transmission services; and
- Maintain the reliability, safety and security of the transmission system through the supply of prescribed transmission services.

4.2 Regulatory Test

This program comprises a number of smaller projects, none of which would be subject to the regulatory test.

5 GOVERNANCE

5.1 Business Case Approvals

Funding for the initiatives included in this program will be the subject to the approval of a business case for each of the initiatives.

5.2 Project Risk

Transend's 2007 Business Risk Review identifies a number of risks that directly relate to this project. The implementation of this project will contribute to the mitigation of these risks, which are summarised in the following table. Project specific risks will be identified during the project initiation process and included in the business case.

Risk	Description	Revised consequence	Revised likelihood	Revised risk rating
Asset management	Risk that Transend is responsible for inappropriate asset management that results in equipment failure, a major bushfire or damage to third party property impacting on operations of the power system and / or resulting in property damage or loss of life	Moderate	Moderate	High
Safety	Transend is responsible for or contributes to an incident or condition that place the safety of employees, contractors or the public at risk	Major	Unlikely	High

5.3 Conformance with Policies & Procedures

This project is at a very early stage. An initial Project Definition form has been completed, together with a Capital Project Investment Report and a Substation Asset Management Condition Monitoring report.

WorleyParsons concludes that the project has been developed in conformance with Transend's policies and procedures, particularly the Investment Process Governance Framework and the Project Initiation and Development Procedure.

6 EFFICIENCY

6.1 Estimating Basis

The estimates are based on Transend's experience and recent procurement costs of similar equipment by Transend and others.

6.2 Costs

Excluding cost escalators and risk factor, the estimated expenditure in the Next Regulatory Control Period (June 09, $m) is $3.594m.

Including cost escalators and risk factor, Transend's proposed fall of expenditure is shown in the following table (when the dollar amounts are in June 09 $m):

2009/10	2010/11	2011/12	2012/13	2013/14	TOTAL
0.746	1.380	1.207	0.843	0.365	4.541

6.3 Project Delivery

The implementation of the various initiatives included in the substation asset condition monitoring enhancement program will be reviewed prior to submission of each individual business case.

7 ASSESSMENT

This program consists of a twelve initiatives, each with their own investment drivers, as discussed in Section 1. WorleyParsons considers that Transend has demonstrated that there is a justifiable need for each initiative within the program, to improve asset management and enhance productivity.

Transend's cost estimates are based on Transend's experience and recent procurement costs of similar equipment by Transend and others. WorleyParsons has no evidence to suggest that these estimates are unreasonable.

Although there will be flexibility as to the timing of individual initiatives within this program, WorleyParsons supports the proposed implementation over the Next Regulatory Control Period in order to realize the benefits of improved asset management and enhanced productivity.

WorleyParsons considers that the project aligns with Transend's strategic plans, governance arrangements and Capex policies and procedures, as discussed in Section 2.3 and Section 5.

WorleyParsons has not identified any inaccuracies in the information provided in relation to this project.

8 CONCLUSION

WorleyParsons considers that the proposed project cost and timing as proposed by Transend are reasonable and should be included in the ex-ante cap as proposed by Transend.

CORPORATE IT PACKAGE SYSTEMS

1 PROJECT DESCRIPTION

1.1 Project Identification

ND1011

1.2 CAPEX Category

Information Technology

1.3 Background

Transend maintains ongoing investment in appropriate information technology (IT) packaged systems necessary to support business needs. Transend has a preference for “off the shelf” packaged systems to support business software needs.

Transend has in place a number of corporate IT package systems, consisting of third party products together with some internally developed software applications that provide interfaces to those products. These systems address requirements surrounding the management of Transend’s financial, human resources and compliance information and obligations.

1.4 Project Description

This program involves the upgrading of existing IT package systems or the procurement of new systems over the Next Regulatory Control Period as appropriate. Key IT package systems included in this category include financial, human resources and compliance systems.

The main component of this program relates to the implementation of an Enterprise Resource Planning (ERP) package, at a cost of $2.8m. This solution would provide Transend with broad end-to-end functionality to fill current automation gaps for business analytics, financials, human capital management, operations, stock control, and corporate services. The alternative would be to refresh a range of existing systems that are reaching the end of their useful lives.

It is intended that consideration of an ERP will address current issues with resource and project management capabilities and provide an integrated solution to replace current Financial (SunSystems), Asset Management (AMIS) and Human Resource (Aurion & QuickCourse) requirements at a minimum. This solution would potentially also address requirements from Leaders 80/20, NEM Systems, Projects and Contract Management Systems.

The ERP is intended to provide one integrated system to deliver benefits across the organisation through streamlined processes aligned to business requirements. This aligns with the scheduled four year application lifecycle review for SunSystems.

The other key components of the corporate IT package systems program relates to:

- System refresh of the Human Resource system and/or evaluation of the ERP system for HR applications at a cost of $211k – this aligns with the scheduled four-year application lifecycle review for Quickcourse;
- System refresh and/or evaluation of the ERP system to replace SunSystems and Sun EP/Onvision – this aligns with the scheduled four-year review of SunSystems; and
- System refresh and/or evaluation of the ERP system to replace Leaders 80/20.

The remainder of the corporate IT package systems program consists of a number of minor enhancements and integration reviews.

The unescalated expenditure proposed for the various systems is shown in the following table (June 2008, $k):

	09/10	10/11	11/12	12/13	13/14	TOTAL
HR						
Aurion	9	211				220
QuickCourse	3	18				21
Integration Projects	1	1	1	1	1	5
Total	**13**	**230**	**1**	**1**	**1**	**246**
FINANCIAL SYSTEMS						
SunSystems Financials	3	403				406
Sun EO/OnVision	50	50				100
Enterprise Resource Planning		2744	27	32	33	2836
FleetMaster						
Integration Projects	1	1	1	1	1	5
Total	**54**	**3198**	**28**	**33**	**34**	**3347**
COMPLIANCE SYSTEMS						
Leaders	5	305	5	6	6	327
Total	**5**	**305**	**5**	**6**	**6**	**327**
TOTAL	**72**	**3733**	**34**	**40**	**41**	**3920**

2 PROJECT NEED

Investment in IT package systems is driven primarily by the need to deliver services that maintain reliability, efficiency, capacity and supportability in the areas of financial, human resource, and compliance management. This project aims to ensure that Transend's IT package systems can continue to sustain or enhance where necessary, business, statutory and regulatory requirements.

2.1 Drivers

The project drivers for each of the three areas are shown in the following tables:

Human Resource System

No.	Category	Description	Priority
1.	Efficiency / Effectiveness	Increasing levels of business process automation to increase efficiency and reduce labour requirements.	High
2.	Efficiency / Effectiveness	Increasing business process maturity levels to reduce risk and improve effectiveness.	High
3.	Efficiency / Effectiveness	Maintaining system operation to provide the required business services.	High
4.	Effectiveness	Micropay doesn't track all leave types. Specifically, flex and time in lieu are not tracked by the application. This issue will be resolved by the implementation of the Aurion application.	Medium
5.	Efficiency	The current systems do not provide for employee self-service activities. The result is a lot of manual labour by the HR staff. This issue will be resolved by the implementation of the Aurion application.	Medium
6.	Engagement	The current processes provide line managers with infrequent reports on employee activity with little relevance. Line managers have little involvement in the HR processes.	Medium
7.	Awareness	The current system only provides for limited reporting to management	Medium
8.	Effectiveness	The current system does not track job costing. As such, job costing is manually tracked and recorded in separate journals in the financial accounting system.	Medium
9.	Efficiency	The current system is very labour intensive with many manual processes	Medium
10.	Engagement	The current system does not provide any mechanism for an approval process	Medium
11.	Effectiveness	The current system does not track or enforce the HR related business rules	Medium

Financial Systems

No.	Category	Description	Priority
1.	Efficiency / Effectiveness	Increasing levels of business process automation to increase efficiency and reduce labour requirements.	High
2.	Efficiency / Effectiveness	Increasing business process maturity levels to reduce risk and improve effectiveness.	High
3.	Efficiency / Effectiveness	Maintaining system operation to provide the required business services.	High
4.	Awareness / Effectiveness	Improve the availability of financial data across the business to enable more effective budgeting and allow more informed business decisions (Improved recently with the release of Sun EP).	High
5.	Effectiveness	Alignment of asset information with the WASP system to achieve a consistent asset register enabling more accurate cost tracking and asset management practices.	High
6.	Effectiveness	Centralise recording of financial data on the value of stock and spare parts held to provide a holistic view.	Medium
7.	Effectiveness	Ability to charge out stock and spare parts when they are issued to ensure accurate financial tracking	Medium
8.	Effectiveness	Tracking of stock levels and lead times. Warning when stock reaches a critical levels etc to enable more effective inventory management.	Medium
9.	Efficiency	Automated re-ordering of stock or spare parts in areas of fast moving stock to reduce the occurrence of stock short falls.	Medium
10.	Effectiveness	Recording of the Geographic location of stock items to enable more effective and efficient inventory management.	Medium
11.	Effectiveness	Technical data of stock items and spare parts to support asset management business needs.	Medium
12.	Effectiveness	Central repository of supplier information to act as the database of record for all of Transend.	Medium
13.	Effectiveness	State-wide access to the stock system to allow processes to be completed on-site of the asset location	Medium

Compliance Systems

No.	Category	Description	Priority
1.	Efficiency / Effectiveness	Increasing levels of business process automation to increase efficiency and reduce labour requirements.	High
2.	Efficiency / Effectiveness	Increasing business process maturity levels to reduce risk and improve effectiveness.	High
3.	Efficiency / Effectiveness	Maintaining system operation to provide the required business services.	High
4.	Effectiveness	Under certain conditions, obligations cannot be moved from one management group to another. The supplier is working with Transend to resolve this issue.	Medium
5.	Effectiveness	Updating obligation structure	Medium

2.2 Timing

Investment timing is coordinated to meet business needs and is also influenced by the performance of specific IT package systems and the level of vendor support. The proposed expenditures are timed to align with scheduled application lifecycle reviews.

2.3 Strategic Alignment

Transend has identified the alignment of this project to the organisation's Strategic Plan, as shown in the following table:

Strategic result area	Strategic performance objective	Program objective
Safety and Work environment	Recognition as an employer of choice	Augment the transmission network to comply with transmission licence obligations and other ESI obligations at the least cost
Organisational efficiency and effectiveness	Fundamental business support systems re-engineered for business advantage	Upgrade or replacement of IT packaged systems as appropriate is fundamental to sustaining or enhancing organisational efficiency and effectiveness
Organisational efficiency and effectiveness	Continuously improve key business processes	Upgrade or replacement of IT packaged systems as appropriate a fundamental component of the continual improvement process
Organisational efficiency and effectiveness	Continuously improve commercial focus within the business	Contemporary IT packaged systems are vital to ensuring financial performance is monitored and optimised
Good corporate citizenship	Compliance with legal obligations	Ensure that the tools are available to monitor and control compliance with the law, regulations and industry codes of practice

WorleyParsons supports the ongoing need to review and enhance IT systems to support the efficient and effective operation of the business.

3 ALTERNATIVES

3.1 Options

The options considered were:

- Do nothing – would result in software that does not support business requirements or becomes increasingly difficult to support and maintain, it would also generate security issues when application integrity is compromised and application upgrades are not performed, maintenance costs increase and ultimately vendor support is removed.
- Replace software after it fails or becomes unsupportable – would cause reduction in support of business requirements, a large increase in management and maintenance costs would also occur and business productivity would decrease.
- Manage software replacement cycles – provides the greatest level of support for business requirements and minimises management and maintenance costs, planned replacement increases business productivity and leverages opportunities for systems integration.

Further options specific to each project within the IT package systems program will be considered in detail during the project initiation process.

3.2 Options Analysis

The third option is favoured by Transend, as it best meets the business needs. WorleyParsons also supports this option, which is based on the approach of ongoing life-cycle management of Transend's package systems, rather than reacting to situations as they arise.

3.3 Consideration of Non Network Solutions

Not applicable to this project.

3.4 Capex/Opex Trade-offs

Not explicitly considered at this stage, although the existence of some Opex savings has been stated in the documentation.

4 REGULATORY CONSIDERATIONS

4.1 Alignment with NER Capital Expenditure Objectives

The project expenditure is required in order to meet the following capital expenditure objectives identified in clause 6A.6.7(a) of the NER:

- Comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services.

As stated in Section 2, this project aims to ensure that Transend's IT package systems can continue to sustain or enhance where necessary, business, statutory and regulatory requirements.

4.2 Regulatory Test

Not applicable to this project.

5 GOVERNANCE

5.1 Business Case Approvals

Business cases for the projects identified within this program have not been submitted for approval at this time because they have not been developed to a stage sufficient for business case submission. Individual business cases will be prepared as necessary.

5.2 Assumptions

The assumptions specifically related to this program are:

- Corporate acquisitions will not alter the human resource requirements currently scoped by the HRMIS project;
- Refresh and consideration of whole of business solution (ERP) will occur in 2010/11;
- Storage hardware capable of handling peak Inputs / Outputs per second is available;
- The IT Infrastructure team provide a processing hardware environment capable of handling peak CPU Operations per second;
- System maintenance requirements will increase with application size, complexity and age;
- All proposed Leaders 80/20 compliance module implementations receive final approval from appropriate sources;
- The systems utilise separate production and preproduction environments; and
- Implementation of a replicated test environment will not affect system licensing requirements.

5.3 Project Risk

Transend’s 2007 Business Risk Review identifies a number of risks that are directly related to this project. The implementation of this project will contribute to the mitigation of these risks, which are summarised in the following table.

Risk ID No.	Risk Name	Risk Description	Revised consequence	Revised likelihood	Revised rating
2.11	IT operation and development	Operating and developing the Corporate It infrastructure and associated services	Moderate	Moderate	High
3.1	Financial management	Risk of compromised reporting of financial information and/or financial losses	Moderate	Unlikely	Moderate
3.2	Fraud	Risk that fraudulent activities are not detected in a timely manner resulting in loss of revenue and reputation	Minor	Unlikely	Low
4.1	Compliance	Non-compliance with statutory obligations and regulations and/or failure of compliance monitoring systems	Moderate	Unlikely	Moderate
4.4	Security	Failure to put in place appropriate security arrangements and compliance with Transend's TNSP licence and as an owner/operator of critical infrastructure	Catastrophic	Rare	High

Project specific business risks will be identified and included in each business case.

5.4 Conformance with Policies & Procedures

An Asset Management Plan has been prepared for this program – Corporate IT Package Systems Asset Management Plan FY2007-08 to FY2013-14. The Asset Management Plan is a component of Transend's Corporate IT Asset Management Framework and has been prepared in conformance with the asset management plan template contained in the framework.

6 EFFICIENCY

6.1 Estimating Basis

Costs for the proposed ERP system are based on SAP Systems indicative quote for the SAP Business All-In-One ERP system for 250 users. At the time of the lifecycle review a detailed request for tender will be developed with up to date business requirements which may alter the ultimate project costs.

In preparing the cost estimates, Transend has analysed historical expenditure for the various IT package systems and has projected licence fees, labour for development and maintenance, and supplier maintenance. Transend has appropriately allocated the costs between Capex and Opex. In projecting the labour required, Transend has applied scaling factors, based on the size and complexity of the systems involved.

6.2 Costs

Excluding cost escalators and risk factor, the estimated expenditure in the Next Regulatory Control Period (June 09, $m) is $3.920M.

Including cost escalators and risk factor, Transend's proposed fall of expenditure is shown in the following table:

2009/10	2010/11	2011/12	2012/13	2013/14	TOTAL
0.113	3.545	0.113	0.317	0.124	4.211

6.3 Project Delivery

The majority of Corporate IT package systems comprise the purchase of equipment or services from preferred suppliers or vendors for IT package systems.

7 ASSESSMENT

WorleyParsons considers that Transend has demonstrated that there is a justifiable need for the program, to sustain and enhance business, statutory and regulatory requirements, as discussed in Section 2. The program provides IT solutions that support the key areas of financial, human resources and compliance management. A wide range of detailed issues and needs have been identified in each of these three key areas.

As discussed in Section 3, WorleyParsons considers the option proposed by Transend as being reasonable. WorleyParsons supports the approach of ongoing life-cycle management of Transend's package systems, rather than "do nothing" or waiting until software fails or becomes unsupportable. The "do nothing" is not viable for systems supporting key areas of the business, and waiting until software fails or becomes unsupportable exposes the business to risk and is likely to be more expensive.

Transend's cost estimates are based on Level 1 estimates. Costs for the ERP system are based on an indicative quote and estimates have been prepared based on historical expenditure, projected licence fees, labour for development and maintenance, and supplier maintenance. In projecting the labour required, Transend has applied scaling factors depending on the size and complexity of the system involved. WorleyParsons is satisfied that the forecast costs are reasonable for the work proposed.

WorleyParsons is satisfied that expenditure for the program is required over the Next Regulatory Control Period to meet business needs and has been timed to align with scheduled application lifecycle reviews.

WorleyParsons considers that the project aligns with Transend's strategic plans, governance arrangements and Capex policies and procedures, as discussed in Section 5.

WorleyParsons has not identified any inaccuracies in the information provided in relation to this project.

8 CONCLUSION

WorleyParsons considers that the proposed project cost and timing as proposed by Transend are reasonable and should be included in the ex-ante cap as proposed by Transend.

ELECTRONA STAGE 2 DEVELOPMENT

1 PROJECT DESCRIPTION

1.1 Project Identification

ND0967

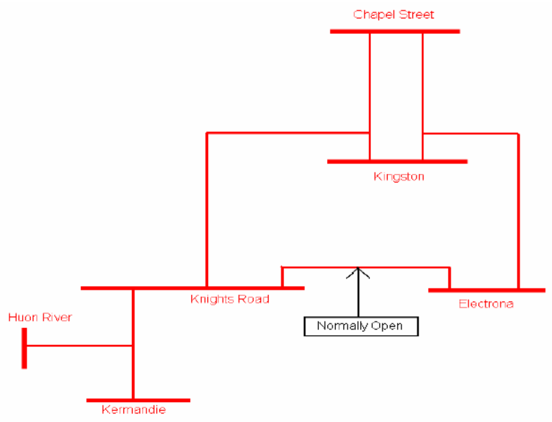
1.2 CAPEX Category

Augmentation

1.3 Brief Overview

In December 2005, Aurora requested that the 11 kV connection site at Electrona Substation be developed to improve the reliability and security of supply in adjacent areas. This was achieved with the Electrona Substation Stage 1 development works, which consisted of the installation of a second 17/25 MVA transformer, new 11 kV switchgear, a new 110kV transformer bay, new 110 kV transmission line bays, a 110 kV bus coupler circuit breaker and associated protection and control equipment at Electrona Substation.

Supply to the Huon area is provided from Chapel Street as shown in the following single line diagram:



Electrona and Knights Road substations (and hence Huon River and Kermandie substations) are unable to provide firm supply (N-1) due to protection and communication limitations associated with the transmission lines that supply Electrona and Knights Road substations. The project objective is to improve the security and reliability of supply to Electrona and Knights Road substations by providing firm supply to them.

1.4 Project Description

Due to an operational constraint, the Knights Road-Electrona 110 kV transmission line can only be closed for short periods under certain conditions. The constraint arises due to the protection systems being unable to discriminate for certain faults between the Knights Road-Electrona and the Chapel Street-Kingston-Electrona and Chapel Street-Knights Road-Electrona 110 kV transmission lines. The network topology and circuit lengths make it very difficult to accurately grade the existing distance protection at each of the three substations.

The project involves the replacement of transmission line distance protection schemes on the Chapel Street-Kingston-Electrona, Chapel Street-Knights Road-Electrona and Knights Road-Electrona transmission lines at Chapel Street, Kingston and Knights Road substations (new protection schemes were installed at Electrona substation as part of the Stage 1 development). The protection schemes installed on these transmission lines are an obsolete electro-mechanical design and have been programmed for replacement (except for one relay at Chapel Street Substation).

Transend engaged Hydro Tasmania Consulting to develop conceptual designs and provide input on protection requirements.

The implementation of this project requires reliable and secure communications between Knights Road and Electrona. This need will be met by the installation of an optical ground wire that will be installed as part of the Knights Road-Electrona 110 kV transmission line replacement project, also scheduled for completion in 2011. The SCADA at Knights Road Substation will need to be upgraded prior to this project – the SCADA upgrade will be incorporated into the protection replacement project (asset renewal).

