RFP 002/10 - Overload of Bordertown Substation

Evaluation Report of RFP 002/10

10 January 2013

SA Power Networks
www.sapowernetworks.com.au

Disclaimer

This Evaluation Report has been prepared in accordance with the requirements of Section 4 of ESCOSA Guideline 12 – Demand Management for Electricity Distribution Networks and of Clause 5.6.2 of the National Electricity Rules. The purpose of the Evaluation Report is to publicly announce the outcomes of SA Power Networks evaluation of the proposals it has received in response to a Request for Proposals it has issued and to make known the option recommended as a result of that evaluation.

This document is not intended to be used by other parties for any purpose, such as making decisions to invest in generation, transmission or distribution capacity. This document has been prepared using information provided by, and reports prepared by, a number of third parties.

While care was taken in the preparation of the information in this report, and it is provided in good faith, SA Power Networks accepts no responsibility or liability for any loss or damage that may be incurred by any person acting in reliance on this information or assumptions drawn from it.

Executive Summary

This Evaluation Report addresses options developed to resolve the projected network limitations described in "RFP002/10 Projected Distribution Network constraint: Overload of Bordertown Substation". This RFP was issued by SA Power Networks in March 2010.

The limitations identified were:

- An overload of the 33/11kV transformers at Bordertown substation;
- An overload of the thermal capacity of the 33kV sub-transmission line servicing Bordertown substation;
- Inadequate voltages at Bordertown substation;
- An overload of the N-1 capacity of Keith Connection point.

Three submissions were received in response to the RFP, two for small diesel power stations to be used for network support and one for reactive support. All three were found to be technically compliant in that they resolved the identified network constraints either individually or when combined with other augmentations.

Of the three, one was found to be more economic than the preferred network solution and extensive commercial negotiations were started. Those negotiations have now been successfully completed with the signing of a contract (subject to completion of the Regulatory Test) for the provision of network support from this third party through the installation of a small diesel fuelled power station at Bordertown.

The planned commencement date for this support is 1st December 2013.

Table of Contents

1 Definitions

Act	Electricity Act 1996
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
Application Notice	A notice made available to Registered Participants and Interested Parties pursuant to clause 5.6.6 of the NER
Base Case	The existing distribution system against which all credible options are compared.
Base Scenario	The market scenario considered most likely to occur when undertaking the Regulatory Test which is used as the reference case when considering alternative plausible market scenarios
Credible Option	A network augmentation or set of network augmentations which resolves all network constraints; ie a consistent solution.
Demand Management (DM)	Demand Management is the management of the level or pattern of energy use on the transmission / distribution network, so as to minimise the supply cost to customers whilst maintaining or enhancing customer service levels. Supply costs include costs of projects associated with the augmentation of, or extension to, the transmission or distribution network, and include network losses
DNSP	Distribution Network Service Provider
DM	Demand Management
DUOS	Distribution Use of System charges applicable to Registered Participants in the NEM
Economic Surplus	The difference between the cost of producing goods or services and the benefits gained from their production
EDC	Electricity Distribution Code as published by ESCOSA
EMNP	An Eligible Major Network Project is any proposal (or proposals) to augment or expand the distribution network that would have a combined capital cost of $2 million or more and which could reasonably be viewed as addressing a single constraint or could be regarded as a single expansion
ElectraNet (EN)	The Transmission Network Service Provider in South Australia. The company responsible for suppling the transmission network in SA that links major generators to the distribution network.
ESCOSA	Essential Services Commission of South Australia established under the Essential Services Commission Act 2002
ESDP	Electricity System Development Plan (ESDP) developed annually by SA Power Networks and published by 30 June. The ESDP includes details of projected limitations on SA Power Networks Distribution system for at least the next three year period and provides the information needed for a party to register as an Interested Party as defined within ESCOSA Guideline 12

ETC	Electricity Transmission Code as published by ESCOSA
Guideline 12 (GL 12)	ESCOSA Electricity Industry Guideline 12 – Demand Management for Electricity Distribution Networks
Interested Party	Individuals or organisations registered with SA Power Networks in accordance with Guideline 12 that have an interest in the long term planning of the distribution network, Demand Management initiatives, addressing a particular constraint, or more generally in addressing Demand Management issues
N	The state of the network with all items of plant and equipment in service.
N-1	The state of the network with one item of plant or equipment out of service. Most parts of the Distribution Network are designed to operate satisfactorily with one element out of service. See radial supply.
NEM	National Electricity Market
NER	National Electricity Rules. The term “Rules” shall be construed as a reference to the NER.
NPV	Net Present Value
O&M	Operating and Maintenance
OLTC	On Load Tap Changer – a device used to control the output voltage of a transformer
POE	Probability of Exceedance. The probability that actual load will exceed forecast load in any one year.
pu	Per Unit. In practical terms this corresponds to a percentage of the nominal value with 1.0 pu = 100%. For instance a voltage of 0.95pu = 95% of nominal voltage.
PV	Photo-voltaic
QOS	Quality of Supply
RDP	Regional Development Plan
Radial Supply	In country areas a substation may be supplied by only a single sub transmission line. This is called a radial supply (See N-1)
Reasonableness Test	Reasonableness Test - as defined in ESCOSA Electricity Industry Guideline 12 is a screening test that identifies whether or not a DM solution to a constraint is economically and technically feasible.
Registered Participant	A person who is registered with AEMO as a Network Service Provider, a System Operator, a Network Operator, a Special Participant, a Generator, a Customer or a Market Participant
Regulatory Test	The Test (version 3) promulgated by the AER that all major network investment must comply with. Also known simply as the Test.
RFP	Request for Proposals
Rules	National Electricity Rules (NER)
SA Power Networks	We are South Australia’s principal Distribution Network Service Provider

	(DNSP), and are responsible for the distribution of electricity to all distribution grid connected customers within the State under a regulatory framework. We are a partnership of Cheung Kong Infrastructure Holdings Ltd (CKI), Hong Kong Electric International Ltd (HEI) and Spark Infrastructure
SAIDI	System Average Interruption Duration Index. This is the average annual outage duration for each customer supplied with electricity.
SAIFI	System Average Interruption Frequency Index. The average number of times that a customer losses supply in a year.
STPIS	Service Target Performance Investment Scheme. A scheme scheme developed and published by the AER in accordance with clause 6.6.2 of the NER.
TNSP	Transmission Network Service Provider
TUOS	Transmission Use of System charges applicable to Registered Participants in the NEM
VCR	Value of Customer Reliability. An estimate of the value that customers place on the reliable supply of electricity. Expressed in $ per MWh of load that is not supplied.
VoLL	Value of Lost Load as measured in the NEM
WACC	Weighted Average Cost of Capital. References to “Discount Rate” shall be construed as references to WACC.

2 Introduction

SA Power Networks is South Australia's principal DNSP and is responsible for the distribution of electricity to all distribution grid connected customers within South Australia under a regulatory framework. SA Power Networks design, install, upgrade, repair and maintain the 'poles and wires' which make up the distribution network carrying the electrical energy to South Australian homes and businesses.

We identified in 2009, a possible EMNP to upgrade the Bordertown substation and related sub transmission infrastructure that supplies it to address a forecasted overload occurring from 2011/12. In accordance with the requirements of the National Electricity Rules and ESCOSA Guideline 12 we consulted with Registered Participants, Interested Parties and customers by issuing a Request for Proposals in 2010 seeking potential non network solutions to address the identified constraints - RFP002/10 Overload of Bordertown Substation.

This report summarises the evaluation of the proposals received in response to that RFP along with SA Power Networks own network solutions under the principles outlined within section 4 of the GL12 process and in accordance with the Regulatory Test version 3 as published by the AER.

This report describes:
- the network consultation and regulatory process (Section 3);
- the constraints and operating environment pertaining to Bordertown (Section 4);
- the network and third party support options considered in (Section 5);
- the credible scenarios tested and market benefits considered in the evaluation of the options (Section 6); and
- the outcome of the Regulatory Test (Section 7).

3 Network Augmentation Consultation Process

3.1 Background

Prior to undertaking an augmentation of its power system that involves a significant level of expenditure, SA Power Networks is required to consult with affected parties, Registered Participants and Interested Parties under ESCOSA Guideline 12 for projects with an expected total capital cost of between $2 million and $10 million and under the NER for projects in excess of this value.

ESCOSA Guideline 12

Under ESCOSA Guideline 12 we prepare an annual ESDP that identifies actual and forecast constraints on the distribution network for the following three year period. This report details existing and projected distribution system limitations for the 13 regions presently covered by our regional development plans and is published on 30 June each year.

