Demand Management Investigation Report

Willoughby STS

Summary

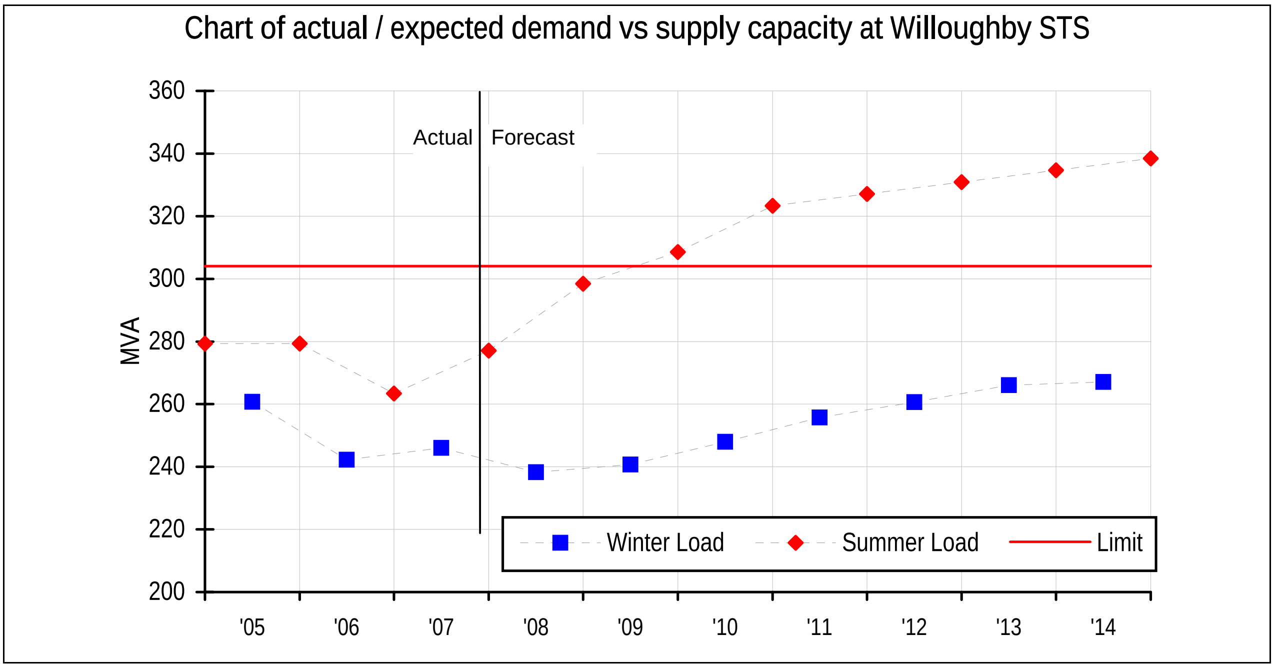
EnergyAustralia carried out an investigation of demand management (DM) options in the Willoughby sub-transmission substation area in 2007/08. The aim was to determine if there were cost effective demand management measures that could defer the need for a $30m investment in a new 132/11kV zone substation, while maintaining network performance at the required level through the 2009/10 summer. This report concludes that cost effective demand management options are available.

Screening Test Outcomes

A DM screening test (DMST) completed in August 2007 concluded that to achieve a one year deferral of the proposed new zone investment we would need to implement demand reductions totalling 4.5MVA before summer 2009/10. The savings from this deferral were estimated at $2.48m or $550/kVA. For two year deferral, 13.6MVA peak demand reduction is required before summer 2010/11. The deferral value would be $4.8m or $350/kVA.