2 PROJECT NEED

The project is required to improve the security and reliability of supply to Electrona and Knights Road substations by providing firm supply to them (N-1). The transmission line protection schemes installed on the Chapel Street-Kingston-Electrona, Chapel Street-Knights Road-Electrona and Knights Road-Electrona at Chapel Street, Kingston and Knights Road substations are an obsolete design and need to be replaced.

The current arrangements will not comply with clause 5.(1)(a)(i) of the Electricity Supply Industry (Network Performance Requirements) Regulations 2007 in that “no more than 25 MW of load is capable of being interrupted by a credible contingency event” at Knights Road Substation. The combined load at Huon River, Kermandie and Knights Road substations is expected to exceed 25 MW by 2009.

2.1 Drivers

The main drivers for the project (in decreasing order of importance) are:

- Improve the security and reliability of supply to Electrona and Knights Road (and hence to Huon River and Kermandie) substations by providing firm supply to them; and
- Replace assets that are at the end of their useful lives.

2.2 Timing

The project is scheduled for completion in 2011, which is later than the probable timing of non-conformance with the ESR (Network Performance Requirements) Regulations. It is desirable that the removal of the operational restrictions on closing the tie between Electrona and Knights Road substations occur as soon as practicable to improve the reliability and security of supply to both substations. The project has been timed to tie in with the Electrona-Knights Road transmission line replacement project, which is also scheduled for 2011, because of the need to utilize the optical ground wire for communication purposes.

2.3 Strategic Alignment

Transend has identified the alignment of this project to the organisation's Strategic Plan, as shown in the following table:

Strategic Result Area	Strategic Performance Objective/outcome	Proposal Objectives
Market & regulatory framework	Fulfil transmission licence obligations and other ESI obligations	Augment the transmission network to comply with transmission licence obligations at the least cost
Customer relationship	Involve customers in decisions that affect them	Consult with Aurora Energy and other stakeholders as appropriate to ensure that the project outcomes meet customer and stakeholder expectations
Transmission system performance	Maintain transmission performance	Augment the transmission network to maintain or improve transmission network performance as appropriate
Asset management	Compliance with transmission planning criteria	Augment the transmission network to comply with the transmission planning criteria (network performance requirements)

3 ALTERNATIVES

3.1 Options

Transend has considered the following options:

Option	Brief Description	Assessment
Option 1	Do nothing	This option does not address the identified project objectives and would not allow Transend to achieve the capital expenditure objectives identified in the NER
Option 2	Augment the transmission network to allow the Knights Road-Electrona 110 kV transmission line to operate normally closed	This option will meet the project objectives and will contribute to the achievement of the capital expenditure objectives

3.2 Options Analysis

No other viable options were identified, and the "do nothing" option was assessed as being not acceptable. The existing relays could not be utilised because they do not have the required functionality. More specifically, the existing relays:

- Have insufficient zones;
- Cannot cater for the reverse current logic ; and
- Have timing and discrimination issues.

WorleyParsons was not able to identify any other viable options, so accepts the option proposed by Transend as being reasonable.

3.3 Capex/Opex Trade-offs

Replacement of the transmission line protection relays with relays that have self monitoring capabilities will reduce the frequency of preventive maintenance and hence operating expenditure. Transend estimates that the implementation of this project will result in savings of operating expenditure of up to $36 000 ($2007) over the Next Regulatory Control Period. These operating expenditure savings have already been included in Transend's Opex forecasts. Although difficult to quantify, Transend also expects to realise a marginal reduction in corrective maintenance costs.

3.4 Consideration of Non-network Solutions

Although non-network solutions such as DSM do not appear to have been actively considered, WorleyParsons does not consider that such solutions would be viable in this case, based on the previous study by Energex. As well, there would still be issues with obsolete equipment.

4 REGULATORY CONSIDERATIONS

4.1 Alignment with NER Capital Expenditure Objectives

The project expenditure is required in order to meet the following capital expenditure objectives identified in clause 6A.6.7(a) of the NER:

- Comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services; and
- Maintain the reliability, safety and security of the transmission system through the supply of prescribed transmission services.

4.2 Regulatory Test

The NER require TNSPs to apply the regulatory test to new network investments (augmentations) estimated to require a total capitalised expenditure in excess of $1m. Proposed new network investments or non-network alternative options may satisfy the test via one of its two limbs – the "reliability" limb or the "market benefit" limb. For this project (which is classified as a small network augmentation under the NER), Transend intends to apply the "reliability" limb, which is satisfied if, having regard to a number of alternative options, timings and market development scenarios, it is necessitated to meet the service standards under the NER or applicable regulatory instruments, minimising the present value of the costs.

This project is classified as a small transmission network asset, and as such, the project is subject to the consultation process under clause 5.6.6A of the NER.

5 GOVERNANCE

5.1 Business Case Approvals

A business case has not yet been submitted for this project.

5.2 Assumptions

The following key assumptions have been made:

- That the communications between Knights Road and Electrona will be upgraded by the installation of an optical ground wire that will be installed as part of the Knights Road-Electrona 110 kV transmission line replacement project; and
- The upgrade of the SCADA at Knights Road Substation will be incorporated into the protection replacement project (asset renewal).

5.4 Project Risk

Transend's 2007 Business Risk Review identifies a number of risks that directly relate to this project. The implementation of this project will contribute to the mitigation of these risks, which are summarised in the following table. Project specific risks will be identified during the project initiation process and included in the business case.

Risk	RISK DESCRIPTION	CONSEQUENCE	Likelihood	Rating
Power System Compliance	Failure to operate the power system in accordance with Legislative and Contractual obligations	Major	Rare	High
Compliance	Does not comply with the power system requirements under the NER	Moderate	Unlikely	Moderate

5.4 Conformance with Policies & Procedures

WorleyParsons notes that this project is at an early stage of development, but found that the project has been developed in conformance with Transend's policies and procedures, particularly the Investment Process Governance Framework.

6 EFFICIENCY

6.1 Estimating Basis

The estimates for this project comprise a Level 1 estimate and with align the values contained in Transend's Capital Accumulation Model used for the submission.

6.2 Costs

Excluding cost escalators and risk factor, the project cost is estimated at $1.237m (June 09, $), which includes expenditure of $0.012m in 2008/09.

Including cost escalators and risk factor, Transend's proposed fall of expenditure is shown in the following table:

2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	TOTAL 09/10-13/14
0.015	0.350	1.172				1.536

6.3 Design Considerations

Transend has proposed the installation of duplicated primary protection as follows:

- 3 line end differential protection between Chapel Street/Kingston/Electrona;
- 3 line differential protection between Chapel Street/Kingston/Knights Road; and
- 2 line end differential protection between Electrona and Knights Road.

Transend proposes to install the relays in its standard protection panels.

Following a review by one of its experienced protection engineers, WorleyParsons considers that the protection design is appropriate, in line with good industry practice, and that the costs are reasonable for the work proposed.

6.4 Project Delivery

At this stage it is envisaged that this project will be implemented using a separate design and construct approach. Preferred contractors experienced in this type of work will be engaged to undertake the works to complete this project.

7 ASSESSMENT

WorleyParsons considers that Transend has demonstrated that there is a justifiable need for the project, to improve the reliability and security of supply to the Electrona and Knights Road substations by providing firm supply to them, as discussed in Section 2. It is anticipated that Transend will be in breach of the ESR (Network Performance) Regulations in 2009. The project will remove existing operational constraints and allow firm supply from four substations.

As discussed in Section 3, Transend considered only two options – "do nothing" and the preferred option. WorleyParsons was not able to identify any other viable options, and considers that the "do nothing" option was not acceptable, given the current inability to provide firm supply and the impending breach of the regulations. Accordingly, WorleyParsons accepts the option proposed by Transend as being reasonable.

The cost estimates for this project are based on Level 1 estimates. Based on the review by one of its experienced protection engineers, WorleyParsons is satisfied that the design is appropriate and that the forecast costs are reasonable for the work proposed.

The project has been timed to tie in with the Electrona-Knights Road transmission line replacement project. This is later than the probable timing of non-conformance with the ESR (Network Performance Requirements) Regulations. On this basis, WorleyParsons considers that the proposed timing is reasonable.

WorleyParsons considers that the project aligns with Transend's strategic plans, governance arrangements and Capex policies and procedures, as discussed in Section 5.

WorleyParsons has not identified any inaccuracies in the information provided in relation to this project.

8 CONCLUSION

WorleyParsons considers that the proposed project cost and timing as proposed by Transend are reasonable and should be included in the ex-ante cap as proposed by Transend.

NEW NORFOLK SUBSTATION HV PROTECTION UPGRADE

1 PROJECT DESCRIPTION

1.1 Project Identification

ND0729-3

1.2 CAPEX Category

Connection

1.3 Brief Overview

Aurora Energy has requested that the high voltage (HV) distribution feeder protection at a number of substations be upgraded to provide additional functionality and to grade correctly with its downstream protection. Bridgewater, Kingston, New Norfolk, Norwood, Railton, Rokeby, St Marys and Ulverstone substations have been identified by Aurora as high priority sites that need to be upgraded.

This project also includes the replacement of the protection schemes associated with the transformers that supply the HV switchboards.

The new protection schemes will comprise microprocessor-based relays with self-diagnostic capabilities that reduce the need for regular preventive maintenance. These low maintenance relays will also reduce the risk of inadvertent errors while handling this protection equipment during intrusive testing of the protection systems.

The replacement of protection on the HV distribution feeders at New Norfolk Substation is part of the HV Substation protection upgrade project.

1.4 Project Description

Aurora has requested that the following features be provided for HV feeder protection:

- Inverse time curve protection characteristics;
- Live-line settings that are able to be remotely activated;
- 20 seconds auto-reclose dead times;
- Impedance to fault figures available at the Network Operation and Control System; and
- Dial-up access to relays for engineering functions, event logs and fault recording data.

An assessment has identified that the HV feeder protection at a number of substations, including New Norfolk, is not capable of providing the required functionality and that the protection schemes need to be replaced. These protection schemes were installed in the 1970s and 1980s and are an obsolete “static” design.

The protection schemes associated with the transformers that supply the HV switchboards are also an obsolete “static” design. This project also includes the replacement of these protection schemes.

Replacement or the obsolete “static” relays is consistent with the recommendations made in Transend’s asset management plan for HV substation protection. Transend’s long-term strategy is to install state of the art microprocessor based units with self-diagnostic and fault recording features.

The project involves the following tasks at New Norfolk Substation:

- Replace existing protection, metering and control schemes on all 22 kV outgoing feeders;
- Provide facility for connection of Aurora Energy's Power Quality Meters on all 22 kV outgoing feeders;
- Interface new relays to the bus blocking scheme associated with 22 kV bus section A and B;
- Replace existing bus over current protection scheme associated with 22 kV bus section A and B;
- Replace existing transformer protection scheme on T1 and T2 with standard transformer protection scheme housed in new stand alone panel; and
- Connect new relays to new SCADA system.

2 PROJECT NEED

The project is required to meet the needs of Aurora Energy, and is in line with Transend's asset management plans and strategic protection upgrade program.

This project will provide the following benefits that will ultimately improve the performance of the power system:

- Better protection coordination with Aurora's distribution network;
- Better power quality monitoring and assessment;
- Remote monitoring, interrogation and adjustment capability; and
- Improved fault location leading to reduced outage duration.

2.1 Drivers

The main driver for the project is to meet Aurora's protection functionality requirements in order to improve supply reliability to consumers.

2.2 Timing

The proposed commissioning date is July 2010, which ties in with the timetable submitted by Aurora in its request letter.

2.3 Strategic Alignment

Transend has identified the alignment of this project to the organisation's Strategic Plan, as shown in the following table:

Strategic Result Area	Strategic Performance Objective/outcome	Proposal Objectives
Customer relationship	Involve customers in decisions that affect them	Install reliable assets that are able to meet customers' performance expectations at connection points
Transmission system development & performance	Maintain transmission connection site performance	Enhance the reliability of electricity supply by eliminating sources of asset failure and operator error and reduce supply restoration times. Install low maintenance assets and adopt project implementation methodologies that optimise plant and distribution circuit outage requirements. Enhance the ability to monitor the quality of electricity supply.
Shareholder's value	Provide appropriate and sustainable returns to shareholders	Undertake prudent asst investments to ensure appropriate returns

3 ALTERNATIVES

3.1 Options

Transend considered the following options:

Option No.	Option description	Reason for selection/rejection
1	Do nothing	Does not address the request from Aurora.
2	Replace protection and control equipment	This option proposes the design, procurement and installation of new protection and control equipment associated with the transformers and HV switchboards at 8 substations, including New Norfolk Substation. This option cost-effectively addresses the investment needs.

3.2 Options Analysis

No other viable options were identified by Transend, and the "do nothing" option was assessed as being not acceptable.

WorleyParsons was not able to identify any other viable options, so accepts the option proposed by Transend as being reasonable.

3.3 Consideration of Non Network Solutions

Not applicable for this project.

3.4 Capex/Opex Trade-offs

Replacement of the HV feeder protection relays with relays that have self monitoring capabilities will reduce the frequency of preventive maintenance and hence operating expenditure. Transend estimates that the implementation of this project will result in savings of operating expenditure of up to $41 600 (June 07, $) over the Next Regulatory Control Period. These operating expenditure savings have already been included in the optimised works program. Although difficult to quantify, Transend also expects to realise a marginal reduction in corrective maintenance costs.

4 REGULATORY CONSIDERATIONS

4.1 Alignment with NER Capital Expenditure Objectives

The project expenditure is required in order to meet the following capital expenditure objectives identified in clause 6A.6.7(a) of the NER:

- Comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services; and
- Maintain the quality, reliability, and security of supply of prescribed transmission services.

4.2 Regulatory Test

This project is not subject to the regulatory test, as it is less than $1m.

5 GOVERNANCE

5.1 Business Case Approvals

This project is included in a business case approved by the Board on 25 October 2007, which covered upgrading protection in eight substations, including New Norfolk Substation.

5.2 Assumptions

None identified at this stage.

5.3 Project Risk

The key risks for the project were assessed by Transend as shown in the following table:

Risk	Likelihood	Consequence	Gross Risk Rating	Mitigation	Net Risk Rating
Capital cost overrun	Possible	Moderate	Moderate	Consult with Aurora regarding prudent costs for the full installation	Low
Project delivery delayed	Possible	Minor	Low	Implement good project management and regular project reporting	Low
Interruption of supply	Moderate	Moderate	Moderate	Ensure that inspection and test plans are prepared and reviewed for all commissioning works	Low
Asset performance risk	Moderate	Moderate	Moderate	Transend has to approve the design before implementation	Low
Key resources not available	Moderate	Moderate	Moderate	Involve key stakeholders when deciding priorities	Low

5.4 Conformance with Policies & Procedures

WorleyParsons notes that this project is at an early stage of development, but found that the project has been developed in conformance with Transend's policies and procedures, particularly the Investment Process Governance Framework.

6 EFFICIENCY

6.1 Estimating Basis

The estimates for this project comprise Level 1 estimates and align with the values contained in Transend's Capital Accumulation Model used for the submission.

6.2 Costs

As a committed project, real cost escalators and risk factor have not been applied to this project.

The fall of expenditure (June 09, $m) is shown in the following table:

2009/10	2010/11	2011/12	2012/13	2013/14	TOTAL
0.223	0.719				0.942

In addition, it is proposed to spend $0.01m in 2008/09.

6.3 Design Considerations

The existing protection and control relays on the transformers and HV switchboards associated with this substation have the following deficiencies in meeting customer requirements:

- They do not operate with inverse time curve characteristics;
- They do not have a live-line remote setting;
- They are no longer supported (including spares) by the manufacturer;
- They require more frequent testing and maintenance;
- They do not have fault recording facilities; and
- They do not provide impedance to fault figures that can be made available in NOCS.

The design approach adopted by Transend is to:

- Replace the protection and control systems that are of an obsolete design in accordance with the Asset Management Plan for HV Substation Protection;
- Use relays with self-diagnostic features to ensure high availability and reliability of protection and control systems;
- Use relays that allow longer intervals between testing;
- Use relays with inbuilt post-fault analysis features to enable fault analysis to be conducted for each fault; and
- Provide remote access to the protection relays.

Transend proposes to install the relays in its standard protection panels.

Following a review by one of its experienced protection engineers, WorleyParsons considers that the protection design is appropriate, in line with good industry practice, and that the costs are reasonable for the work proposed.

6.4 Project Delivery

The design and construction work is to be completed by Hydro Consulting, with Transend procuring the feeder protection relays and transformer protection panels for free issue to Hydro Consulting.

7 ASSESSMENT

WorleyParsons considers that Transend has demonstrated that there is a justifiable need for the project, to meet Aurora's protection functionality requirements in order to improve supply reliability to consumers, as discussed in Section 2. The project is required to meet the needs of Aurora Energy and is in line with Transend's asset management plans and strategic protection upgrade program.

Transend assessed only two options – "do nothing" and the preferred option. WorleyParsons considers that he "do nothing" option is not acceptable as it does not meet the connection request from Aurora. As discussed in Section 3, WorleyParsons was not able to identify any other viable options, so accepts the option proposed by Transend as being reasonable.

Transend's cost estimates are based on Level 1 estimates. Based on a review by one of its experienced protection engineers, WorleyParsons is satisfied that the protection design is appropriate, in line with good industry practice, and that the costs are reasonable for the work proposed.

WorleyParsons considers that the proposed timing for the project is reasonable, as the project has been timed to align with the timetable requested by Aurora.

WorleyParsons considers that the project aligns with Transend's strategic plans, governance arrangements and Capex policies and procedures, as discussed in Section 5.

WorleyParsons has not identified any inaccuracies in the information provided in relation to this project.

8 CONCLUSION

WorleyParsons considers that the proposed project cost and timing as proposed by Transend are reasonable and should be included in the ex-ante cap as proposed by Transend.

APPENDIX 5: CONTINGENT PROJECTS

Project	Indicative cost (June 09, $m)
Burnie-Smithton new transmission line	88
Sheffield-Farrell new transmission line	79
Sheffield-George Town new transmission line	70
Sheffield-Burnie new transmission line	52
St Helens new 110/22kV connection site	47
Palmerston-Sheffield transmission line augmentation	22
Waddamana-Lindisfarne 220 kV transmission line second circuit	22
Trevallyn Substation new 220/110 kV injection point	21
Queenstown Substation security upgrade	11

BURNIE-SMITHTON NEW 110 kV TRANSMISSION LINE

1 PROJECT DESCRIPTION

1.1 Project Identification

ND1014

1.2 CAPEX Category

Augmentation

1.3 Brief Overview

The Burnie–Smithton new transmission line project comprises the construction of a new double–circuit transmission line between Burnie and Smithton substations and augmentation of the existing Burnie–Smithton transmission line. The technical parameters for the new transmission line (nominal operating voltage, capacity etc) have not yet been determined in detail.

1.4 Background

Transfer capacity from Smithton Substation is currently limited to the rating of the 110 kV double-circuit transmission line that connects Burnie Substation to Smithton Substation. The Burnie–Smithton transmission line already operates non-firm under high output from the Bluff Point and Studland Bay power stations. A generator run-back scheme is in place that decreases generation from Bluff Point and Studland Bay power stations in the event of the loss of one of the transmission circuits that comprise the Burnie–Smithton transmission line so the remaining in-service circuits do not become overloaded.

If generation developments in north-western Tasmania occur, the proposed contingent project would remove a transmission network constraint. The project would proceed if the cost of the augmentation was less than the benefits, including by allowing dispatch of lower cost generation to the market.