Where a network project to address a constraint is deemed an EMNP under GL12 , a Reasonableness Test must be undertaken to assess the potential for demand management and third party solutions to resolve the constraint. SA Power Networks is required to issue an RFP for all projects that pass the Reasonableness Test (except where an exemption is granted). The RFP must be published on our website, issued to all Interested Parties, and publicly advertised in local newspapers in general circulation within South Australia.

All responses to the RFP along with our own proposed solutions must be evaluated on an equal footing and the results of that evaluation published in an Evaluation Report (this document).

National Electricity Rules

Clause 5.6.2 of the NER also places obligations on a DNSPs such as SA Power Networks to consult with Registered Participants and Interested Parties (as defined by the NER) regarding augmentations and extensions to the distribution system where the expected capitalised expenditure is in excess of $10 million. This process is controlled by regulations released by the AER; in this case, version 3 of the Regulatory Test.

The process followed by SA Power Networks has been designed to comply with the consultation requirements of both ESCOSA Guideline 12 and the NER.

Reasonableness Test

Reasonableness Test, “RT 007/09 – Overload of Bordertown Substation” was published on our website in December 2009. This document identified that the constraints in the Bordertown region could potentially be resolved through the use of a demand management / non-network solution and that a Request for Proposals should therefore be issued. The Reasonableness Test report is available on the SA Power Networks website at:

http://www.sapowernetworks.com.au/centric/industry/our_network/annual_network_plans.jsp

Request for Proposals

SA Power Networks published “RFP002/10 – Projected Distribution Network Constraint: Overload of Bordertown Substation” on its website in March 2010. RFP002/10 closed for public submissions on 22nd September 2010. It is available on our website as above.

Three responses were received in response to the RFP: two for network support using small diesel powered generation plant and one for reactive support using Static VAr Compensation (SVC). Following assessment of the three proposals received, further information was requested from the two generation proponents in January 2011 in order to complete the initial evaluation. On receipt of this information one of the proposals was found to be potentially superior to the preferred network solution.

After extensive commercial negotiations the final Regulatory Test (described below) was applied to the range of viable solutions identified.

3.2 The Regulatory Test

Where a RFP has been issued and/or where alternatives to a RFP are proposed, all conforming proposals and options including those developed by SA Power Networks must be evaluated on terms laid out in the regulations. Which particular Regulatory Test process that the proposals are to be evaluated under is determined by the expected total capital cost of the proposed viable solutions. In this case, as the amount of the preferred network option is greater than $10 million, the evaluation falls under the AER's Regulatory Test Version 3 rather than the ESCOSA GL12 process. This Test has two limbs:

1. the Reliability Limb; and
2. the Market Benefits Limb.

The Reliability Limb is a strict least cost test and applies where the network is being upgraded to "meet the service standards linked to the technical requirements of schedule 5.1 *(of the NER)*, or applicable regulatory instruments" whereas, the Market Benefit Limb is to be used in all other cases.

This evaluation has been performed using the Market Benefits Limb, as in addition to the constraints caused by the voltage and thermal limits of equipment there are significant impacts on customer reliability which SA Power Networks considered should be included within the evaluation.

The Market Benefits limb has two components:

1. The cost of an option which includes the costs of construction, operation and maintenance; and
2. The benefits to the market of an option which include changes in network reliability and changes in electrical losses.

The preferred option is the one with the highest Net Present Value of the difference between benefits and costs; ie the option that maximises the likely economic surplus of parties operating in the electricity market.

Full details of the test including worked examples can be obtained from the AER website at the address below. Details of how to dispute the outcome of the Regulatory Test can also be found at the same location.

http://www.aer.gov.au/node/1678

4 Bordertown Distribution Network

4.1 Description

Bordertown 33/11kV substation is part of the South East 33,000V (33kV) electricity distribution system. It contains two 5MVA 33/11kV transformers with a combined summer cyclic normal rating of 12.5MVA. It is located on the western outskirts of Bordertown near the intersection of Ramsay Terrace and Pigeon Flat Road. Four 11kV feeders provide supply to the local rural, residential and commercial load. The overall arrangement of the distribution system is shown below in Figure 1.

The substation is supplied directly from Keith 132/33kV Connection Point by a radial 48km, 33kV sub-transmission line. A 33kV voltage regulator with an extended tap range is located on the line near Wirrega, approximately 28km from Keith, 20 km from Bordertown.

SA Power Networks has no committed distribution augmentations that impact on the 11kV distribution network that services the Bordertown area. Since the RFP was published, two small private generators (both 0.5 MVA) have been installed at Tatiara Meats and Blue Lake Milling in a non export capacity.

The largest customers in the Bordertown area are:

- Eudunda Farmers;
- Bordertown High School;
- Blue Lake Milling;
- Tatiara Meats; and
- Tatiara Seeds.

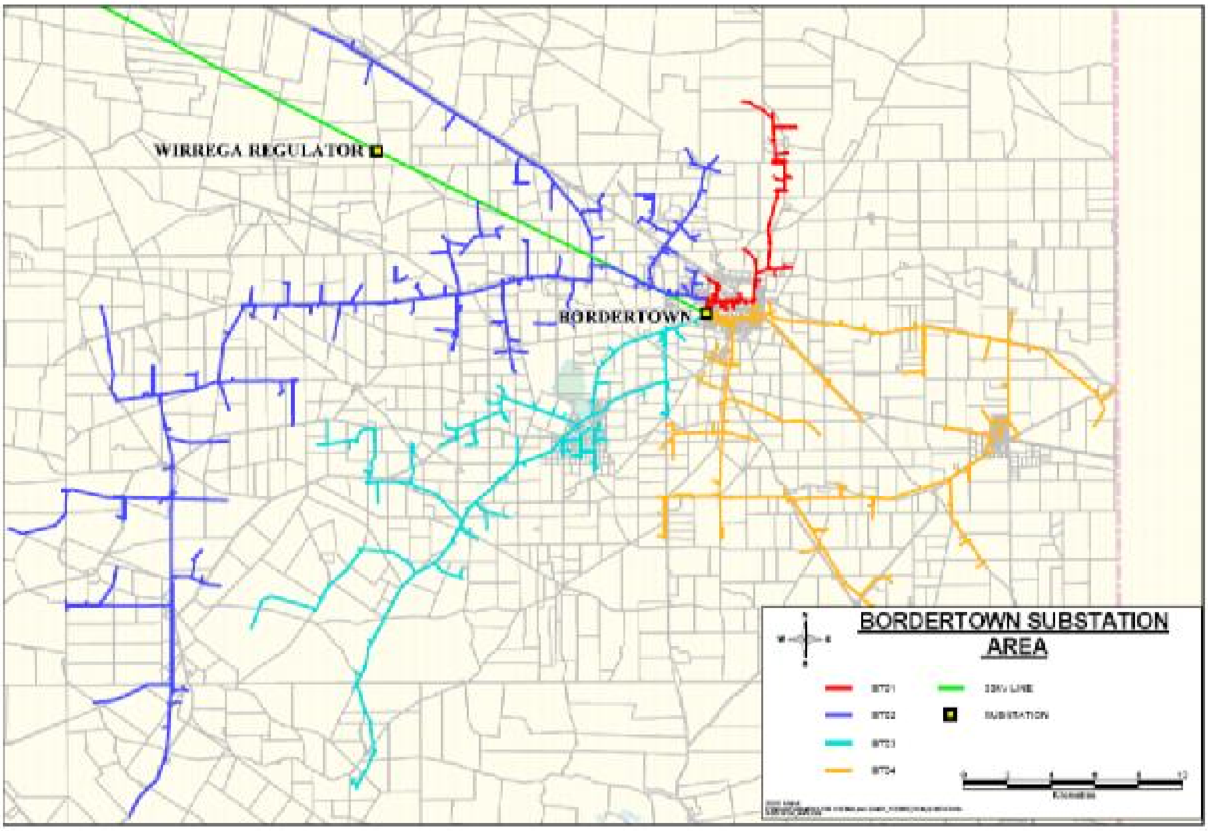

Figure 1 Bordertown Electricity Supply System

4.2 Load Forecast and Characteristics

Bordertown substation supplies approximately 3,000 customers (2012) in the township of Bordertown and the surrounding rural area. The electrical load in the Bordertown region comprises mainly residential customers, but also includes some commercial and agricultural complexes. The present growth is dependent on future employment retention and expansion in the area. Demand forecasts for Bordertown Substation show a growth in peak demand at an average rate 4% per annum expecting to increase from 13.3MVA in summer 2013/14 to 20.4MVA in summer 2024/25, as shown in Table 1. These values have been revised down from the figures published in 2010 within the RFP. This growth represents the moderate 10% POE forecast which we use for planning purposes.

