Demand Management Investigation Report

St Ives zone substation upgrade

Summary

EnergyAustralia carried out an investigation of demand management (DM) options in the St Ives area in 2010. The aim was to determine if there were cost effective demand management measures that could reduce peak electrical loads during the peak period, while maintaining network performance at the required level through both 2011 and 2012 winter. This report concludes that there is a cost-effective demand management option available in the targeted area.

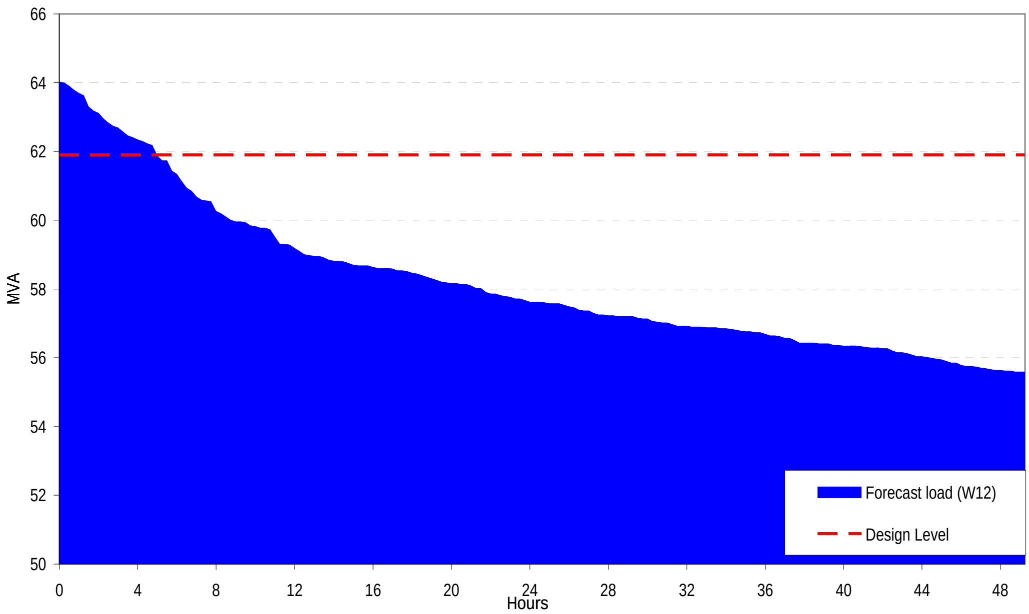
Screening Test Outcomes

A DM screening test was completed in February 2010 and concluded that it is not considered reasonable to expect that it would be cost-effective to postpone the proposed replacement of the three existing 33kV feeders and some limiting equipment by implementing DM strategies. However, it would be reasonable to expect to cost effectively reduce the load above the licence level at St Ives zone substation.

DM Requirement

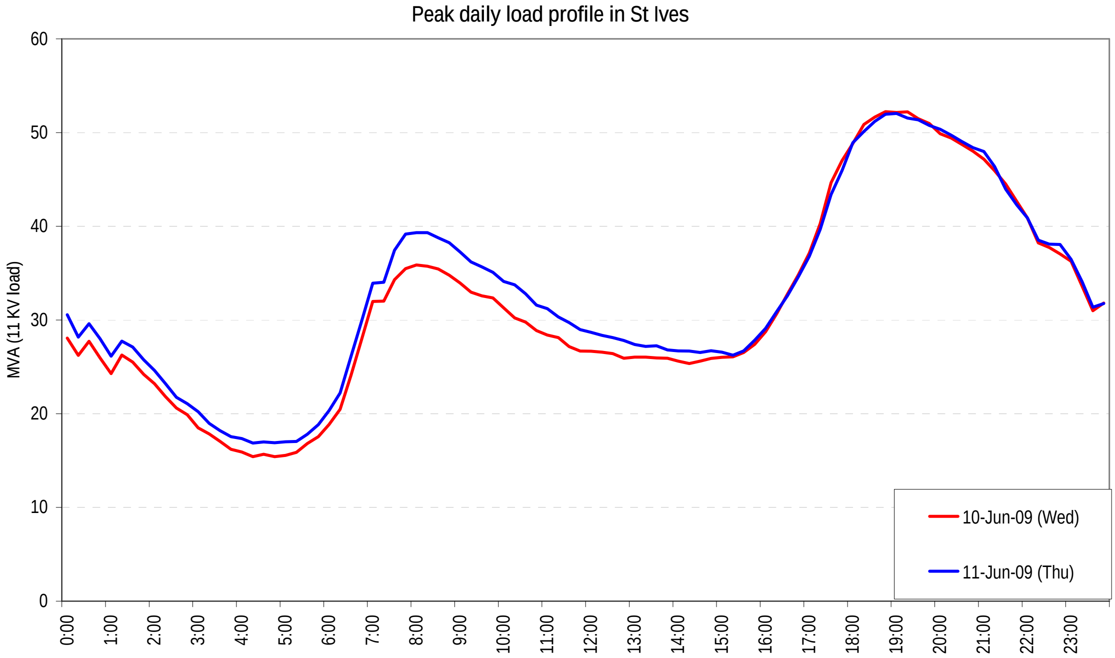
The load at St Ives substation is forecast to be above the level of the applicable licence criteria for the 2011 and 2012 winter seasons. Reductions in the demand during these two seasons would remove or reduce the amount and duration of the load above the design level.