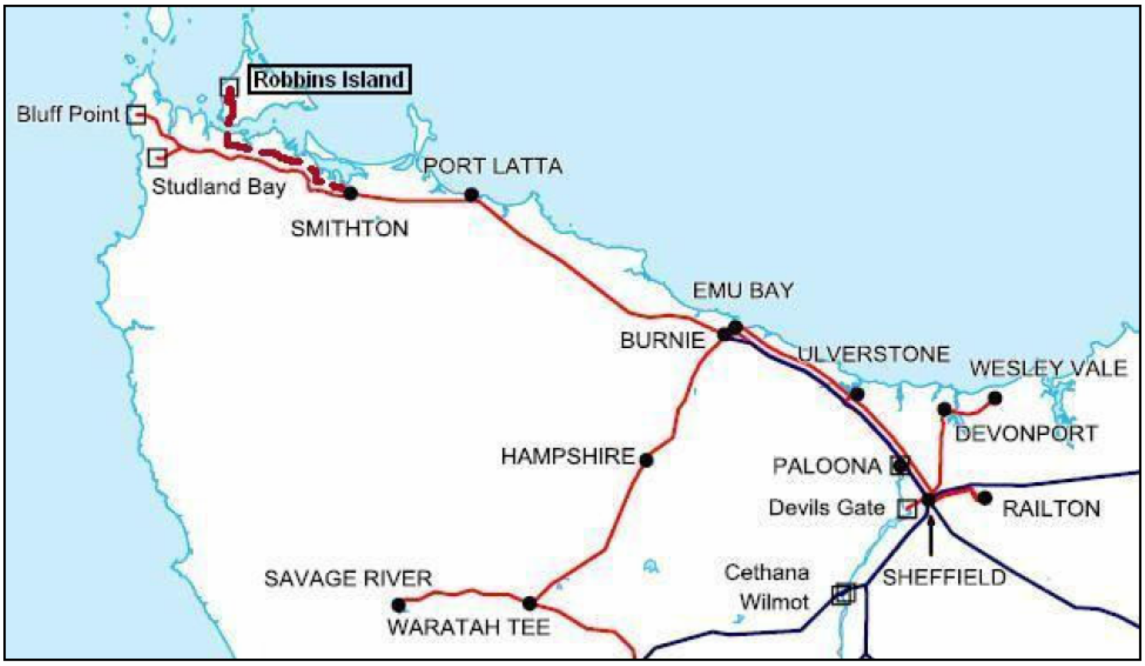
The analysis undertaken by ROAM Consulting (refer to appendix 11 of Transend's revenue proposal) identified the potential for generation developments in north-western Tasmania. The generation project identified by ROAM Consulting that relates to the Burnie–Smithton transmission line contingent project is the "Robbins Island – 240 MW of wind generation" project. ROAM Consulting has assigned a final probability of proceeding of 15.2 per cent for this project. If this (or other) generation development occurs in the north-west region, increased power transfer capacity will be required between Burnie and Smithton substations.

ROAM Consulting acknowledged that the amount of wind generation likely to be installed is heavily dependent on the level of government action with regard to the management of greenhouse emissions. Recent indications from the Federal Government are that it is becoming more likely that the introduction of initiatives to reduce greenhouse emissions will be put in place in the Next Regulatory Control Period. This is expected to lead to a greater price differential between non-renewable and renewable energy sources, with non-renewable energy becoming relatively more expensive.

Transend has undertaken scenario studies for the north-west and west areas of Tasmania to identify the impact that generation developments would have on the transmission network.

Figure 1 presents a geographical representation of the transmission network in north-western Tasmania and it also shows the potential Robbins Island generation development.

Figure 1 – North-west Tasmanian transmission network and potential Robbins Island development



With increased relatively low cost generation in the north-west region, there is a greater prospect that an augmentation to relieve transmission constraints will pass the regulatory test. Transend contends that this project should be accepted as a contingent project for the Next Regulatory Control Period because of uncertainty about the trigger event occurring and uncertainty about the scope and cost of the project.

2 PROJECT NEED

2.1 Drivers

The driver for this project is to provide adequate network capacity to allow the connection of new generation in the north-western region.

2.2 Timing

The timing of this project is uncertain. Based on the analysis undertaken by ROAM Consulting, the potential generation developments may occur in 2013–14.

2.3 Strategic Alignment

Clear linkages to Transend's strategic plan would be established in accordance with business practice when the project is initiated.

3 ALTERNATIVES

3.1 Options

Table 1 summarises the options considered at this time. Detailed technical options relating to this project would be considered should the trigger event occur. Further options may be identified during the project initiation process or be proposed by interested parties as part of the public consultation process.

Table 1 – Options considered

Option	Description	Consideration
1	Do nothing	This option would continue to leave the transmission network severely constrained and would not allow Transend to achieve the capital expenditure objectives identified in the NER.
2	Further develop a network control scheme	This option would be implemented through a large run-back scheme, similar to what is in place currently. As the Burnie–Smithton 110 kV transmission line already constrains the transmission network, including the Robbins Island development, this would require over 300 MW runback/constraint upon the occurrence of a contingent event.
3	Construct a new Burnie–Smithton 220 kV transmission line	This option would provide additional power transfer capacity from north-western Tasmania, it would provide a market benefit and it would contribute to the achievement of the capital expenditure objectives.
4	Construct a new Burnie–Smithton 110 kV transmission line	This option would provide additional power transfer capacity from north-western Tasmania, it would provide a market benefit and it would contribute to the achievement of the capital expenditure objectives.

3.2 Options Analysis

Further options may be identified during the project initiation process or be proposed by interested parties as part of the public consultation process. At this stage, Transend favours Option 4 which is the least cost option.

3.3 Consideration of Non Network Solutions

Not practicable for this project.

4 REGULATORY CONSIDERATIONS

4.1 NER Requirements

Clause 6A.8.1 requires that a contingent project:

- Is reasonably required in order to achieve any of the “capital expenditure objectives”:
- Capex is not otherwise provided for (in part or in whole) in the allowance:
- Reasonably reflects the “capital expenditure criteria”:
  - Efficient costs;
  - The costs a prudent operator would incur; and
  - A “realistic expectation” of demand forecasts and cost inputs,

  taking into account the “capital expenditure factors”.
- Exceeds the cost threshold (in Transend’s case, this is $10m).

4.2 Alignment with NER Capital Expenditure Objectives

This project would be required to achieve the following capital expenditure objectives identified in clause 6A.6.7(a) of the NER:

- Meet the expected demand for prescribed transmission services over the regulatory control period; and
- Comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services.

In particular, Transend has a regulatory obligation under section 14 of its licence to plan and procure transmission system augmentations that are shown to satisfy the regulatory test.

4.3 Regulatory Test

If there was sufficient relatively-low-cost existing, committed, and/or advanced generation capacity constrained by the Burnie-Smithton 110 kV transmission line, then Transend would undertake the regulatory test to determine whether there would be a market benefit in removing the constraint. If such a benefit was demonstrated (put simply, by demonstrating that the cost of the augmentation was less than the benefit to the market from the augmentation), then Transend would be required to implement such an augmentation.

This project would be classified as a “large transmission network asset” and would be subject to a public consultation process as defined in clause 5.6.6 of the NER.

4.4 Contingency Trigger

Under clause 6A.8.1(c) of the NER, the following matters are to be considered in determining whether a trigger event is appropriate:

- Trigger event to be reasonably specific and capable of objective verification;
- Trigger event, if it occurs, makes the contingent project reasonably necessary to achieve any of the “capital expenditure objectives”;
- Trigger event to generate increased costs or categories of costs that relate to a specific location rather than the transmission network as a whole;
- Trigger event to be described in such terms that the occurrence of the event is all that is required for the revenue determination to be amended; and
- Trigger event to be probable during the regulatory control period, but inclusion in the ex ante cap is not appropriate because of:
    - Uncertainty of timing; and
    - Uncertainty of cost.

The trigger proposed for this project is:

Committed and/or advanced generation projects in the north-western region in excess of 50 MW, resulting in successful application of the regulatory test for augmentation of the Burnie-Smithton transmission corridor.

5 EFFICIENCY

5.1 Estimating Basis

A level one estimate has been prepared for this project. The estimated cost of this project is indicative only; however any such project would be expected to exceed the $10 million contingent project threshold.

A detailed project scope and cost estimate will be required before any amendment to the revenue determination is considered by the AER should the specified trigger event occur during the Next Regulatory Control Period.

5.2 Costs

The estimated expenditure in the Next Regulatory Control Period is $88m (June 09, $). Detailed economic analysis has not been completed for this project. Further economic analysis will be undertaken during the project initiation process, should the trigger event occur.

5.3 Design Considerations

The scope of work for this project is wholly within the shared transmission network and is physically removed from any generator connection. It is not possible to accurately define the scope of this project at this early stage and as such, the scope of this project would most likely change following detailed analysis. As such, WorleyParsons is not able to comment on the design aspects.

5.4 Project Delivery

The transmission line component of this project would be expected to be implemented using a separate design and separate construct approach. The substation and switching station components of this project would be expected to be undertaken using a design and construct approach. Preferred contractors experienced in this type of work would be engaged to undertake the works to complete this project.

6 ASSESSMENT

6.1 NER Requirements

The driver for this project is to provide adequate network capacity to allow the connection of new generation in the north-western region. WorleyParsons considers that the project is reasonably required to meet two of the “capital expenditure objectives” (as discussed in Section 4.2), should the trigger event occur.

Having reviewed the detailed list of projects underpinning Transend's submission, WorleyParsons is confident that this project has not been included (in whole or in part) in Transend's forecast Capex.

At this early stage, there is much uncertainty in relation to the scope and costs for the project. Transend has prepared Level 1 estimates (based on the assumption that the new line would be double circuit 110 kV) that represent the same level of accuracy as the Capex projects contained in Transend's revenue proposal. Based on the process utilised to prepare the estimates, WorleyParsons considers that the estimated costs are efficient for the assumed project scope. It is also relevant to note that for the trigger event to have occurred, Transend would have had to prepare detailed scoping and cost estimates and have gone through the requisite public consultation process.

This project is not dependant on demand forecasts, as it is driven by the probable connection of new generation. The cost inputs for this contingent project align with those used in Transend's submission, and on that basis, WorleyParsons is satisfied that the project is based on a realistic expectation of cost inputs, taking into account the "capital expenditure factors".

The estimated costs for the project are clearly well above the threshold value of $10m.

6.2 Trigger Event

Given that new generation in the north-western region could arise at various locations and at various capacities, WorleyParsons considers that the trigger event is reasonably specific and capable of objective verification.

If the trigger event occurs, Transend would be obliged under its licence to proceed with the project. The trigger event would generate costs that relate to a specific location that is, the Burnie-Smithton transmission line corridor.

The trigger event is described in terms such that the occurrence of the event is all that is required for the revenue determination to be amended that is, once the application of the regulatory test was successful, there would be no outstanding requirements preventing the revenue determination being amended.

Based on the ROAM report and WorleyParsons' sensitivity analysis, WorleyParsons considers there is a reasonable probability that the project will be required during the Next Regulatory Control Period, but notes that the timing is uncertain. As previously noted, the scope and therefore cost of the project is uncertain at this early stage. WorleyParsons considers that it is not appropriate for this project to be included in the ex ante cap due to the uncertainty in both the timing and the cost of the project.

7 CONCLUSION

WorleyParsons considers that this proposed project meets the NER requirements for contingent projects and should be accepted by the AER as a contingent project.

SHEFFIELD-FARRELL NEW TRANSMISSION LINE

1 PROJECT DESCRIPTION

1.1 Project Identification

ND1016

1.2 CAPEX Category

Augmentation

1.3 Brief Overview

The Sheffield–Farrell new transmission line project comprises the construction of a new transmission line between Sheffield and Farrell substations. It is also likely that a new switching station would be needed in the Staverton area near Cethana Power Station that would consolidate the three incoming circuits from Farrell Substation and the four incoming circuits from Cethana, Wilmot, Lemonthyme and Fisher power stations into the six circuits (three double-circuit towers) that would connect to Sheffield Substation. The technical parameters for the proposed third circuit (nominal operating voltage, capacity etc) and the configuration of the transmission network have not yet been determined in detail.

1.4 Background

Transfer capacity between Sheffield and Farrell substations is currently limited to the rating of the double circuit 220 kV transmission line that connects Sheffield and Farrell substations. The Sheffield–Farrell transmission line already constrains the transmission network under certain circumstances (even using dynamic ratings) and a System Protection Scheme is in place that allows the transmission line to operate beyond firm capacity when Basslink is exporting energy.

If generation developments on Tasmania's west coast occur, the proposed contingent project would remove a transmission network constraint. The project would proceed if the cost of the augmentation was less than the benefits, including by allowing dispatch of lower cost generation to the market and deferring construction of higher cost generation.

The analysis undertaken by ROAM Consulting (refer to appendix 11 of Transend's revenue proposal) identified the potential for generation developments on Tasmania's west coast. The generation project identified by ROAM Consulting that relates to the Sheffield–Farrell transmission line contingent project is "Heemskirk – 160 MW of wind generation".

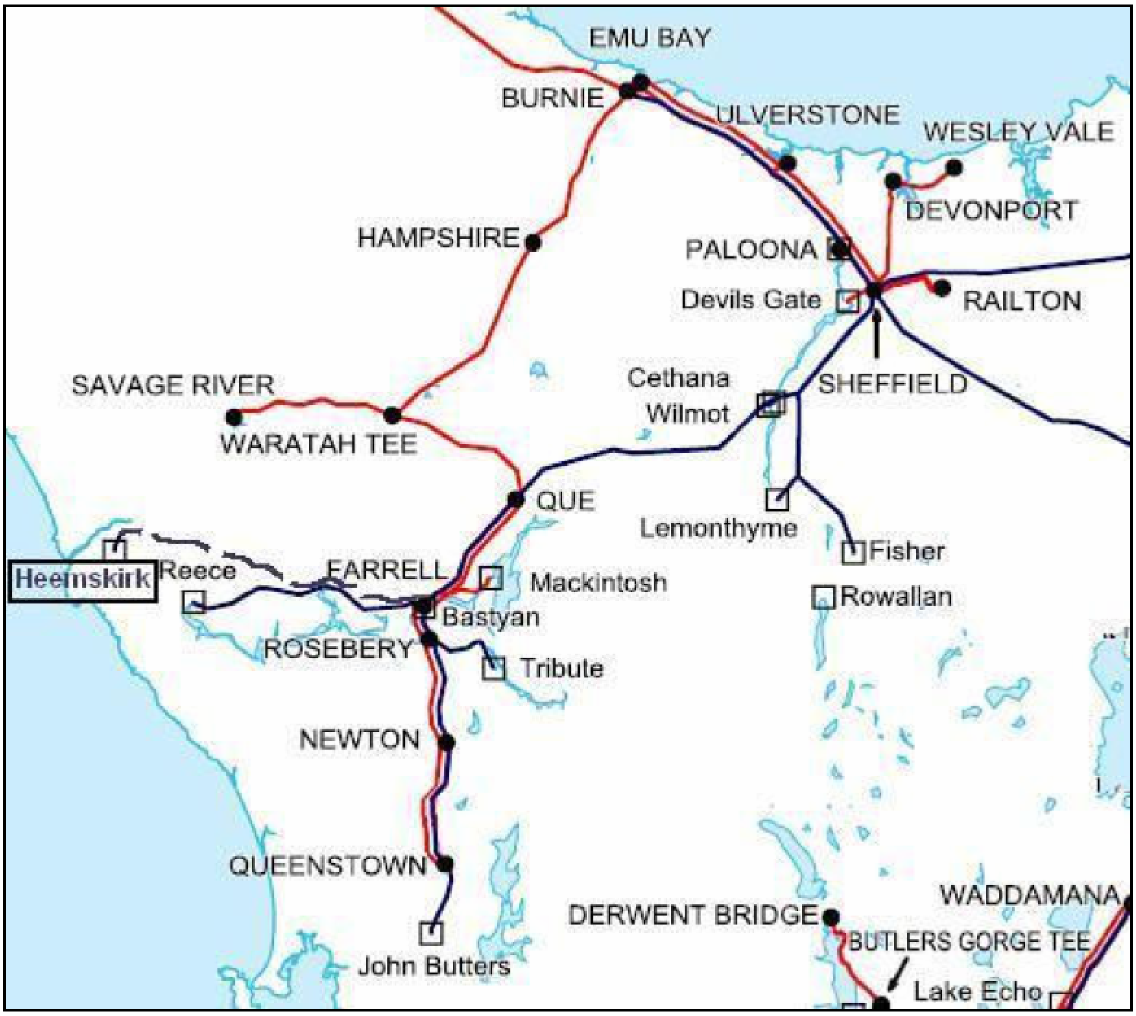
ROAM Consulting has assigned a final probability of proceeding of 15.2 per cent for this project. If this (or other) generation developments occur in the west coast region, increased power transfer capacity will be required between Sheffield and Farrell substations.

ROAM Consulting acknowledged that the amount of wind generation likely to be installed is heavily dependent on the level of government action with regard to the management of greenhouse emissions. Recent indications from the Federal Government are that it is becoming more likely that the introduction of initiatives to reduce greenhouse emissions will be put in place in the Next Regulatory Control Period. This is expected to lead to a greater price differential between non-renewable and renewable energy sources, with non-renewable energy becoming relatively more expensive.

Transend has undertaken scenario studies for the north-west and west coast areas of Tasmania to identify the impact that generation developments would have on the transmission network.

Figure 1 presents a geographical representation of the transmission network in western Tasmania and it also shows the potential Heemskirk generation development.

Figure 1 – Western Tasmanian transmission network and potential Heemskirk development



With increased relatively low cost generation in the western region, there is a greater prospect that an augmentation to relieve transmission constraints will pass the regulatory test. Transend contends that this project should be accepted as a contingent project for the Next Regulatory Control Period because of uncertainty about the trigger event occurring and uncertainty about the scope and cost of the project.

2 PROJECT NEED

2.1 Drivers

The driver for this project is to provide adequate network capacity to allow the connection of new generation in the north-western and western regions.

2.2 Timing

The timing of this project is uncertain. Based on the analysis undertaken by ROAM Consulting, the potential generation developments may occur in 2012–13.

2.3 Strategic Alignment

Clear linkages to Transend's strategic plan would be established in accordance with business practice when the project is initiated.

3 ALTERNATIVES

3.1 Options

Table 1 summarises the options considered at this time. Detailed technical options relating to this project would be considered should the trigger event occur. Further options may be identified during the project initiation process or be proposed by interested parties as part of the public consultation process.

Table 1 – Options considered

Option	Description	Consideration
1	Do nothing	This option would continue to leave the transmission network severely constrained and would not allow Transend to achieve the capital expenditure objectives identified in the NER.
2	Develop a network control scheme	This option would be implemented through a large run-back scheme or west coast area generation constraints. As the Sheffield–Farrell 220 kV transmission line already constrains the transmission network, including the Heemskirk development, this would require over 160 MW runback/ constraint.
3	Construct a new Farrell–Burnie transmission line	This option would provide additional power transfer capacity, but not enough to relieve overloading on Sheffield–Farrell 220 kV transmission line. It would also most likely create the need to augment or replace the transmission lines between Sheffield and Burnie substations.
4	Augment the transmission network between Sheffield and Farrell substations	This option would provide additional power transfer capacity from Tasmania's west coast, it would provide a market benefit and it would contribute to the achievement of the capital expenditure objectives.

3.2 Options Analysis

Further options may be identified during the project initiation process or be proposed by interested parties as part of the public consultation process. At this stage, Transend favours Option 4.

3.3 Consideration of Non Network Solutions

Not practicable for this project.

4 REGULATORY CONSIDERATIONS

4.1 NER Requirements

Clause 6A.8.1 requires that a contingent project:

- Is reasonably required in order to achieve any of the “capital expenditure objectives”;
- Capex is not otherwise provided for (in part or in whole) in the allowance;
- Reasonably reflects the “capital expenditure criteria”;
  - Efficient costs;
  - The costs a prudent operator would incur; and
  - A “realistic expectation” of demand forecasts and cost inputs,

  taking into account the “capital expenditure factors”.
- Exceeds the cost threshold (in Transend’s case, this is $10m).

4.2 Alignment with NER Capital Expenditure Objectives

This project would be required to achieve the following capital expenditure objectives identified in clause 6A.6.7(a) of the NER:

- Meet the expected demand for prescribed transmission services over the regulatory control period; and
- Comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services.

In particular, Transend has a regulatory obligation under section 14 of its licence to plan and procure transmission system augmentations that are shown to satisfy the regulatory test.

4.3 Regulatory Test

If there was sufficient relatively-low-cost existing, committed, and/or advanced generation capacity constrained by the Sheffield-Farrell transmission line, then Transend would undertake the regulatory test to determine whether there would be a market benefit in removing the constraint. If such a benefit was demonstrated (that is, that the cost of the augmentation was less than the benefit to the market from the augmentation), then Transend would be required to implement such an augmentation.

This project would be classified as a “large transmission network asset” and would be subject to a public consultation process as defined in clause 5.6.6 of the NER.

4.4 Contingency Trigger

Under clause 6A.8.1(c) of the NER, the following matters are to be considered in determining whether a trigger event is appropriate:

- Trigger event to be reasonably specific and capable of objective verification;

- Trigger event, if it occurs, makes the contingent project reasonably necessary to achieve any of the “capital expenditure objectives”;
- Trigger event to generate increased costs or categories of costs that relate to a specific location rather than the transmission network as a whole;
- Trigger event to be described in such terms that the occurrence of the event is all that is required for the revenue determination to be amended; and
- Trigger event to be probable during the regulatory control period, but inclusion in the ex ante cap is not appropriate because of:
    - Uncertainty of timing; and
    - Uncertainty of cost.

