Reasonableness Test RT 002/13

Glenelg North N-1 Cable 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 while still providing adequate customer voltage levels.

GUIDELINE 12 REASONABLENESS TEST

Reliability constraint at Glenelg North Substation

1. CURRENT SUPPLY ARRANGEMENT

Glenelg North

Glenelg North Substation is located in the suburb of Glenelg in Adelaide, near Pine Avenue and to the south of Burrupa Avenue. It is supplied via a single 66kV sub-transmission line from Plympton Substation, which forms part of the meshed Metro South network. Glenelg North Substation contains two 10MVA 66/11kV transformers, purchased in 1963 and 1966, that supply 6 x 11kV feeders.

The substation has a total normal capacity of 27.9 MVA and a firm delivery capacity of 15 MVA. Its forecast load for summer 2013/14 under 10%POE conditions is 18.2 MVA. It currently supplies approximately 5,500 customers who are predominately residential with some commercial and light industrial load.

The existing 66kV sub-transmission line between Glenelg and Plympton Substations was originally built in 1955 and consists of 3.6 km of overhead line and 0.32km of Copper cable. The line has a summer rating of 55MVA. As the substation has only one source of supply, the firm rating of Glenelg North Substation following a sub-transmission fault is 0 MVA (ie supply shall be lost to the entire load until either manual load transfers to other substations via 11kV feeder ties can be performed or the sub-transmission line is returned to service).

The substation has 11kV feeder ties to Morphettville, Plympton and Henley Beach South Substations to the South East, North East and North of Glenelg North Substation respectively. Approximately 5.6 MVA can be transferred at peak times within 4 hours during summer 2013/14.

The substation is severely space constrained with very limited room for expansion.

The area under consideration is shown on Figure 1.