Based on the latest forecasts, peak demand reductions of 0.3MVA before winter 2011 and 1.9MVA before winter 2012 would be required to reduce the forecast peak load to the design levels. The following chart shows the forecast load duration curve for winter 2012. It shows that the load would be above the design level for about 5 hours. The forecast load duration curve for winter 2011 is shown in Appendix A



St Ives Zone Winter Peak Day Load

The following chart shows the winter peak load profile in St Ives zone. The profile suggests that residential loads dominate winter evening peak demand. Any DM solution would need to be effective during business days between 17:30 and 20:30pm in winter. The load profiles of the top 10 days for winter 2009 in Appendix B show that the load profiles are quite consistent.



Demand Management Investigation

The overall investigation approach was to identify potential DM options, assess the likely size of the demand reduction and rank them based on their cost ($/kVAh) to EA. The most cost-effective options might result in a feasible project. We identified major customers based on their maximum monthly peak demand and collected information about the usage of energy and possible DM options. We also reviewed existing investigation reports from the Demand Management and Planning Project (DMPP) in St Ives area. Using all this information, we prepared a list of potential DM options.

For each of the options we assessed the likely size of demand reduction that would result at the time of network peak at the zone substation. We also estimated the cost of implementing DM options to EnergyAustralia. Based on these estimates, we ranked the options.

Identified DM options

- Customer power factor correction
- Relocatable generators
- Customers' standby diesel generator
- Commercial lighting upgrades and fixed dimming unit
- Commercial air conditioning (HVAC) System upgrade

Demand Management Options and Analysis

Power factor correction

Where customers' loads exhibit poor power factor, peak demands on the network are higher than they would otherwise be. Based on actual electrical demand data from 2008/09, we identified that five customers had poor power factor. The estimated potential demand reduction effective at zone substation level is about 0.13MVA in winter. From our experience, the estimated cost of facilitating the program is about $33,000, including all project management, customer contact and incentive costs.

Relocatable generators

EnergyAustralia has used relocatable generators to provide reliable temporary load reductions in other areas. In the event that a large amount of peak demand reduction is required, this would result in a reliable project that would be under our control and could be delivered at a well-defined cost.

In general, using generators can be a cost effective DM option if a suitable location can be identified. In our analysis, we propose to install one 0.5MVA for the first year and 2x1MVA generators for the second year. The estimated cost to EnergyAustralia would be approximately $430k for the first year and $488k for the second year.

Customer standby diesel generator

One customer has a standby generator that was installed for emergency use only and is not synchronised to run in parallel with the incoming supply. The customer indicated that the standby generator could be used if management approves. However, the generator was manufactured in 1975 and it would be expensive to install a SCTT control system if not impossible. The customer's winter peak load in 2009 varied between 220 to 300kVA during 5:30pm to 8:30pm as shown in Appendix C. This option will not be explored any further.

Commercial lighting upgrade and fixed dimming units

From the review of DMPP investigation reports, we identified some commercial customers who have the potential to reduce their peak demand by modifying their lighting system. We classified them into two categories, i.e. installing lighting voltage reduction unit (dimming devices) and upgrading light fittings to efficient T5 fittings. To implement the lighting projects, we expect customers would require a subsidy that would vary from site to site based on their different investment criteria.

