Transmission Project Approval Report
PAR2008–024
Work Request No. WR350002
Project No. C0077036

17 July 2008

AFD ARCHERFIELD – Recover 33 kV Switchgear

Disclaimer

Whilst care was taken in the preparation of the information in this document, and it is provided in good faith, ENERGEX accepts no responsibility or liability (including without limitation, liability to any person by reason of negligence or negligent misstatement) for any loss or damage that may be incurred by any person acting in reliance on this information or assumptions drawn from it, except to the extent that liability under any applicable Queensland or Commonwealth of Australia statute cannot be excluded.

<u>TABLE OF CONTENTS</u>

1.0 PREAMBLE

This document has been prepared to comply with clause 5.6.2 of the National Electricity Rules (NER), which requires ENERGEX to:

- Identify future technical limitations to its network.
- Conduct an economic cost effectiveness analysis of possible solutions to the limitations in accordance with the Australian Electricity Regulator's (AER) Regulatory Test version 3 (November 2007) for projects greater than $1 million.

This project has been considered under the reliability limb of the regulatory test as the service standards linked to the technical requirements of Schedule 5.1 of the NER are unable to be met as detailed in Section 2.3 of this report.

This project was previously identified in ENERGEX's Annual Network Management Plan.

2.0 EXISTING NETWORK

2.1 Introduction

Archerfield bulk supply substation (SSAFD) is an existing 110/33 kV substation that provides 33 kV supply to the Rocklea (SSRLA), Oxley (SSOXL), Cooper's Plains (SSCPL) and Salisbury (SSSBY) zone substations. In addition, 33/11 kV transformers at SSAFD also supply primarily industrial loads in the suburbs of Rocklea, Archerfield and Yeerongpilly.

SSAFD is supplied from Rocklea transmission substation (H16) via two transformer ended 110 kV feeders F817 and F818.

SSAFD consists of three 33 kV buses. One is an outdoor 33 kV ring bus and the other two form a 33 kV indoor switchboard.

Figures 1 and 2 below provide geographic and schematic views of the network area under study.

Figure 1: Existing Network Arrangement (Geographic View)

