DRAFT DEMAND MANAGEMENT SCREENING TEST

St Ives Zone Substation

Current Supply Arrangements

St Ives zone substation is supplied from Kuringai STS by three 33kV underground feeders. The three cables are gas pressure construction and two of the cables have been scheduled for replacement before 2017, and the third cable is scheduled for replacement in 2022.

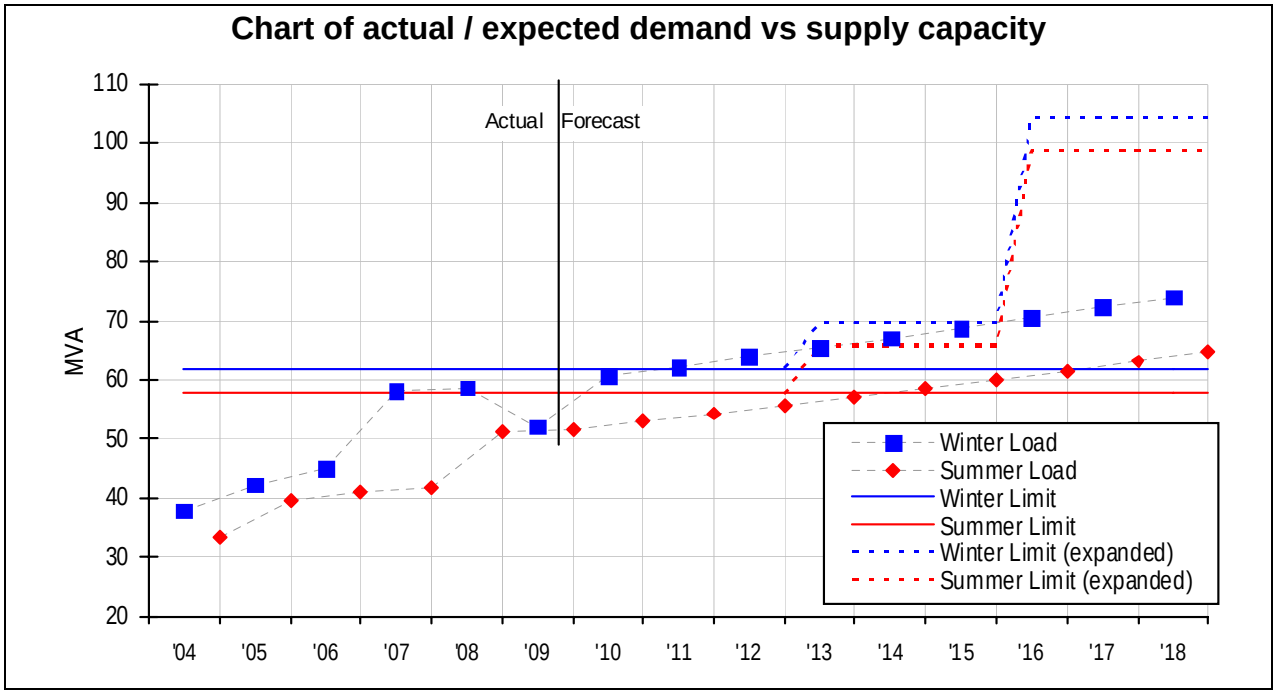
The capacity of St Ives zone substation is limited by the rating of the 33kV underground feeders, resulting in a licence capacity of 57.6MVA in summer and 61.9MVA in winter.

St Ives supplies the St Ives, Terrey Hills, St Ives Chase, Bobbin Head, Turramurra, Pymble, East Wahroonga, East Killara, East Lindfield, and Gordon areas.