The trigger proposed for this project is:

At least 50 MW of committed and/or advanced generation projects in the west coast area, resulting in successful application of the regulatory test for augmentation of the Sheffield-Farrell transmission corridor.

5 EFFICIENCY

5.1 Estimating Basis

A level one estimate has been prepared for this project. The estimated cost of this project is indicative only; however any such project would be expected to exceed the $10 million contingent project threshold.

A detailed project scope and cost estimate will be required before any amendment to the revenue determination is considered by the AER should the specified trigger event occur during the Next Regulatory Control Period.

5.2 Costs

The estimated expenditure in the Next Regulatory Control Period is $79m (June 09, $). Detailed economic analysis has not been completed for this project. Further economic analysis will be undertaken during the project initiation process, should the trigger event occur.

5.3 Design Considerations

The scope of work for this project is wholly within the shared transmission network and is physically removed from any generator connection. It is not possible to accurately define the scope of this project at this early stage and as such, the scope of this project would most likely change following detailed analysis. As such, WorleyParsons is not able to comment on the design aspects.

5.4 Project Delivery

The transmission line component of this project would be expected to be implemented using a separate design and separate construct approach. The substation and switching station components of this project would be expected to be undertaken using a design and construct approach. Preferred contractors experienced in this type of work would be engaged to undertake the works to complete this project.

6 ASSESSMENT

6.1 NER Requirements

The driver for this project is to provide adequate network capacity to allow the connection of new generation in the north-western and western regions. WorleyParsons considers that the project is reasonably required to meet two of the “capital expenditure objectives” (as discussed in Section 4.2), should the trigger event occur.

Having reviewed the detailed list of projects underpinning Transend’s submission, WorleyParsons is confident that this project has not been included (in whole or in part) in Transend’s forecast Capex.

At this early stage, there is much uncertainty in relation to the scope and costs for the project. Transend has prepared Level 1 estimates (based on the assumption that the new line would be a single circuit 220 kV) that represent the same level of accuracy as the Capex projects contained in Transend’s Revenue Proposal. Based on the process utilised to prepare the estimates, WorleyParsons considers that the estimated costs are efficient for the assumed project scope. It is also relevant to note that for the trigger event to have occurred, Transend would have had to prepare detailed scoping and cost estimates and have gone through the requisite public consultation process.

This project is not dependant on demand forecasts, as it is driven by the probable connection of new generation. The cost inputs for this contingent project align with those used in Transend’s revenue proposal, and on that basis, WorleyParsons is satisfied that the project is based on a realistic expectation of cost inputs, taking into account the “capital expenditure factors”.

The estimated costs for the project are clearly well above the threshold value of $10m.

6.2 Trigger Event

Given that new generation in the western region could arise at various locations and at various capacities, WorleyParsons considers that the trigger event is reasonably specific and capable of objective verification.

If the trigger event occurs, Transend would be obliged under its licence to proceed with the project. The trigger event would generate costs that relate to a specific location that is, the Sheffield-Farrell transmission line corridor.

The trigger event is described in terms such that the occurrence of the event is all that is required for the revenue determination to be amended that is, once the application of the regulatory test was successful, there would be no outstanding requirements preventing the revenue determination being amended.

Based on the ROAM report and WorleyParsons’ sensitivity analysis, WorleyParsons considers there is a reasonable probability that the project will be required during the Next Regulatory Control Period, but notes that the timing is uncertain. As previously noted, the scope and therefore cost of the project is uncertain at this early stage. WorleyParsons considers that it is not appropriate for this project to be included in the ex ante cap due to the uncertainty in both the timing and the cost of the project.

7 CONCLUSION

WorleyParsons considers that this proposed project meets the NER requirements for contingent projects and should be accepted by the AER as a contingent project.

SHEFFIELD-GEORGE TOWN NEW 220 kV TRANSMISSION LINE

1 PROJECT DESCRIPTION

1.1 Project Identification

ND1017

1.2 CAPEX Category

Augmentation

1.3 Brief Overview

The project comprises the establishment of a third 220 kV transmission line between Sheffield and George Town substations, including the construction of switch bays at Sheffield and George Town substations to cater for the new transmission line.

1.4 Background

Transfer capacity between the north-western and western areas of Tasmania and the remainder of the transmission system is limited to the rating of the 220 kV transmission lines that connect Sheffield Substation to George Town and Palmerston substations. Currently the Sheffield–George Town transmission lines already constrain the transmission network under certain circumstances (even when using dynamic ratings) and a System Protection Scheme is in place that allows the transmission line to operate beyond its firm capacity when Basslink is exporting energy.

If generation developments in the north-western and/or western areas of Tasmania occur, the proposed contingent project would remove a transmission network constraint. The project would proceed if the cost of the augmentation was less than the benefits, including by allowing dispatch of lower cost generation to the market and/or deferring higher cost generation development.

The analysis undertaken by ROAM Consulting (refer to Appendix 11 of Transend's Revenue Proposal) identified the potential for significant generation developments in the north-western and western areas of Tasmania. The generation projects identified by ROAM Consulting that relate to the Sheffield–George Town transmission line contingent project are:

- Robbins Island – 240 MW of wind generation in the north-western area of Tasmania; and
- Heemskirk – 160 MW of wind generation in the western area of Tasmania.

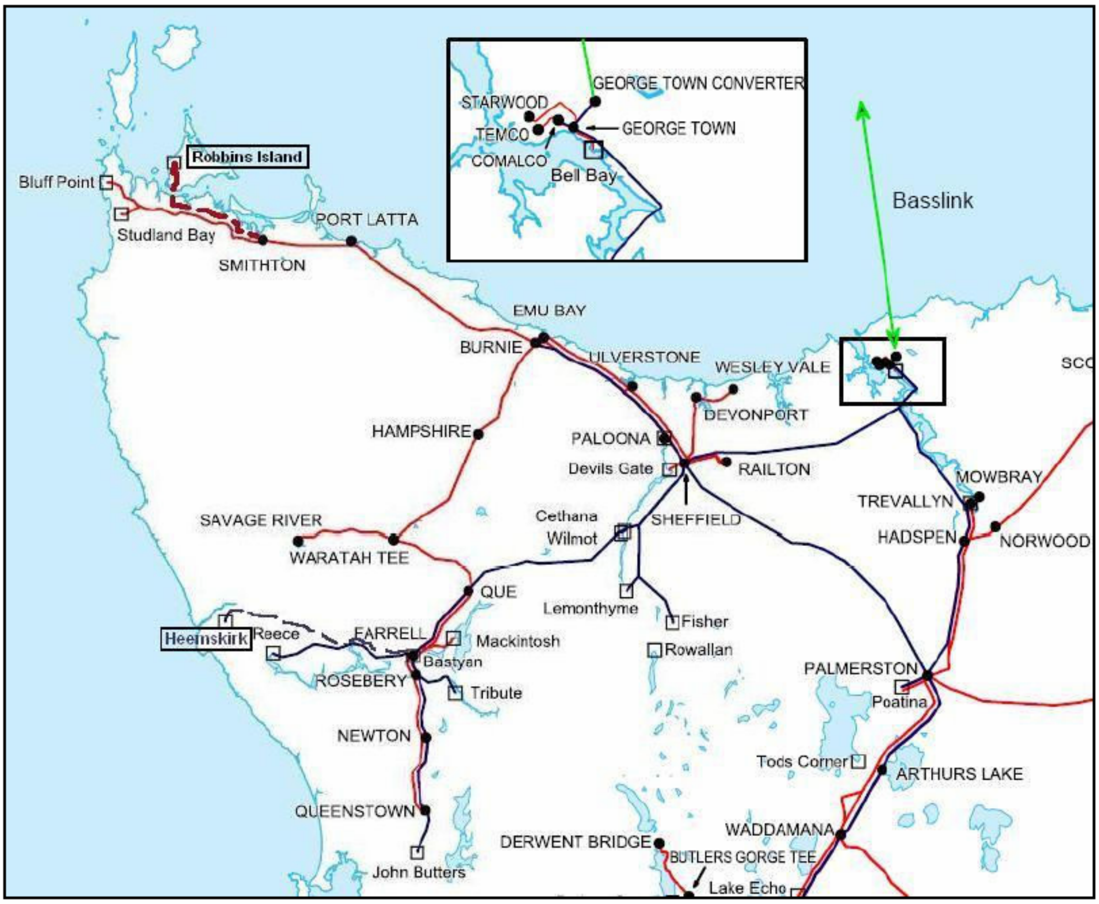
ROAM Consulting has assigned a final probability of proceeding of 15.2 per cent for each of these projects. If these (or other) generation developments occur in the north-western and western regions, increased power transfer capacity may be required between Sheffield and George Town substations.

ROAM Consulting acknowledged that the amount of wind generation likely to be installed is heavily dependent on the level of government action with regard to the management of greenhouse emissions. Recent indications from the Federal Government are that it is becoming more likely that the introduction of initiatives to reduce greenhouse emissions will be put in place in the Next Regulatory Control Period. It is expected to lead to a greater price differential between non-renewable and renewable energy sources, with non-renewable energy becoming relatively more expensive.

Transend has undertaken scenario studies for the north-western and western areas of Tasmania to identify the impact that generation developments would have on the transmission network.

Figure 1 presents a geographical representation of the transmission network in north-western, western and northern Tasmania and it also shows the potential Heemskirk and Robbins Island generation developments.

Figure 1 – Transmission network in the north-west and west coast areas of Tasmania, including Robbins Island and Heemskirk potential generation



With increased relatively-low-cost generation in the north-west and/or western regions, there is a greater prospect that an augmentation to relieve transmission constraints will pass the regulatory test. Transend considers that this project should be accepted as a contingent project for the Next Regulatory Control Period because of uncertainty about the trigger event occurring and uncertainty about the scope and cost of the project.

2 PROJECT NEED

2.1 Drivers

The driver for this project is to provide adequate network capacity to allow the connection of new generation in the north-western and/or western regions.

2.2 Timing

The timing of this project is uncertain. Based on the analysis undertaken by ROAM Consulting, the potential generation developments may occur in 2013–14.

2.3 Strategic Alignment

Clear linkages to Transend's strategic plan would be established in accordance with business practice when the project is initiated.

3 ALTERNATIVES

3.1 Options

Table 1 summarises the options considered at this time. Detailed technical options relating to this project would be considered should the trigger event occur. Further options may be identified during the project initiation process or be proposed by interested parties as part of the public consultation process.

Table 1 – Options considered

Option	Description	Consideration
1	Do nothing	This option would constrain generation on the transmission network and would not allow Transend to achieve the capital expenditure objectives identified in the NER.
2	Develop a network control scheme	Alternative technical solutions including network control schemes would be considered as part of the detailed analysis.
3	Construct a new transmission line between Sheffield and George Town substations	This option would provide additional power transfer capacity from Tasmania's north-west and west coast areas, it would provide a market benefit and it would contribute to the achievement of the capital expenditure objectives.

3.2 Options Analysis

Further options analysis would be conducted should the trigger event occur. At this stage, Option 3 is the preferred option.

3.3 Consideration of Non Network Solutions

Not practicable for this project.

4 REGULATORY CONSIDERATIONS

4.1 NER Requirements

Clause 6A.8.1 requires that a contingent project:

- Is reasonably required in order to achieve any of the "capital expenditure objectives";
- Capex is not otherwise provided for (in part or in whole) in the allowance;
- Reasonably reflects the "capital expenditure criteria":

- Efficient costs;
- The costs a prudent operator would incur; and
- A “realistic expectation” of demand forecasts and cost inputs,

taking into account the “capital expenditure factors”.

- Exceeds the cost threshold (in Transend’s case, this is $10m).

4.2 Alignment with NER Capital Expenditure Objectives

This project would be required to achieve the following capital expenditure objectives identified in clause 6A.6.7(a) of the NER:

- Meet the expected demand for prescribed transmission services over the regulatory control period; and
- Comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services.

In particular, Transend has a regulatory obligation under section 14 of its licence to plan and procure transmission system augmentations that are shown to satisfy the regulatory test.

4.3 Regulatory Test

If there was sufficient relatively-low-cost existing, committed, and/or advanced generation capacity constrained by the Sheffield-George Town 220 kV transmission line, then Transend would undertake the regulatory test to determine whether there would be a market benefit in removing the constraint. If such a benefit was demonstrated (that is, the cost of the augmentation was less than the benefit to the market from the augmentation), then Transend would be required to implement such an augmentation.

This project would be classified as a “large transmission network asset” and would be subject to a public consultation process as defined in clause 5.6.6 of the NER.

4.4 Contingency Trigger

Under clause 6A.8.1(c) of the NER, the following matters are to be considered in determining whether a trigger event is appropriate:

- Trigger event to be reasonably specific and capable of objective verification;
- Trigger event, if it occurs, makes the contingent project reasonably necessary to achieve any of the “capital expenditure objectives”;
- Trigger event to generate increased costs or categories of costs that relate to a specific location rather than the transmission network as a whole;
- Trigger event to be described in such terms that the occurrence of the event is all that is required for the revenue determination to be amended; and
- Trigger event to be probable during the regulatory control period, but inclusion in ex ante cap is not appropriate because of:
    - Uncertainty of timing; and

- Uncertainty of cost.

The trigger proposed for this project is:

Committed and/or advanced generation in the north-western and/or western regions in excess of 50 MW, resulting in successful application of the regulatory test for augmentation of the Sheffield–George Town transmission corridor.

5 EFFICIENCY

5.1 Estimating Basis

A level one estimate has been prepared for this project. The estimated cost of this project is indicative only; however any such project would be expected to exceed the $10 million contingent project threshold.

A detailed project scope and cost estimate will be required before any amendment to the revenue determination is considered by the AER should the specified trigger event occur during the Next Regulatory Control Period.

5.2 Costs

The estimated expenditure in the Next Regulatory Control Period is $70m (June 09, $). Detailed economic analysis has not been completed for this project. Further economic analysis will be undertaken during the project initiation process, should the trigger event occur.

5.3 Design Considerations

The scope of work for this project is wholly within the shared transmission network and is physically removed from any generator connection. It is not possible to accurately define the scope of this project at this early stage and as such, the scope of this project would most likely change following detailed analysis. As such, WorleyParsons is not able to comment further on the design aspects.

5.4 Project Delivery

The transmission line component of this project would be expected to be implemented using a separate design and separate construct approach. The substation and switching station components of this project would be expected to be undertaken using a design and construct approach. Preferred contractors experienced in this type of work would be engaged to undertake the works to complete this project.

6 ASSESSMENT

6.1 NER Requirements

The driver for this project is to provide adequate network capacity to allow the connection of new generation in the north-western and/or western regions. WorleyParsons considers that the project is reasonably required to meet two of the “capital expenditure objectives” (as discussed in Section 4.2), should the trigger event occur.

Having reviewed the detailed list of projects underpinning Transend's submission, WorleyParsons is confident that this project has not been included (in whole or in part) in Transend's forecast Capex.

At this early stage, there is much uncertainty in relation to the scope and costs for the project. Transend has prepared Level 1 estimates (based on the assumption that the new line would be single circuit 220 kV) that represent the same level of accuracy as the Capex projects contained in Transend's revenue proposal. Based on the process utilised to prepare the estimates, WorleyParsons considers that the estimated costs are efficient for the assumed project scope. It is also relevant to note that for the trigger event to have occurred, Transend would have had to prepare detailed scoping and cost estimates and have gone through the requisite public consultation process.

This project is not dependant on forecast demand growth, as it is driven by the probable connection of new generation. The cost inputs for this contingent project align with those used in Transend's revenue proposal, and on that basis, WorleyParsons is satisfied that the project is based on a realistic expectation of cost inputs, taking into account the "capital expenditure factors".

The estimated costs for the project are clearly well above the threshold value of $10m.

6.2 Trigger Event

Given that new generation in the north-western and western regions could arise at various locations and at various capacities, WorleyParsons considers that the trigger event is reasonably specific and capable of objective verification.

If the trigger event occurs, Transend would be obliged under its licence to proceed with the project. The trigger event would generate costs that relate to a specific location that is, the Sheffield–George Town transmission corridor.

The trigger event is described in terms such that the occurrence of the event is all that is required for the revenue determination to be amended that is, once the application of the regulatory test was successful, there would be no outstanding requirements preventing the revenue determination being amended.

Based on the ROAM report and WorleyParsons' sensitivity analysis, WorleyParsons considers there is a reasonable probability that the project will be required during the Next Regulatory Control Period, but notes that the timing is uncertain. As previously noted, the scope and therefore cost of the project is uncertain at this early stage. WorleyParsons considers that it is not appropriate for this project to be included in the ex ante cap due to the uncertainty in both the timing and the cost of the project.

7 CONCLUSION

WorleyParsons considers that this proposed project meets the NER requirements for contingent projects and should be accepted by the AER as a contingent project.

SHEFFIELD-BURNIE NEW 220 kV TRANSMISSION LINE

1 PROJECT DESCRIPTION

1.1 Project Identification

ND0978

1.2 CAPEX Category

Augmentation

1.3 Brief Overview

The project comprises the establishment of a new double-circuit 220 kV transmission line between Sheffield and Burnie substations, including the construction of switch bays at Sheffield and Burnie substations to cater for the new circuits. The existing 220 kV Sheffield–Burnie transmission line will be decommissioned.

1.4 Background

There are currently three circuits in the transmission corridor between Sheffield and Burnie substations; a double-circuit 110 kV transmission line and a single-circuit 220 kV transmission line. Operating under the N-1 criterion, transfer capacity from Burnie Substation is currently limited to the rating of the 110 kV double-circuit Sheffield–Burnie transmission line.

If generation developments in north-west Tasmania occur, the proposed contingent project would remove a transmission network constraint. The project would proceed if the cost of the augmentation was less than the benefits, including by allowing dispatch of lower cost generation to the market and/or deferring the development of higher cost generation.

The analysis undertaken by ROAM Consulting (refer to appendix 11 of Transend's revenue proposal) identified potential significant generation developments in the north-west area of Tasmania. Specifically, the proposed generation project identified that has the potential to impact on the Sheffield–Burnie transmission line contingent project is the "Robbins Island – 240 MW of wind generation" project. ROAM Consulting has assigned a final probability of proceeding of 15.2% for this project. If this (or other) generation development occurs in the north-west region, increased power transfer capacity may be required between Sheffield and Burnie substations.

ROAM Consulting acknowledged that the amount of wind generation likely to be installed is heavily dependent on the level of government action with regard to the management of greenhouse emissions. Recent indications from the Federal Government are that it is becoming more likely that the introduction of initiatives to reduce greenhouse emissions will be put in place in the Next Regulatory Control Period. This is expected to lead to a greater price differential between non-renewable and renewable energy sources, with non-renewable energy becoming relatively more expensive.

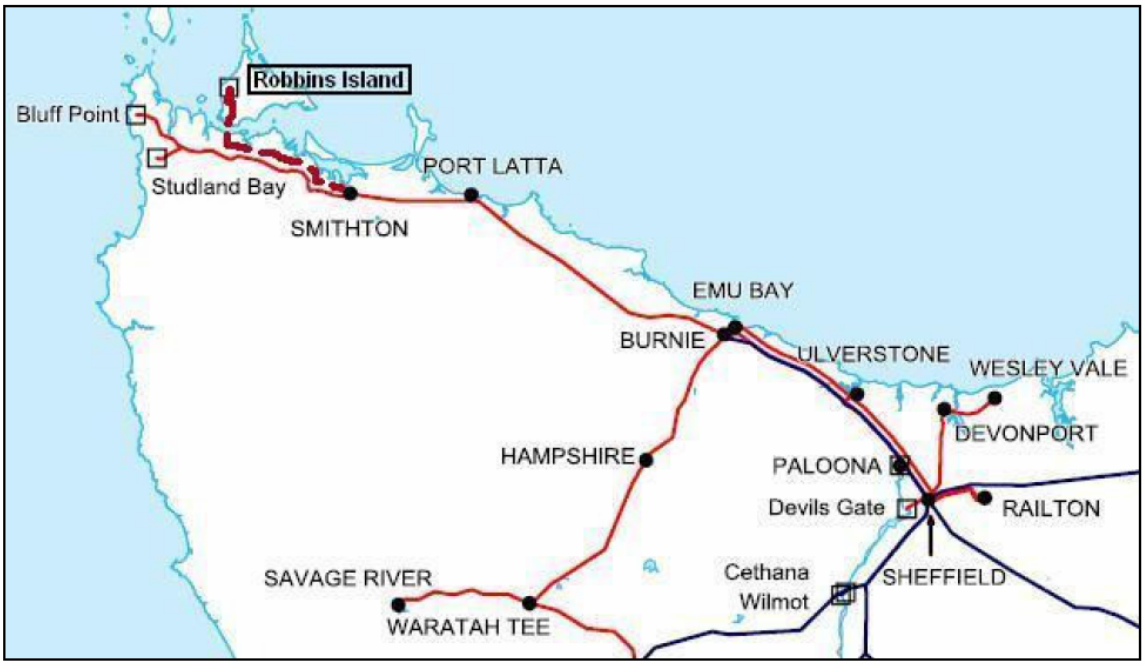
Transend has performed scenario studies for the north-west and west coast areas of Tasmania to identify the impact that generation developments would have on the transmission network. With increased relatively low cost generation in the north-west region, there is a greater prospect that an augmentation to relieve transmission constraints will pass the regulatory test.