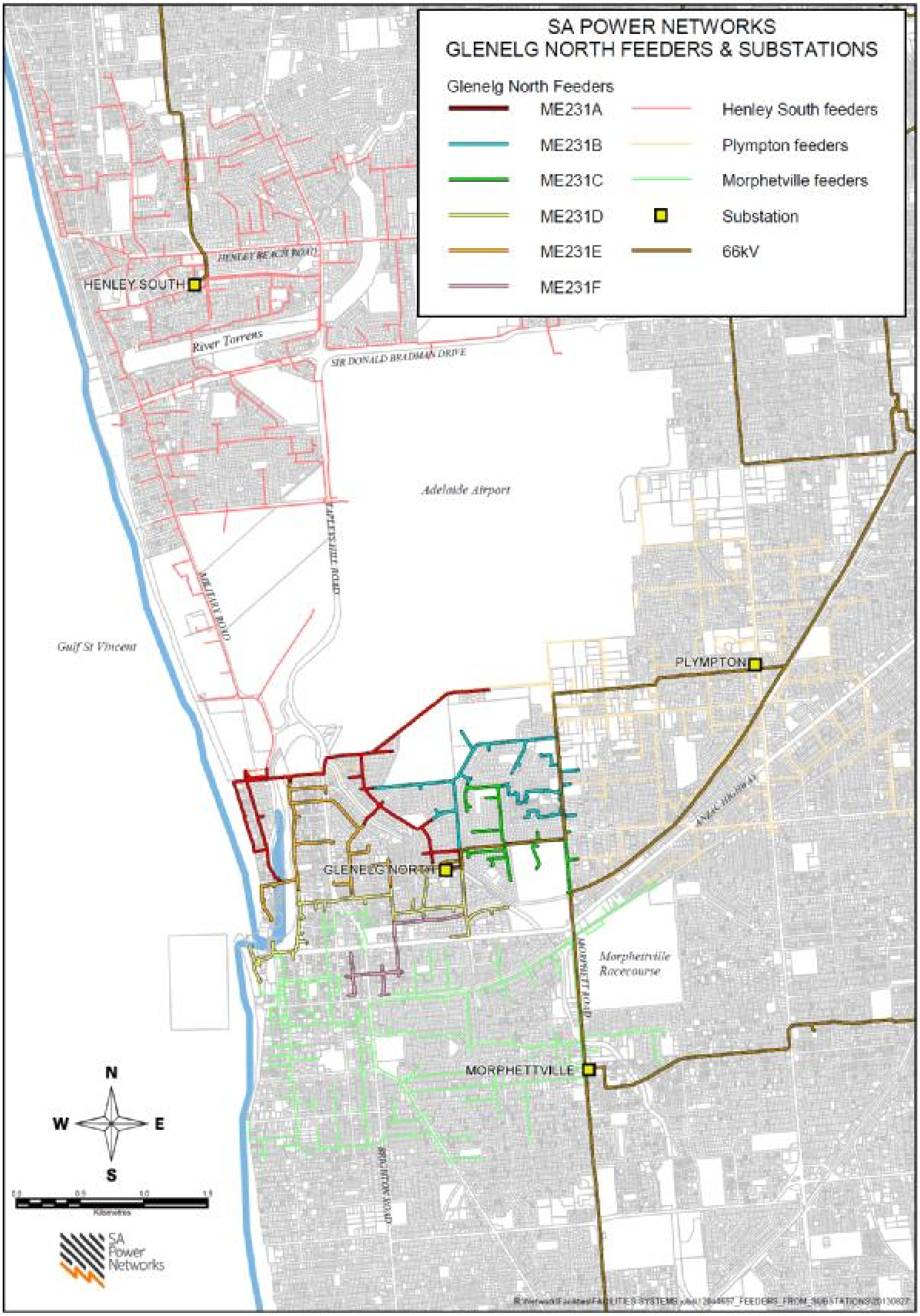

Figure 1 Locality of Glenelg North Substation

2. FORECAST LOAD AND CAPACITY

2.1 Load Forecast

The total 11kV load at Glenelg North Substation is forecast to grow at an average rate of 1.2% per annum, which sees the load increase from 18.2 MVA in 2013/14 to 21.7 MVA by 2028/29, as shown in Table 1. This growth represents the moderate 10% POE forecast which SA Power Networks uses for planning purposes of its sub-transmission lines. The forecast takes into account all known existing or committed demand management programmes and also includes an adjustment for the presence of any exiting embedded generation. The Power Factor at peak load times is 0.93.

Based on the available information, there is approximately 1.5 MW of roof top PV installed by customers serviced by Glenelg North. This represents about 8% of the total customer load on the substation. At peak load times, these PV systems are supplying approximately 0.3 MVA of load. The impact of this PV installation is included in the forecast information provided in Table 2.

Table 1: Forecast load growth at Glenelg North

Summer Year	MVA	MW	MVAr
2013/14	18.2	16.7	7.4
2014/15	18.5	16.9	7.5
2015/16	18.7	17.1	7.6
2016/17	19.1	17.4	7.8
2017/18	19.4	17.7	7.9
2018/19	19.6	17.9	8.0
2019/20	19.8	18.1	8.1
2020/21	20.0	18.2	8.1
2021/22	20.2	18.4	8.2
2022/23	20.4	18.6	8.3
2023/24	20.6	18.8	8.4
2024/25	20.8	19.0	8.5
2025/26	21.0	19.2	8.6
2026/27	21.2	19.4	8.6
2027/28	21.4	19.6	8.7
2028/29	21.7	19.8	8.8

SA Power Networks has no other committed distribution or sub-transmission augmentations in the area serviced by Glenelg North Substation.

There is no known significant embedded generation permanently connected to Glenelg North Substation other than domestic roof top PV. The SA Water Waste Water site near Glenelg that is normally supplied from Plympton Substation with a backup supply from Glenelg North does have some generation capacity, however this plant is designed to be non export under all network conditions.

SA Power Networks is not aware of any existing or committed embedded generation augmentations that could potentially impact on the distribution network serviced by Glenelg North Substation.

2.2 Pattern of Use

Peak electricity demand at Glenelg North occurs during the summer months, predominantly as a result of air-conditioning load.

The load profile from the 4th January 2013 is typical of the load on the substation during peak periods. It shows some sign of PV penetration with a fairly sharp peak between 15:00 and 20:00 followed by a sharp decline in demand from this time on, possibly caused by the onset of a sea breeze reflecting the sea side locality. The load is above 85% of peak between 14:30 and 20:30 and above 95% of peak between 16:30 and 19:30.