Table 1: Forecast peak MVA demand at Bordertown

Year	Bordertown Substation Load (MVA)
2013/14	13.3
2014/15	13.8
2015/16	14.4
2016/17	14.9
2017/18	15.5
2018/19	16.2
2019/20	16.8
2020/21	17.5
2021/22	18.2
2022/23	18.9
2023/24	19.7
2024/25	20.4

Peak electricity demand occurs during the summer, predominantly as a result of air-conditioning and water pumping loads. As the rating of electrical plant typically decreases with increasing temperature this is also the period with the most onerous operating conditions. The absolute network peak demand occurred on 29th January 2009 as part of the exceptional heat wave that occurred in that year. A more typical peak occurred on the 6th February 2009 as illustrated in Figure 2. One notable element of the curve is the time of the peak (21:00) which is significantly later than is typical for the rest of the network. This late peak (after dark) mitigates the impact any PV generation may have on the forecast. The peak load usually occurs for a period of only 3 to 4 hours per day. This is a shorter period than in the rest of the network. Winter load is approximately half that of the summer load reflecting the highly seasonal nature of the demand.

The forecast power factor at peak load times at the 11kV bus is 0.98 lagging. This power factor includes the impact of the existing 2.5 MVAr capacitor bank which suggests that further power factor correction would have little impact on or ability to reduce the load on the transformers.

The load duration curve (figure 3) for the period 2008-2009 has a typical shape illustrating that peak load occurs for only a very few hours per year. As an example, load in excess of 90% of peak is expected to occur for no more than 11 hours per annum and load in excess of 80% of peak for no more than 54 hours per annum.

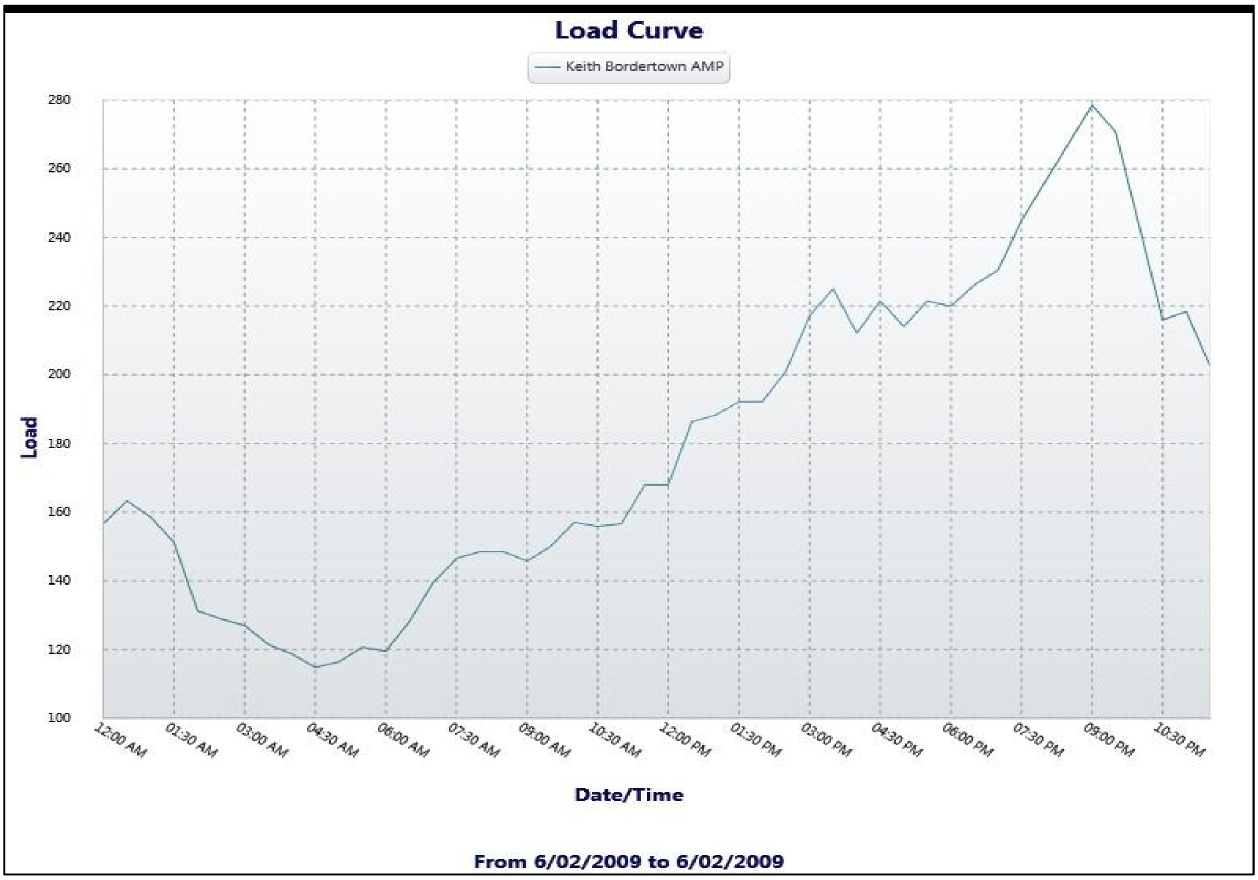

Figure 2 Peak summer load

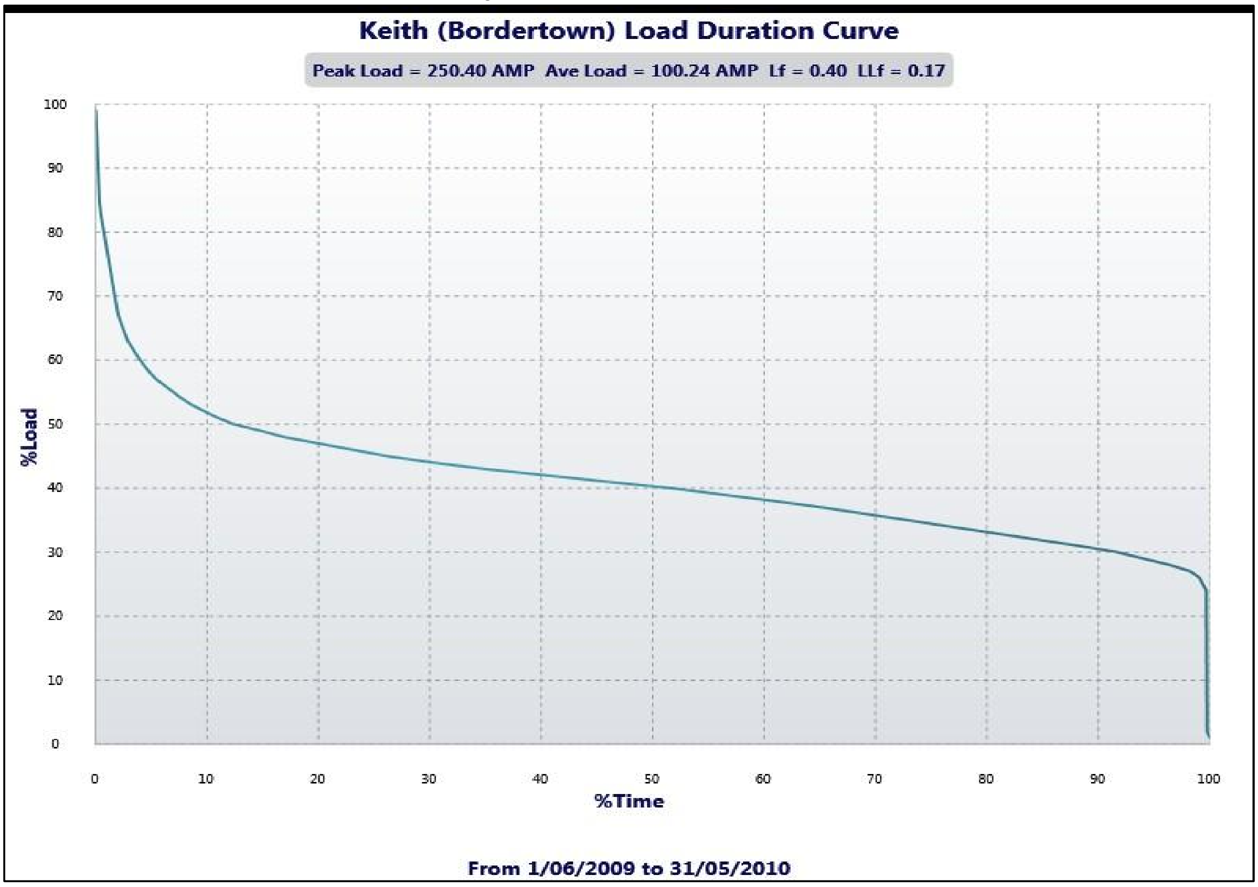

Figure 3: Load duration 2008-2009

4.3 Planning Criteria

As a Network Service Provider (NSP) within the National Electricity Market, we must comply with the National Electricity Rules and in particular with the technical standards contained in Schedule 5.1 relating to reliability and system security. In addition, as a licensed electricity entity in South Australia, we must also comply with the service obligations imposed by ESCOSA under the EDC.