Separately to the potential generation development, augmentation of the Sheffield–Burnie 220 kV transmission line would be required under continued high load growth. Whilst there may be increased generation in the region, analysis of wind farm generation patterns indicates that wind farm generation output cannot be relied upon to meet maximum demand.

When the north-west area load reaches approximately 360 MW, a contingency on the 220 kV Sheffield–Burnie No. 1 circuit will result in overloading of the Sheffield–Burnie 110 kV transmission line. As such, reinforcement to the existing Sheffield–Burnie transmission corridor is required. Under a high load growth scenario the area load will reach 360 MW in 2016. This would require capital expenditure in the Next Regulatory Control Period for the line to be commissioned in time to meet load requirements.

Figure 1 presents a geographical representation of the north-west area of Tasmania with the proposed Robbins Island generation development shown.

Figure 1 – North-west Tasmanian transmission network and potential Robbins Island development



Transend contends that this project should be accepted as a contingent project for the Next Regulatory Control Period because of uncertainty about the trigger event occurring and uncertainty about the scope and cost of the project. The project is forecast to take four years from inception to commissioning.

2 PROJECT NEED

2.1 Drivers

The drivers for this project are to provide adequate network capacity to allow the connection of new generation in the north-western and western regions and/or to cater for load growth in the region.

2.2 Timing

The timing of this project is uncertain. Based on the analysis undertaken by ROAM Consulting, the potential generation developments may occur in 2013–14. Under a high load growth scenario, the augmentation would be required to be completed in 2016, requiring commencement in the Next Regulatory Control Period.

2.3 Strategic Alignment

Clear linkages to Transend's strategic plan would be established in accordance with business practice when the project is initiated.

3 ALTERNATIVES

3.1 Options

Table 1 summarises the options considered at this time. Detailed technical options relating to this project would be considered should the trigger event occur. Further options may be identified during the project initiation process or be proposed by interested parties as part of the public consultation process.

Table 1 – Options considered

Option	Description	Consideration
1	Do nothing	This option would continue to leave the transmission network severely constrained and would not allow Transend to achieve the capital expenditure objectives identified in the NER.
2	Network control scheme	This option would only be viable as an alternative to a generation-driven augmentation. It would be implemented through a large run-back scheme, similar to that currently in place for contingency on the Burnie–Smithton transmission line. Once the area load reaches 360 MW, this option will involve load shedding.
3	Construct a new Sheffield Burnie 220 kV transmission line	This option would provide additional power transfer capacity and would contribute to the achievement of the capital expenditure objectives.

3.2 Options Analysis

Further options may be identified during the project initiation process or be proposed by interested parties as part of the public consultation process. At this stage, Transend favours Option 3 as it considers this is the only feasible option. Detailed technical options relating to this project would be considered should the trigger event occur.

3.3 Consideration of Non Network Solutions

Not practicable for this project.

4 REGULATORY CONSIDERATIONS

4.1 NER Requirements

Clause 6A.8.1 requires that a contingent project:

- Is reasonably required in order to achieve any of the "capital expenditure objectives";
- Capex is not otherwise provided for (in part or in whole) in the allowance;

- Reasonably reflects the “capital expenditure criteria”;
    - Efficient costs;
    - The costs a prudent operator would incur; and
    - A “realistic expectation” of demand forecasts and cost inputs,

  taking into account the “capital expenditure factors”.
- Exceeds the cost threshold (in Transend’s case, this is $10m).

4.2 Alignment with NER Capital Expenditure Objectives

This project would be required to achieve the following capital expenditure objectives identified in clause 6A.6.7(a) of the NER:

- Meet the expected demand for prescribed transmission services over the regulatory control period;
- Comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services; and
- Maintain the reliability, safety and security of the transmission system through the supply of prescribed transmission services.

In particular, Transend has a regulatory obligation under section 14 of its licence to plan and procure transmission system augmentations that are shown to satisfy the regulatory test.

4.3 Regulatory Test

If there was sufficient relatively low cost existing, committed, and/or advanced generation capacity constrained by the Sheffield–Burnie 220 kV transmission line, then Transend would undertake the regulatory test to determine whether there would be a market benefit in removing the constraint. If such a benefit was demonstrated (if the cost of the augmentation was less than the benefit to the market from the augmentation), then Transend would be required to implement such an augmentation.

Alternatively, or in addition to the generation impacts, if demand growth in the north-western area tracked higher than the present medium forecast—indicating that it was likely for the demand of 360 MW to be reached in the Next Regulatory Control Period, or in the first four years of the 2014–19 Regulatory Control Period—then Transend would undertake the regulatory test to identify the investment in the Sheffield–Burnie transmission corridor that satisfied the test. Transend would be required to implement an augmentation project that satisfied the test.

This project would be classified as a “large transmission network asset” and would be subject to a public consultation process as defined in clause 5.6.6 of the NER.

4.3 Contingency Trigger

Under clause 6A.8.1(c) of the NER, the following matters are to be considered in determining whether a trigger event is appropriate:

- Trigger event to be reasonably specific and capable of objective verification;

- Trigger event, if it occurs, makes the contingent project reasonably necessary to achieve any of the “capital expenditure objectives”;
- Trigger event to generate increased costs or categories of costs that relate to a specific location rather than the transmission network as a whole;
- Trigger event to be described in such terms that the occurrence of the event is all that is required for the revenue determination to be amended; and
- Trigger event to be probable during the regulatory control period, but inclusion in ex ante cap is not appropriate because of:
    - Uncertainty of timing; and
    - Uncertainty of cost.

The trigger proposed for this project is:

- Demand in Tasmania’s north-western region exceeds 360 MW; and/or
- In excess of 50 MW committed and/or advanced generation projects in the north-western region,

resulting in successful application of the regulatory test for augmentation of the Sheffield-Burnie transmission corridor.

5 EFFICIENCY

5.1 Estimating Basis

A level one estimate has been prepared for this project. The estimated cost of this project is indicative only; however any such project would be expected to exceed the $10 million contingent project threshold.

A detailed project scope and cost estimate will be required before any amendment to the revenue determination is considered by the AER should the specified trigger event occur during the Next Regulatory Control Period.

5.2 Costs

The estimated expenditure in the Next Regulatory Control Period is $52m (June 09, $). Detailed economic analysis has not been completed for this project. Further economic analysis will be undertaken during the project initiation process, should the trigger event occur.

5.3 Design Considerations

The scope of work for this project is wholly within the shared transmission network and is physically removed from any generator connection. It is not possible to accurately define the scope of this project at this early stage and as such, the scope of this project would most likely change following detailed analysis. As such, WorleyParsons is not able to comment on the design aspects.

5.4 Project Delivery

This project would be expected to be implemented using a separate design and separate construct approach. Preferred contractors experienced in this type of work would be engaged to undertake the works to complete this project.

6 ASSESSMENT

6.1 NER Requirements

The drivers for this project are to provide adequate network capacity to allow the connection of new generation in the north-western and western regions and/or to cater for load growth in the region. WorleyParsons considers that the project is reasonably required to meet two of the "capital expenditure objectives" (as discussed in Section 4.2), should the trigger event occur.

Having reviewed the detailed list of projects underpinning Transend's submission, WorleyParsons is confident that this project has not been included (in whole or in part) in Transend's forecast Capex.

At this early stage, there is much uncertainty in relation to the scope and costs for the project. Transend has prepared Level 1 estimates (based on the assumption that the new line would be single circuit 220 kV) that represent the same level of accuracy as the Capex projects contained in Transend's revenue proposal. Based on the process utilised to prepare the estimates, WorleyParsons considers that the estimated costs are efficient for the assumed project scope. It is also relevant to note that for the trigger event to have occurred, Transend would have had to prepare detailed scoping and cost estimates and have gone through the requisite public consultation process.

If the trigger event turns out to be connection of new generation, this project would not be dependant on demand forecasts. Should increasing demand provide the trigger event, this would become evident by analysis of the 2011 actual MDs.

The cost inputs for this contingent project align with those used in Transend's submission, and on that basis, WorleyParsons is satisfied that the project is based on a realistic expectation of cost inputs, taking into account the "capital expenditure factors".

The estimated costs for the project are clearly well above the threshold value of $10m.

6.2 Trigger Event

Given that new generation in the north-western region could arise at various locations and at various capacities, WorleyParsons considers that the trigger event is reasonably specific and capable of objective verification.

If the trigger event occurs, Transend would be obliged under its licence to proceed with the project. The trigger event would generate costs that relate to a specific location that is, the Burnie-Smithton transmission line corridor.

The trigger event is described in terms such that the occurrence of the event is all that is required for the revenue determination to be amended that is, once the application of the regulatory test was successful, there would be no outstanding requirements preventing the revenue determination being amended.

Based on the ROAM report and WorleyParsons' sensitivity analysis, WorleyParsons considers there is a reasonable probability that the project will be required during the Next Regulatory

Control Period, but notes that the timing is uncertain. As previously noted, the scope and therefore cost of the project is uncertain at this early stage. WorleyParsons considers that it is not appropriate for this project to be included in the ex ante cap due to the uncertainty in both the timing and the cost of the project.

7 CONCLUSION

WorleyParsons considers that this proposed project meets the NER requirements for contingent projects and should be accepted by the AER as a contingent project.

ST HELENS NEW 110/22 kV CONNECTION SITE

1 PROJECT DESCRIPTION

1.1 Project Identification

ND0936

1.2 CAPEX Category

Augmentation

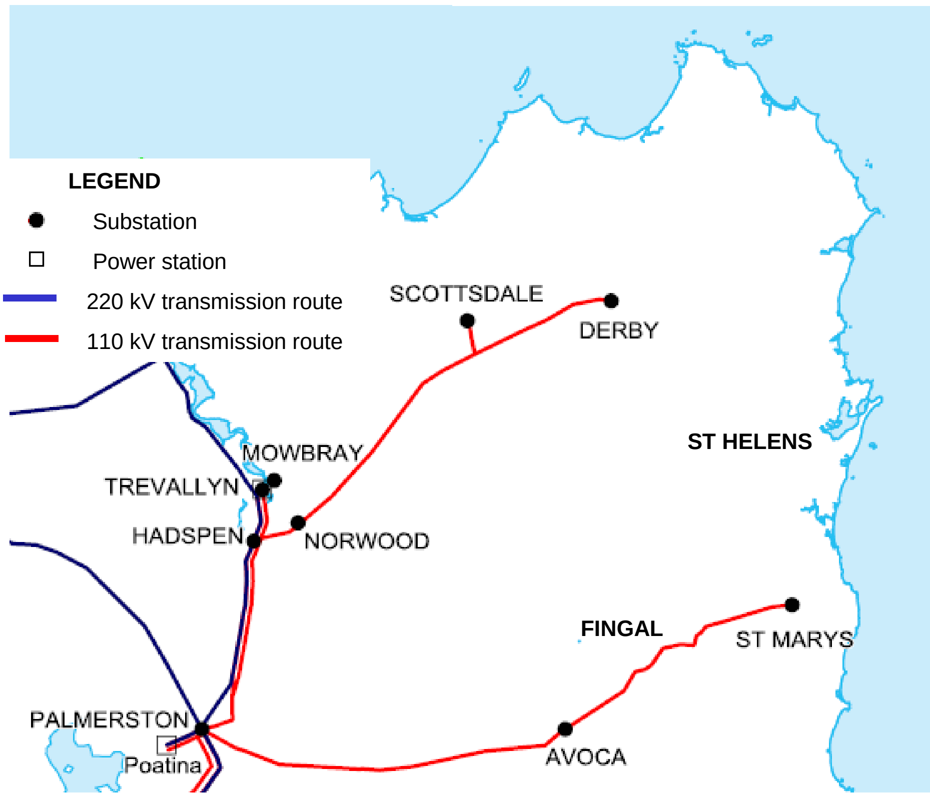
1.3 Brief Overview

The St Helens' new 110/22 kV connection site project comprises the construction of a 110 kV transmission line from Derby Substation to a new connection site at St Helens. The establishment of a new connection site at St Helens would be the first stage of the long-term strategy to form a 110 kV transmission connection between Derby and St Marys substations.

1.4 Background

The St Helens and Fingal valley areas of Tasmania's east coast are supplied via the Palmerston–Avoca and Avoca–St Marys 110 kV transmission lines. Alternative supplies from Derby and Triabunna substations are able to cater for a small proportion of the load in the area under certain circumstances. A diagram of the current arrangement for the east coast of Tasmania is presented in Figure 1. Triabunna Substation is well to the south of St Marys Substation.

Figure 1 – Northern area of Tasmania with St Helens and Fingal valley areas



The east coast area has experienced significant demand growth in recent years, with demand growth at Avoca and St Marys substations anticipated to average 5.4 and 3.0 per cent respectively. In particular, St Helens and surrounding areas have experienced considerable demand growth. The St Helens area is currently supplied from St Marys Substation.

The current arrangement does not comply with clause 5.(1)(a)(iv) of the Electricity Supply Industry (Network Performance Requirements) Regulations 2007 (network performance requirements) in that the “unserved energy to load that is interrupted consequent on damage to a network element resulting from a credible contingency event is not to be capable of exceeding 300 MWh at any time.” Based on the current demand forecast, by 2016, the current arrangement will also not comply with clause 5.(1)(a)(i) of the network performance requirements in that “no more than 25 MW of load is capable of being interrupted by a credible contingency event”. The primary cause of the non-compliance is the loss of the Palmerston–Avoca or Avoca– St Marys 110 kV transmission lines because of a credible contingency event.

Preliminary investigations have identified that the construction of a new 110 kV transmission line from Derby Substation to a new substation site in the St Helens area is the least-cost and most appropriate strategic solution to address the identified issues. However, the investment to achieve compliance exceeds the $15m threshold set by the jurisdiction’s minimum network performance standards. Preliminary analysis suggests that based on existing load levels, investment in the Next Regulatory Control Period may not provide sufficient benefit to achieve Ministerial approval under the reliability limb of the regulatory test.

An unexpected demand increase in the St Helens area would increase the reliability benefits associated with this investment, and may therefore influence the outcome of the regulatory test and advance the need for this project to within the Next Regulatory Control Period. Transend would work with the DNSP, Aurora Energy to undertake this analysis.

Transend contends that this project should be accepted as a contingent project for the Next Regulatory Control Period because of uncertainty about the trigger event occurring and uncertainty about the scope and cost of the project.

2 PROJECT NEED

2.1 Drivers

The drivers for this project are:

- To cater for forecast demand growth in the St Helens area; and
- Comply with the minimum network performance levels under the ESI Regulations.

2.2 Timing

The timing of this project is uncertain. Based on the current demand forecast, by 2016, the current arrangement will not comply with clause 5.(1)(a)(i) of the network performance requirements in that “no more than 25 MW of load is capable of being interrupted by a credible contingency event”.

2.3 Strategic Alignment

Clear linkages to Transend's strategic plan would be established in accordance with business practice when the project is initiated.

3 ALTERNATIVES

3.1 Options

Table 1 summarises the options considered at this time. Detailed technical options relating to this project would be considered should the trigger event occur. Further options, including non-network solutions, may be identified during the project initiation process or be proposed by interested parties as part of the public consultation process.

Table 1 – Options considered

Option	Description	Consideration
1	Do nothing	This option would leave the transmission system severely constrained and would not allow Transend to achieve the capital expenditure objectives identified in the NER
2	Second Palmerston–Avoca and Avoca–St Marys 110 kV transmission lines	This option is technically feasible, but it is not the least cost solution and does not provide the benefit of providing a transmission connection to Derby Substation
3	New 110 kV transmission line between Derby and St Marys substations	This option is technically feasible, but it is not the least cost solution
4	New 110 kV transmission line between Triabunna and St Marys substations	This option is technically feasible, but it is not the least cost solution
5	New 110 kV transmission line from Derby Substation to a new connection site at St Helens	This option is technically feasible, is the least cost solution which addresses the investment need and is consistent with the strategy to provide a transmission connection to Derby Substation

3.2 Consideration of Non Network Solutions

Non-network solutions would be considered during the project initiation process.

3.3 Options Analysis

At this stage, Transend favours Option 5 as it is the least cost solution that addresses the investment needs. This project would be subject to joint planning with Aurora to identify the optimal solution.

4 REGULATORY CONSIDERATIONS

4.1 NER Requirements

Clause 6A.8.1 requires that a contingent project:

- Is reasonably required in order to achieve any of the “capital expenditure objectives”;
- Capex is not otherwise provided for (in part or in whole) in the allowance;
- Reasonably reflects the “capital expenditure criteria”;
  - Efficient costs;
  - The costs a prudent operator would incur; and
  - A “realistic expectation” of demand forecasts and cost inputs,

  taking into account the “capital expenditure factors”.
- Exceeds the cost threshold (in Transend’s case, this is $10m).

4.2 Alignment with NER Capital Expenditure Objectives

This project would be required to achieve the following capital expenditure objectives identified in clause 6A.6.7(a) of the NER:

- Meet the expected demand for prescribed transmission services over the regulatory control period;
- Comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services; and
- Maintain the reliability, safety and security of the transmission system through the supply of prescribed transmission services.

In particular, Transend has a regulatory obligation under section 14 of its licence to plan and procure transmission system augmentations that are shown to satisfy the regulatory test.

4.3 Regulatory Test

This project is forecast to take three years from inception to commissioning. If demand growth in the area tracked higher than the present medium forecast—indicating that there was likely to be sufficient benefit from the connection in the Next Regulatory Control Period, or in the first three years of the 2014–19 Regulatory Control Period—then Transend would undertake the regulatory test to identify the investment serving the St Helens area that satisfied the test.

This project would be classified as a “large transmission network asset” and would be subject to a public consultation process as defined in clause 5.6.6 of the NER.

4.4 Contingency Trigger

Under clause 6A.8.1(c) of the NER, the following matters are to be considered in determining whether a trigger event is appropriate:

- Trigger event to be reasonably specific and capable of objective verification;

- Trigger event, if it occurs, makes the contingent project reasonably necessary to achieve any of the “capital expenditure objectives”;
- Trigger event to generate increased costs or categories of costs that relate to a specific location rather than the transmission network as a whole;
- Trigger event to be described in such terms that the occurrence of the event is all that is required for the revenue determination to be amended; and
- Trigger event to be probable during the regulatory control period, but inclusion in ex ante cap is not appropriate because of:
    - Uncertainty of timing; and
    - Uncertainty of cost.

The trigger proposed for this project is:

The demand forecast in the east coast region exceeds 55 MW, resulting in successful application of the regulatory test for augmentation of the transmission system to the St Helens area.

5 EFFICIENCY

5.1 Estimating Basis

A level one estimate has been prepared for this project. The estimated cost of this project is indicative only; however any such project would be expected to exceed the $10 million contingent project threshold.

A detailed project scope and cost estimate will be required before any amendment to the revenue determination is considered by the AER should the specified trigger event occur during the Next Regulatory Control Period.

5.2 Costs

The estimated expenditure in the Next Regulatory Control Period is $47m (June 09, $). Detailed economic analysis has not been completed for this project. Further economic analysis will be undertaken during the project initiation process, should the trigger event occur.

5.3 Design Considerations

The scope of work for this project is wholly within the shared transmission network and is physically removed from any generator connection. It is not possible to accurately define the scope of this project at this early stage and as such, the scope of this project would most likely change following detailed analysis. As such, WorleyParsons is not able to comment on the design aspects.

5.4 Project Delivery

The transmission line component of this project would be expected to be implemented using a separate design and separate construct approach. The substation and switching station components of this project would be expected to be undertaken using a design and construct approach. Preferred contractors experienced in this type of work would be engaged to undertake the works to complete this project.

6 ASSESSMENT

6.1 NER Requirements

The drivers for this project are to cater for forecast demand growth in the St Helens area and to comply with the minimum network performance levels under the ESI Regulations. WorleyParsons considers that the project is reasonably required to meet three of the “capital expenditure objectives” (as discussed in Section 4.2), should the trigger event occur.