Based on our own cost analysis, we estimated that program would cost EA up to $418,700. About five projects were identified. The potential peak demand reduction is expected to be about 81kVA.

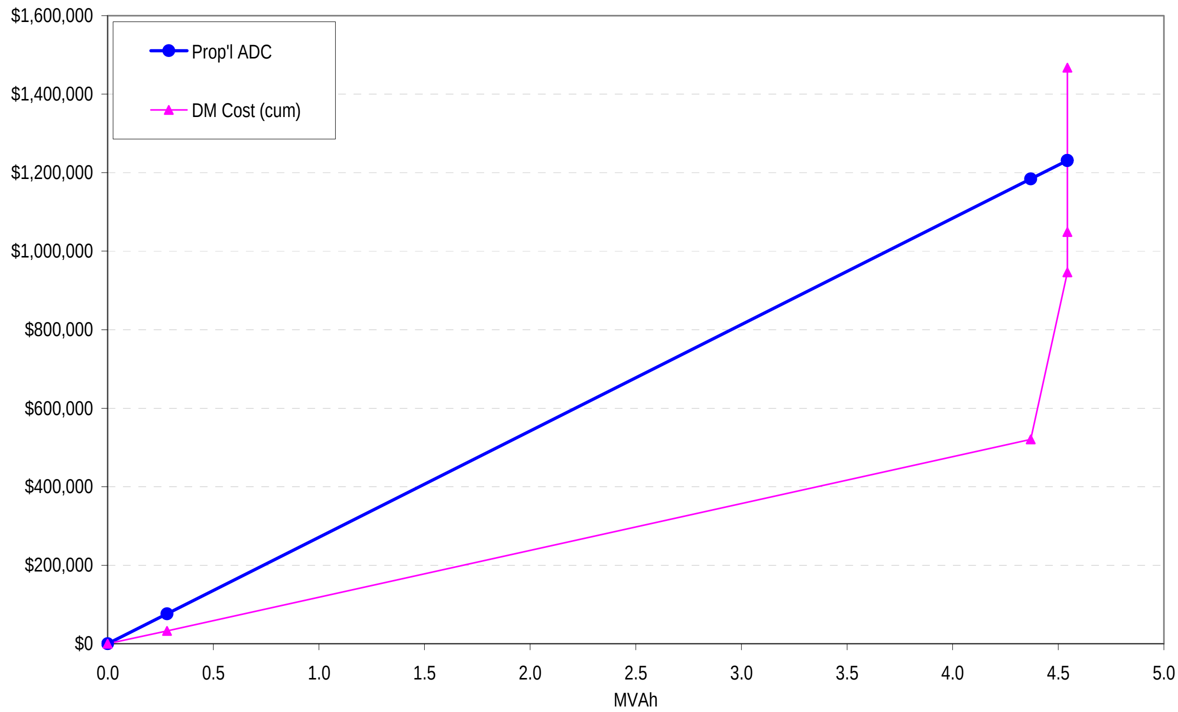
Commercial air conditioning (HVAC) system upgrade

Improvements to HVAC systems can be achieved with equipment changes or control improvements. Major equipment changes (to more efficient models) are generally only practical if replacement of plant is being considered for other reasons. About three projects were identified, which could reduce peak demand by 24kVA. The estimated cost is about $102,400.

Summary of DM Project Cost and Load Reduction for 1st and 2nd year

Based on our investigation and analysis, we have estimated DM project cost and the resulting reduction in the amount of load above the design. We ranked the options according to the cost to EA ($MVAh). The results are shown in the following table and chart. The power factor correction program and lease generator project are assessed as cost effective.

DM Options	Incremental Impact (MVAh)	Total Cost to EA ($)	Cost to EA ($/MVAh)	Cost to EA (cum)	ADC outcome (cum)	Time for Implementation
Power factor correction	0.3MVAh	$33,000	$117,562	$0.033m	$0.077m	0.5 – 1 year
Relocatable leased generator for winter 2012	4.1MVAh	$487,300	$119,181	$0.521m	$1.18m	1 – 2 year
Relocatable leased generator for winter 2011	0.2MVAh	$425,900	$2,460,800	$0.947m	$1.23m	1 – 2 year



Feasible Options

On the basis of this analysis, we found that a power factor correction program and relocatable generator options would be cost-effective. Because the leasing genset is large enough to deal with the first and second year load, the customer power factor correction option would not be required.