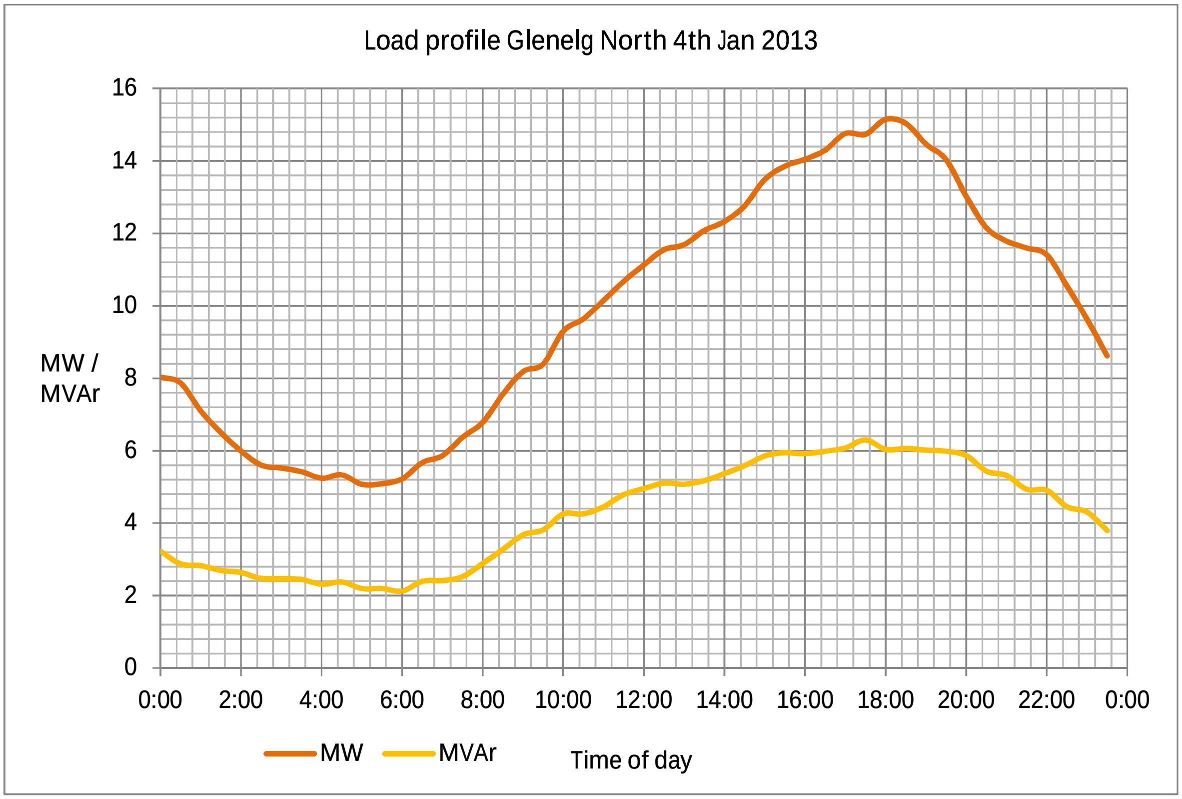

Figure 2 Load profile Glenelg North

In terms of the annual spread, loads in the area supplied by Glenelg North Substation are fairly typical of predemoninately residential substations with a sharp peak occurring on a few hot days a year and a quite low average for the rest of the time. Numerically, the load is in excess of 95% of the peak for approximately 12 hours per annum and in excess of 85% of peak for approximately 52 hours a year. Average load is approximately 42% of peak.