Having reviewed the detailed list of projects underpinning Transend’s submission, WorleyParsons is confident that this project has not been included (in whole or in part) in Transend’s forecast Capex.

At this early stage, there is much uncertainty in relation to the scope and costs for the project. Transend has prepared Level 1 estimates (based on the assumption that the new line would be double circuit 110 kV strung on one side only) that represent the same level of accuracy as the Capex projects contained in Transend’s revenue proposal. Based on the process utilised to prepare the estimates, WorleyParsons considers that the estimated costs are efficient for the assumed project scope. It is also relevant to note that for the trigger event to have occurred, Transend would have had to prepare detailed scoping and cost estimates and have gone through the requisite public consultation process.

This project is dependant on demand forecasts, which would need to be reviewed in 2012 to establish whether the project would need to commence in the Next Regulatory Control Period. The cost inputs for this contingent project align with those used in Transend’s submission, and on that basis, WorleyParsons is satisfied that the project is based on a realistic expectation of cost inputs, taking into account the “capital expenditure factors”.

The estimated costs for the project are clearly well above the threshold value of $10m.

6.2 Trigger Event

Given that load growth in the east coast region can be monitored and projections made, WorleyParsons considers that the trigger event is reasonably specific and capable of objective verification.

If the trigger event occurs, Transend would be obliged under its licence to proceed with the project. The trigger event would generate costs that relate to a specific location that is, the Palmerston-Avoca and Avoca-St Marys transmission lines.

The trigger event is described in terms such that the occurrence of the event is all that is required for the revenue determination to be amended that is, once the application of the regulatory test was successful, there would be no outstanding requirements preventing the revenue determination being amended.

As previously noted, the scope and therefore cost of the project is uncertain at this early stage. WorleyParsons considers that it is not appropriate for this project to be included in the ex ante cap due to the uncertainty in both the timing and the cost of the project.

For this project to be required during the Next Regulatory Control Period, load growth would need to be higher than is currently expected (in order to provide sufficient benefits to achieve Ministerial approval under the reliability limb of the regulatory test). On this basis, the AER may wish to consider excluding this project from the list of contingent projects.

7 CONCLUSION

WorleyParsons considers that this proposed project meets the NER requirements for contingent projects and should be accepted by the AER as a contingent project.

PALMERSTON-SHEFFIELD 220 kV TRANSMISSION LINE AUGMENTATION

1 PROJECT DESCRIPTION

1.1 Project Identification

ND1015

1.2 CAPEX Category

Augmentation

1.3 Brief Overview

This project comprises the augmentation of the Palmerston–Sheffield 220 kV transmission line and the associated switch bays at Palmerston and Sheffield substations. The technical parameters (capacity etc) for the augmented transmission line have not yet been determined in detail, however the indicative cost is based upon re-tensioning the Palmerston-Sheffield 220 kV line to a design temperature of 80 degrees Celsius.

1.4 Background

Transfer capacity between the north-western and western areas of Tasmania and the remainder of the transmission system is limited to the rating of the 220 kV transmission lines that connect Sheffield Substation to George Town and Palmerston substations. It should be noted that currently the Palmerston–Sheffield 220 kV transmission line already constrains the transmission network under certain circumstances (even with dynamic operation) and that a System Protection Scheme is in place that allows the transmission line to operate beyond firm capacity when Basslink is exporting energy.

If generation developments in the north-western and/or western areas of Tasmania occur, the proposed contingent project would remove a transmission network constraint. The project would proceed if the cost of the augmentation was less than the benefits, including allowing dispatch of lower cost generation to the market.

The analysis undertaken by ROAM Consulting (refer to Appendix 11 of Transend’s revenue proposal) identified the potential for significant generation developments in the north-western and western areas of Tasmania.

The generation projects identified by ROAM consulting that relate to the Palmerston–Sheffield transmission line contingent project are the:

- Robbins Island – 240 MW of wind generation in the north western area of Tasmania; and
- Heemskirk – 160 MW of wind generation in the western area of Tasmania.

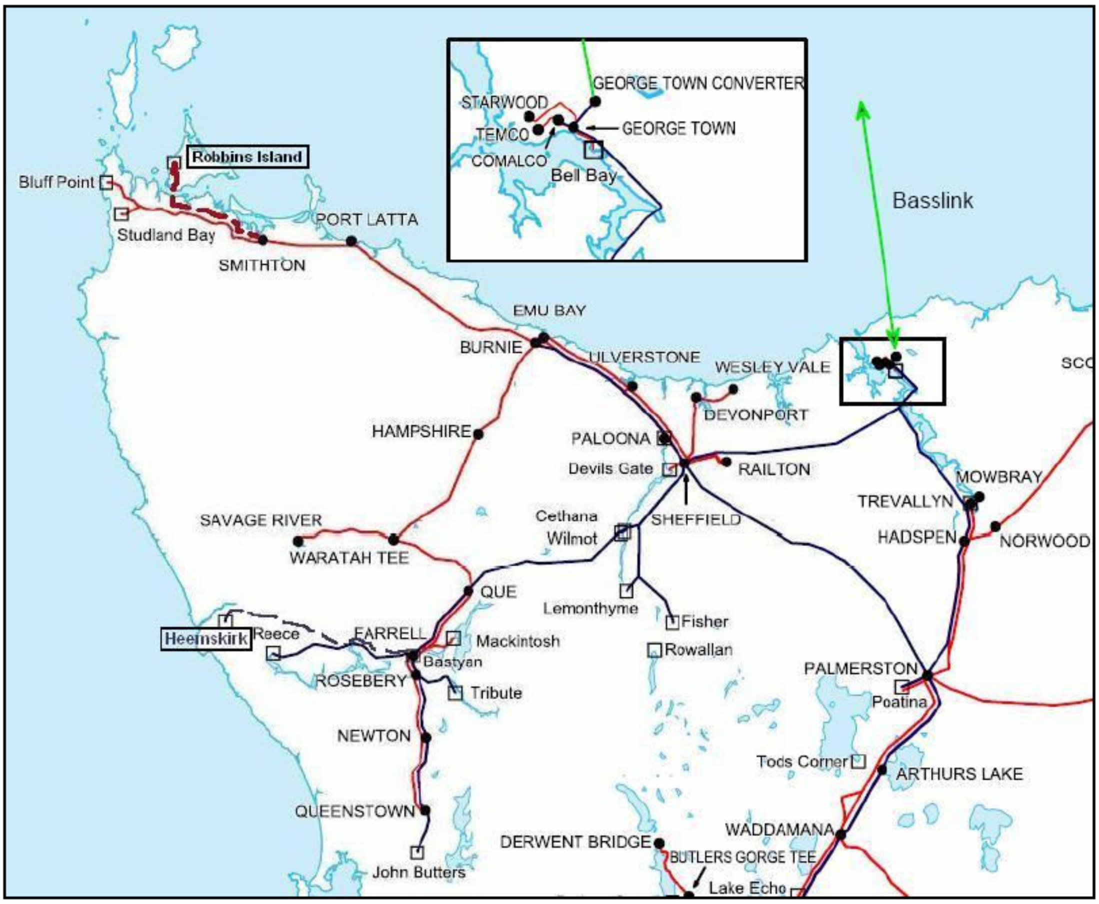
ROAM Consulting has assigned a final probability of proceeding of 15.2 per cent for each of these projects. If these (or other) generation developments occur, increased power transfer capacity may be required between Palmerston and Sheffield substations.

ROAM Consulting acknowledged that the amount of wind generation likely to be installed is heavily dependent on the level of government action with regard to the management of greenhouse emissions. Recent indications from the Federal Government are that it is becoming more likely that the introduction of initiatives to reduce greenhouse emissions will be put in place in the Next Regulatory Control Period. This is expected to lead to a greater price differential between non-renewable and renewable energy sources, with non-renewable energy becoming relatively more expensive.

Transend has undertaken scenario studies for the north-west and western areas of Tasmania to identify the impact that generation developments would have on the transmission network.

Figure 1 presents a geographical representation of the transmission network in north-western, western and northern Tasmania and it also shows the potential Heemskirk and Robbins Island generation developments.

Figure 1 – Transmission network in the north-west and west coast areas of Tasmania, including Robbins Island and Heemskirk potential generation



With increased relatively-low-cost generation in the north-west and/or western regions, there is a greater prospect that an augmentation to relieve transmission constraints will pass the regulatory test. Transend considers that this project should be accepted as a contingent project for the Next Regulatory Control Period because of uncertainty about the trigger event occurring and uncertainty about the scope and cost of the project.

2 PROJECT NEED

2.1 Drivers

The driver for this project is to provide adequate network capacity to allow the connection of new generation in the north-western and western regions.

2.2 Timing

The timing of this project is uncertain. Based on the analysis undertaken by ROAM Consulting, the potential generation developments may occur in 2013–14.

2.3 Strategic Alignment

Clear linkages to Transend's strategic plan would be established in accordance with business practice when the project is initiated.

3 ALTERNATIVES

3.1 Options

Table 1 summarises the options considered at this time. Detailed technical options relating to this project would be considered should the trigger event occur. Further options may be identified during the project initiation process or be proposed by interested parties as part of the public consultation process.

Table 1 – Options considered

Option	Description	Consideration
1	Do nothing	This option would constrain generation on the transmission network and would not allow Transend to achieve the capital expenditure objectives identified in the NER.
2	Develop a network control scheme	Alternative technical solutions including network control schemes would be considered as part of the detailed analysis.
3	Augment the Palmerston–Sheffield transmission line, by re-tensioning the line to allow a design temperature of 80^{O}C or re-conductoring the line	This option would provide additional power transfer capacity from Tasmania's north-west and west coast areas, it would provide a market benefit and it would contribute to the achievement of the capital expenditure objectives.

3.2 Options Analysis

Further options analysis would be conducted should the trigger event occur.

3.3 Consideration of Non Network Solutions

Not practicable for this project.

4 REGULATORY CONSIDERATIONS

4.1 NER Requirements

Clause 6A.8.1 requires that a contingent project:

- Is reasonably required in order to achieve any of the "capital expenditure objectives";
- Capex is not otherwise provided for (in part or in whole) in the allowance;

- Reasonably reflects the “capital expenditure criteria”;
    - o efficient costs;
    - o the costs a prudent operator would incur; and
    - o a “realistic expectation” of demand forecasts and cost inputs,

  taking into account the “capital expenditure factors”.
- Exceeds the cost threshold (in Transend’s case, this is $10m).

4.2 Alignment with NER Capital Expenditure Objectives

This project would be required to achieve the following capital expenditure objectives identified in clause 6A.6.7(a) of the NER:

- Meet the expected demand for prescribed transmission services over the regulatory control period; and
- Comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services.

In particular, Transend has a regulatory obligation under section 14 of its licence to plan and procure transmission system augmentations that are shown to satisfy the regulatory test.

4.3 Regulatory Test

If there was sufficient relatively-low-cost existing, committed, and/or advanced generation capacity constrained by the Palmerston–Sheffield 220 kV transmission line, then Transend would undertake the regulatory test to determine whether there would be a market benefit in removing the constraint. If such a benefit was demonstrated (put simply, by demonstrating that the cost of the augmentation was less than the benefit to the market from the augmentation), then Transend would be required to implement such an augmentation.

This project would be classified as a “large transmission network asset” and would be subject to a public consultation process as defined in clause 5.6.6 of the NER.

4.4 Contingency Trigger

Under clause 6A.8.1(c) of the NER, the following matters are to be considered in determining whether a trigger event is appropriate:

- Trigger event to be reasonably specific and capable of objective verification;
- Trigger event, if it occurs, makes the contingent project reasonably necessary to achieve any of the “capital expenditure objectives”;
- Trigger event to generate increased costs or categories of costs that relate to a specific location rather than the transmission network as a whole;
- Trigger event to be described in such terms that the occurrence of the event is all that is required for the revenue determination to be amended; and
- Trigger event to be probable during the regulatory control period, but inclusion in ex ante cap is not appropriate because of:

- o Uncertainty of timing; and
- o Uncertainty of cost.

The trigger proposed for this project is: At least 50 MW of actual, committed and/or advanced generation projects in the north-western and/or western regions, resulting in successful application of the regulatory test for augmentation of the Palmerston–Sheffield transmission corridor.

5 EFFICIENCY

5.1 Estimating Basis

A level one estimate has been prepared for this project. The estimated cost of this project is indicative only; however any such project would be expected to exceed the $10 million contingent project threshold.

A detailed project scope and cost estimate will be required before any amendment to the revenue determination is considered by the AER should the specified trigger event occur during the Next Regulatory Control Period.

5.2 Costs

The estimated expenditure in the Next Regulatory Control Period is $22m (June 09, $). Detailed economic analysis has not been completed for this project. Further economic analysis will be undertaken during the project initiation process, should the trigger event occur.

5.3 Design Considerations

WorleyParsons notes that Transend favours the option of re-tensioning the existing the line, rather than re-conductoring, which would be expected to be the cheaper option of the two.

The scope of work for this project is wholly within the shared transmission network and is physically removed from any generator connection. It is not possible to accurately define the scope of this project at this early stage and as such, the scope of this project would most likely change following detailed analysis. As such, WorleyParsons is not able to comment further on the design aspects.

5.4 Project Delivery

The transmission line component of this project would be expected to be implemented using a separate design and separate construct approach. The substation and switching station components of this project would be expected to be undertaken using a design and construct approach. Preferred contractors experienced in this type of work would be engaged to undertake the works to complete this project.

6 ASSESSMENT

6.1 NER Requirements

The driver for this project is to provide adequate network capacity to allow the connection of new generation in the north-western and western regions. WorleyParsons considers that the project is reasonably required to meet two of the “capital expenditure objectives” (as discussed in Section 4.2), should the trigger event occur.

Having reviewed the detailed list of projects underpinning Transend’s submission, WorleyParsons is confident that this project has not been included (in whole or in part) in Transend’s forecast Capex.

At this early stage, there is much uncertainty in relation to the scope and costs for the project. Transend has prepared Level 1 estimates (based on the assumption that the existing line would be re-tensioned) that represent the same level of accuracy as the Capex projects contained in Transend’s revenue proposal. Based on the process utilised to prepare the estimates, WorleyParsons considers that the estimated costs are efficient for the assumed project scope. It is also relevant to note that for the trigger event to have occurred, Transend would have had to prepare detailed scoping and cost estimates and have gone through the requisite public consultation process.

This project is not dependant on demand forecasts, as it is driven by the probable connection of new generation. The cost inputs for this contingent project align with those used in Transend’s submission, and on that basis, WorleyParsons is satisfied that the project is based on a realistic expectation of cost inputs, taking into account the “capital expenditure factors”.

The estimated costs for the project are clearly well above the threshold value of $10m.

6.2 Trigger Event

Given that new generation in the north-western and western regions could arise at various locations and at various capacities, WorleyParsons considers that the trigger event is reasonably specific and capable of objective verification.

If the trigger event occurs, Transend would be obliged under its licence to proceed with the project. The trigger event would generate costs that relate to a specific location that is, the Palmerston-Sheffield transmission line.

The trigger event is described in terms such that the occurrence of the event is all that is required for the revenue determination to be amended that is, once the application of the regulatory test was successful, there would be no outstanding requirements preventing the revenue determination being amended.

Based on the ROAM report and WorleyParsons’ sensitivity analysis, WorleyParsons considers there is a reasonable probability that the project will be required during the Next Regulatory Control Period, but notes that the timing is uncertain. As previously noted, the scope and therefore cost of the project is uncertain at this early stage. WorleyParsons considers that it is not appropriate for this project to be included in the ex ante cap due to the uncertainty in both the timing and the cost of the project.

7 CONCLUSION

WorleyParsons considers that this proposed project meets the NER requirements for contingent projects and should be accepted by the AER as a contingent project.

WADDAMANA-LINDISFARNE SECOND 220 kV CIRCUIT

1 PROJECT DESCRIPTION

1.1 Project Identification

ND0935

1.2 CAPEX Category

Augmentation

1.3 Brief Overview

This project involves the installation of a second 220 kV transmission circuit from Waddamana Substation to Lindisfarne Substation and a second 220/110 kV auto-transformer at Lindisfarne Substation. The work includes the installation of:

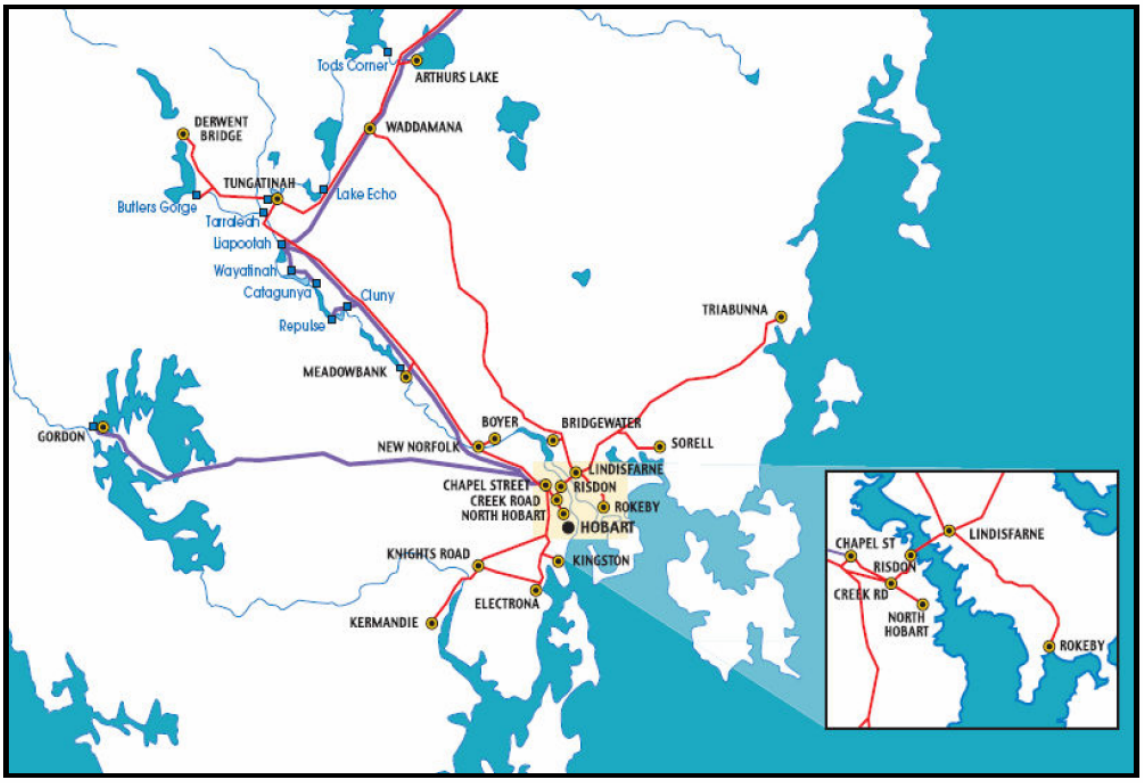
- 99 kilometres of 220 kV transmission line to be strung on the existing double circuit towers;
- One new switchyard bay at Waddamana Substation and two at Lindisfarne Substation; and
- Circuit breakers, associated protection and control and required civil works.

1.4 Background

Southern Tasmania's electricity is supplied via a series of 110 kV transmission lines from the Upper Derwent region and 220 kV transmission lines from Liapootah Substation in the Lower Derwent and Gordon Substation into Chapel Street Substation. The closest source of electricity to the Hobart region is from the Upper and Lower Derwent power schemes north-west of Hobart and Gordon power station west of Hobart. Additional power requirements above the local generation come from Palmerston Substation through the 220 kV Liapootah–Palmerston transmission lines and the 110 kV Waddamana–Palmerston transmission line.

The southern electricity transmission system is presented in Figure 1 below.

Figure 1 – Southern area transmission system



Under certain system conditions, the existing southern Tasmanian network now has insufficient capacity to supply all customer load. The network can transfer sufficient power into southern Tasmania to supply up to 640 MW of electricity during cold periods. However, the southern system peak was above 751 MW in July 2008, and this is expected to continue to increase.

The amount of demand that can be supported relies heavily on the southern generation, especially Hydro Tasmania's Gordon power station. Gordon power station consists of three generation units rated at 144MW, connected to Chapel Street Substation via a double circuit line. To minimise the likelihood of supply disruption in southern Tasmania, Transend presently has a network support agreement in place with Hydro Tasmania. This agreement provides a short term solution that alleviates some, but not all, network constraints in southern Tasmania.