- Relocatable generators

EnergyAustralia has used leased diesel generators in other areas as a successful DM option. Identification of a suitable site where generators can be installed temporarily is a critical element of this option. During our investigation, we identified a likely location for the project, and assessed issues of ease of access, noise, exhaust stack installation, fuel refilling, earthing, and generator control communication.

The generator would be remotely controlled and monitored via a reliable communications link to the EA Control Room. The generator would start and run automatically with the ability to be controlled by the System operator (via SCADA). Then they will automatically synchronise and connect to EA network. The control and communications of gensets will be explored and developed further in the next stage.

Based on our experience of developing similar projects, we found that this option is technically feasible and commercially viable. Estimated cost, based on our current contracts for generator leasing and experience with previous projects is $913k for the two winter seasons (0.5MVA genset for the first winter 2011 and 2x1MVA for the second winter 2012).

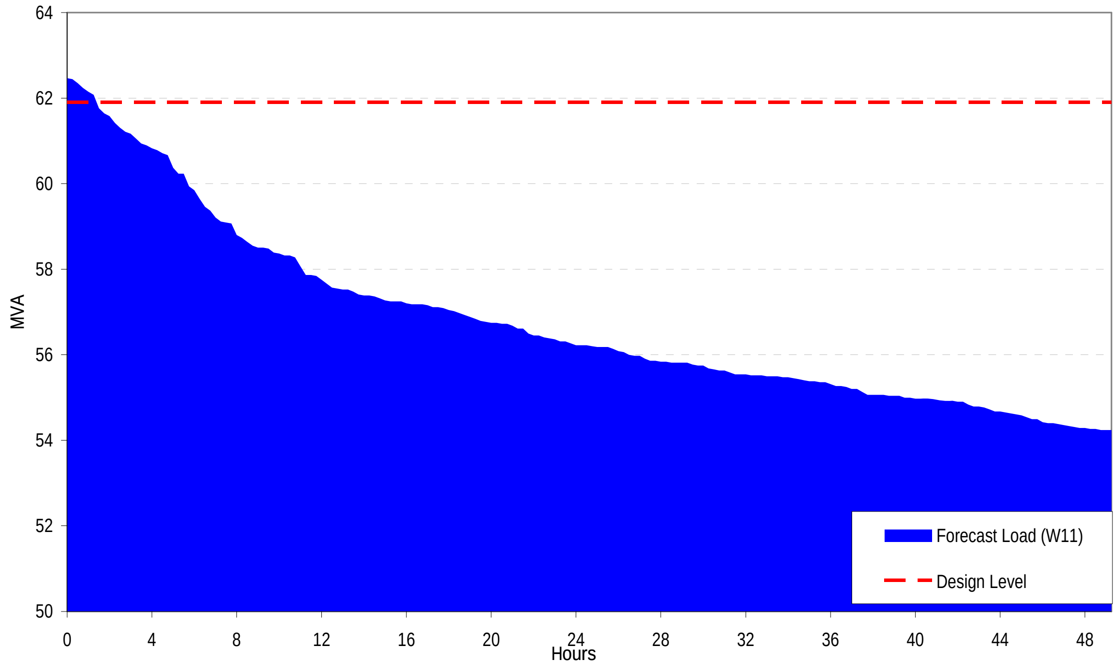
The peak demand for winter 2010 was 53.5MVA at 18:45 on June 29, 2010. This was much lower than the forecast 60.7MVA. This suggests any revision to forecast load for 2011 may be lower and that DM requirement may change.

Conclusion

We identified a feasible DM option of using leased generators. The DM option is sufficiently large to provide peak demand relief in St Ives area in winter 2011 and winter 2012. This option should be developed further to enable implementation to commence before winter 2011. Development should consider the need to remain flexible as there is a likelihood that demand forecasts could be revised.