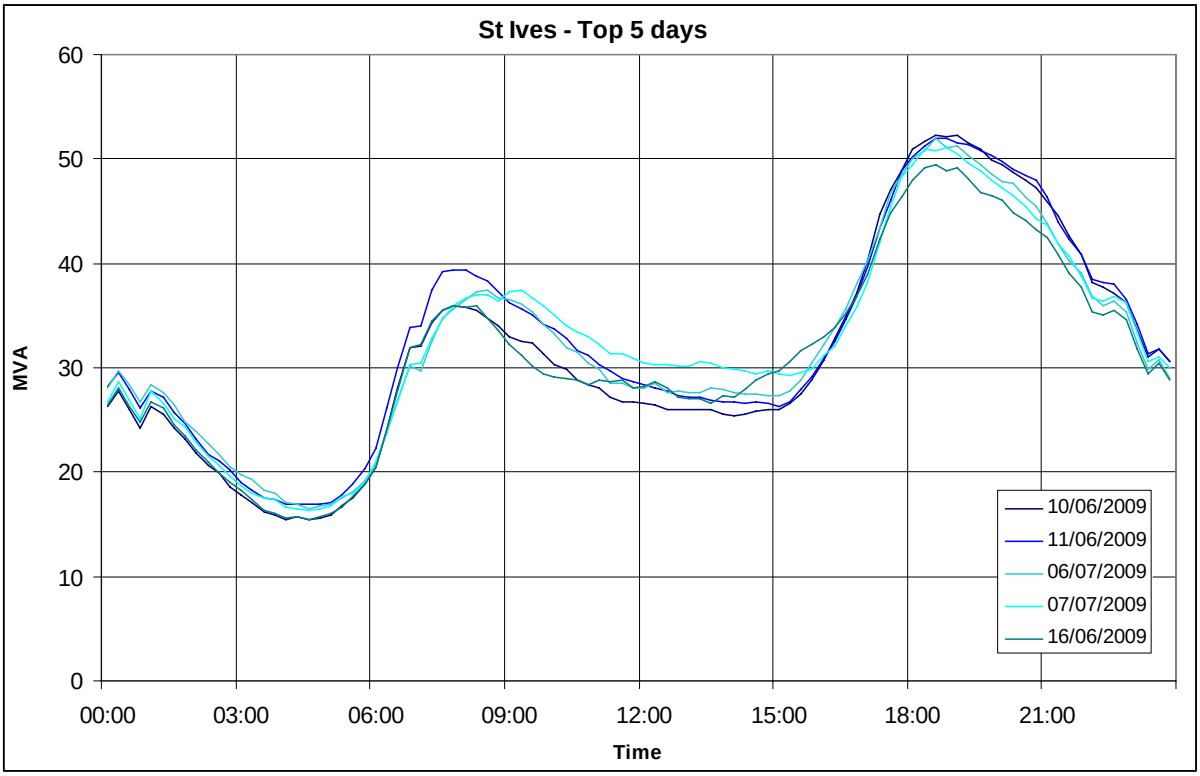
Supply Capacity and Demand Forecast

The load at St Ives zone substation is forecast to grow at 2.5% per annum in summer and winter. The load in this area is predominantly residential with evening peaks, between 6pm and 8pm, with winter peak demand higher than in summer.

The forecast peak demand for St Ives zone substation is shown on the chart below. In winter 2013 the peak load would be approximately 3.5MVA above the licence capacity. The dotted lines show the expanded capacity that would be achieved by the proposed two stage supply side strategy.



The load cycle for St Ives zone substation is shown on the chart below, the five days with the highest loads for winter 2009 are shown.



Supply Strategy Option

The preferred supply side option is in two stages. The first is to replace the three existing 33kV feeders, install an additional fourth 33kV feeder and replace some limiting equipment before May 2013. This would cost approximately $7.3m and, to meet the required completion date of May 2013, a decision on this investment would need to be made by March 2010. This would represent a bringing forward of the need to replace the existing cables. However it is more cost effective to install all four cables at the one time.

The second stage is to install a fourth transformer at St Ives zone substation, which would be required before May 2016. The cost for this stage is estimated at $5.9m.

Required Demand Management Characteristics

Demand management achieved from winter 2013 would be effective in deferring the need for the first stage of the project. If its impact persisted until winter 2016, it might also be effective in deferring the need for the second stage. The following scenarios have been developed on the assumption that demand reductions are persistent. If the particular DM options chosen are not persistent, the cost and impact results will be different.

If a reduction of 0.7MVA could be achieved from winter 2016, the need for the second stage of the project could be deferred until 2017. The first stage would still be required in 2013. This would represent approximately 1% of the forecast load on St Ives zone substation. The saving would be $360,000, or $516/kVA.