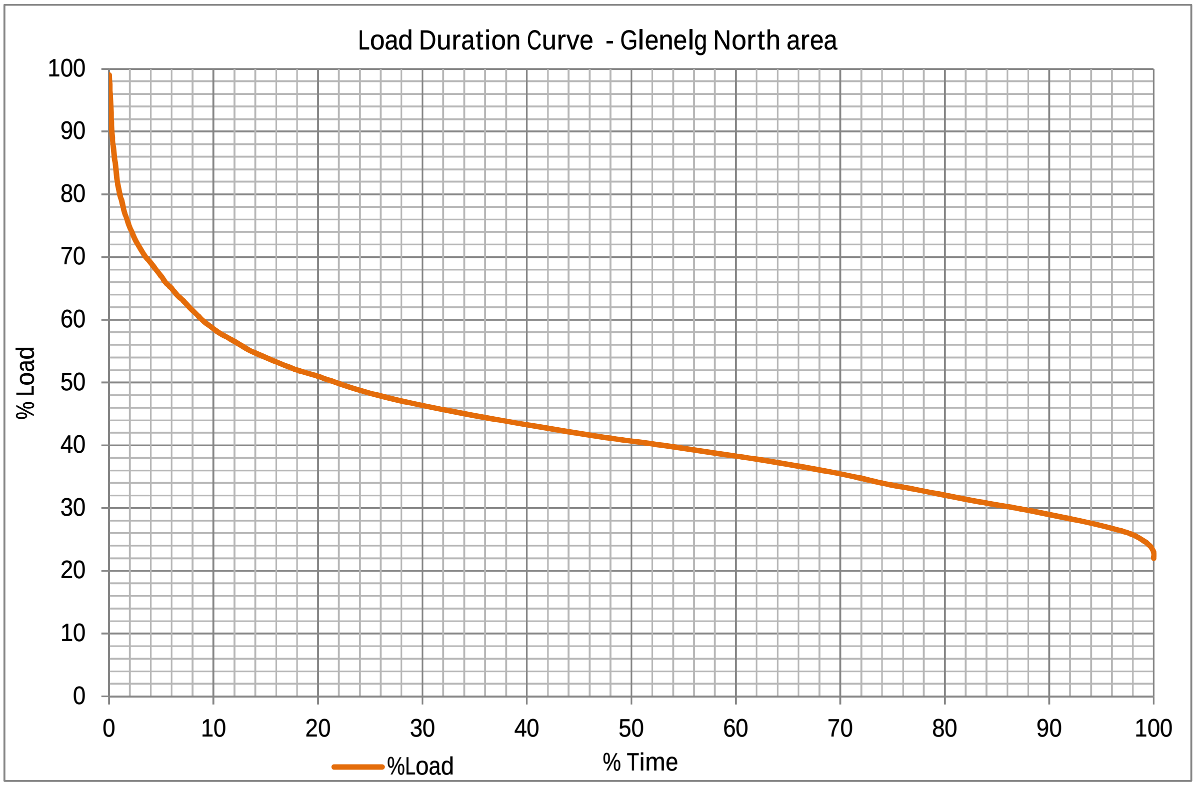

Figure 3 Load duration curve - Glenelg North area

2.3 System Limitations

Following the loss of the single 66kV supply, not all load at Glenelg North substation at peak times can be transferred to other substations within 4 hours. In summer 2013-14, the forcast load at risk is 11MW and there is an estimated 4,329 hours annually in which some load is at risk. By summer 2019-20, this load at risk will have risen to 12.9 MW and the number of hours for which some load is at risk will have increased to 6,198.

It is possible to increase the amount of load that can be transferred by moving load further east from Morphettville and Plympton Substations, however this additional shuffle may take up to 16 hours to execute depending on the circumstances of the day and the availability of line crews.

Line repair times for the overhead section of the 66kV line is normally in the order of 4 hours, however repair times for the 66kV underground section of the line may be up to 10 days or more depending on the availability of external specialist resources.

The identified need is to reduce the load at risk at Glenelg North Substation following a fault of the existing 66kV cable.

3. NETWORK UPGRADE

The preferred network option to address the identified need is to provide a duplicate section of 66kV cable to act as a backup in the event of failure of the existing cable.

It is expected that the preferred option will cost in the range of $6 - $7 million.

Alternatives considered include:

- Providing a second 66kV supply from Morphettville Substation. This has the added benefit of allowing permanent transfers of load from Morphettville Substation back to Glenelg North Substation thereby better utilising the installed capacity at this site.

- Increasing the transfer capacity between Glenelg North and Morphettville and Plympton Substations by installing further 11kV feeders, replacement of transformers and other capacity related constraints.

The alternative options considered are either more expensive or offer insufficient deferral benefits to be cost effective when compared to the preferred option.

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 Glenelg North Substation or
- Increase transfer capacity by decreasing load at Morphettville and Plympton Substations.

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 (MW)

Year	MW
2014	11.4
2015	11.7
2016	11.9
2017	12.3
2018	12.6
2019	12.8
2020	13.1
2021	13.3
2022	13.5

In order to be considered feasible, any demand management solution must be:

1. Financially viable;
2. Technically viable; and
3. Able to be implemented in sufficient time to resolve the identified constraint.

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 on a $ per kVA basis. The minimum and maximum amounts specified have been derived using different assumptions with respect to the cost of capital. This value has been varied 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 Demand Management (DM) solution proposed will be evaluated against the preferred network solution in a full RIT-D evaluation. Details of how this is performed can be obtained from the Demand Side Engagement Document available from 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	$600	$900	$60	$80
2 year Deferral	$1,300	$1,800	$120	$150
3 year Deferral	$1,900	$2,500	$170	$220

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 existing 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 existing standby generators within the region to make this option feasible.

4.3.b Install new diesel generation

It is unlikely that planning permission would be given to install a medium sized (11-15 MW) power plant within or near a residential suburb. In addition, recent experience indicates that the $ per kVA value available is too small to support a peaking plant, even if one could be built.

4.3.c Install power factor correction

This option is not technically feasible as there are not enough large customers supplied by Glenelg North Substation to make individual power factor correction viable. In addition, substation based correction would not address the identified need as the entire load normally supplied by this substation needs to be either curtailed or offloaded in the event of a failure of the 66kV line or cable.

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 2 x 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 whilst 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 feeders from 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 per kVA reduction. Given the size of the constraint, it is highly unlikely that sufficient volume would be available to address the identified need.

4.3.f Peak load control – curtailable load

This solution 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 supplied by Glenelg North, Morphettville or Plympton Substations for this option to be viable.

4.3.g Residential compact fluorescent lamp (CFL) program

This option was deemed not to be relevant due to peak load conditions occurring during daylight hours. The load contribution from residential 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 their infancy. 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 to make this option viable in preference to the proposed network solution.

4.3.i Energy Storage

Use of energy storage technology such as flow batteries, typically costs in the order of $6000 per kVA, which is significantly more than the amount available to economically address the identified need compared with the preferred network solution.

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/or economically viable.

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