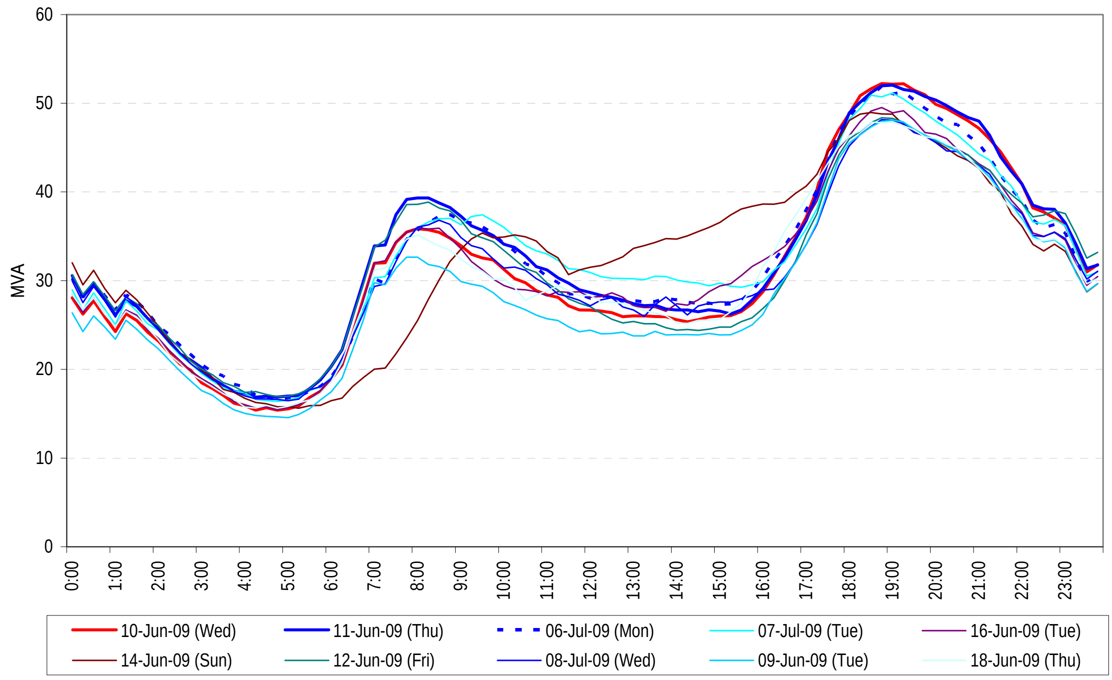
Appendix A: The Forecast Load Duration Curve

In winter 2011, the load would be above the design level for 1.5 hours.