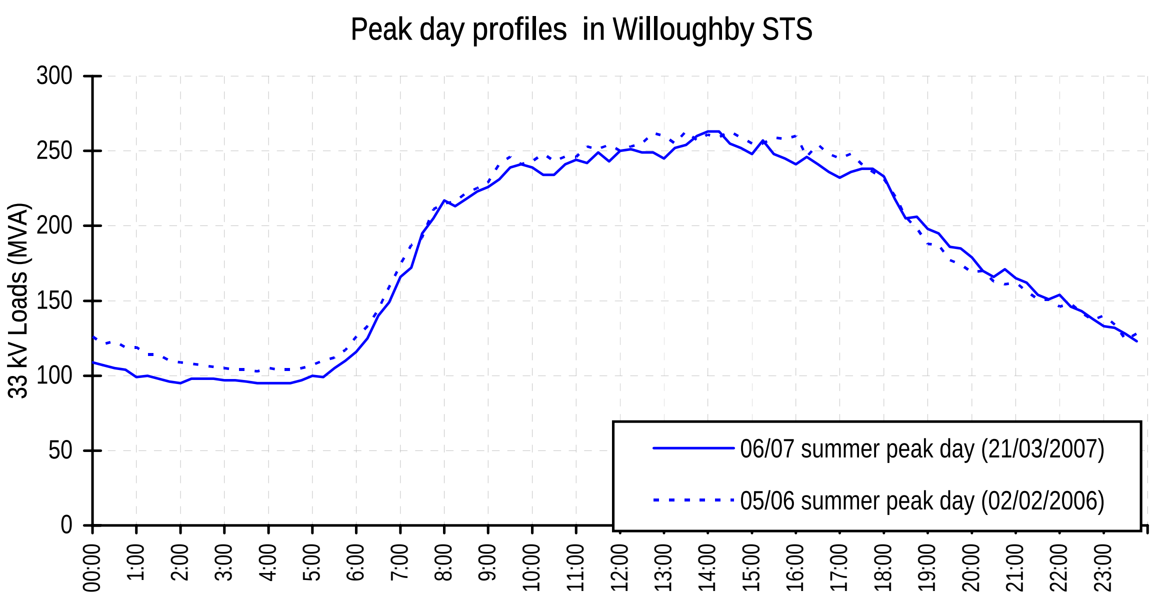
Revised Demand and Capacity Forecasts

The demand forecast for Willoughby STS has been revised since completion of the DMST. The peak demand in summer 2009/10 will be 308.5MVA which is same as the earlier forecast. The one year deferral value would be $4.0m or $900/kVA. However, the forecast peak demand in summer 2010/2011 will be 323.3MVA, which is 5.7MVA higher than previously estimated, meaning 19.3MVA peak demand reduction required before summer 2010/11 for a two year deferral. The savings from this deferral were estimated at $7.8m or $406/kVA.



Willoughby STS Peak Day Load Profiles

The following charts show the summer peak load profiles at Willoughby sub-transmission substation.



The load profiles suggest that commercial loads dominate the summer daily peak demand. Any DM solution would need to be effective during business day between 12 noon to 6pm. The load profiles of the top 10 days for summer in Appendix A 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 ($/kVA) to EA. The most cost-effective options might result in a feasible project. We identified major customers based on their maximum monthly peak demand, visited the potential sites 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 in Willoughby STS area. Using all this information, we prepared a list of potential DM options for further investigation.

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 and compared them to the potential savings from deferring the proposed supply side investment.

Identified DM options

- Power factor correction
- Embedded generation
- Customer's load shifting
- Electric hot water conversion
- Customers' standby diesel generators
- Commercial air conditioning system upgrades
- Commercial lighting upgrades and fixed dimming unit
- Control of residential air conditioner, pool pumps and commercial lighting/HVAC

Demand Management Options and Analysis

Power factor correction

Where customer's loads exhibit poor power factor, peak demands on the network are higher than they would otherwise be. Based on actual electrical demand data from 2007, we identified that thirteen customers had poor power factor. The estimated potential demand reduction effective at subtransmission level is about 522kVA in summer. From our experience, the estimated cost of facilitating the program is about $20,000 or $38/kVA.

One submission proposed 4MVA peak demand reduction by implementation PFC program. After analysing customers' metering data in 2006/07 financial year, we estimated that potential peak demand reduction at customers' site would be 1.2MVA. The estimated implementation cost is $942/kVA.

Embedded Generation

Cogeneration is production of electrical and thermal energy from the same primary fuel source. Three respondents to our Consultation Paper proposed that they could reduce peak load permanently in Willoughby area by installing cogeneration system at customers' sites. Cogeneration plant will generate electricity for the customer's load and have absorption chillers which will use waste heat from the engines to generate chilled water for air conditioning system. The plant will also have heat exchangers to provide hot water for domestic and space heating.

One project at a commercial site in North Sydney is already committed and has already received a subsidy from the DMPP project. We are negotiating with equipment supplier to ensure the system is managed in such a way to maximise the probability of providing reliable network support. The estimated cost is about $50,000 - $80,000 for 2.3MVA cogeneration system plus 0.7MVA peak demand reduction due to using absorption chillers, a total peak load reduction of 3MVA.