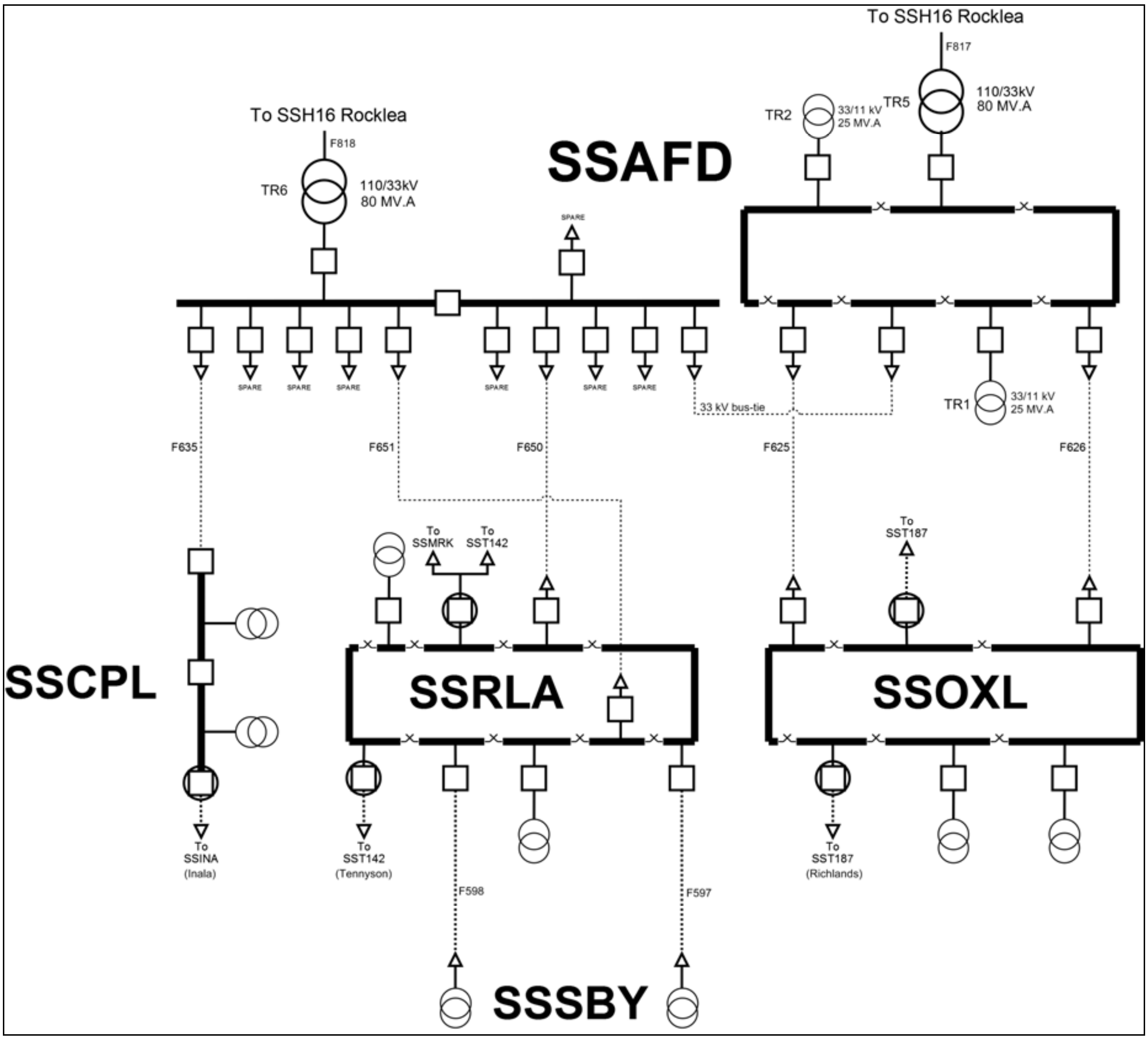


Figure 2: Existing Network Arrangement (Schematic View)

2.2 Approved Capex / Opex Works

Approved works not yet commissioned within the study area include:

- WR330489 SSINA to T187 – Uprate 33 kV feeder F618 by September 2008.

The above works will allow the entire SSCPL load to be transferred from SSAFD to Inala Zone Substation (SSINA) under contingency conditions. SSINA is supplied from Richlands bulk supply substation (SST187).

2.3 Applied Service Standard

The service standards that are applicable to a consideration of supply constraints affecting this area of study are summarised below:

- Bulk Supply Substations

  As per ENERGEX Supply Security Standard, an Urban Mixed / Predominantly Industrial bulk supply substation is required to have full N-1 capability. This requires that the substation be able to withstand a credible single contingency without an interruption to supply of greater than one minute.

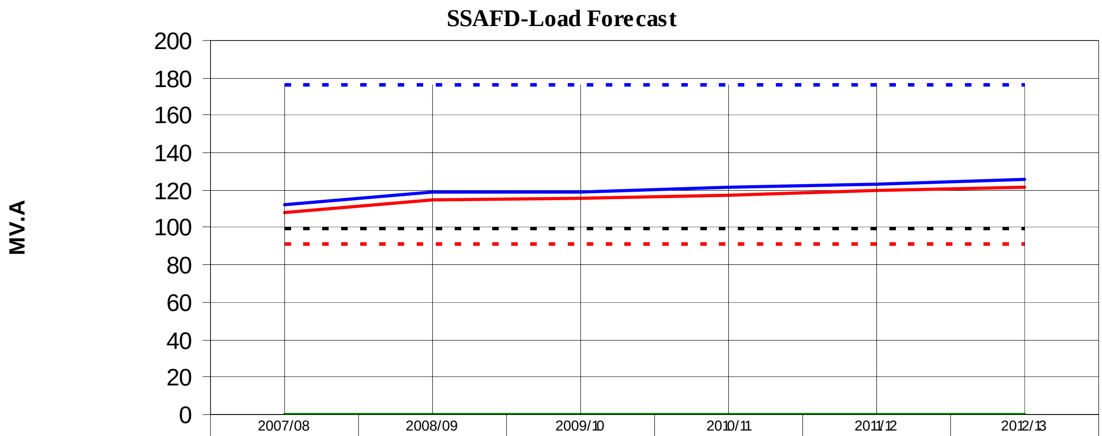
2.4 Limitations of the Existing Network

The existing network limitations are as follows:

2.4.1 Subtransmission Network Limitations

Substation Capacity

SSAFD is equipped with 2 x 80 MV.A 110/33 kV transformers. The substation capacity is limited by the transformers, providing a Normal Cyclic Capacity (NCC) of 176 MV.A. The 5 year 10% POE and 50% POE load forecasts, and the existing normal cyclic capacity (NCC), emergency cyclic capacity (ECC) and residual load at risk (RLAR) of SSAFD, are shown below:



	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13
10% POE Load	111.90	118.72	119.25	121.40	123.61	125.88
Summer NCC	176.00	176.00	176.00	176.00	176.00	176.00
50% POE Load	108.31	115.04	115.48	117.57	119.71	121.91
Summer ECC	91.45	91.45	91.45	91.45	91.45	91.45
Summer 2HR	100.00	100.00	100.00	100.00	100.00	100.00
Residual LAR	0.00	0.00	0.00	0.00	0.00	0.00

Figure 3: Substation Load Forecast (Existing Network)

As outlined in the table above, the 10% POE load on the substation is not forecast to exceed the NCC of the substation within the next five years. The 50% POE load, prior to completing manual load transfers, is forecast to exceed two hour emergency capacity (2HEC) of the substation from summer 2007/08.

It is possible to transfer SSOXL to SST187, and also SSCPL to SST187 from summer 2008/09. After these transfers are completed, there is no RLAR.

The 33/11 kV zone substation transformers have not been considered in this report as there are no forecast limitations on these within the next five years.

As shown in Figure 2, the 33 kV indoor and outdoor buses are linked by a bus-tie cable. The NCC and 2HEC of this bus-tie are limited to 400 A by existing CTs on the outdoor bus. These CTs are presently unused. The 5 year 10% POE load forecast, 50% POE load forecast with TR6 out of service, and existing NCC and 2HEC of the bus-tie connecting the 33 kV outdoor bus to the indoor bus are shown below:

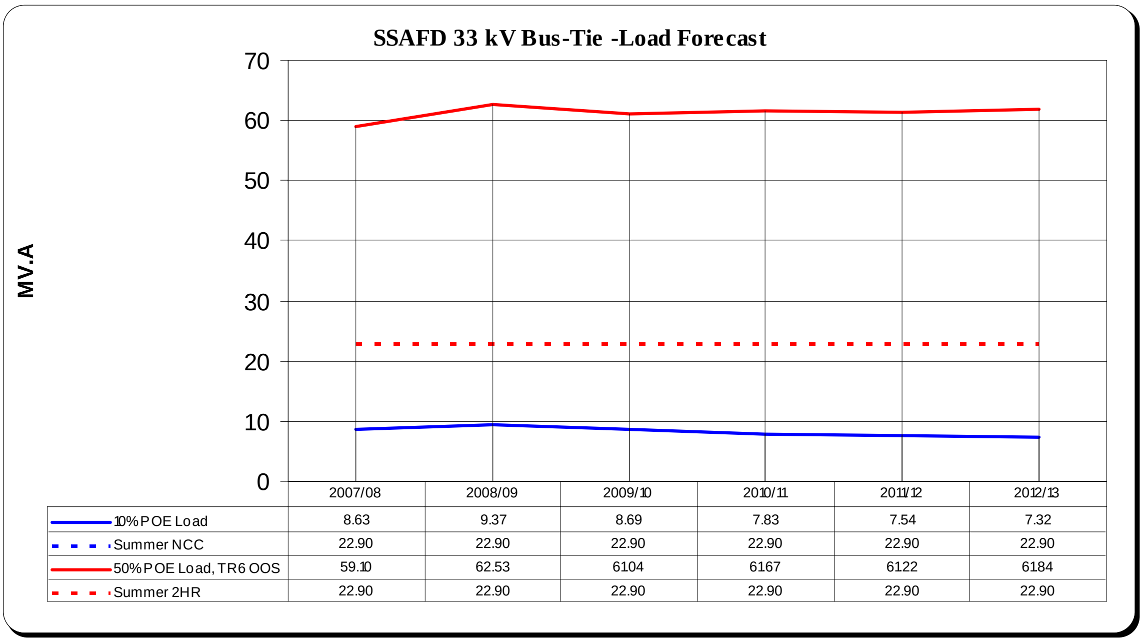


Figure 4: 33 kV Bus-tie Load Forecast (Existing Network)