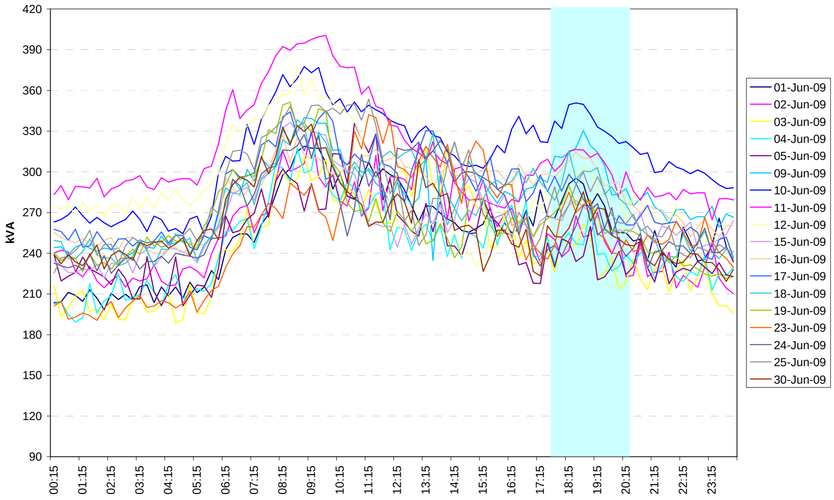
Appendix B: Additional Data

Top 10 days winter 2009 daily load profiles in St Ives area

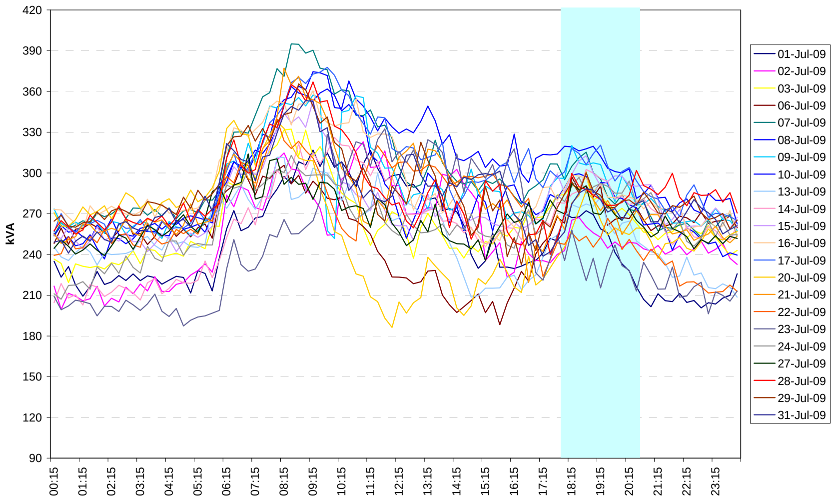


Appendix C: Customer's winter peak load profiles

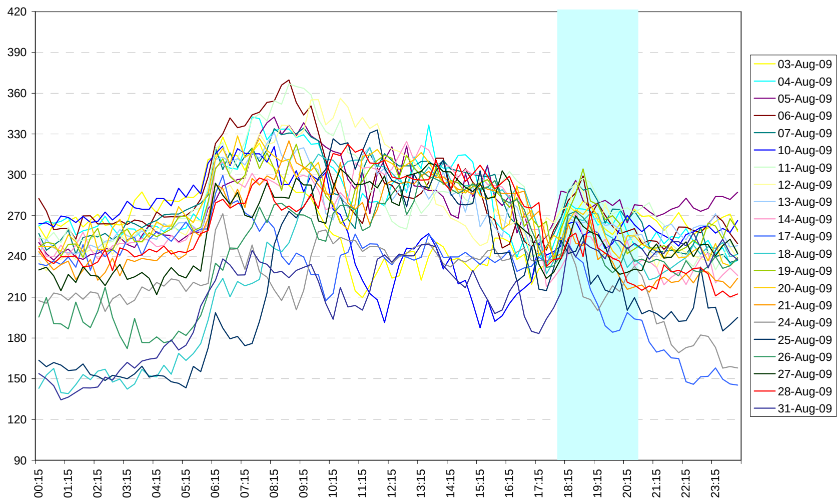
1) weekdays in June 2009



2) weekdays in July 2009



3) weekdays in August 2009



Appendix D: DM Screening Test

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.

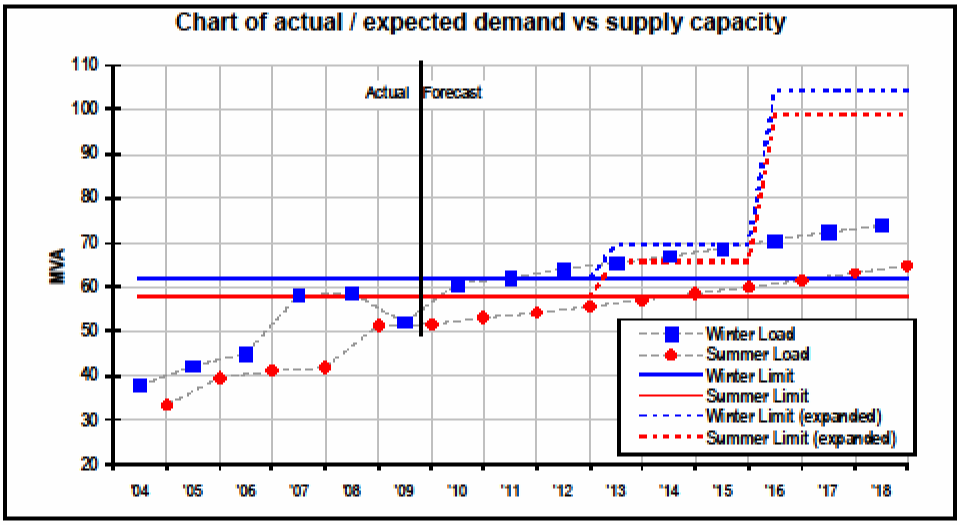
St Ives supplies the St Ives, Terrey Hills, St Ives Chase, Bobbin Head, Turramurra, Pymble, East Wahroonga, East Killara, East Lindfield, and Gordon areas.