As part of the southern power system security project, Transend commissioned McLennan Magasanik Associates (MMA) to undertake an independent assessment of the net market benefits (in accordance with the requirements of the regulatory test) of options for alleviating the constraints in the southern transmission network. MMA's study assessed the net market benefits of alternative options under three scenarios:

- Scenario 1 – Do nothing – under which there is no investment in generation or transmission assets;
- Scenario 2 – Network augmentation – investment in a new double circuit 220 kV transmission line between the existing Waddamana and Lindisfarne substations (developed either complete or in two stages) and related substation upgrades; or
- Scenario 3 – Gas-fired generation – a thermal generation investment alternative involving installation of up to four 75 MW open-cycle gas turbines (OCGT) and/or a 225 MW combined-cycle gas turbine (CCGT) located at Bridgewater.

Summary and conclusions of MMA's net market benefits assessment

Table 1 shows the investment option that provided the maximum market benefit under each of the three economic growth scenarios and value of customer reliability (VCR) estimates. In all cases, the alternative proposed network augmentation programs out-performed the generation.

Table 1: Preferred staging option for each scenario

	High growth	Medium growth	Low growth
$30,000/MWh VCR	Straight double circuit augmentation	Staged double circuit augmentation	Staged double circuit augmentation
$10,000/MWh VCR	Straight double circuit augmentation	Staged double circuit augmentation	Staged double circuit augmentation

The choice to build either a straight or staged double-circuit line depends on the future level of demand growth relative to the cost differential of stringing one or two circuits. Both the staged and straight double circuit network augmentations provided higher net market benefits than the generation investment under five of the six scenarios.

The straight double circuit augmentation provided higher net market benefits than the staged double circuit augmentation under high economic growth conditions. In all other scenarios, the staged double circuit augmentation yielded the highest net market benefits. Therefore, the staged double circuit option provided the maximum market benefits under the majority of scenarios.

Southern transmission augmentation stage 1, involving the installation of a single circuit 220 kV transmission line between Waddamana and Lindisfarne substations, is now a committed project and expected to be completed by 2011.

There are a number of possible scenarios that would justify stringing the second circuit in the 2009-14 Regulatory Control Period, involving assessment of the cost of the augmentation, projected demand and projected southern Tasmanian generation availability.

Cost sensitivity

The difference in net market benefits between the straight double-circuit augmentation and the staged double circuit augmentation is less than 1 per cent in the majority of scenarios.

As part of the tender process for the proposed line, Transend is seeking prices for stringing the line with both single and double-circuits. The resulting cost differential based on actual market prices (rather than estimates used in the regulatory test analysis) will be considered against demand and generation projections, and the regulatory test sensitivity analysis re-run to determine whether or not there is a greater market benefit from stringing both circuits of the line in the first instance.

Load and generation sensitivity

With the proposed construction of the Waddamana–Lindisfarne No. 1 220 kV circuit, and the southern reactive support, a southern area load of 925 MW (assumed 80 per cent southern generation and one Gordon power station unit out of service) can be supported. The current drought conditions may lead to further constraints in southern generation. Sensitivities studies have been conducted by making the following machines unavailable:

- Two machines at Gordon power station; and
- All three machines at Gordon power station.

With two machines out and with the proposed reactive support, the maximum southern demand that can be supported is 880 MW and with no Gordon units available, southern demand is restricted to 775 MW.

Therefore,

- When available generation from Gordon power station is the equivalent of two machines (that is, when one machine is out of service), the trigger is southern area load reaching 925 MW;
- When available generation from Gordon power station is the equivalent of one machine (that is, when two machines are out of service), the trigger is southern area load reaching 880 MW; or
- When there was no available generation from Gordon power station (that is, when the power station is shut down), the trigger is southern area load reaching 775 MW.

The continuation of the current drought conditions could precipitate such reductions in available generation from Gordon power station. In addition, a penstock outage or a double circuit outage (mainly caused by ice build up on the circuits) at Gordon power station will lead to complete station shutdown. This would also limit the maximum southern demand that can be supplied to 775 MW.

With the current demand in the southern area exceeding 750 MW, the forecast 775 MW would be exceeded in 2010.

If generation capability in the southern area continues to drop due to the drought conditions, Transend would adjust its assumptions on the generation levels for the southern area and conduct a market benefit analysis to determine the optimum time for the implementation of the second Waddamana–Lindisfarne transmission circuit.

Transend contends that this project should be accepted as a contingent project for the Next Regulatory Control Period because of uncertainty about the trigger event occurring and uncertainty about the scope and cost of the project.

2 PROJECT NEED

2.1 Drivers

The drivers for this project are:

- To cater for forecast demand growth in the Southern area; and
- Improve the security of supply to the southern region.

2.2 Timing

The timing of this project is uncertain. Investment timing is driven mainly by load growth and cost estimates. The proposed investment expenditure is currently scheduled for the Next Regulatory Control Period, with project initiation towards the end of the period.

2.3 Strategic Alignment

Clear linkages to Transend's strategic plan would be established in accordance with business practice when the project is initiated.

3 ALTERNATIVES

3.1 Options

Table 2 summarises the options considered at this time. Further options may be identified during the project initiation process or be proposed by interested parties as part of the public consultation process.

Table 2 – Options considered

Option	Description	Consideration
1	Do nothing, under which there is no investment in generation or transmission assets	This option would leave the transmission system severely constrained and would not allow Transend to achieve the capital expenditure objectives identified in the NER
2	Network augmentation – investment in a new double circuit 220 kV transmission line between the existing Waddamana and Lindisfarne substations (developed either complete or in two stages) and related substation upgrades.	This augmentation option would provide additional power transfer capacity to the southern network and would contribute to the achievement of the capital expenditure objectives.
3	Gas-fired generation – a thermal generation investment alternative involving installation of up to four 75 MW open-cycle gas turbines (OCGT) and/or a 225 MW combined-cycle gas turbine (CCGT) located at Bridgewater.	This option would delay the transmission augmentation but would contribute to the achievement of the capital expenditure objectives and hence considered in the analysis.

3.2 Consideration of Non Network Solutions

Non-network solutions would be considered during the project initiation process.

3.3 Options Analysis

As part of the southern power system security project, an economic evaluation of the above options was conducted by Transend and MMA. In all cases, the alternative proposed network augmentation outperformed the generation. Further economic analysis will be undertaken during the project initiation process, should the trigger event occur.

The technical and economic analysis conducted by Transend and MMA has concluded that option 2 as the preferred option. In light of this, Transend proposes to build a staged double circuit 220 kV line between Waddamana and Lindisfarne substations, with one circuit installed initially on the towers by 2011.

It is also proposed that the second circuit could be added at a later date when justified by the costs and benefits at that time.

4 REGULATORY CONSIDERATIONS

4.1 NER Requirements

Clause 6A.8.1 requires that a contingent project:

- Is reasonably required in order to achieve any of the “capital expenditure objectives”;
- Capex is not otherwise provided for (in part or in whole) in the allowance;
- Reasonably reflects the “capital expenditure criteria”;
  - efficient costs;
  - the costs a prudent operator would incur; and
  - a “realistic expectation” of demand forecasts and cost inputs,

taking into account the “capital expenditure factors”.

- Exceeds the cost threshold (in Transend’s case, this is $10m).

4.2 Alignment with NER Capital Expenditure Objectives

This project would be required to achieve the following capital expenditure objectives identified in clause 6A.6.7(a) of the NER:

- Meet the expected demand for prescribed transmission services over the regulatory control period;
- Comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services; and
- Maintain the reliability, safety and security of the transmission system through the supply of prescribed transmission services.

In particular, Transend has a regulatory obligation under section 14 of its licence to plan and procure transmission system augmentations that are shown to satisfy the regulatory test.

Under certain scenarios, there may be a market benefit from either stringing the second circuit in the Next Regulatory Control Period:

- When the line is constructed; or
- As a staged augmentation.

The choice to build either a straight or staged double-circuit line depends on the future level of demand growth relative to the cost differential of stringing one or two circuits. Actual market prices may indicate that there is a market benefit from initially stringing the line as a straight double-circuit.

Alternatively, if the cost differential is significant, under certain load and generation scenarios the transmission network would be unable to effectively deliver enough electricity to southern Tasmania without breaching southern voltage stability limits. The additional investment in additional transfer capacity may therefore be required to improve the overall capability of the southern transmission network, provide for future growth, address local network constraints and provide security for Hobart's electricity supply.

4.3 Regulatory Test

This project would be classified as a "large transmission network asset" and would be subject to a public consultation process as defined in clause 5.6.6 of the NER.

4.4 Contingency Trigger

Under clause 6A.8.1(c) of the NER, the following matters are to be considered in determining whether a trigger event is appropriate:

- Trigger event to be reasonably specific and capable of objective verification;
- Trigger event, if it occurs, makes the contingent project reasonably necessary to achieve any of the "capital expenditure objectives";
- Trigger event to generate increased costs or categories of costs that relate to a specific location rather than the transmission network as a whole;
- Trigger event to be described in such terms that the occurrence of the event is all that is required for the revenue determination to be amended; and
- Trigger event to be probable during the regulatory control period, but inclusion in ex ante cap is not appropriate because of:
    - Uncertainty of timing; and
    - Uncertainty of cost.

The trigger proposed for this project is:

Either,

- The demand forecast in Tasmania's southern area exceeds 880 MW; or
- Gordon power station is not able to provide reactive support when the southern area load exceeds 775 MW;

and there is successful application of the regulatory test for further augmentation of the transmission capacity into Southern Tasmania.

5 EFFICIENCY

5.1 Estimating Basis

A level one estimate has been prepared for this project. The estimated cost of this project is indicative only; however any such project would be expected to exceed the $10 million contingent project threshold.

A detailed project scope and cost estimate will be required before any amendment to the revenue determination is considered by the AER should the specified trigger event occur during the Next Regulatory Control Period.

5.2 Costs

The estimated expenditure in the Next Regulatory Control Period is $22m (June 09, $). Detailed economic analysis has not been completed for this project. Further economic analysis will be undertaken during the project initiation process, should the trigger event occur.

5.3 Design Considerations

The scope of work for this project is wholly within the shared transmission network and is physically removed from any generator connection. It is not possible to accurately define the scope of this project at this early stage and as such, the scope of this project would most likely change following detailed analysis. As such, WorleyParsons is not able to comment on the design aspects.

5.4 Project Delivery

The transmission line component of this project would be expected to be implemented using a separate design and separate construct approach. The substation components of this project would be expected to be undertaken using a design and construct approach. Preferred contractors experienced in this type of work would be engaged to undertake the works to complete this project.

6 ASSESSMENT

6.1 NER Requirements

The drivers for this project are to cater for forecast demand growth in the Southern area and to improve the security of supply to the southern region. WorleyParsons considers that the project is reasonably required to meet three of the “capital expenditure objectives” (as discussed in Section 4.2), should the trigger event occur.

Having reviewed the detailed list of projects underpinning Transend’s submission, WorleyParsons is confident that this project has not been included (in whole or in part) in Transend’s forecast Capex.

At this early stage, there is much uncertainty in relation to the scope and costs for the project. Transend has prepared Level 1 estimates (based on the assumption that the second 220 kV line would be constructed after the first 220 kV line was in service) that represent the same level of accuracy as the Capex projects contained in Transend’s revenue proposal. Based on the process utilised to prepare the estimates, WorleyParsons considers that the estimated costs are efficient for the assumed project scope. It is also relevant to note that for the trigger event to have occurred, Transend would have had to prepare detailed scoping and cost estimates and have gone through the requisite public consultation process.

This project is dependant on demand forecasts, which would need to be reviewed to establish whether the project would need to commence in the Next Regulatory Control Period. The cost inputs for this contingent project align with those used in Transend's submission, and on that basis, WorleyParsons is satisfied that the project is based on a realistic expectation of cost inputs, taking into account the "capital expenditure factors".

The estimated costs for the project are clearly well above the threshold value of $10m.

6.2 Trigger Event

Given that load growth in the southern region can be monitored and projections made, WorleyParsons considers that the trigger event is reasonably specific and capable of objective verification.

If the trigger event occurs, Transend would be obliged under its licence to proceed with the project. The trigger event would generate costs that relate to a specific location that is, the Southern area.

The trigger event is described in terms such that the occurrence of the event is all that is required for the revenue determination to be amended that is, once the application of the regulatory test was successful, there would be no outstanding requirements preventing the revenue determination being amended.

Based on the load forecasts, WorleyParsons considers there is a reasonable probability that the project will be required during the Next Regulatory Control Period, but notes that the timing is uncertain. As previously noted, the scope and therefore cost of the project is uncertain at this early stage. WorleyParsons considers that it is not appropriate for this project to be included in the ex ante cap due to the uncertainty in both the timing and the cost of the project.

7 CONCLUSION

WorleyParsons considers that this proposed project meets the NER requirements for contingent projects and should be accepted by the AER as a contingent project.

TREVALLYN SUBSTATION NEW 220 kV INJECTION POINT

1 PROJECT DESCRIPTION

1.1 Project Identification

ND0935

1.2 CAPEX Category

Augmentation

1.3 Brief Overview

The project comprises the establishment of a transmission line from Hadspen Substation to Trevallyn Substation, and an additional 220/110 kV injection point at Trevallyn Substation. The scope includes:

- 1.3 km of single circuit 220 kV transmission line;
- 1 x 220 kV switchgear bay;
- 1 x 200 MVA, 220/110 kV auto-transformer;
- 1 x 110 kV switchgear bay;
- Associated protection and control for 220 kV circuit; and
- Associated protection and control for 220/110 kV auto-transformer.

1.4 Background

The northern area of Tasmania is currently supplied from Hadspen and Palmerston substations. When northern area load reaches around 355 MW, overloading of each Hadspen Substation 220/110 kV network transformer can occur as a result of the loss of the other transformer. Augmentation of the Hadspen-Trevallyn transmission corridor would address this constraint.

The northern area as a whole is supplied from:

- Palmerston Substation via one 152 MVA, 220/110 kV auto-transformer and a 110 kV circuit between Palmerston and Waddamana substations; and
- Hadspen Substation via two 200 MVA, 220/110 kV auto-transformers.

Two 220 kV and two 110 kV circuits connect the Palmerston and Hadspen substations 220 kV and 110 kV busbars respectively, which are part of the core gird.

Poatina Power Station connects into both the Palmerston Substation 220 kV bus (4 x 50 MW) and the 110 kV bus (2 x 50 MW).

Figure 1 shows a geographical map of the northern area.

Figure 1 – Geographic representation of northern Tasmania transmission system

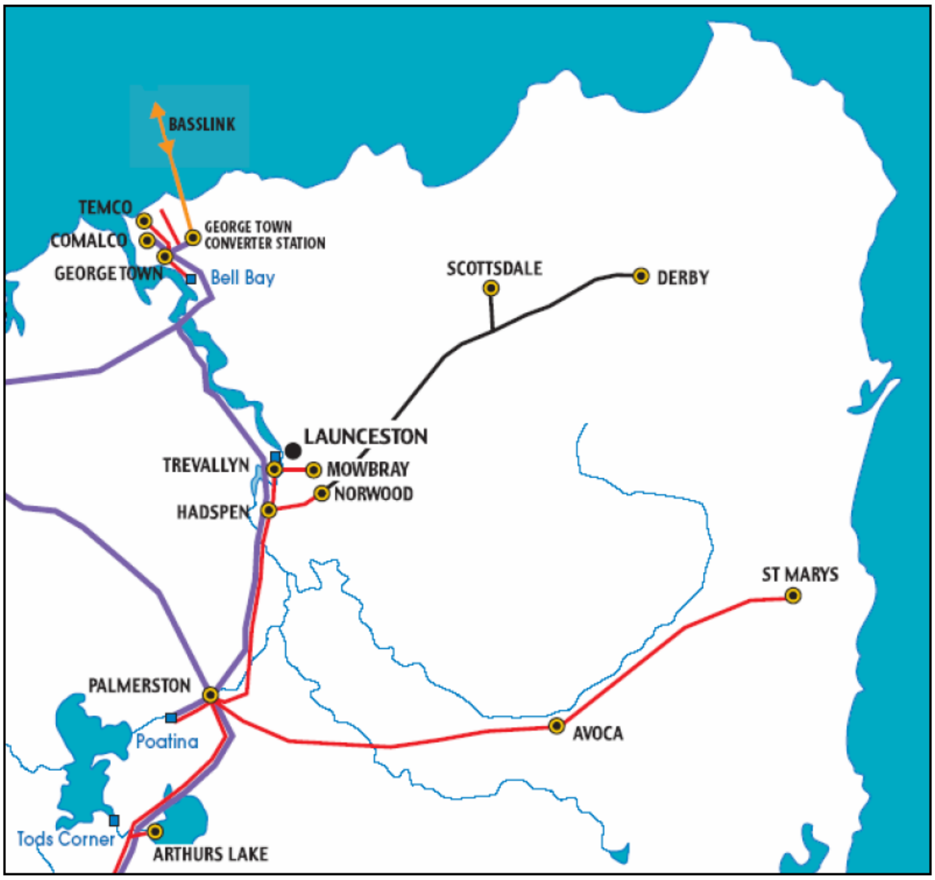
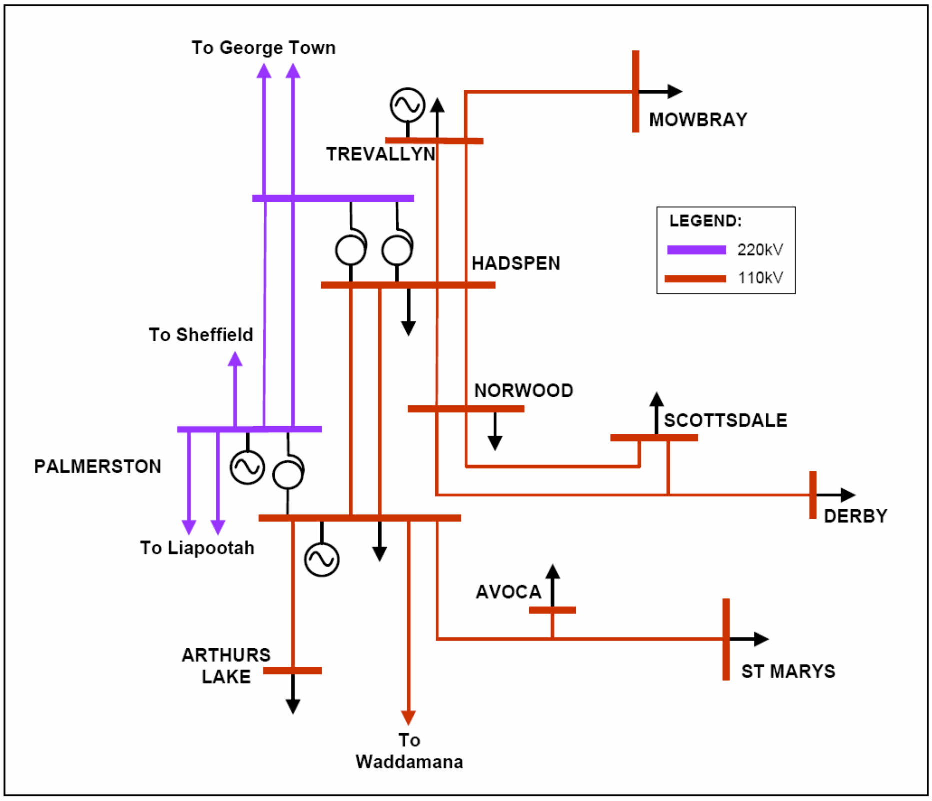


Figure 2 shows the electrical single line diagram of the northern area transmission network.

Figure 2 – Northern area single line diagram



The current winter Coincident Maximum Demand (CMD) in the northern area is 285.1 MW. Overloading on either of the auto-transformers at Hadspen Substation will occur in the event of the loss of the remaining 220/110 kV auto-transformer at Hadspen Substation when the CMD in the northern area exceeds 355 MW.

Table 1 shows the CMD of the northern area for both medium and high load growth scenarios. The CMDs were derived from Transend's load forecast by applying the 10 per cent POE.