Another potential cogeneration project is at Gore Hill commercial site. The estimated demand reduction is about 4MVA. The net cost to EnergyAustralia is estimated to be $875,000 or $219/kVA. The developer has accepted the proposed cogeneration system and lodged a development application to Willoughby Council. The initial technique assessment has been completed. After having meetings with the developer and cogeneration company, we found out the project hasn't been approved yet by the council due to other issues, which means the project can not been delivered on time as per our request. This option will not be considered further.

One submission proposed using packed cogeneration at 6 to 8 customers in the area and the estimated peak load reduction is about 4.5MVA. The cost to EA is about $2.3M or $511/kVA. We have formed the view these potential projects can not be implemented on time as our request and will not be considered further.

Customer's load shifting

One respondent to our Consultation Paper suggested they could shift peak load in commercial/industrial sites in Willoughby area. The potential peak demand reduction could be 1MVA. The estimated cost to EnergyAustralia is about $567,000, or $567 per KVA.

Electrical hot water conversion

One respondent to our Consultation Paper suggested they could shift peak load permanently in the Willoughby area by replacing existing continuous electrical hot water systems to natural gas, or solar hot water system or heat pump system. But this option has limited impact on peak demand reduction due to hot water peak consuming period. We estimated that the potential demand reduction is about 300kVA, at an estimated cost of $968,000 or $3,227/kVA.

Customers standby diesel generators

One respondent to our Consultation Paper suggested they could reduce peak load in the Willoughby area by using 2 - 3 customers' standby diesel generators. The demand reduction would be limited to the customers' own peak load – total about 2 - 3MVA in summer day time. The estimated cost to EnergyAustralia is about $400,000 - $630,000 or $200 - $210/kVA.

Commercial air conditioning (HVAC) system upgrade

Improvements to HVAC systems can be achieved with control improvements, or equipment changes. Major equipment changes (to more efficient models) are generally only practical if replacement of plant is being considered for other reasons.

a) Air conditioning control system

More than thirty customers were identified with potential demand reduction from installing additional control equipment in HVAC system. The peak summer load reduction would be 420kVA. The estimated cost is about $1,185,000 or $2,820/kVA.

b) Chiller replacement

About twenty customers were identified with potential for replacing their chillers with more efficient ones, which could reduce peak demand by 1,350kVA. The estimated cost is about $5,247,000 or $3,890/kVA.

c) Ice storage system

Two respondents to our Consultation Paper suggested they could shift peak load permanently in Willoughby area by replacing existing conventional air conditioners with the ice storage air conditioners. The proposed ice storage will be imported from USA. An ice storage air conditioner produces ice in the off-peak time and melts it to cool down the space in the day time. One submission asks for $1500/kW as subsidy from EA without offering total peak demand reduction. Another submission asks for $247,540 or $550/kVA as subsidy from EA with estimated 450kVA potential demand reduction. Our subsequent discussion with responders to reveal that they are still negotiating with US manufactures of Ice Storage System (ISS) and based on their program assumption of importing 100 ISS units per month. We did not consider these options further because the specified product is not available in the Australian market at present and we had enough lower cost DM options from other submissions.

Commercial lighting upgrade and fixed dimming units

From the survey and reviewing DMPP investigation reports, we identified some commercial customers who have the potential to reduce their peak demand by modifying their lighting system. We classify them in three categories, i.e. installing lighting voltage reduction unit (dimming devices), replacing high wattage dichroic down lights with efficient low wattage one and upgrading light fitting to efficient T5 fittings. Different customers have different investment criteria. To implement the lighting projects, customers require subsidy from EA which varies from $0 to $2,400/kVA due to customer's different investment criteria.

We select a range of low cost lighting projects and propose to implement an energy efficiency lighting campaign program. Based on our own cost analysis, we estimated that the program will cost EA up to $150,000 or $550/kVA. The cumulated potential peak demand reduction is expected to be about 210kVA to 310kVA. 33 customers will be involved and assuming 50% acceptance rate.

Control of residential air conditioner, pool pumps and commercial lighting/HVAC

One respondent to our Consultation Paper suggested they could shift peak load in the Willoughby area by controlling residential air conditioner and pool pumps, plus commercial lighting/HVAC upgrade. However, this option has limited impact on peak demand reduction due to usage pattern of residential air conditioners and pool pump. We estimated that the potential demand reduction is about 1.9MVA, at an estimated cost of $972/kVA.