In order to meet these obligations at minimum cost, SA Power Networks has developed a set of planning criteria which, when applied to the load forecasts, identifies both future network constraints and the preferred timing of system augmentations to relieve those constraints. These planning criteria are fully described in our ESDP which is published annually on 30 June and is available from our website.

The planning criteria relevant to the Bordertown constraints are:

- Peak forecast load not greater than the substation's normal capacity (a tolerance of 0.2 MVA is added to the forecast load to allow for metering errors).
- Peak forecast load is not greater than the substation's firm delivery capacity (ie N-1 capacity plus all load transfers plus an additional 5 MVA of load at risk until a mobile substation can be connected).
- A standard customer supply voltage of 230V with an upper limit of 253V (230V plus 10%) and a lower limit of 216V (230V minus 6%). Due to the length of the 11kV feeders at Bordertown, substation, 11kV bus voltage levels (at the substation) must be maintained above 0.98pu (10.78kV) in order to meet this target.
- A sub-transmission line must not be loaded above its calculated thermal rating to avoid breaching statutory clearances between the line and the nearest object to the line.

In addition, as ElectraNet's Keith Connection Point is deemed a category 4 connection point by the ETC, forecast peak load at the connection point must not exceed the connection point's N-1 transformer rating.

4.4 Service Standards / QOS

The relevant region of South Australia covered by this RFP is categorised as "South East" (for the purposes of the Service Standards contained within the EDC (refer to clause 1.2). The required restoration times for the South East region are 80% of outages within 4 hours and 90% within 5 hours.

For the South East region two reliability standards apply:
1. the average number of minutes off supply per customer should not exceed 330 minutes per annum; and
2. the number of supply interruptions per annum per customer experienced should not exceed 2.7.

Whilst SA Power Networks is permitted to meet its service obligations by procuring support services from an alternative network service provider, generator, retailer or customer (ie load curtailment or demand management), we are still responsible for meeting the service standards and any liabilities associated with not failure to do so.

SA Power Networks must ensure that its distribution system meets the voltage and quality of supply limits specified in section 1.2.4 of the EDC. In particular, we must ensure that the distribution network is designed, installed, operated and maintained such that:

- at the customer's supply address:
  - the voltage is as set out in AS 60038;
  - the voltage fluctuations that occur are contained within the limits as set out in AS/NZS 61000 Parts 3.3 and 3.5 and AS2279 Part 4;
  - the harmonic voltage distortions do not exceed the values in AS/NZS 61000 Part 3.2 and AS 2279 Part 2 and as set out in the schedule to the standard connection and supply contract;
  - the voltage unbalance factor in 3 phase supplies does not exceed the values set out in the schedule to the standard connection and supply contract.
- SA Power Networks must ensure that any interference caused by its distribution network is less than the limits set out in AS/NZS 61000 Part 3.5 and AS/NZS 2344.

Any third party solution must be capable of meeting these standards in order to be considered a viable solution.

4.5 Projected Network Constraints

SA Power Networks has identified the following network constraints in this area:

- The substation 33/11kV transformers are forecast to be overloaded at peak times under both the N and N-1 planning criteria by summer 2013/14. See table 2 below.
- Inadequate voltages under peak conditions will occur from approximately 2015/16. As the sub transmission line already has one 33kV regulator with an extended tap range at Wirrega; adding a second regulator to the line would impose unacceptable voltage swings following network faults.
- The Keith Connection Point has a N-1 capacity of 37 MVA which is expected to be exceeded in 2017/18.
- The 33 kV sub-transmission line between Keith Connection Point and Bordertown is approximately 47 km long and has a summer normal rating of 13MVA. The line has high losses at peak times (> 4 MW) which cause the line's thermal capacity to be exceeded before the load at Bordertown reaches 13 MVA. Note: solutions that reduce these line losses will also delay the connection point constraint at Keith.

Given the isolation of Bordertown Substation load transfers are not possible as no ties to other substations exist.

The following table provides an indication of the level and period of load reduction required to resolve the Bordertown transformer constraints. Similar reductions are required for the line constraint and slightly less for the connection point constraint.

Table 2: Bordertown Substation Load at risk

Year	Bordertown Substation Load (MVA)	Load at Risk			
		N (MVA)	Hours per annum	N-1 (MVA)	Hours per annum
2013/14	13.3	0.8	5	1.2	11
2014/15	13.8	1.3	9	1.7	21
2015/16	14.4	1.9	15	2.3	31
2016/17	14.9	2.4	24	2.8	63
2017/18	15.5	3.0	40	3.4	84
2018/19	16.2	3.7	71	4.1	112
2019/20	16.8	4.3	93	4.7	141
2020/21	17.5	5.0	112	5.4	167
2021/22	18.2	5.7	141	6.1	199
2022/23	18.9	6.4	167	6.8	253
2023/24	19.7	7.2	215	7.6	318
2024/25	20.4	7.9	253	8.4	430
2025/26	21.3	8.8	318	9.2	539
2026/27	22.1	9.6	430	10.0	680
2027/28	23.0	10.5	539	10.9	866

.

5 Options for Reinforcement

5.1 Proposals received in response to RFP

Three proposals were received in response to the RFP:

- A proposal from Vibe Energy for a small peak lopping diesel power station on land close to Bordertown substation;
- A proposal from Investec for a small peak lopping diesel power station on industrial land near Bordertown Substation;
- A proposal from American Superconductors for reactive support at Bordertown Substation using their proprietary SVC technology.

The power stations have several impacts on the network:

- They reduce the peak power demand to within the capacity of the existing system's sub-transmission lines and substation transformers.
- The load reduction reduces losses in the sub-transmission system and substation transformers.
- They act as a minor source of reactive power and therefore increase the stability of the network following disturbances.
- They can be called on at off peak times following the loss of equipment to minimise the amount of load that must be shed until repairs can be made or emergency equipment installed.

As the demand grows, so does the level of generation required and the expected number of hours which the power station must run in order to achieve the same level of benefit. The generator's run time costs are the product of these two elements and are the major economic constraint on delaying upgrades by simply continuing to increase the level of localised generation employed.

Reactive support as proposed by American Superconductors works by raising the voltage at the 33kV bus at Bordertown to approximately 0.97pu. This has five impacts on the system:

- It reduces the line currents required to supply a given level of power and therefore the line losses;
- It reduces the required tap setting at the Bordertown transformers and at the mid line regulator and therefore the transformer losses;
- The reduction in losses delays the sub transmission line and connection point overloads;
- It increases the ability of the system to withstand voltage fluctuations in the upstream network and therefore both the power quality and stability of the Bordertown system.
- It may increase the current flow through the transformers and therefore bring forward the date of the transformer overload. The magnitude of this impact is highly dependent on the particulars of the network under consideration.

All three proposals have been assessed and found to be technical compliant in that they address, or in combination with other proposed augmentations address, the constraints identified in the RFP.

5.2 Network augmentations to address constraints

In addition, five potential network augmentations were developed to address the identified constraints. As no single augmentation resolves all of the identified constraints; the network solution to the limitations consists of a combination of the following elements (see section 5.4). The augmentations are:

- Increase the thermal rating of the line (Aug N1)

The thermal rating of the existing radial line can be increased from T60 to T80 by upgrading sections of the line, for instance by the addition of new poles in the middle of long spans. This would increase the summer thermal limit of the line from 13 MVA to approximately 19.2 MVA. The work can be done in two stages – Keith to Wirrega and Wirrega to Bordertown.

- The construction of a second 33kV transmission line (Aug N2)

This line would be built in two stages as a double circuit line on a new easement in parallel with the existing line using a medium sized conductor. The first stage would be from Keith to Wirrega (approximately 28 km) followed by a second stage from Wirrega to Bordertown (approximately 20 km). The line would be built to 66kV standard but energised at 33kV to facilitate the long term future upgrade of the sub-transmission system to 66kV. As each stage was commissioned, the existing line would be decommissioned.
The new line would reduce line losses and improve the voltage at the 33kV bus at Bordertown, thereby delaying the connection point upgrade and the voltage constraint at Bordertown. It also substantially improves reliability as it provides a second source of supply to Bordertown.

