Reasonableness Test RT 006/13

Kapunda 33/11kV Substation
N-1 Capacity Constraint

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GLOSSARY OF TERMS

Term	Meaning
Contingency Condition (N-1)	The term used to describe the state of the Distribution Network when any one piece of plant (N-1) is out of service, with the rest of the Network remaining intact.
Connection Point	A substation shared with ElectraNet, at which electrical power is injected from the ElectraNet Transmission Network into SA Power Networks' Distribution Network.
Distribution System	Shall have the meaning as defined within Chapter 10 of the National Electricity Rules.
Firm Delivery Capacity (N-1 Rating)	The maximum allowable load of a Substation under single Contingency Conditions, including any short term overload capacity.
POE	Probability of Exceedance. The 50% POE forecast (1 in 2 year event) is compared against the substation's firm delivery capacity.
PV	Photovoltaic (also known as solar cells)
Transfer Capacity	The amount of load that can be transferred to an adjacent substation via the 11kV feeder network, while still providing adequate customer voltage levels.

GUIDELINE 12 REASONABLENESS TEST

N-1 Capacity Constraint at Kapunda Substation

1. CURRENT SUPPLY ARRANGEMENT

Kapunda

Kapunda 33/11kV Substation is located near the township of Kapunda in the Mid North region and is supplied from the Templers 132/33kV Connection Point.

Kapunda Substation contains one 12.5MVA 33/11kV transformer, installed in 2012, and supplies approximately 1700 customers via two 11kV feeders who are predominantly residential, rural and agricultural.

There are limited 11kV feeder ties to the adjacent Freeling Substation to the South of Kapunda Substation. During the 2015/16 summer under 50% PoE conditions approximately 0.5 MVA of load can be transferred to the neighbouring substation via the 11kV feeder network within 4 hours. Transfer capacity is limited by the available spare capacity adjacent 11kV feeders and the requirement to maintain adequate customer voltage levels.

Kapunda Substation has a firm delivery capacity of 0 MVA. For the summer of 2015/16, the 50% PoE forecast is 5.9 MVA. 5.4MVA of customer load is forecast to be unsupplied during a contingent event after all available load transfers have been implemented. This load will remain unsupplied until a mobile substation can be deployed and installed (typically up to 24 hours).

The area under consideration is shown on Figure 1 below.