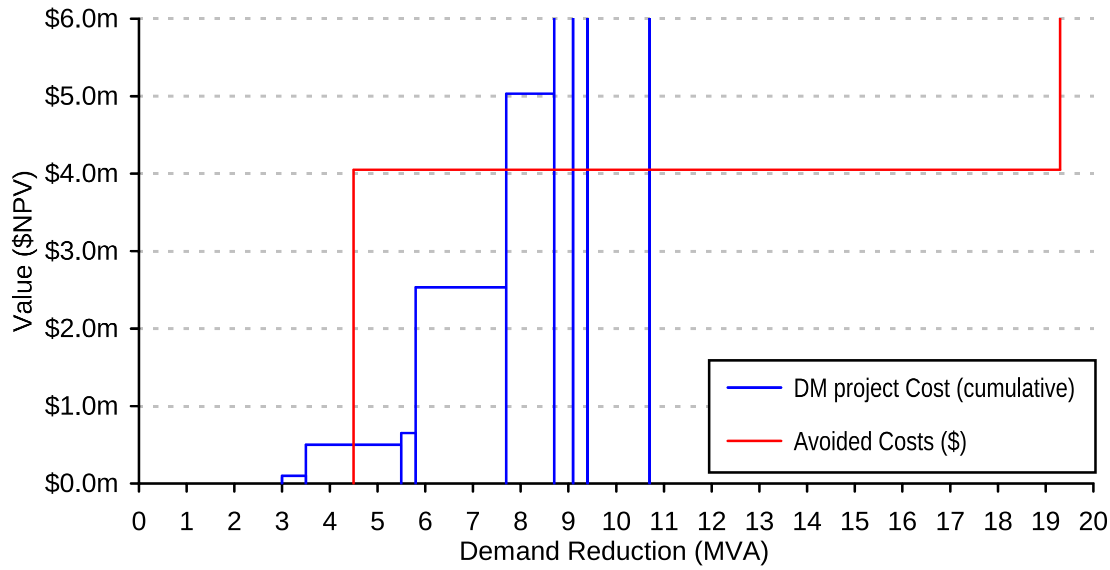
Summary of DM Project Cost and Load Reduction

Based on our investigation, we have estimated the DM project cost and potential load reduction. The following table summarises results of studies. We ranked the options according to the cost to EA ($/kVA)

DM Options for summer	Peak Load Reduction	Total cost to EA ($NPV)	Cost to EA ($/kVA)	No. of Customers Involved	Time for Implementation
Cogeneration in a commercial building at North Sydney	3MVA	$50,000 - 80,000	$17 - $27	1	0.5 – 1 year
Power factor correction	0.52MVA	$20,000	$38	13	0.5 – 1 year
Customers' diesel standby generators	2 - 3MVA	$400,000 - $630,000	$200 - $210	2 - 3	1 – 2 year
Lighting project	0.21 – 0.31MVA	$111,000 - $150,000	$490 - $530	About 33	1 – 2 years
Control of residential air conditioner, pool pumps and commercial lighting/HVAC	1.9MVA	$1,884,000	$972	1,500	1 – 2 years
Control equipment for HVAC	0.42MVA	$1,185,000	$2,820	36	1 – 2 years
Electrical hot water conversion	0.3MVA	$968,000	$3,227	1,000	1 – 2 years
Chillers replacement	1.35MVA	$5,247,000	$3,890	21	2 – 3 years

The chart below compares the cost and demand reduction impact of the identified options to the value of avoided distribution costs and DM requirements. Stacking the options from lowest relative cost to highest shows that sufficient demand reduction has been identified to achieve a one year deferral.

Comparison of DM project costs, avoided distribution costs and MVA of demand reduction



Feasible Options

On the basis of this analysis, we found that there are several feasible options that could achieve sufficient cost-effective demand reductions to achieve a one year deferral. A more detailed review of each of these was undertaken.

- Customer power factor correction

Our analysis of metering data showed just thirteen target sites for PFC in the area. Based on our review of the load profiles of the customers and the resulting probability of coincidence, this should result in a reduction of peak demand at the zone of 522kVA. Total cost to EA to undertake such a program is estimated at $20,000, including all project management, customer contact and direct costs.

- Lighting projects

Based on reviewing DMPP survey results, we selected the low cost lighting project. These total 60 projects involved 33 customers and include 15 down lights replacement and 18 lighting dimming device installations. The implementation of those projects should result in peak demand reduction of 210kVA to 310kVA (assuming 50% - 75% acceptance rate). Total cost to EA to undertake such a program is estimated between $111,000 to $150,000, including all project management, customer contact and subsidies.