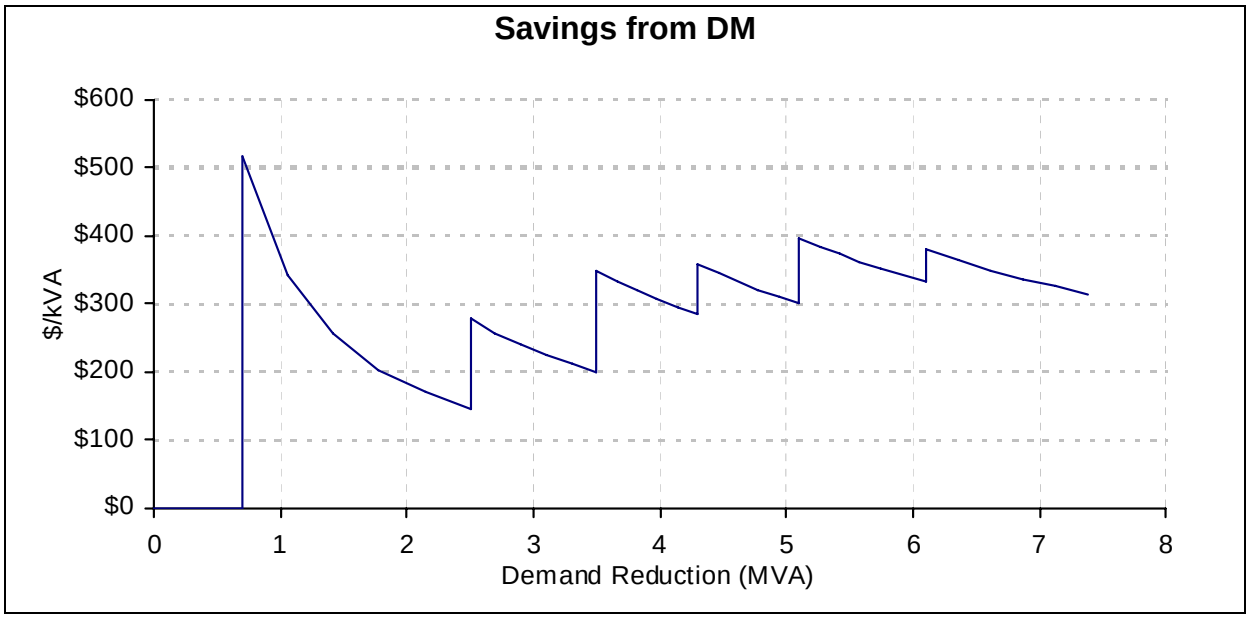
If a reduction of 2.5MVA could be achieved, the need for the second stage of the project could be deferred until 2018. The first stage would still be required in 2013. This would represent approximately 3.5% of the forecast load on St Ives zone substation. The saving would be $700,000, or $278/kVA.

If a reduction of 3.5MVA could be achieved, the need for the first stage of the project could be deferred until 2014, and the need for the second stage could be deferred until 2018. This would represent approximately 6% of the forecast load on St Ives zone substation. The saving would be $700,000, or $278/kVA.

Further reductions would lead to further changes in the timing of the needs, with additional benefits. The requirements and benefits are illustrated in the chart below.

A demand management scoping investigation into the St Ives area occurred in April 2002. This identified two major customers supplied by St Ives zone as sites for potential demand reductions opportunities.

In 2006, the Demand Management and Planning Project (DM&PP) investigated and identified demand management opportunities in the Sydney metropolitan region at large customer sites. The DM&PP identified the same two large customers and identified demand reduction opportunities including PFC, installation of variable speed drives, lighting efficiency, and HVAC efficiency measures. Unfortunately, since most of these measures are related to business activities they may have limited impact on winter evenings.



The size of the reduction required to defer the need for the first stage of the project is relatively large (3.5MVA) and would need to persist until 2017 to achieve the full benefit.

The load on St Ives zone is predominately residential, which limits the availability of opportunities and increases the cost and time required to implement effective demand management measures.

However, the demand reduction required to defer the need for second stage is modest and the potential savings are significant.

Recommendation

Based on this analysis it is not considered reasonable to expect that it may be cost-effective to postpone the first stage of proposed supply-side solution by implementing demand management strategies.

However it is considered reasonable to expect that it may be cost-effective to postpone the second stage of proposed supply-side solution by implementing demand management strategies from winter 2016.

The need for the second stage – the installation of the fourth transformer – is currently forecast for winter 2016. A demand management investigation undertaken now would be out of date by 2016. Accordingly, the findings of this report should be reviewed as forecasts are revised, and a demand management investigation commenced at an appropriate future date.

Forecast Load above Licence Capacity

The load at St Ives zone substation is forecast to be above the level of the applicable licence criteria for winter 2011 and winter 2012. Reductions in the demand during these seasons would reduce the amount and duration of the load above the design level, reducing the possibility that customers would supply if a major system failure occurring during peak load times.

Reducing the loads below the licence capacity would defer the need for a solution until the planned construction date.

The load forecast to exceed the licence capacity by 300kVA in winter 2011, and 1.9MVA in winter 2012.

Analysis of Value

The basis for calculating the avoided distribution cost (ADC) is the difference in cash flows from delivering the supply side option two years earlier in winter 2011 when the load first exceeds the licence capacity and the expected delivery date of 2013.

Assuming the load could be reduced to less than the licence capacity for both years, a demand management solution would be considered cost effective if it cost less than the ADC. This can be separated into components relating to each year.

The difference in value between bringing forward the supply side solution forward to winter 2011 and building the supply side option for winter 2013 is $1.06 million.

The difference in value between bringing forward the supply side solution forward to winter 2012 and building the supply side option for winter 2013 is $630,000.

For winter 2011 a demand management strategy would be considered cost effective if it cost less than $430,000, or $1433/kVA.

For winter 2012 a demand management strategy would be considered cost effective if it cost less than $630,000 or $331/kVA.

The demand reductions required are modest, and the value at which they would be cost effective is high.

Conclusion

Cost effective demand management options may be available for both the winter 2011 and winter 2012 seasons. An investigation will be undertaken to identify potential demand management options.