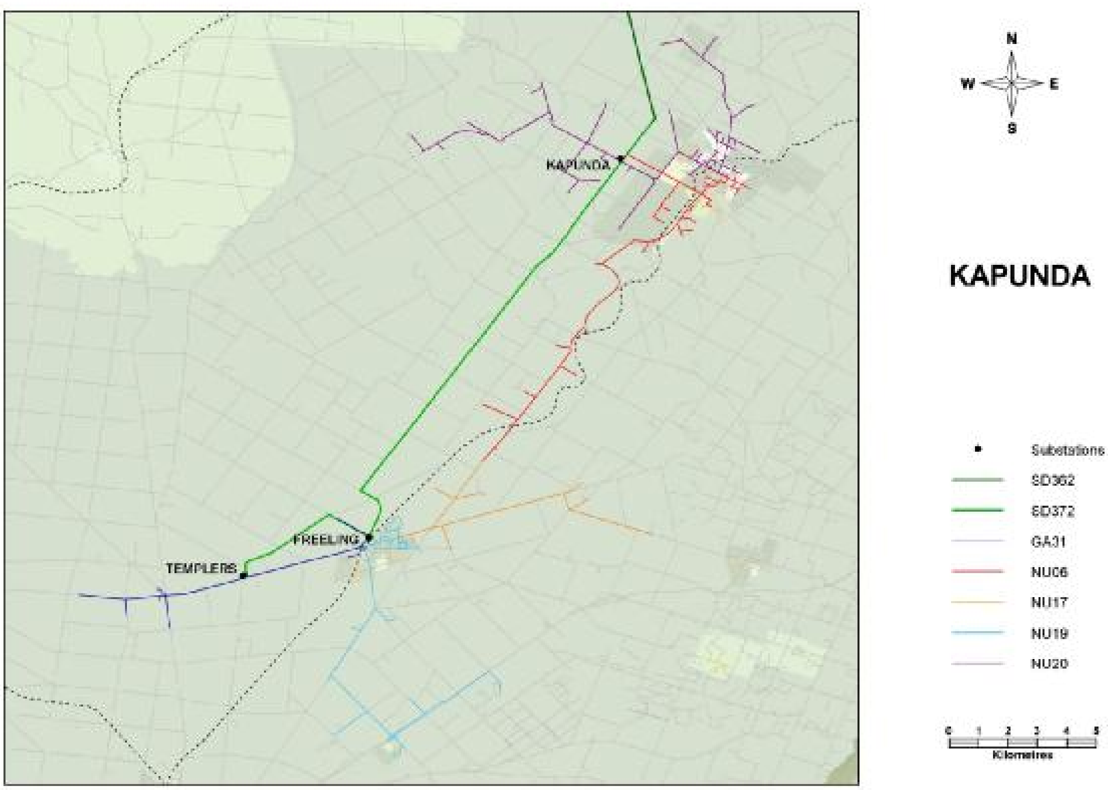

Figure 1 Locality of Kapunda Substation

2. FORECAST LOAD AND CAPACITY

2.1 Load Forecast

Total 11kV load at Kapunda Substation is forecast to grow at an average rate of 4% per annum, which sees the load increase from 5.8 MVA in 2013/14 to 8.6 MVA in 2023/24, as shown in Table 1. This growth represents the moderate 50% POE forecast which SA Power Networks uses for contingency planning purposes. The forecast takes into account all known existing or committed demand management programmes, and also includes an adjustment for the presence of any embedded generation including roof top PV installed. Power factor at peak times is 0.93.

Table 1 Forecast load growth at Kapunda Substation

Summer Year	MVA	MW	MVAr
2013/14	5.8	5.4	2.1
2014/15	6.1	5.7	2.2
2015/16	6.3	5.9	2.3
2016/17	6.6	6.1	2.4
2017/18	6.8	6.4	2.5
2018/19	7.1	6.6	2.6
2019/20	7.4	6.9	2.7
2020/21	7.7	7.2	2.8
2021/22	8.0	7.4	2.9
2022/23	8.3	7.7	3.1
2023/24	8.6	8.0	3.2

SA Power Networks has no committed distribution or sub transmission augmentations in the Kapunda area.

There is no known significant embedded generation permanently connected to Kapunda substation other than domestic roof top PV, the impact of which is included in the above forecast.

SA Power Networks is not aware of any existing or committed embedded generation augmentations that will potentially impact on the distribution network that services Kapunda Substation.

2.2 Pattern of Use

Peak electricity demand at Kapunda Substation occurs during summer, predominantly as a result of air-conditioning.

The peak load profile from the 12th March 2013 is typical of the load on the substation during peak periods. It shows some sign of PV penetration with a fairly sharp peak at approximately 17:30 followed by a sharp drop off from 20:00. In numbers, load is above 85% of peak between 16:30 and 19:30 and above 95% of peak between 17:00 and 18:00.