- Cogeneration system in commercial sites at North Sydney

The cogeneration plant will generate electricity for the customer's load. The waste heat from engines will be used in absorption chillers that generate chilled water for air conditioning system. The plant will also comprise heat exchanger to provide hot water for domestic and space heating.

One customer has committed to install the system in the commercial building in North Sydney. The size of the cogeneration system is 2.3MVA. Additional two absorption chillers will be used which will reduce up to 0.7MVA peak electrical demand. This option will give us a maximum of 3MVA peak load reduction in total. At present, we are negotiating with the customer to ensure the cogeneration system is managed in such a way to maximise the probability of providing reliable network support during system peak period. The net cost to EA is estimated to be $50,000 - $80,000 or $17 - $27/kVA.

- External aggregator

One respondent to our Consultation Paper suggested they could reduce 2 - 3MVA peak load by using customers' standby generators. We undertook further investigation and found that the total daily peak demand of the selected 2 – 3 customers was 2.7MVA to 3MVA in summer 2007/08. The generators' capacities are 5.2MVA to 6.6MVA.

The proposal is to enter a contract with the external aggregator to allow EnergyAustralia to remove the customers loads from the network by transferring them temporarily to the standby generators within defined duration and frequency limits over summer 2009/10.

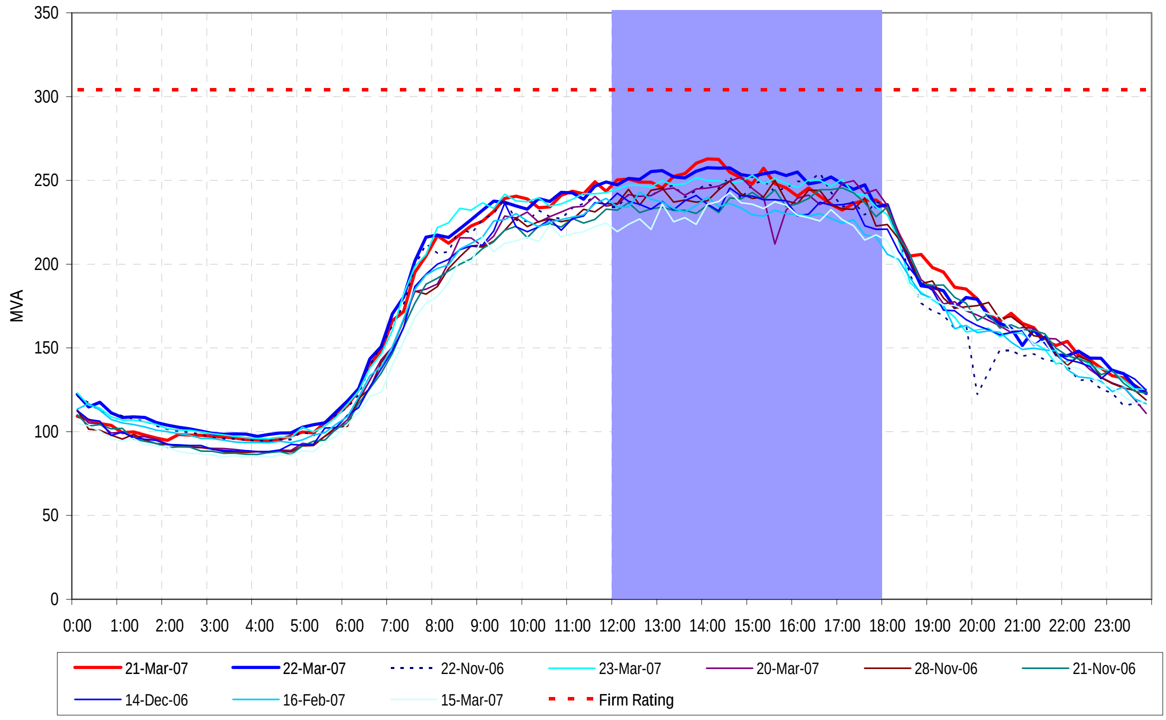
EnergyAustralia control room staff will make request call to the aggregator 2 - 3 hours before the despatch. The aggregator will transfer the agreed customers' loads from our grid to the gensets. Based on our experiences from similar project, we found that this option is technically feasible and commercially viable. The net cost to EnergyAustralia is estimated to be $400,000 - $630,000 or $200 - $210/kVA.