- The addition of a third 5 MVA transformer at Bordertown (Aug N3)

This increases both the N and N-1 capacity of the substation and reduces the losses through the existing transformers.

- The addition of a new single transformer substation (Aug N4)

This would be located under the existing 33kV line some distance upstream of Bordertown. This option would also require some new 11kV lines to be constructed to tie into the existing feeder network. Due to the existing 11kV feeder locations, it is likely that this additional capacity would be economically limited to no more than about 3 MVA. This represents approximately four years of growth. Benefits include offloading of Bordertown's transformers, improving reliability through improved 11kV feeder transfers under N-1 and a small decrease in losses.

- The transfer of load from Keith Connection Point to Kincraig Connection Point (Aug N5)

It is possible to delay the overload of Keith Connection point by transferring Padthaway Substation from Keith to Kincraig Connection Point and performing some additional voltage support works. While this does not directly address constraints at Bordertown, it does relieve the forecast capacity constraint at Keith.

5.3 Other Options Considered

A number of other network options were considered and discarded as either not being technically feasible or uneconomic. They were:

- Replacement of the existing line.

This option consists of replacing the existing line conductor with one built to a higher standard and with lower impedance. This option has been discarded as Bordertown is on a radial supply and would need to be temporarily supplied by large scale local generation (up to 7 MVA) during the winter construction period. The requirement for system support during the construction period makes this option more expensive than building a new second line.

- A second large substation within the Bordertown area.

A second large substation would mitigate the constraints imposed by the capacity of the existing 33/11 kV transformers at Bordertown but would not help either of the constraints on Keith Connection Point or those imposed by the existing 33kV line such as poor system stability, high losses and poor voltage at peak times. It is also substantially more expensive than adding a third transformer or a small modular substation elsewhere along the existing 33kV line.

- Series capacitors to lower the line impedance.

Placing capacitor banks in series with the transmission line reduces the reactive component of the line impedance and therefore the voltage drop over the line. However the effectiveness of this option is severely limited by the high resistance of the existing conductor on the Keith to Bordertown line.

- Raising the transmission voltage from 33kV to 66kV.

While this option may remain the ideal long term solution, this option would require the addition of either a 132/66 kV or 33/66kV substation at Keith, a new line built to 66kV standards and substantial rebuilding of the existing Bordertown substation. The option has been excluded as a solution in the short term on cost grounds.

- Demand management using direct load control.

There is currently a mid sized trial of this technology about to start in the Adelaide Metro region. Bordertown was not considered a viable location for this trial as the technology is too experimental and consumer support too uncertain to be relied on at this time. Depending on the results of this trial, it is possible that this technology could be used at Bordertown to delay future upgrades from 2015 onwards.

5.4 Credible Options

As none of the proposed augmentations, network or third party solutions in isolation, offer a complete and economic method of resolving the identified constraints, the following four credible options were considered within the evaluation.

Note: due to the lengthy time that commercial negotiations have taken, a temporary (mobile) transformer was added at Bordertown Substation for the 2011-12 and 2012-13 peak summer seasons. Consequently the first augmentation assessed in each option occurs for the 2013-14 summer which is later than proposed in the original RFP.

5.4.1 Generation and Network – Preferred option

This combination of augmentations is the least cost alternative in terms of the Regulatory Test. It initially uses peak lopping generation to initially delay system upgrades and subsequent system upgrades to reduce the cost of future increases in the required level of generation. Separate evaluations have been run for both the Vibe Energy and Investec proposals.

Table 3 Preferred Option - elements and dates

Year	Activity
2013	Install peak lopping generation
2015	Install reactive support at Bordertown (SVC or similar)
2016	Increase the thermal line limit from Keith to Wirrega (Aug N1);
2017	Install a third 5 MVA transformer (Aug N3) and raise the thermal line limit between Wirrega and Bordertown (Aug N1)
2021	Transfer Padthaway load from Keith to Kincraig (Aug N5) [1]
2022	Build stage 1 of the second line (Keith to Wirrega) (Aug N2)
2023	Build small additional substation near Bordertown (Aug N4)
2024	Build stage 2 of the second line (Wirrega to Bordertown) (Aug N2)

[1] This is after the planned capacity upgrade at Kincraig.

5.4.2 Traditional network

This option represents the sole use of 'traditional' network upgrades by SA Power Networks only such as additional transformers, line upgrades and new lines to resolve the constraints.

Table 4 Traditional option - elements and dates

Year	Activity
2013	Install additional 5 MVA transformer at Bordertown Substation (Aug N3); Build stage 1 of the second line (Keith to Wirrega) (Aug N2); Raise the thermal line limit between Wirrega and Bordertown (Aug N1)
2016	Transfer Padthaway to Kincraig Connection Point (Aug N5)
2018	Build stage 2 of the second (Wirrega to Bordertown) (Aug N2)
2021	Build small additional substation near Bordertown (Aug N4)
2023	Upgrade Keith Connection Point

5.4.3 Network plus Reactive Support

This option represents the optimised combination of network upgrades that does not utilise peak lopping generation.

Table 5 Reactive Support Option - elements and dates

Year	Activity
2013	Install Reactive Support at Bordertown (SVC or similar); Install additional 5 MVA transformer at Bordertown Substation (Aug N3); Raise the thermal line limit between Bordertown and Keith (Aug N1)
2016	Build stage 1 of the second line (Keith to Wirrega) (Aug N2)
2019	Build stage 2 of the second line (Wirrega to Bordertown) (Aug N2); Transfer Padthaway to Kincraig Connection Point (Aug N5)
2021	Build small additional substation near Bordertown (Aug N4)
2024	Upgrade Keith Connection Point

6 Market Scenarios and Benefits Considered

In line with the principles expressed in the AER's Regulatory Test, the credible options described in section 5 have been evaluated under a number of different scenarios. The Base Scenario was developed to represent the most likely situation that would eventuate. Alternative scenarios were then formulated to assess sensitivity to potential variations in assumptions. All scenarios have been conducted over a ten year period of analysis.

The following assumptions were subjected to a sensitivity analysis by varying each component singularly whilst leaving the others value according to the base scenario.

6.1 Discount Rate

The Regulatory Test requires the NPV analysis to apply a discount rate appropriate for the analysis of a private enterprise investment in the electricity sector. The AER has stated that:

- "the regulatory WACC might reasonably be considered the lower boundary of the discounts rate but not the mean value around which sensitivity testing is conducted"; and
- "the discount rate adopted for the purpose of the regulatory test evaluation should be a commercial discount rate in order to ensure network and non-network investments are compared on a competitively neutral basis".

SA Power Networks has determined that the appropriate real pre-tax weighted average cost of capital for non regulated work is between 10 and 15 percent. In assessing whether the rate at the lower or higher end of the range should be applied, consideration should be given to factors such as the period of the investment, counterparty risk, size, complementary business opportunities and other risk strategies and adjustments.

In our view, it is reasonable for this evaluation to use a base rate of 10% with the regulatory WACC (8.98%) and 12% being used as the low and high values respectively.

6.2 Electricity demand forecast

For the Base Scenario the medium forecast growth rate for Bordertown substation of 4.0% was used as the base value. The outcome has also been tested against a high growth rate of 5.0% and a low growth rate of 3% as part of the sensitivity analysis. Please note, all forecast loads contained within this report represent the medium forecast.
Note: the forecast demand for this substation has been revised downwards since the RFP was published. This has effectively delayed the onset of the identified system constraints by two years.

6.3 SA Power Networks project costs

SA Power Networks has prepared cost estimates for the work it would have to undertake for each augmentation option. This includes the network changes required to support each third party option. These costs are based on standard historical costs adjusted to 2012 dollar values. These costs do not include any allowance for risk or contingencies.

In the Base Scenario, the costs as estimated have been used. Variations of 80% and 120% of the base values have been used to assess the potential impact of variations in construction costs and the impact of unforseen events.

6.4 Third party costs

The price offered to SA Power Networks for the supply of a peak lopping power station has not been subjected to specific variations in project costs, operating and maintenance costs or depreciation as the risk reflected in these variations is carried by the third party and not the electricity market.

6.5 MWh cost of Electricity Generated

The number of support hours required by SA Power Networks from the power station may vary significantly from year to year depending on the actual level of customer demand, which in turn is related to the prevailing weather conditions.

Variations have therefore been applied to the cost of fuel as a proxy for:

- Changes in the average number of support hours;
- Changes in the level of fuel taxes including the introduction of greenhouse gas taxes in one form or another;
- Actual changes in fuel price or other consumables paid for by SA Power Networks;

A wider range has been used for fuel than for other variables given the greater volatility of costs and operational hours required. A base value of $420 per MWh of generation has been chosen with variations of $300 per MWh and $600 per MWh for the low and high cases.