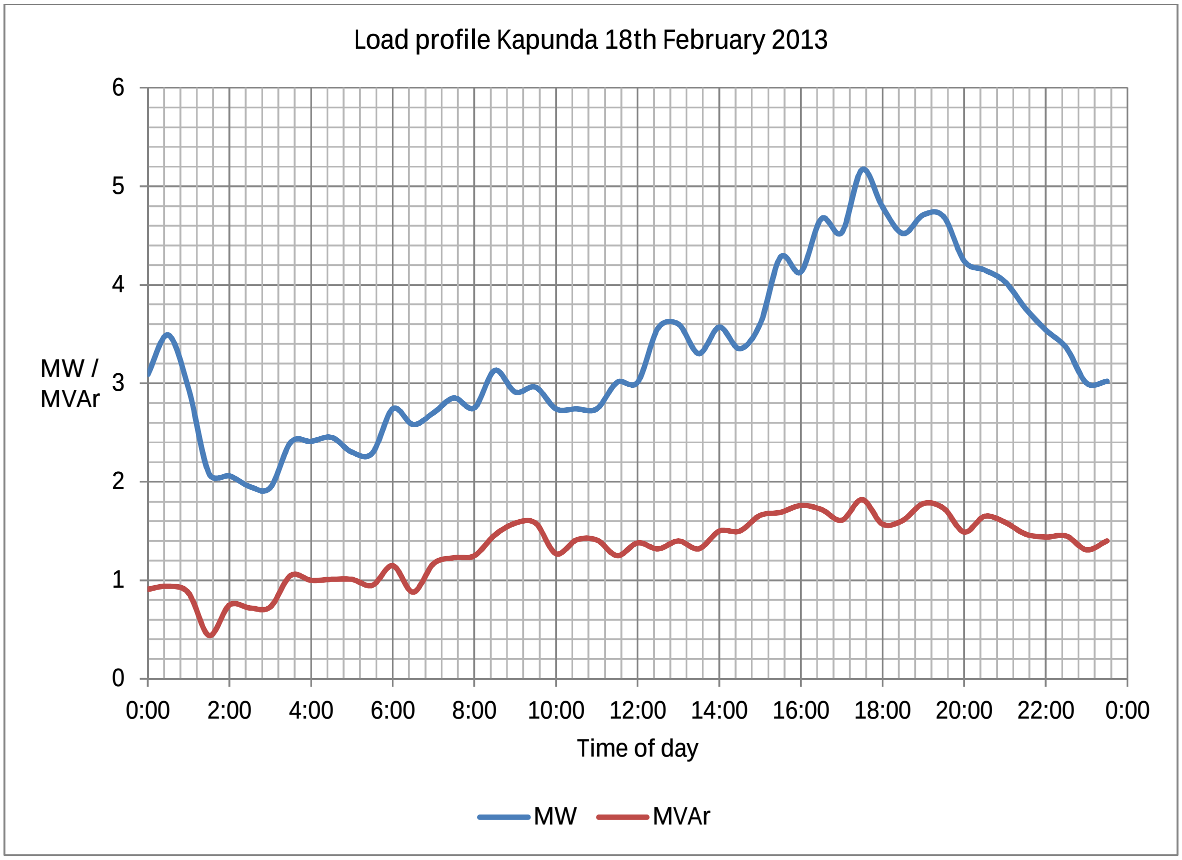

Figure 2 Load profile Kapunda

In terms of the annual spread, loads in the Kapunda area are fairly typical of residential, rural and agricutural load, in particular the load shows:

- A sharp peak occuring on a few hot days a year, compared with a low average.
- Loads are in excess of 95% of peak for approximately 3.5 hours a year
- Loads are in excess of 85% of peak for approximately 44 hours a year.
- Average load is approximately 45% of peak.