Table 1 – Forecast coincident maximum demand in northern area

Year	Summer (MW)		Winter (MW)	
	Medium	High	Medium	High
2007[1]	167.3	167.3	285.1	285.1
2008	169.1	174.8	289.2	294.9
2010	173.8	183.2	305.6	320.0
2012	182.6	196.8	318.0	340.9
2014	186.5	204.9	328.0	362.2
2016	197.2	221.5	343.1	382.8
2018	205.7	234.8	355.8	404.7
2023	230.3	275.7	401.1	478.6

[1] Actual demand derived from metering data

By observing the generation metering data during 2007 summer and winter, the 95 per cent confidence level generation in the local area for area loads of greater than its 90 percentile was identified and is shown in Table 2. Based on these findings for the planning studies during summer, zero generation from Trevallyn Power Station and one Poatina Power Station 110 kV machine generating at 36 MW was assumed. During winter, two Trevallyn Power Station machines each generating at 20 MW and one Poatina Power Station 110 kV machine generating at 18 MW was assumed. Musselroe Bay generation was assumed to be zero in this option analysis. This is based on the operation experience of the existing wind farms. All the other generations except Tods Corner are assumed to be available for the planning studies in the northern area.

Table 2 – Generation pattern used in this option analysis

Season	Peak load (MW)	90 pct (MW)	Trevallyn (MW)	TR+PO110 kV (MW)	Musselroe (MW)	Generation pattern assumed
Summer	167.3	137.1	0	36	0	0TR+1PO110kV@36MW
Winter	285.1	225.0	40	58	0	2TR@40MW+1PO110kV@18MW

Coincident maximum demand (CMD) of 355 MW in Tasmania’s northern area is reached in 2018 under a medium load growth scenario. However under a high load growth scenario the CMD of 355 MW is reached in 2014. It is therefore possible that to meet customer demand an augmentation of the Hadspen-Trevallyn transmission corridor may be required in the Next Regulatory Control Period. Preliminary analysis suggests that the least cost solution is installing a third 220/110 kV auto-transformer at Hadspen Substation. However, analysis also suggests there may be a market benefit in providing a 220 kV injection point at Trevallyn substation instead, in order to meet the compliance issue and diversify the major supply points in northern Tasmania.

Transend contends that this project should be accepted as a contingent project for the Next Regulatory Control Period because of uncertainty about the trigger event occurring, which in this case is high load growth in the northern area.

2 PROJECT NEED

2.1 Drivers

The drivers for this project are:

- To cater for forecast demand growth in the northern area; and
- Comply with the minimum network performance levels under the ESI Regulations.

2.2 Timing

The timing of this project is uncertain. The project would be required in 2014 based on a high load forecast scenario and in 2018 based on a medium load forecast scenario.

2.3 Strategic Alignment

Clear linkages to Transend's strategic plan would be established in accordance with business practice when the project is initiated.

3 ALTERNATIVES

3.1 Options

Table 1 summarises the options considered at this time. Further options may be identified during the project initiation process or be proposed by interested parties as part of the public consultation process.

Table 1 – Options considered

Option	Description	Consideration
1	Do nothing	This option would leave the transmission system severely constrained and would not allow Transend to achieve the capital expenditure objectives identified in the NER
2	Generation support	This option involves obtaining a network support service agreement and may not be as cost effective as the proposed option.
3	Construct new 220/110 kV injection point at Trevallyn Substation	This option would address the compliance issue and also diversify the major supply points in the northern area. This would be the preferred option.
4	Construct Hadspen 3rd 220/110 kV auto-transformer	This option would address the compliance issue and is likely to be at less cost than the proposed option. However, it may not provide the maximum market benefit due to the lack of diversification in major supply points.

3.2 Consideration of Non Network Solutions

Non-network solutions would be considered during the project initiation process.

3.3 Options Analysis

At this stage, Transend favours Option 3 as it addresses the compliance issue and provides diversification in major supply points. This project would be subject to joint planning with Aurora to identify the optimal solution.

4 REGULATORY CONSIDERATIONS

4.1 NER Requirements

Clause 6A.8.1 requires that a contingent project:

- Is reasonably required in order to achieve any of the "capital expenditure objectives";
- Capex is not otherwise provided for (in part or in whole) in the allowance;
- Reasonably reflects the "capital expenditure criteria";

- Efficient costs;
- The costs a prudent operator would incur; and
- A “realistic expectation” of demand forecasts and cost inputs,

taking into account the “capital expenditure factors”.

- Exceeds the cost threshold (in Transend’s case, this is $10m).

4.2 Alignment with NER Capital Expenditure Objectives

This project would be required to achieve the following capital expenditure objectives identified in clause 6A.6.7(a) of the NER:

- Meet the expected demand for prescribed transmission services over the regulatory control period;
- Comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services; and
- Maintain the reliability, safety and security of the transmission system through the supply of prescribed transmission services.

In particular, Transend has a regulatory obligation under section 14 of its licence to plan and procure transmission system augmentations that are shown to satisfy the regulatory test.

4.3 Regulatory Test

This project is forecast to take two years from inception to commissioning. If demand growth in the northern area tracked higher than the present medium forecast—indicating that it was likely for the demand threshold to be reached in the Next Regulatory Control Period, or in the first two years of the 2014-19 Regulatory Control Period—then Transend would undertake the regulatory test to identify the investment in the Hadspen–Trevallyn transmission corridor that satisfied the test.

This project would be classified as a “large transmission network asset” and would be subject to a public consultation process as defined in clause 5.6.6 of the NER.

4.4 Contingency Trigger

Under clause 6A.8.1(c) of the NER, the following matters are to be considered in determining whether a trigger event is appropriate:

- Trigger event to be reasonably specific and capable of objective verification;
- Trigger event, if it occurs, makes the contingent project reasonably necessary to achieve any of the “capital expenditure objectives”;
- Trigger event to generate increased costs or categories of costs that relate to a specific location rather than the transmission network as a whole;
- Trigger event to be described in such terms that the occurrence of the event is all that is required for the revenue determination to be amended; and
- Trigger event to be probable during the regulatory control period, but inclusion in ex ante cap is not appropriate because of:

- Uncertainty of timing; and
- Uncertainty of cost.

The trigger proposed for this project is:

- Demand in Tasmania's northern area exceeds 320 MW and is forecast to exceed 355 MW within three years; and
- There is successful application of the regulatory test for augmentation of the Hadspen-Trevallyn transmission corridor.

5 EFFICIENCY

5.1 Estimating Basis

A level one estimate has been prepared for this project. The estimated cost of this project is indicative only; however any such project would be expected to exceed the $10 million contingent project threshold.

A detailed project scope and cost estimate will be required before any amendment to the revenue determination is considered by the AER should the specified trigger event occur during the Next Regulatory Control Period.

5.2 Costs

The estimated expenditure in the Next Regulatory Control Period is $21m (June 09, $). Detailed economic analysis has not been completed for this project. Further economic analysis will be undertaken during the project initiation process, should the trigger event occur.

5.3 Design Considerations

The scope of work for this project is wholly within the shared transmission network and is physically removed from any generator connection. It is not possible to accurately define the scope of this project at this early stage and as such, the scope of this project would most likely change following detailed analysis. As such, WorleyParsons is not able to comment on the design aspects.

5.4 Project Delivery

This project would be expected to be implemented using a separate design and separate construct approach. Preferred contractors experienced in this type of work would be engaged to undertake the works to complete this project.

6 ASSESSMENT

6.1 NER Requirements

The drivers for this project are to cater for forecast demand growth in the northern area and to comply with the minimum network performance levels under the ESI Regulations. WorleyParsons considers that the project is reasonably required to meet three of the "capital expenditure objectives" (as discussed in Section 4.2), should the trigger event occur.

Having reviewed the detailed list of projects underpinning Transend's submission, WorleyParsons is confident that this project has not been included (in whole or in part) in Transend's forecast Capex.

At this early stage, there is much uncertainty in relation to the scope and costs for the project. Transend has prepared Level 1 estimates (based on the assumption that the new line would be single circuit 220 kV) that represent the same level of accuracy as the Capex projects contained in Transend's revenue proposal. Based on the process utilised to prepare the estimates, WorleyParsons considers that the estimated costs are efficient for the assumed project scope. It is also relevant to note that for the trigger event to have occurred, Transend would have had to prepare detailed scoping and cost estimates and have gone through the requisite public consultation process.

This project is dependant on demand forecasts, which would need to be reviewed in 2011 to establish whether the project would need to commence in the Next Regulatory Control Period. The cost inputs for this contingent project align with those used in Transend's submission, and on that basis, WorleyParsons is satisfied that the project is based on a realistic expectation of cost inputs, taking into account the "capital expenditure factors".

The estimated costs for the project are clearly well above the threshold value of $10m.

6.2 Trigger Event

Given that load growth in the northern region can be monitored and projections made, WorleyParsons considers that the trigger event is reasonably specific and capable of objective verification.

If the trigger event occurs, Transend would be obliged under its licence to proceed with the project. The trigger event would generate costs that relate to a specific location that is, the Hadspen-Trevallyn transmission line corridor.

The trigger event is described in terms such that the occurrence of the event is all that is required for the revenue determination to be amended that is, once the application of the regulatory test was successful, there would be no outstanding requirements preventing the revenue determination being amended.

As previously noted, the scope and therefore cost of the project is uncertain at this early stage. WorleyParsons considers that it is not appropriate for this project to be included in the ex ante cap due to the uncertainty in both the timing and the cost of the project.

For this project to be required during the Next Regulatory Control Period, load growth would need to be high. On this basis, the AER may wish to consider excluding this project from the list of contingent projects.

7 CONCLUSION

WorleyParsons considers that this proposed project meets the NER requirements for contingent projects and should be accepted by the AER as a contingent project.

QUEENSTOWN TRANSMISSION SECURITY UPGRADE

1 PROJECT DESCRIPTION

1.1 Project Identification

ND0957

1.2 CAPEX Category

Augmentation

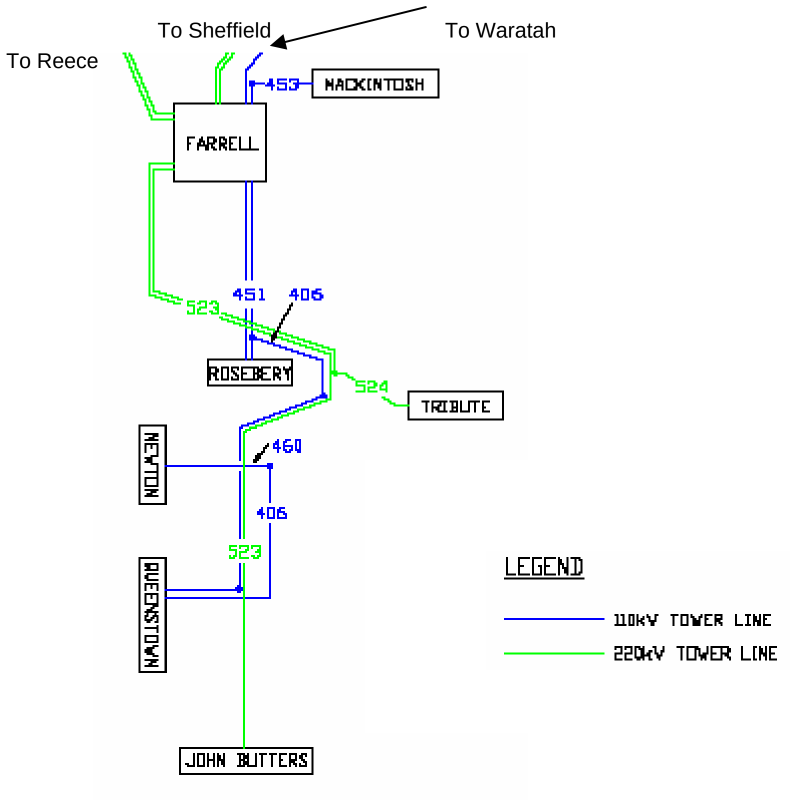
1.3 Brief Overview

The Queenstown transmission security upgrade project comprises the establishment of a 220/110 kV supply from a transmission circuit adjacent to Queenstown Substation.

1.4 Background

Queenstown Substation is supplied from Farrell Substation via the Farrell–Rosebery–Queenstown 110 kV transmission line. In turn, Newton Substation is supplied via the Queenstown–Newton 110 kV transmission line. There is currently no alternate supply to Queenstown or Newton substations. A single line diagram of the current electrical connections on the west coast is presented in Figure 1.

Figure 1 – Electrical connections on the west coast



The current arrangement does not comply with clause 5.(1)(a)(i) and clause 5.(1)(a)(iv) of the Electricity Supply Industry (Network Performance Requirements) Regulations 2007 (network performance requirements), which state that:

- “No more than 25 MW of load is to be capable of being interrupted by a credible contingency event”; and
- The “unserved energy to load that is interrupted consequent on damage to a network element resulting from a credible contingency event is not to be capable of exceeding 300 MWh at any time.”

Under the current arrangement, a contingency event on the Farrell–Rosebery–Queenstown transmission line will interrupt more than 25 MW of load and result in unserved energy of more than 300 MWh (883 MWh based on 2007 load).

Preliminary investigations have identified that the establishment of a 220 kV supply from an adjacent transmission circuit presents the best long term solution to provide alternate supply to Queenstown Substation. This would ensure compliance with the network performance requirements.

The demand at Queenstown and Newton substations is predominantly from direct-connect customers that operate mining and processing facilities. Transend intends to undertake further discussions with these customers regarding their long-term plans to ensure as far as practicable that the investment is needed in the long term. In addition, Transend intends to explore the option of establishing interruptibility contracts with the directly connected customers. These customers may agree to provide sufficient interruptible load to allow Transend to meet the network performance requirements at lower cost than through network augmentation.

Transend contends that this project should be accepted as a contingent project for the Next Regulatory Control Period because of uncertainty about the trigger event occurring and uncertainty about the scope and cost of the project.

2 PROJECT NEED

2.2 Drivers

The driver for this project is to comply with the network performance requirements.

2.3 Timing

The timing of this project is uncertain. Transend will need to establish the future load requirements of major customers in the area and whether significant load can be made subject to interruptibilty contracts.

2.4 Strategic Alignment

Clear linkages to Transend’s strategic plan would be established in accordance with business practice when the project is initiated.

3 ALTERNATIVES

3.1 Options

Table 1 summarises the options considered at this time. Detailed technical options relating to this project would be considered should the trigger event occur. Further options may be identified during the project initiation process or be proposed by interested parties as part of the public consultation process.

Table 1 – Options considered

Option	Description	Consideration
1	Do nothing	This option would continue to leave the transmission network severely constrained and would not allow Transend to achieve the capital expenditure objectives identified in the NER.
2	Establish transmission loop between Queenstown, Newton and Rosebery substations	This option is technically feasible, but it is not the least cost solution. It also presents considerable easement and planning issues because of the environmentally sensitive terrain in much of the west coast area.
3	Tee off the Farrell–John Butters 220 kV transmission line and install a 220/22 kV auto-transformer	This option is initially the least cost option, but it would introduce a number of technical issues and complexities. It would also require significant further investment should additional load be connected to Queenstown Substation 11 kV or Newton Substation.
4	Tee off the Farrell–John Butters 220 kV transmission line and install a 220/110 kV auto-transformer	This option is technically feasible and best meets the long term supply needs at Queenstown and Newton substations, but it is not the least cost solution.

3.2 Options Analysis

Further options may be identified during the project initiation process or be proposed by interested parties as part of the public consultation process. At this stage, Transend favours Option 4 on the basis that it provides the best long term solution. Option 3 would have a lower initial cost, but introduces some technical difficulties and would require additional costs in the event of connection of further load.

3.3 Consideration of Non Network Solutions

Transend will explore the practicability of interruptability contracts with major customers in the area, which may allow deferment of the proposed works.

4 REGULATORY CONSIDERATIONS

4.1 NER Requirements

Clause 6A.8.1 requires that a contingent project:

- Is reasonably required in order to achieve any of the “capital expenditure objectives”.
- Capex is not otherwise provided for (in part or in whole) in the allowance.
- Reasonably reflects the “capital expenditure criteria”:
  - Efficient costs;
  - The costs a prudent operator would incur; and

- A “realistic expectation” of demand forecasts and cost inputs,

taking into account the “capital expenditure factors”.

- Exceeds the cost threshold (in Transend’s case, this is $10m).

4.2 Alignment with NER Capital Expenditure Objectives

This project would be required to achieve the following capital expenditure objectives identified in clause 6A.6.7(a) of the NER:

- Comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services; and
- Maintain the reliability, safety and security of the transmission system through the supply of prescribed transmission services.

In particular, Transend has a regulatory obligation under section 14 of its licence to plan and procure transmission system augmentations that are shown to satisfy the regulatory test.

4.3 Regulatory Test

Should the network option prove the optimal solution, this project would be classified as a “large transmission network asset” and would be subject to a public consultation process as defined in clause 5.6.6 of the NER.

4.4 Contingency Trigger

Under clause 6A.8.1(c) of the NER, the following matters are to be considered in determining whether a trigger event is appropriate:

- Trigger event to be reasonably specific and capable of objective verification;
- Trigger event, if it occurs, makes the contingent project reasonably necessary to achieve any of the “capital expenditure objectives”;
- Trigger event to generate increased costs or categories of costs that relate to a specific location rather than the transmission network as a whole;
- Trigger event to be described in such terms that the occurrence of the event is all that is required for the revenue determination to be amended; and
- Trigger event to be probable during the regulatory control period, but inclusion in ex ante cap is not appropriate because of:
    - Uncertainty of timing; and
    - Uncertainty of cost.

The trigger proposed for this project is:

- Transend is unable to negotiate non-network solutions that enable it to meet the minimum network performance requirements for the Queenstown and Newton load; and

- Successful completion of the regulatory test for augmentation of the supply to Queenstown substation.

5 EFFICIENCY

5.1 Estimating Basis

A level one estimate has been prepared for this project. The estimated cost of this project is indicative only.

A detailed project scope and cost estimate will be required before any amendment to the revenue determination is considered by the AER should the specified trigger event occur during the Next Regulatory Control Period.

5.2 Costs

The estimated expenditure in the Next Regulatory Control Period is $11m (June 09, $). Detailed economic analysis has not been completed for this project. Further economic analysis will be undertaken during the project initiation process, should the trigger event occur.

5.3 Design Considerations

The scope of work for this project is wholly within the shared transmission network and is physically removed from any generator connection. It is not possible to accurately define the scope of this project at this early stage and as such, the scope of this project would most likely change following detailed analysis. As such, WorleyParsons is not able to comment on the design aspects.

5.4 Project Delivery

The transmission line component of this project would be expected to be implemented using a separate design and separate construct approach. The substation components of this project would be expected to be undertaken using a design and construct approach. Preferred contractors experienced in this type of work would be engaged to undertake the works to complete this project.

6 ASSESSMENT

6.1 NER Requirements

The driver for this project is to comply with the network performance requirements. WorleyParsons considers that the project is reasonably required to meet two of the “capital expenditure objectives” (as discussed in Section 4.2), should the trigger event occur.

Having reviewed the detailed list of projects underpinning Transend’s submission, WorleyParsons is confident that this project has not been included (in whole or in part) in Transend’s forecast Capex.

At this early stage, there is much uncertainty in relation to the scope and costs for the project. Transend has prepared Level 1 estimates (based on the assumption that the project would involve the installation of a 220/110 kV transformer) that represent the same level of accuracy as the Capex projects contained in Transend's revenue proposal. Based on the process utilised to prepare the estimates, WorleyParsons considers that the estimated costs are efficient for the assumed project scope. It is also relevant to note that for the trigger event to have occurred, Transend would have had to prepare detailed scoping and cost estimates and have gone through the requisite public consultation process.

This project is not dependant on demand forecasts, as Transend currently fails to meet the network performance requirements. The cost inputs for this contingent project align with those used in Transend's submission, and on that basis, WorleyParsons is satisfied that the project is based on a realistic expectation of cost inputs, taking into account the "capital expenditure factors".

The estimated costs for the project are above the threshold value of $10m, but only by 10%, which is less than the accuracy of the estimates.

6.2 Trigger Event

Given that the results of negotiations with major customers in the area will define the need for this project, WorleyParsons considers that the trigger event is reasonably specific and capable of objective verification.

If the trigger event occurs, Transend would be obliged under its licence to proceed with the project. The trigger event would generate costs that relate to a specific location that is, the Queenstown Substation.

The trigger event is described in terms such that the occurrence of the event is all that is required for the revenue determination to be amended that is, once the application of the regulatory test was successful, there would be no outstanding requirements preventing the revenue determination being amended.

WorleyParsons considers there is a reasonable probability that the project will be required during the Next Regulatory Control Period, as it is problematic whether the customer negotiations would be successful, but notes that the timing is uncertain. As previously noted, the scope and therefore cost of the project is uncertain at this early stage. WorleyParsons considers that it is not appropriate for this project to be included in the ex ante cap due to the uncertainty in both the timing and the cost of the project.

7 CONCLUSION

WorleyParsons considers that this proposed project meets the NER requirements for contingent projects and should be accepted by the AER as a contingent project.