6.6 Cost of losses

Both Guideline 12 and the AER Market Benefits Limb require changes in the value of electrical losses to be considered when evaluating options. This is calculated by first converting the estimated peak loss into an annual MWh quantity and then multiplying by the average cost of production in the South Australian market. The peak or average market price paid is not used as it includes an element of profit which is excluded under the transfer of economic surplus rules. This cost tends to vary over the years depending on the fuel mix and level of government taxes and subsidies.

The evaluation used $35 per MWh as the base value and a range of $20 per MWh (57%) and $60 per MWh (170%) as low and high values given the uncertainties in the calculation process and future generation costs.

6.7 Value of Customer Reliability (VCR)

The Market Benefits Limb of the Test requires changes in network reliability to be assessed. In cases where an augmentation changes the expected number or duration of customer outages, a benefit (positive or negative) should be applied against the option to reflect the increase or decrease in reliability benefits obtained by Market Participants. This benefit is dependent on the economic activities impacted and therefore on the number and duration of outages and on the time of day, season and location of the loss of supply. The change in reliability is measured in $ per MWh of electrical production or consumption that didn't occur as a result of the loss of supply. The AER has recently published values of approximately $44,300 in 2010 dollars as the average value for South Australia.

Given the substantial variations in the value of the actual losses incurred by any one outage and the large variability in outages in a given year; a base value of $50,000 per MWh has been used with variations of 50% and 150% for the low and high case respectively. ($25,000 and $75,000).

Note: this benefit excludes the value of any reliability or performance scheme payments accrued or paid by SA Power Networks such as Guaranteed Service Level payments or STPIS penalties. Changes in the expected levels of these payments are excluded from the Regulatory Test as they represent transfers of economic surplus between Market Participants.

6.8 Operating and Maintenance Costs

Operating and maintenance costs have been derived as a fixed proportion (ie 1.5% per annum) of the capital cost based on average historical levels. It is considered highly unlikely that any specific elements exist in this instance that would cause a variation from the state average on a systemic basis. Therefore no analysis has been done for a variation in the O&M costs.

6.9 Depreciation

In all cases, the capital cost was depreciated using a straight line method over the life of the asset. The remaining asset life (the depreciated value of the asset) was added back in the final year of the evaluation as an approximation of the residual value of each augmentation. Each set of assets was split into three cost components and depreciated according to the following asset lives:

- Lines = 55 years
- Substations = 45 years
- Reactive Support = 20 years

No variation has been applied to depreciation rates as it is considered unlikely that a substantial variation in the expected life of the assets will occur.

As stated earlier, the assessment has been conducted over a ten year period.

6.10 Impact on market behaviour

Under the Market Benefits Limb of the Test, changes in market behaviour caused by differences between the options should be considered. These impacts include changes in the bidding behaviour of generation companies and the level of voluntary load shedding at peak days. These changes are driven both by changes in the level of market competition and by changes in the average cost of production. In this case, SA Power Networks has decided that there will be no material change in market behaviour due to:

- The diesel powered generation only displacing other diesel powered generation rather than cheaper sources due to the plant being only called on to generate at peak load times and the unavailability of alternative fuel sources in this region.
- The size of both proposed power stations are tiny when compared to the overall peak demand in the South Australian market and therefore does not threaten to displace any other planned generation within the State.

7 Option Evaluation

All four options described in section 5 were evaluated over range of scenarios described in section 6. In each case, the preferred option utilising the offer from Vibe energy for third party network support combined with various network augmentations was the most economic choice. Consequently SA Power Networks will resolve the Bordertown constraints by engaging Vibe Energy to offer third party network support through the use of a small embedded power station at Bordertown.

The evaluation tables below summarise the outcome of each scenario over the three growth projections. No weighting has been applied to any option as in all cases the preferred solution was the most economic. The “total combined value” is the summation of the direct costs associated with the various augmentation options while the benefit values represent the benefits associated with reduction in losses or improved customer reliability. The ranking within the “Total Combined Value” section indicates the most economic option. The “Diff to preferred” column indicates the difference between the various options for each scenario and is an indication of the margin between the options. Direct costs represent the NPV of each option’s augmentation costs. This column is that which would have been used had the Reliability Limb of the Regulatory Test been applied.

Table 6 Evaluation Study Results - medium growth

Scenario	Description	Total Combined Value (ie Market Benefits Limb)			Direct Costs (ie Reliability Limb)			Benefits		
		Total $'000's)	Rank	Diff to preferred	Total $'000's	Rank	Diff to preferred	Total $'000's	Rank	Diff to preferred
Default	Preferred Solution (Vibe)	-$6,342	1	$0	$9,792	1	$0	-$16,134	3	$4,583
Default	Traditional network	-$2,535	3	$3,807	$18,182	4	$8,390	-$20,717	1	$0
Default	Network + Reactive support	-$3,204	2	$3,138	$14,875	3	$5,082	-$18,078	2	$2,639
Default	Investec	-$1,581	4	$4,761	$13,772	2	$3,980	-$15,353	4	$5,364
Low Discount	Preferred Solution (Vibe)	-$7,385	1	$0	$9,761	1	$0	-$17,146	3	$4,810
Low Discount	Traditional network	-$4,365	3	$3,020	$17,592	4	$7,830	-$21,957	1	$0
Low Discount	Network + Reactive support	-$4,742	2	$2,642	$14,513	3	$4,751	-$19,255	2	$2,701
Low Discount	Investec	-$2,360	4	$5,025	$13,970	2	$4,208	-$16,330	4	$5,627
High Discount	Preferred Solution (Vibe)	-$4,153	1	$0	$9,809	1	$0	-$13,961	3	$4,089
High Discount	Traditional network	$1,316	4	$5,469	$19,366	4	$9,557	-$18,050	1	$0
High Discount	Network + Reactive support	-$36	2	$4,117	$15,517	3	$5,708	-$15,553	2	$2,497
High Discount	Investec	$34	3	$4,186	$13,291	2	$3,482	-$13,257	4	$4,793
Low Losses	Preferred Solution (Vibe)	-$5,811	1	$0	$9,792	1	$0	-$15,604	3	$4,158
Low Losses	Traditional network	-$1,579	3	$4,232	$18,182	4	$8,390	-$19,761	1	$0
Low Losses	Network + Reactive support	-$2,413	2	$3,399	$14,875	3	$5,082	-$17,287	2	$2,474
Low Losses	Investec	-$1,050	4	$4,761	$13,772	2	$3,980	-$14,822	4	$4,939
High Losses	Preferred Solution (Vibe)	-$7,227	1	$0	$9,792	1	$0	-$17,019	3	$5,291
High Losses	Traditional network	-$4,128	3	$3,099	$18,182	4	$8,390	-$22,310	1	$0
High Losses	Network + Reactive support	-$4,522	2	$2,705	$14,875	3	$5,082	-$19,397	2	$2,914
High Losses	Investec	-$2,465	4	$4,761	$13,772	2	$3,980	-$16,238	4	$6,073
Low VCR	Preferred Solution (Vibe)	$1,106	1	$0	$9,792	1	$0	-$8,686	3	$2,787
Low VCR	Traditional network	$6,709	4	$5,603	$18,182	4	$8,390	-$11,474	1	$0
Low VCR	Network + Reactive support	$4,913	2	$3,807	$14,875	3	$5,082	-$9,962	2	$1,512
Low VCR	Investec	$5,476	3	$4,371	$13,772	2	$3,980	-$8,296	4	$3,178
High VCR	Preferred Solution (Vibe)	-$13,790	1	$0	$9,792	1	$0	-$23,582	3	$6,378
High VCR	Traditional network	-$11,778	2	$2,012	$18,182	4	$8,390	-$29,961	1	$0
High VCR	Network + Reactive support	-$11,320	3	$2,470	$14,875	3	$5,082	-$26,195	2	$3,766
High VCR	Investec	-$8,638	4	$5,152	$13,772	2	$3,980	-$22,410	4	$7,551