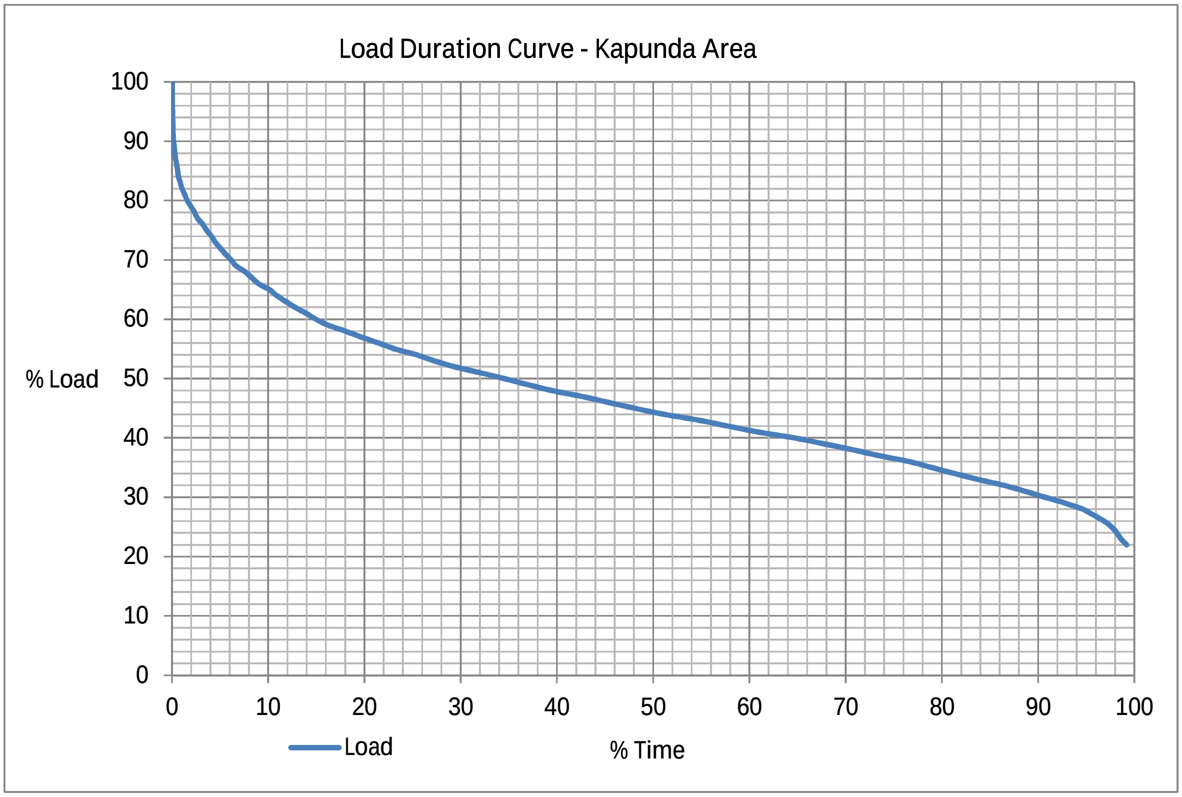

Figure 3 Load duration curve - Kapunda area

2.3 System Limitations

Following the loss of the single 33/11kV transformer, minimal load at Kapunda substation can be transferred to other substations under 50% POE conditions. In summer 2015-16 peak load at risk is 5.8MVA and there is some load at risk all year. By summer 2019-20 load at risk has risen to 6.9 MVA.

Following transfers to adjacent substations, the load at risk will be unsupplied until a mobile substation can be installed (typically up to 24 hours).

The identified need is to reduce the load at risk at Kapunda substation following a transformer outage.

3. NETWORK UPGRADE

Network options that have been investigated to resolve these potential overloads include the following:

Option 1:

- Construct a new 33/11kV substation in the region with sufficient 11kV feeder ties to Kapunda to allow load to be transferred following the loss of a transformer.

Option 2:

- Upgrade Kapunda Substation with a second 33/11kV transformer.

The preferred solution, when the net present value, timing and effectiveness of related upgrade projects is considered, is to upgrade Kapunda 33/11kV Substation with second 33/11kV transformer (Option 2). The indicative cost for this project is in the order of $4,500,000. This project is planned for completion in 2015.

4. DEMAND MANAGEMENT ANALYSIS

4.1 Required Demand Management Characteristics

For a demand management option to be credible it must be capable of either:

- Reducing the load at risk at Kapunda substation

Given the substantial hours at risk this load reduction must be available all year and include both day and evening hours. It may operate post fault in conjunction with manual line switching operations.