As outlined above, there are no forecast NCC limitations on the bus-tie within the next 5 years. However, for the loss of one of the 110 kV feeders or 110/33 kV transformers at SSAFD, the 2HEC of the 33 kV bus-tie is forecast to be exceeded from summer 2007/08.

Substation Fault Level

The existing fault level at the SSAFD busbars (11 kV and above) are shown in Table 1. The fault current ratings of a number of 33 kV circuit breakers at SSAFD are shown in Table 2:

Substation	Busbar Voltage (kV)	Three Phase		Phase to Ground	
		(MV.A)	(kA)	(MV.A)	(kA)
SSAFD	33 kV	968.2	16.94	44.4	2.33
	11 kV	204.1	10.71	14.4	2.27

Table 1: Fault Levels at Substation Busbars (Existing Network)

Circuit Breaker	Fault Current Rating (kA)
CB3T12	17.5
CB3X12	17.5
CB6252	17.5
CB6262	17.5

Table 2: SSAFD 33 kV Circuit Breaker Fault Ratings

The fault level of the remaining switchgear is 25 kA or greater. As outlined in the tables above, the fault level at the SSAFD 33 kV bus is approaching the fault current rating of four of the outdoor circuit breakers.

The Powerlink fault level forecast for SSH16 is shown in the table below:

Substation	Busbar Voltage (kV)	2007		2008		2009	
		3PH (kA)	L-G (kA)	3PH (kA)	L-G (kA)	3PH (kA)	L-G (kA)
SSH16	110	22.71	26.41	22.78	26.49	22.50	26.24

Table 3 – SSH16 110 kV Fault Level Forecast

As outlined in the table above, the fault level at SSH16 is forecast to remain level for the coming years. Therefore, the fault level at SSAFD will remain constant. Powerlink have confirmed that this will remain the case until 2013, at which point a third 275/110 kV transformer is scheduled to be installed at SSH16. When this happens, the fault level on the 33 kV bus will exceed the rating of the outdoor circuit breakers shown in Table 2.

2.4.2 Network Reliability

Customer Numbers

The existing substation category and customer numbers are shown in the following table:

Substation	Category	Customer Numbers
SSAFD	Urban	612
SSCPL	Urban	3759
SSOXL	Urban	4091
SSRLA	Urban	4402
SSSBY	Urban	2473

Table 4: Substation Customer Numbers (Existing Network)

SAIDI

The existing SAIDI contribution is shown in the following table:

Substation	12 month SAIDI (mins)	Avg 3Yr SAIDI (mins)
SSAFD	72	79
SSCPL	19	46
SSOXL	147	91
SSRLA	4	34
SSSBY	161	59

Table 5: SAIDI Contribution (Existing Network)

2.5 Impact of Doing Nothing

The following system limitations will occur if no action is taken:

- For an outage of a single 110/33 kV transformer at SSAFD, or either of the 110 kV feeders F816 and F817, both the remaining 110/33 kV transformer and the 33 kV bus-tie at SSAFD are forecast to exceed 2HEC in summer 2007/08.

- After Powerlink install the third 275/110 kV transformer at SSH16, the fault level at the 33 kV bus at SSAFD will exceed the capacity of four of the 33 kV outdoor circuit breakers.

Therefore the option of doing nothing is not viable.

3.0 OPTIONS ANALYSIS

In the process of determining the most cost effective solution to addressing the identified network limitations, ENERGEX has sought to identify a range of technically feasible, alternative options that could satisfy the network requirements in a timely and efficient manner. Those options considered include network solutions, generation options, demand side initiatives and fuel substitution.

As the value of the project did not exceed $10M, this process was not extended to invite comment from interested external parties proposing non-network solutions.