Conclusion

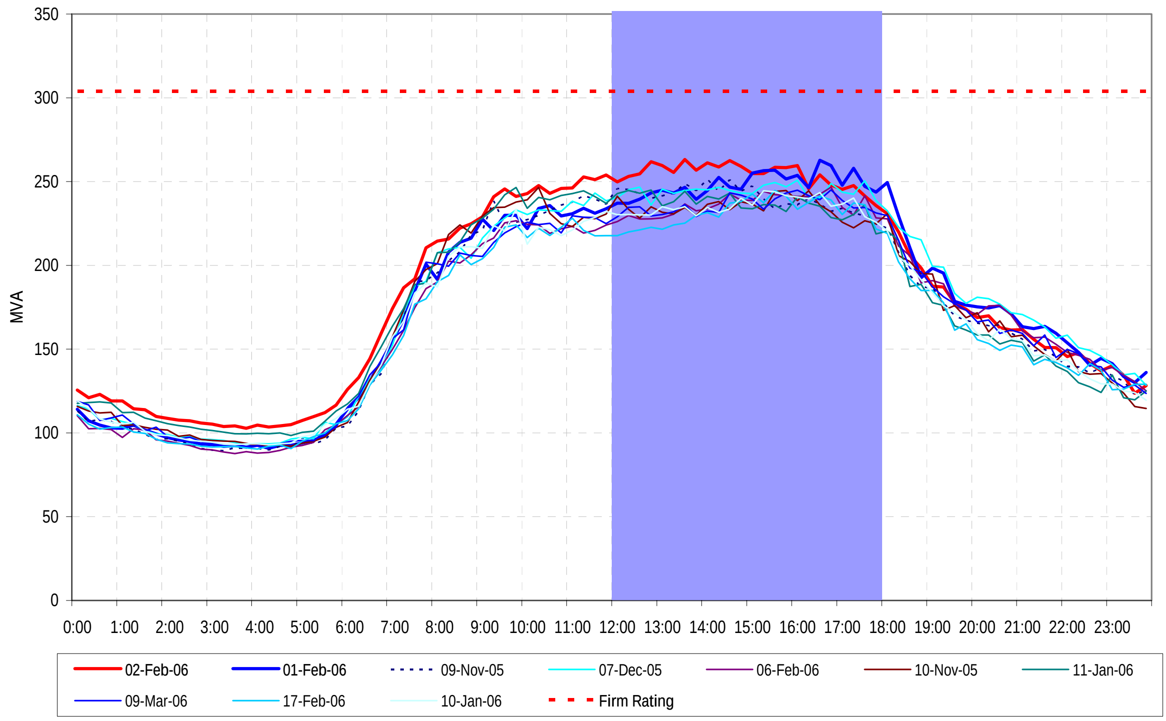
We identified a four feasible DM options that could form a cost effective strategy that would defer the need for the investment for one year. Each of these options will be developed and a final project proposal will be the combination of these four options.

Appendix A: Additional Data

- Top 10 days summer 2006/07 daily load profiles on Willoughby STS



- Top 10 days summer 2005/06 daily load profiles on Willoughby STS



Appendix B: Public Consultation

EnergyAustralia prepared the Willoughby STS Demand Management Options Consultation Paper and advertised it in the Sydney Morning Herald and North Shore Times in October 2007. We also sent a notification to interested parties in the EA register. The Options Paper was also available on EA website for any interested parties to submit responses before the 18th January 2008.

The objective of this consultation was to invite responses from industry experts, consultants, manufacturers of energy efficient equipment, parties interested in demand management and any other member of the public who wished to suggest or offer any energy reduction option or alternative for investigation. We assessed all these options.