Table 2 Load reduction required (MVA)

Year	MVA required
2014	5.6
2015	5.8
2016	6.1
2017	6.3
2018	6.6
2019	6.9
2020	7.2
2021	7.5
2022	7.8

4.2 Demand Management Value

The following table indicates how much can be spent in year 1 to achieve a 1, 2 or 3 year deferral expressed both as an overall cost and as $ per kVA. The minimum and maximum amounts are derived by using different assumptions on the cost of capital from a minimum of 8.98% to 12.5%. The stated benefits also include an allowance of $50k per annum to cover our administrative costs. Note that these figures are indicative only and that any credible DM solution proposed will be evaluated against the preferred network solution in a full RIT-D evaluation. Details of how this is done can be obtained from the Demand Side Engagement Strategy document found on our website.

Table 3 $ per kVA available for Demand Management

Deferral benefits	Total Available Benefit $,000's (min)	Total Available benefit $,000's (max)	$ available per kVA (Min)	$ available per kVA (Max)
1 year Deferral	$337	$466	$58	$80
2 year Deferral	$692	$924	$113	$151
3 year Deferral	$1,018	$1,331	$162	$211

4.3 Demand Management Options Considered

Various Demand Management (DM) technologies were considered to determine their viability to assist in reducing the demand in the constrained area. These DM options were evaluated for both technical feasibility as well as cost effectiveness.

4.3.a Standby diesel generators

Establish contracts with customers who have standby diesel generators on their premises and utilise the generators at peak load times or install peak lopping generators to reduce load at peak times. This option is not viable as there are not enough large customers with standby generators within the region to make this option feasible.

4.3.b Install new diesel generation

Recent experience indicates that the $ per kVA value available is too small to support a peaking plant, even if one could be built in the timeframe required.

4.3.c Install power factor correction

This option is not technically feasible as there are not enough large customers supplied out of Kapunda to make individual power factor correction viable and substation based correction would not address the identified need.

4.3.d Retrofit commercial lighting with efficient lighting.

This option relies upon the ability to upgrade existing commercial fluorescent lighting to T5 lighting. Based on the upgrade of an existing 400W fluorescent bank with a 2x 80W efficient bank to provide the equivalent lumen output, the demand saving per bank is 240W.

The estimated cost for this option is $2,500/kVA. Significant disruption to the customer while the retrofit is carried out can be expected, which may influence the number of willing participants. It is highly unlikely that sufficient volume could be achieved to make a significant difference as most commercial load in the area is supplied by the Morphettville substation.

4.3.e Peak load control – direct load control

Direct load control technology may be available where tripping multiple small air conditioning units supplied from a single distribution transformer can be performed. Recent experiences have shown the costs of such solutions to range from $300 to $800/kVA. Given the size of the constraint it is highly unlikely that sufficient volume would be available to make a significant difference in the size of constraint.

4.3.f Peak load control – curtailable load

This involves establishing a contract with one or more large customer's requiring them to reduce their load by either turning off the power supply to part of their business or shifting load to "off peak" times. Practically, there are no suitable customers with a load large enough to individually have a material impact on the network load for this option to be viable.

4.3.g Residential compact fluorescent lamp (CFL) program

This option was deemed not relevant due to peak load conditions occurring in daylight hours. Load contribution from residential housing lighting during daylight hours is believed to be minimal.

4.3.h Thermal storage systems

Installation of this form of storage system at a suitable site in a previous trial revealed a saving in load in the order of 150kVA. Smaller scale installations have also been trialled and are still very much in the development stage. However, the expected cost of this size of installation ranges from $1,000-1,600/kVA, which is much more expensive than the $ per kVA available.

4.3.i Energy Storage

Use of energy storage technology such as flow batteries is typically in the order of $6000 per kVA, which is significantly more than the available amount.

5. CONCLUSION

Based on the Demand Management options considered when compared to the preferred network solution, it is not possible that sufficient Demand Management measures could be implemented to achieve the demand reduction required to make project deferral technically and economically viable.

The constraint on the Kapunda substation has therefore failed the Reasonableness Test and a Request for Proposal (RFP) will not be issued.