As a result of this process, ENERGEX has identified a range of options that represent practical alternatives to addressing the network limitations.

The alternative options identified through this process are examined below:

3.1 Network Options

3.1.1 Option 1: Remove bus-tie 400/5 A CTs and cut-over to indoor switchgear

To address the forecast limitations, the following is required to be completed by October 2008:

- Remove the unused 400/5 A CTs and install POPS to monitor TR5 and TR6 to alleviate the 2HEC limitations.

In addition, the following work is required to be completed by October 2012:

- Disconnect the existing circuits connected to the outdoor bus, and move to the indoor bus. The feeders will be arranged such that the ENERGEX Supply Security Standards are met. The outdoor circuit breakers will be taken out of service.

This option is technically feasible, and addresses the forecast limitations.

3.1.2 Option 2: Remove bus-tie 400/5 A CTs and replace outdoor 33 kV switchgear

To address the forecast limitations, the following is required to be completed by October 2008:

- Remove the unused 400/5 A CTs and install POPS to monitor TR5 and TR6 to alleviate the 2HEC limitations.

In addition, the following work is required to be completed by October 2012:

- Replace the four outdoor circuit breakers that have insufficient fault level capacity. In addition, the 33 kV outdoor bus will be reconfigured to match the level of security achieved by the indoor bus for bus outages.

This option is technically feasible, and addresses the forecast limitations.

Other network options considered included opening the bus-tie at SSAFD to reduce fault levels. This option was dismissed as not complying with ENERGEX operational practices and as providing poor system reliability.

3.2 Non-network Options / Demand Side Solution

In order to satisfy the Regulatory Test, ENERGEX sought to identify demand side solutions (or demand side/network combinations) that address the network limitations at a cost that was less than the proposed network solution.

To be considered an alternative demand side option, the proposed solution was required to:

- have the capacity to defer the proposed network solution by reducing demand below the identified constraint limits, and
- cost less than the savings gained by deferring or removing the proposed network solution.

This analysis did not identify feasible demand side alternative options.

3.3 Comparison of Options

3.3.1 Technical Comparison

A summarised comparison of the advantages and disadvantages of the alternative development options is given in the following table:

Option	Advantages	Disadvantages
Network Options		
<u>Option 1</u> "Cut-over to indoor switchgear"	• An indoor bus is inherently more reliable than an outdoor bus. • Existing spare switchgear is utilised. • Conforms with network building blocks / architecture.	• There is potential to disturb two gas-filled cables connected to the outdoor bus.
<u>Option 2</u> "Replace outdoor 33 kV Switchgear"	• No obvious advantages were identified.	• An outdoor bus is inherently less reliable than an indoor bus. • Existing spare 33 kV indoor switchgear (refer Figure 2) is not used. • Non-standard substation arrangement, not in line with network building blocks / architecture.

Table 6: Technical Comparison of Alternative Development Options

Based on the above comparison of options, the recommended development is considered to provide the optimum solution to address the forecast overload and fault level limitations.

3.3.2 Cost Comparison

The Regulatory Test requires ENERGEX to identify the option that minimises the present value of costs when compared with alternative options in the majority of reasonable scenarios.

Accordingly a base case net present value comparison of the alternative development options has been undertaken. The financial analysis contained anticipated costs of providing, operating and maintaining the options as well as expected costs of compliance and administration associated with each option. The costs of network losses were excluded from the analysis. The table below provides an overview of the initial capital cost and net present value cost over the period of study for each of the development options.

Option	Description	Initial Capital Cost	Total Capital Cost	PV of Costs	Rank
NETWORK OPTION 1	Remove Unused CT's, Cutover to Indoor Switchgear	$22,813	$1,560,007	$1,222,393	1
NETWORK OPTION 2	Remove unused CT's and replace outdoor switchgear	$22,813	$1,570,700	$1,230,705	2

Table 7: Base Case Net Present Value Comparison

Sensitivity analysis was then conducted on this base case to establish the option that remained the lowest cost option in the majority of cases considered. The table below provides the results of this analysis.