Results

We received 13 submissions with general information

No	Company	Proposed Technology	Proposed kVA demand reduction	Assessed net cost ($/ kVA)	Sites or Clients
1	Energy Response	Advanced control technique Load shedding	2-3MVA	$200-210/kVA	3-4 commercial sites
2	Cogent Energy	Cogeneration	4,000kVA	$219/kVA	1 commercial site in Gore Hill area
3	CBD Energy Ltd	Power factor correction	4,000kVA	$283/kVA	N/A
4	Low Energy Supplies+ Services	▪ Residential air conditioner and pool pump ▪ Commercial lighting and HVAC upgrade	3,900kVA	$483/kVA	1,480 residential and 20 commercial sites
5	Green Energy Capital	Packed cogeneration	4,500kVA	$511/kVA	6 – 8 sites
6	Sustainability Today	DM measures	N/A	$525/kVA	N/A
7	Ethnic Communities' Council of NSW (ECC)	Ice storage air conditioning	450kVA	$550/kVA	50 commercial sites
8	Orbis Environmental Pty Ltd	▪ Commercial/industrial potential load shifting ▪ Residential rebate	1,000kVA	$567/kVA	N/A
9	Next Energy	Ice storage for air conditioning system	6kW per unit	$1,500/kW	N/A
10	Sustainability Today	Fuel switching	300kVA	$3,227/kVA	1,000
11	GRIDX Power Pty Ltd	Cogeneration	1 – 5MVA	N/A	N/A
12	Econnect Australia	▪ Standby generator ▪ CHP/Co-generation	N/A	N/A	N/A
13	Energetics Pty Ltd	DM measures	N/A	N/A	N/A

Appendix C: Specific Site Investigations

As part of the scoping investigation, we visited 10 large customers and assessed other 33 major customers reports written by DMPP connected to Willoughby STS. The purpose of the site survey was to identify any demand management opportunities that could help reduce the summer peak demand.

No.	Customers' Name
1	Telstra exchanger
2	Sydney Harbour Tunnel
3	Greenwood Plaza
4	Northpoint
5	ING Office Trustee P/L
6	YAMAMOTO
7	Marconi
8	99 Mount Street P/L
9	View Hotels Group
10	North Sydney Library

Appendix D: DM Screening test

NIG 11323 Royal North Shore Hospital Redevelopment

DEMAND MANAGEMENT SCREENING TEST

Royal North Shore Hospital Redevelopment

Current Supply Arrangements

The area around Royal North Shore Hospital is supplied from Gore Hill zone substation, which consists of three 25MVA and one 33MVA 33/11kV transformers. It is supplied from Willoughby subtransmission substation (STS).

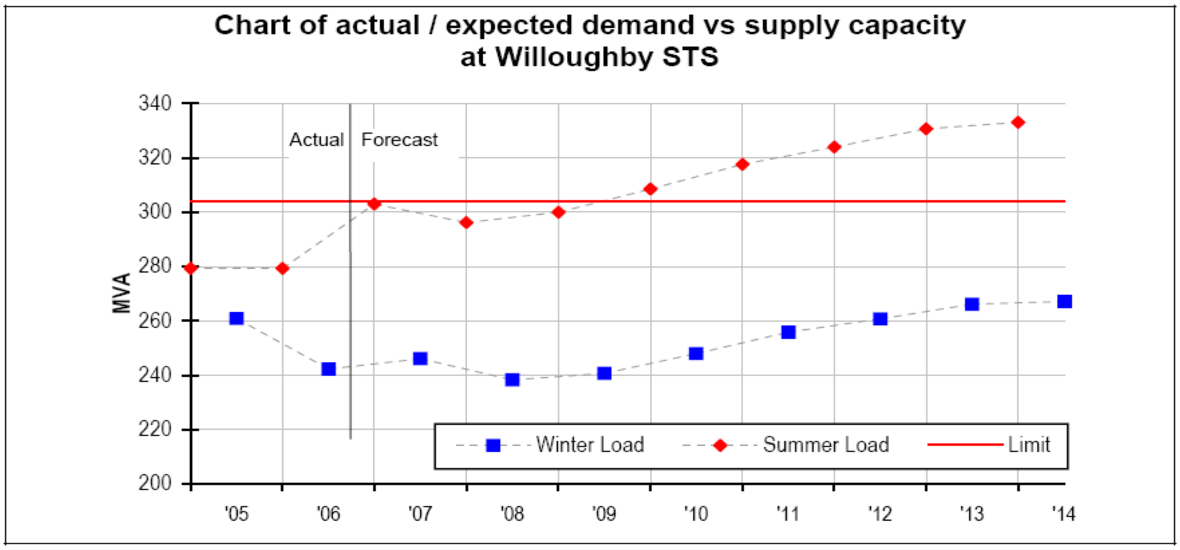
The relevant capacity limit at Gore Hill zone is 102.3MVA in both summer and winter and is determined by transformer capacity. The relevant capacity limit at Willoughby STS is 304MVA in both summer and winter and is also determined by transformer capacity.