Scenario	Description	Total Combined Value (ie Market Benefits Limb)			Direct Costs (ie Reliability Limb)			Benefits		
		Total $'000's)	Rank	Diff to preferred	Total $'000's	Rank	Diff to preferred	Total $'000's	Rank	Diff to preferred
Low Distr Capital	Preferred Solution (Vibe)	-$7,594	1	$0	$8,540	1	$0	-$16,134	3	$4,583
Low Distr Capital	Traditional network	-$6,171	3	$1,423	$14,546	4	$6,006	-$20,717	1	$0
Low Distr Capital	Network + Reactive support	-$6,179	2	$1,416	$11,900	2	$3,360	-$18,078	2	$2,639
Low Distr Capital	Investec	-$2,547	4	$5,047	$12,805	3	$4,265	-$15,353	4	$5,364
High Distr Capital	Preferred Solution (Vibe)	-$5,090	1	$0	$11,045	1	$0	-$16,134	3	$4,583
High Distr Capital	Traditional network	$1,102	4	$6,192	$21,819	4	$10,774	-$20,717	1	$0
High Distr Capital	Network + Reactive support	-$229	3	$4,861	$17,850	3	$6,805	-$18,078	2	$2,639
High Distr Capital	Investec	-$614	2	$4,476	$14,739	2	$3,694	-$15,353	4	$5,364
Low Trans Capital	Preferred Solution (Vibe)	-$6,342	1	$0	$9,792	1	$0	-$16,134	3	$4,583
Low Trans Capital	Traditional network	-$2,535	3	$3,807	$18,182	4	$8,390	-$20,717	1	$0
Low Trans Capital	Network + Reactive support	-$3,204	2	$3,138	$14,875	3	$5,082	-$18,078	2	$2,639
Low Trans Capital	Investec	-$1,581	4	$4,761	$13,772	2	$3,980	-$15,353	4	$5,364
High Trans Capital	Preferred Solution (Vibe)	-$6,342	1	$0	$9,792	1	$0	-$16,134	3	$4,583
High Trans Capital	Traditional network	-$2,535	3	$3,807	$18,182	4	$8,390	-$20,717	1	$0
High Trans Capital	Network + Reactive support	-$3,204	2	$3,138	$14,875	3	$5,082	-$18,078	2	$2,639
High Trans Capital	Investec	-$1,581	4	$4,761	$13,772	2	$3,980	-$15,353	4	$5,364
Low Gen Capital	Preferred Solution (Vibe)	-$6,342	1	$0	$9,792	1	$0	-$16,134	3	$4,583
Low Gen Capital	Traditional network	-$2,535	3	$3,807	$18,182	4	$8,390	-$20,717	1	$0
Low Gen Capital	Network + Reactive support	-$3,204	2	$3,138	$14,875	3	$5,082	-$18,078	2	$2,639
Low Gen Capital	Investec	-$1,581	4	$4,761	$13,772	2	$3,980	-$15,353	4	$5,364
High Gen Capital	Preferred Solution (Vibe)	-$6,342	1	$0	$9,792	1	$0	-$16,134	3	$4,583
High Gen Capital	Traditional network	-$2,535	3	$3,807	$18,182	4	$8,390	-$20,717	1	$0
High Gen Capital	Network + Reactive support	-$3,204	2	$3,138	$14,875	3	$5,082	-$18,078	2	$2,639
High Gen Capital	Investec	-$1,581	4	$4,761	$13,772	2	$3,980	-$15,353	4	$5,364

Table 7 Evaluation Study Results - Low Growth

Scenario	Description	Total Combined Value (ie Market Benefits Limb)			Direct Costs (ie Reliability Limb)			Benefits		
		Total $'000's)	Rank	Diff to preferred	Total $'000's	Rank	Diff to preferred	Total $'000's	Rank	Diff to preferred
Default	Preferred Solution (Vibe)	$567	1	$0	$8,442	1	$0	-$7,875	3	$4,283
Default	Traditional network	$3,607	3	$3,040	$15,765	4	$7,323	-$12,158	1	$0
Default	Network + Reactive support	$2,367	2	$1,800	$10,373	2	$1,931	-$8,006	2	$4,152
Default	Investec	$5,472	4	$4,905	$12,569	3	$4,127	-$7,097	4	$5,061
Low Discount	Preferred Solution (Vibe)	$142	1	$0	$8,446	1	$0	-$8,303	3	$4,492
Low Discount	Traditional network	$2,397	3	$2,254	$15,192	4	$6,746	-$12,795	1	$0
Low Discount	Network + Reactive support	$1,623	2	$1,480	$10,119	2	$1,673	-$8,496	2	$4,299
Low Discount	Investec	$5,308	4	$5,165	$12,798	3	$4,352	-$7,490	4	$5,305
High Discount	Preferred Solution (Vibe)	$1,448	1	$0	$8,395	1	$0	-$6,947	3	$3,829
High Discount	Traditional network	$6,174	4	$4,726	$16,950	4	$8,556	-$10,776	1	$0
High Discount	Network + Reactive support	$3,878	2	$2,430	$10,829	2	$2,434	-$6,951	2	$3,825
High Discount	Investec	$5,784	3	$4,336	$12,030	3	$3,635	-$6,246	4	$4,530
Low Losses	Preferred Solution (Vibe)	$1,056	1	$0	$8,442	1	$0	-$7,386	2	$3,899
Low Losses	Traditional network	$4,480	3	$3,424	$15,765	4	$7,323	-$11,285	1	$0
Low Losses	Network + Reactive support	$3,073	2	$2,017	$10,373	2	$1,931	-$7,300	3	$3,984
Low Losses	Investec	$5,961	4	$4,905	$12,569	3	$4,127	-$6,608	4	$4,677
High Losses	Preferred Solution (Vibe)	-$248	1	$0	$8,442	1	$0	-$8,690	3	$4,923
High Losses	Traditional network	$2,151	3	$2,399	$15,765	4	$7,323	-$13,614	1	$0
High Losses	Network + Reactive support	$1,190	2	$1,438	$10,373	2	$1,931	-$9,183	2	$4,430
High Losses	Investec	$4,657	4	$4,905	$12,569	3	$4,127	-$7,912	4	$5,701
Low VCR	Preferred Solution (Vibe)	$3,934	1	$0	$8,442	1	$0	-$4,508	3	$2,590
Low VCR	Traditional network	$8,667	4	$4,733	$15,765	4	$7,323	-$7,098	1	$0
Low VCR	Network + Reactive support	$5,546	2	$1,612	$10,373	2	$1,931	-$4,827	2	$2,271
Low VCR	Investec	$8,450	3	$4,516	$12,569	3	$4,127	-$4,119	4	$2,979
High VCR	Preferred Solution (Vibe)	-$2,800	1	$0	$8,442	1	$0	-$11,241	2	$5,977
High VCR	Traditional network	-$1,453	2	$1,346	$15,765	4	$7,323	-$17,218	1	$0
High VCR	Network + Reactive support	-$812	3	$1,987	$10,373	2	$1,931	-$11,186	3	$6,032
High VCR	Investec	$2,494	4	$5,294	$12,569	3	$4,127	-$10,075	4	$7,143
Low Distr Capital	Preferred Solution (Vibe)	-$417	1	$0	$7,458	1	$0	-$7,875	3	$4,283

Scenario	Description	Total Combined Value (ie Market Benefits Limb)			Direct Costs (ie Reliability Limb)			Benefits		
		Total $'000's)	Rank	Diff to preferred	Total $'000's	Rank	Diff to preferred	Total $'000's	Rank	Diff to preferred
Low Distr Capital	Traditional network	$454	3	$870	$12,612	4	$5,154	-$12,158	1	$0
Low Distr Capital	Network + Reactive support	$292	2	$709	$8,298	2	$840	-$8,006	2	$4,152
Low Distr Capital	Investec	$4,744	4	$5,161	$11,841	3	$4,383	-$7,097	4	$5,061
High Distr Capital	Preferred Solution (Vibe)	$1,551	1	$0	$9,426	1	$0	-$7,875	3	$4,283
High Distr Capital	Traditional network	$6,759	4	$5,209	$18,917	4	$9,492	-$12,158	1	$0
High Distr Capital	Network + Reactive support	$4,441	2	$2,891	$12,448	2	$3,022	-$8,006	2	$4,152
High Distr Capital	Investec	$6,200	3	$4,649	$13,297	3	$3,871	-$7,097	4	$5,061
Low Trans Capital	Preferred Solution (Vibe)	$567	1	$0	$8,442	1	$0	-$7,875	3	$4,283
Low Trans Capital	Traditional network	$3,607	3	$3,040	$15,765	4	$7,323	-$12,158	1	$0
Low Trans Capital	Network + Reactive support	$2,367	2	$1,800	$10,373	2	$1,931	-$8,006	2	$4,152
Low Trans Capital	Investec	$5,472	4	$4,905	$12,569	3	$4,127	-$7,097	4	$5,061
High Trans Capital	Preferred Solution (Vibe)	$567	1	$0	$8,442	1	$0	-$7,875	3	$4,283
High Trans Capital	Traditional network	$3,607	3	$3,040	$15,765	4	$7,323	-$12,158	1	$0
High Trans Capital	Network + Reactive support	$2,367	2	$1,800	$10,373	2	$1,931	-$8,006	2	$4,152
High Trans Capital	Investec	$5,472	4	$4,905	$12,569	3	$4,127	-$7,097	4	$5,061
Low Gen Capital	Preferred Solution (Vibe)	$567	1	$0	$8,442	1	$0	-$7,875	3	$4,283
Low Gen Capital	Traditional network	$3,607	3	$3,040	$15,765	4	$7,323	-$12,158	1	$0
Low Gen Capital	Network + Reactive support	$2,367	2	$1,800	$10,373	2	$1,931	-$8,006	2	$4,152
Low Gen Capital	Investec	$5,472	4	$4,905	$12,569	3	$4,127	-$7,097	4	$5,061
High Gen Capital	Preferred Solution (Vibe)	$567	1	$0	$8,442	1	$0	-$7,875	3	$4,283
High Gen Capital	Traditional network	$3,607	3	$3,040	$15,765	4	$7,323	-$12,158	1	$0
High Gen Capital	Network + Reactive support	$2,367	2	$1,800	$10,373	2	$1,931	-$8,006	2	$4,152
High Gen Capital	Investec	$5,472	4	$4,905	$12,569	3	$4,127	-$7,097	4	$5,061