	Scenario	NETWORK OPTION 1	NETWORK OPTION 2
1	High WACC	$1,105,402	$1,140,247
	ranking	1	2
2	Low WACC	$1,406,572	$1,444,623
	ranking	1	2
3	Network CAPEX overspend	$1,314,411	$1,353,776
	ranking	1	2
4	Network CAPEX underspend	$1,075,427	$1,107,635
	ranking	1	2
5	Network OPEX over budget	$1,222,398	$1,259,179
	ranking	1	2
6	Network OPEX under budget	$1,167,440	$1,202,231
	ranking	1	2
7	Low growth scenario	$979,551	$986,174
	ranking	1	2
8	High growth scenario	$1,363,030	$1,372,320
	ranking	1	2

Table 8: Sensitivity Analysis - Comparison of Options

3.3.3 Sensitivity Comparison

Option 1 is clearly the lowest cost option in all of the scenarios considered.

4.0 RECOMMENDED DEVELOPMENT (OPTION 1)

4.1 Scope of Proposed Works

Description of Works

To address the limitations at SSAFD, it is proposed to complete the work in two stages. These are:

Stage 1 (October 2008)

- Remove the unused 400/5 A CTs from the outdoor 33 kV bus-tie CB 3X12.
- Install POPS to monitor the remaining 110/33 kV transformer should one be out of service. The POPS will open CB6352 (F635 to SSCPL) if the transformer is overloaded. An existing auto-changeover (ACO) scheme at SSCPL will operate to restore power at SSCPL via Inala zone substation (SSINA).

Stage 2 (October 2012)

- Disconnect the existing 33 kV circuits, including the 110/33 kV transformer, from the outdoor bus and move to the indoor 33 kV switchboard.
- The 33 kV outdoor bus and switchgear can be recovered as required to facilitate the moving of circuits to the indoor bus.

There are no proposed changes to the geographic or operational arrangement of the network. The proposed 33 kV bus configuration at SSAFD is shown in Figure 3.