Supply Capacity and Demand Forecast

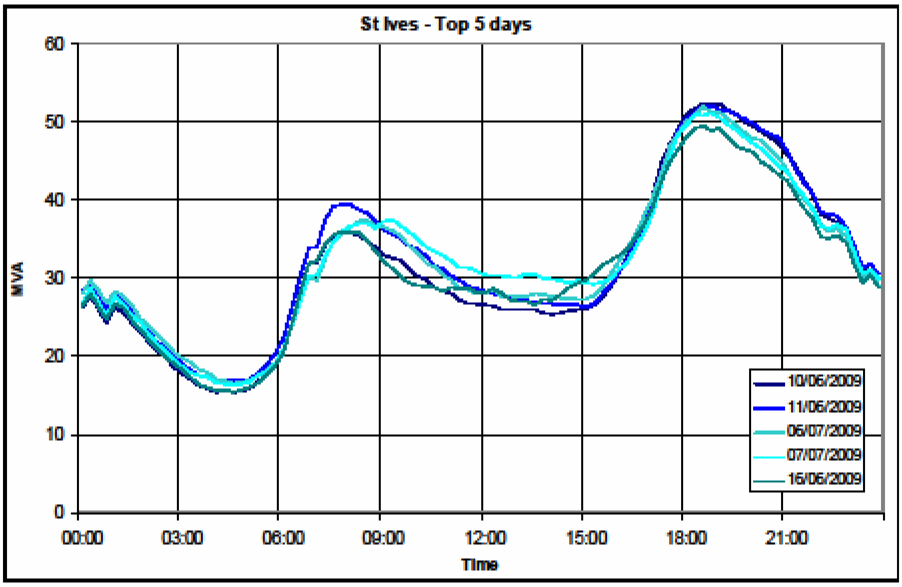
The load at St Ives zone substation is forecast to grow at 2.5% per annum in summer and winter. The load in this area is predominantly residential with evening peaks, between 6pm and 8pm, with winter peak demand higher than in summer.

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.

St Ives Zone Substation Upgrade SJ-06017 SJ-06018



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.



St Ives Zone Substation Upgrade SJ-06017 SJ-06018

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.

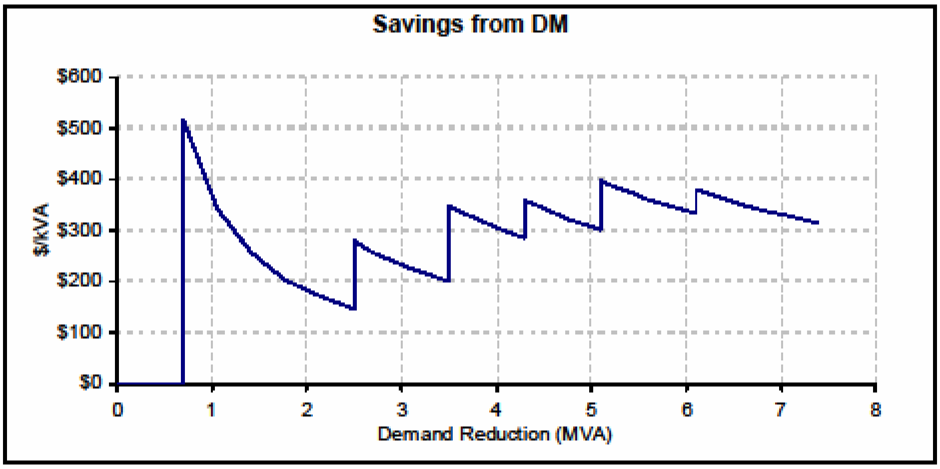
If a reduction of 2.5MVA could be achieved, the need for the second stage of the project could be deferred until 2018. The first stage would still be required in 2013. This would represent approximately 3.5% of the forecast load on St Ives zone substation. The saving would be $700,000, or $278/kVA.

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.

St Ives Zone Substation Upgrade SJ-06017 SJ-06018

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.