Willoughby STS supplies a large part of the North Shore area including North Sydney, Crows Nest, Gore Hill and Chatswood zone substations.

Supply Capacity and Demand Forecast

The area supplied by Willoughby STS consists of a mix of residential and commercial customers. Summer is the most critical season although winter demand is also forecast to approach capacity limits. Peak demand periods tend to be around 4-6pm when the commercial and residential sectors overlap.

The Royal North Shore Hospital (RNSH), which is supplied from Gore Hill zone substation, is proposing a new development with up to 20MVA of additional load, which will be completed in stages starting from 2008. With the addition of this new load in addition to normal load growth we forecast that demand would exceed capacity at Willoughby STS by summer 2009/10.



28 Aug 07 1 DMST - Royal Nth Shore Hospital.doc

Demand at Willoughby STS was 279.3MVA in summer 2005/06, and 260.8MVA in winter 2005. With the new load development at RNSH, we forecast that demand would exceed capacity by 4.5MVA in summer 2009/10, rising to 13.6MVA above capacity in summer 2010/11.

Even with the addition of the new load development at RNSH, we forecast that Gore Hill Zone substation will have sufficient capacity until at least 2020.

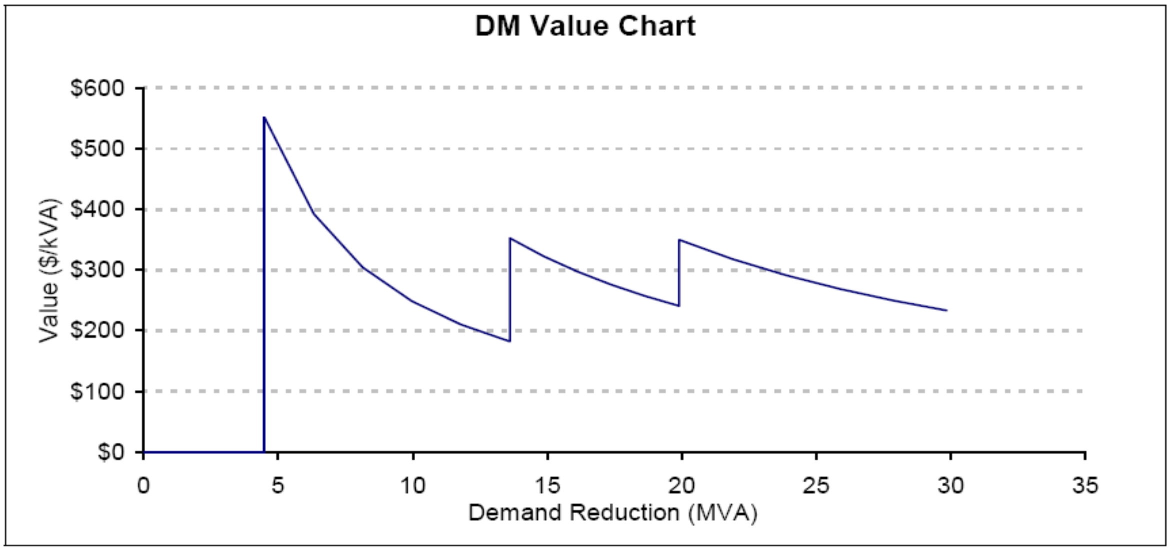
Supply Strategy Option

It is proposed to develop a new 132/11kV RNSH zone substation at an estimated cost of $30m. Commissioning is proposed before summer 2009/10, with an investment decision to be made by December 2007.

Required Demand Management Characteristics

If 4.5MVA of demand reduction could be identified and implemented across Willoughby STS supply area before summer 2009/10, then the proposed investment could be deferred by one year. This represents 1.5% of the demand on this substation. The demand reduction would need to target both the commercial and residential sectors in the summer afternoon and early evening period. The cost saving due to this deferral would be $2.48m, or $550/kVA.

A reduction of 13.6MVA would be required to defer the investment by two years. The savings from this deferral would be $4.8m, or $350/kVA.



Given the size of the demand reduction requirement, the relatively high value of deferral, and the timeframe before an investment decision must be made, it is considered reasonable to expect that demand management could cost effectively defer this investment.

Recommendation

Based on this analysis it is considered reasonable to expect that it may be cost-effective to postpone the proposed supply-side solution by implementing demand management strategies. A demand management investigation will be undertaken involving a full investigation including public consultation and field investigation.