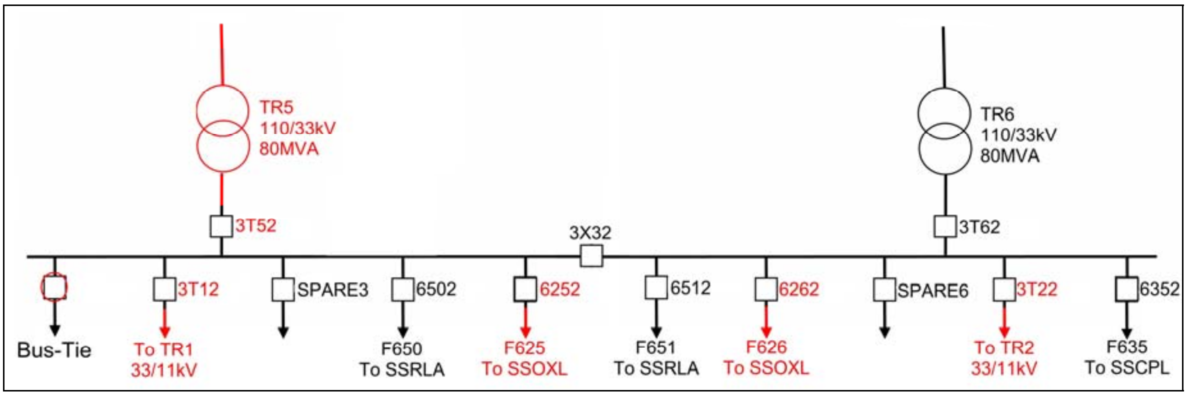


Figure 5: Proposed SSAFD 33 kV bus configuration

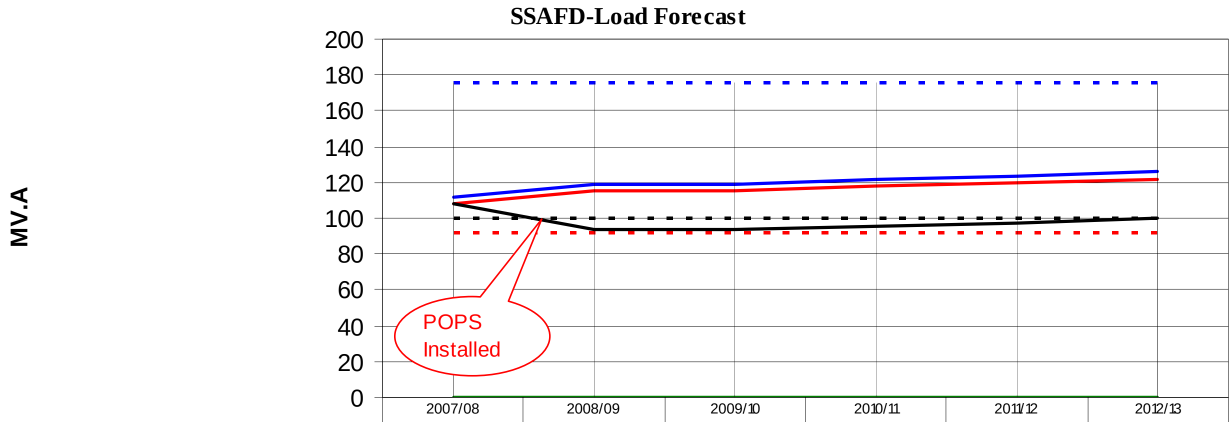
4.2 Impact of Proposed Works

The recommended works will have the following impact:

4.2.1 Subtransmission Network

Substation Capacity

The 5 year 10% POE and 50% POE load forecasts, and the existing normal cyclic capacity (NCC), emergency cyclic capacity (ECC) and residual load at risk (RLAR) of SSAFD are shown below:

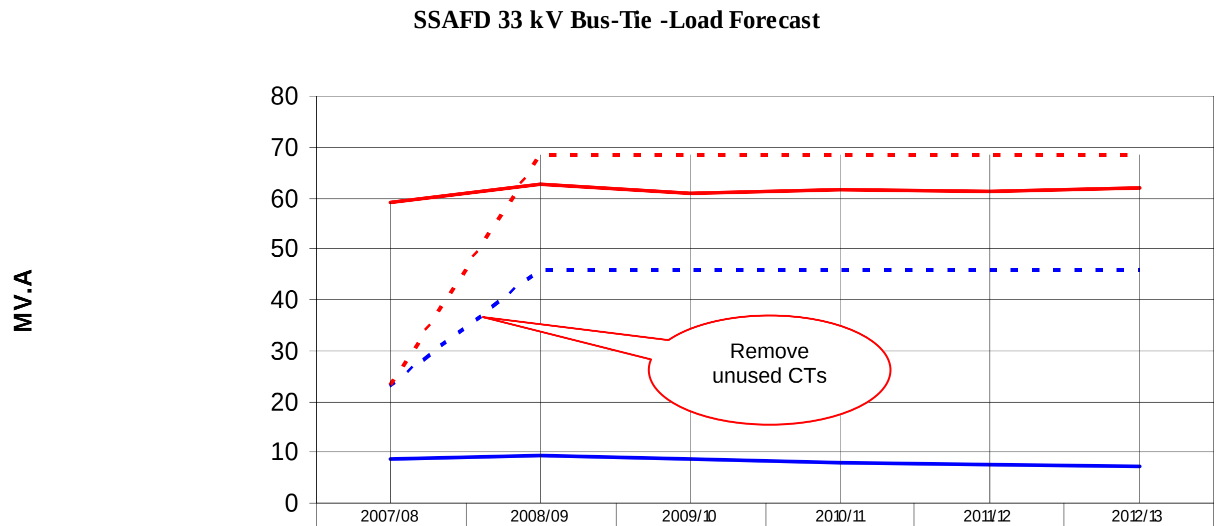


	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13
10% POE Load	111.90	118.72	119.25	121.40	123.61	125.88
Summer NCC	176.00	176.00	176.00	176.00	176.00	176.00
50% POE Load	108.31	115.04	115.48	117.57	119.71	121.91
Summer ECC	91.45	91.45	91.45	91.45	91.45	91.45
50% POE Load - After POPS Operation	108.31	93.30	93.43	95.53	97.69	99.91
Summer 2HR	100.00	100.00	100.00	100.00	100.00	100.00
Residual LAR	0.00	0.00	0.00	0.00	0.00	0.00

Figure 6: Substation Load Forecast (Proposed Network)

As outlined above, after POPS operation, the 50% POE load at SSAFD is reduced below the transformer 2HEC. Although the load remains above the ECC, the reduction of load below 2HEC allows sufficient time to allow for screen switching to complete the required load transfers.