Table 8 Evaluation study Results - High Growth

Scenario	Description	Total Combined Value (ie Market Benefits Limb)			Direct Costs (ie Reliability Limb)			Benefits		
		Total $'000's	Rank	Diff to preferred	Total $'000's	Rank	Diff to preferred	Total $'000's	Rank	Diff to preferred
Default	Preferred Solution (Vibe)	-$56,733	1	$0	$10,147	1	$0	-$66,880	3	$5,484
Default	Traditional network	-$53,207	3	$3,525	$19,156	4	$9,009	-$72,363	1	$0
Default	Network + Reactive support	-$53,842	2	$2,891	$15,857	3	$5,710	-$69,698	2	$2,665
Default	Investec	-$51,878	4	$4,855	$14,127	2	$3,980	-$66,004	4	$6,359
Low Discount	Preferred Solution (Vibe)	-$61,325	1	$0	$10,112	1	$0	-$71,436	3	$5,773
Low Discount	Traditional network	-$58,663	3	$2,662	$18,546	4	$8,435	-$77,209	1	$0
Low Discount	Network + Reactive support	-$59,001	2	$2,324	$15,483	3	$5,372	-$74,484	2	$2,725
Low Discount	Investec	-$56,204	4	$5,120	$14,320	2	$4,208	-$70,524	4	$6,685
High Discount	Preferred Solution (Vibe)	-$46,954	1	$0	$10,170	1	$0	-$57,123	3	$4,855
High Discount	Traditional network	-$41,611	4	$5,343	$20,368	4	$10,198	-$61,978	1	$0
High Discount	Network + Reactive support	-$42,944	2	$4,010	$16,507	3	$6,338	-$59,451	2	$2,527
High Discount	Investec	-$42,677	3	$4,277	$13,652	2	$3,482	-$56,329	4	$5,650
Low Losses	Preferred Solution (Vibe)	-$56,189	1	$0	$10,147	1	$0	-$66,336	3	$4,936
Low Losses	Traditional network	-$52,116	3	$4,073	$19,156	4	$9,009	-$71,272	1	$0
Low Losses	Network + Reactive support	-$52,873	2	$3,316	$15,857	3	$5,710	-$68,730	2	$2,542
Low Losses	Investec	-$51,334	4	$4,855	$14,127	2	$3,980	-$65,461	4	$5,812
High Losses	Preferred Solution (Vibe)	-$57,639	1	$0	$10,147	1	$0	-$67,786	3	$6,396
High Losses	Traditional network	-$55,025	3	$2,613	$19,156	4	$9,009	-$74,181	1	$0
High Losses	Network + Reactive support	-$55,456	2	$2,183	$15,857	3	$5,710	-$71,312	2	$2,869
High Losses	Investec	-$52,784	4	$4,855	$14,12	2	$3,980	-$66,910	4	$7,271
Low VCR	Preferred Solution (Vibe)	-$23,927	1	$0	$10,147	1	$0	-$34,074	3	$3,380
Low VCR	Traditional network	-$18,298	4	$5,629	$19,156	4	$9,009	-$37,454	1	$0
Low VCR	Network + Reactive support	-$20,122	2	$3,805	$15,857	3	$5,710	-$35,979	2	$1,475
Low VCR	Investec	-$19,510	3	$4,417	$14,127	2	$3,980	-$33,636	4	$3,818
High VCR	Preferred Solution (Vibe)	-$89,538	1	$0	$10,147	1	$0	-$99,685	3	$7,587
High VCR	Traditional network	-$88,116	2	$1,422	$19,156	4	$9,009	-$107,272	1	$0
High VCR	Network + Reactive support	-$87,561	3	$1,977	$15,857	3	$5,710	-$103,417	2	$3,855
High VCR	Investec	-$84,245	4	$5,293	$14,127	2	$3,980	-$98,372	4	$8,900
Low Distr Capital	Preferred Solution (Vibe)	-$58,047	1	$0	$8,833	1	$0	-$66,880	3	$5,484

Scenario	Description	Total Combined Value (ie Market Benefits Limb)			Direct Costs (ie Reliability Limb)			Benefits		
		Total $'000's	Rank	Diff to preferred	Total $'000's	Rank	Diff to preferred	Total $'000's	Rank	Diff to preferred
Low Distr Capital	Traditional network	-$57,038	2	$1,009	$15,325	4	$6,492	-$72,363	1	$0
Low Distr Capital	Network + Reactive support	-$57,013	3	$1,034	$12,685	2	$3,853	-$69,698	2	$2,665
Low Distr Capital	Investec	-$52,906	4	$5,141	$13,098	3	$4,265	-$66,004	4	$6,359
High Distr Capital	Preferred Solution (Vibe)	-$55,418	1	$0	$11,461	1	$0	-$66,880	3	$5,484
High Distr Capital	Traditional network	-$49,376	4	$6,042	$22,987	4	$11,526	-$72,363	1	$0
High Distr Capital	Network + Reactive support	-$50,670	3	$4,748	$19,028	3	$7,567	-$69,698	2	$2,665
High Distr Capital	Investec	-$50,849	2	$4,570	$15,155	2	$3,694	-$66,004	4	$6,359
Low Trans Capital	Preferred Solution (Vibe)	-$56,733	1	$0	$10,147	1	$0	-$66,880	3	$5,484
Low Trans Capital	Traditional network	-$53,207	3	$3,525	$19,156	4	$9,009	-$72,363	1	$0
Low Trans Capital	Network + Reactive support	-$53,842	2	$2,891	$15,857	3	$5,710	-$69,698	2	$2,665
Low Trans Capital	Investec	-$51,878	4	$4,855	$14,127	2	$3,980	-$66,004	4	$6,359
High Trans Capital	Preferred Solution (Vibe)	-$56,733	1	$0	$10,147	1	$0	-$66,880	3	$5,484
High Trans Capital	Traditional network	-$53,207	3	$3,525	$19,156	4	$9,009	-$72,363	1	$0
High Trans Capital	Network + Reactive support	-$53,842	2	$2,891	$15,857	3	$5,710	-$69,698	2	$2,665
High Trans Capital	Investec	-$51,878	4	$4,855	$14,127	2	$3,980	-$66,004	4	$6,359
Low Gen Capital	Preferred Solution (Vibe)	-$56,733	1	$0	$10,147	1	$0	-$66,880	3	$5,484
Low Gen Capital	Traditional network	-$53,207	3	$3,525	$19,156	4	$9,009	-$72,363	1	$0
Low Gen Capital	Network + Reactive support	-$53,842	2	$2,891	$15,857	3	$5,710	-$69,698	2	$2,665
Low Gen Capital	Investec	-$51,878	4	$4,855	$14,127	2	$3,980	-$66,004	4	$6,359
High Gen Capital	Preferred Solution (Vibe)	-$56,733	1	$0	$10,147	1	$0	-$66,880	3	$5,484
High Gen Capital	Traditional network	-$53,207	3	$3,525	$19,156	4	$9,009	-$72,363	1	$0
High Gen Capital	Network + Reactive support	-$53,842	2	$2,891	$15,857	3	$5,710	-$69,698	2	$2,665
High Gen Capital	Investec	-$51,878	4	$4,855	$14,127	2	$3,980	-$66,004	4	$6,359