The 5 year 10% POE and 50% POE load forecasts, and the proposed NCC and 2HEC of the 33 kV bus-tie, are shown below:



	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13
10% POE Load	8.63	9.37	8.69	7.83	7.54	7.32
Summer NCC	22.90	45.73	45.73	45.73	45.73	45.73
50% POE Load, TR6 OOS	59.10	62.53	6104	6167	6122	6184
Summer 2HR	22.90	68.59	68.59	68.59	68.59	68.59

Figure 7: 33 kV Bus-tie Load Forecast (Proposed Network)

As outlined in the table above, after the 400 A CTs on the outdoor switchgear have been removed, the NCC of the bus-tie increases to 800 A (limited by CTs on the indoor switchgear), with a 2HEC of 1200 A. Testing of the 800 A CTs on the indoor switchgear has been completed to determine the 2HEC.

If the above contingencies were to occur, the ECC of the bus-tie would still be exceeded. However, as the load is within the 2HEC, there is sufficient time to allow for screen switching to complete the required 33 kV load transfers to reduce load below the bus-tie ECC.

Substation Fault Level

The expected fault levels at SSAFD will not change as a result of this project. The proposed fault current ratings for the 33 kV circuit breakers are shown in the table below:

Circuit Breaker	Proposed Fault Current Rating (kA)
CB3T12	31.5
CB3T22	31.5
CB3T52	31.5
CB6252	31.5
CB6262	31.5

Table 9: Proposed CB Fault Current Ratings

As outlined in the table above, when the 33 kV feeders are moved onto the indoor bus, the fault current rating of the circuit breakers increases to 31.5 kA.

4.3 Project Timing Risk

Project Timing and Associated Risk

The network requirement dates for completion of Stage 1 and Stage 2 of the recommended development are October 2008 and October 2012 respectively. The timing of this project has been reviewed in line with resource constraints and it has been allocated dates of practical completion of September 2008 for Stage 1 and August 2012 for Stage 2.

Level of Risk Associated with the Date of Practical Completion

As the dates of practical completion precede the network requirement dates, the level of network risk associated with this project can be managed using existing network contingency plans.

5.0 APPLICATION OF THE REGULATORY TEST

ENERGEX is required to apply a Regulatory Test in relation to new network augmentation investments estimated to require a total capitalised expenditure in excess of $1 million. The purpose of the Regulatory Test is to analyse and assess the efficiency of new network augmentation investments and non-network alternative options that address the projected network limitations.

Where an investment is a new large distribution asset, clause 5.6.2(f) of the NER requires ENERGEX to publicly consult with Registered Participants, NEMMCO and interested parties on the possible options, including demand side, generation and market network service options, to address the projected limitations of its distribution system.

Where a proposed investment is a mix of augmentation and replacement, a *Regulatory Test* is required if the augmentation component is $1 million or above. Public consultation will be required if the augmentation component is $10 million or above.

The recommended augmentation investment option has a total capitalised expenditure of $1,560,007 and as such it does require a Regulatory Test.

6.0 BUDGET PROVISION

The Budget Provision is outlined in the following table in 2008/09 dollars:

Budget Composition		**Financial Year Provision**	
Component	**Cost (in 08/09 dollars)**	**FY**	**Cost (in 08/09 dollars)**
Transmission	$1,560,007	**2007/08**	$8,780
Distribution	-	**2008/09**	$29,048
TOTAL	$1,560,007	**2009/10**	-
		2010/11	$19,213
		2011/12	$1,502,966
		Total Project Cost	$1,560,007

Table 10: Budget Provision

7.0 RECOMMENDATION

It is recommended that ENERGEX install POPS, remove unused CTs, cutover feeders to the existing indoor bus and recover 33 kV outdoor switchgear, for a total estimated cost of $1,560,007 at 2008/09 prices. The network requirement date for completion of the recommended development is October 2012. The date of practical completion is August 7, 2012.