Demand Management Investigation Report

Cronulla and Caringbah

Summary

EnergyAustralia carried out an investigation of demand management (DM) options in the Cronulla and Caringbah area in 2009. The aim was to determine if there were cost effective demand management measures that could defer the need for a $10.8m investment in a 50MVA 132/11kV transformer and associated switchgear at Cronulla zone substation, while maintaining network performance at the required level from winter 2012 to winter 2015. This report concludes that cost effective demand management options are available.

Screening Test Outcomes

A DM screening test completed in April 2009 concluded that to defer the need for the proposed investment until after winter 2014 we would need to implement demand reductions totalling 5.7MVA in winter and 5.6MVA in summer across both Cronulla and Caringbah zones. The savings from this deferral were estimated at $3.3m or $595/kVA.

Revised Cost Estimate and Demand and Capacity Forecasts

The cost of the proposed suppy side project has been revised from $16.7m to $10.8m. The total project cost includes the cost of installing a third transformer in Cronulla zone and the cost of transferring 4MVA of load from Caringbah zone to Cronulla zone. $1.5m of this spending is non-deferrable because the 132kV outdoor feeder bay works are required for the commissioning of Kurnell in any case.

The demand forecasts for both Cronulla and Caringbah have also been revised since completion of the DMST. The revised forecasts are shown in the following charts.

In Cronulla, the forecast winter peak demand is now below the licence capacity until 2015. However, the forecast summer peak demand in Caringbah is slightly higher than the previous forecast.

Chart of actual / expected demand vs supply capacity at Cronulla zone

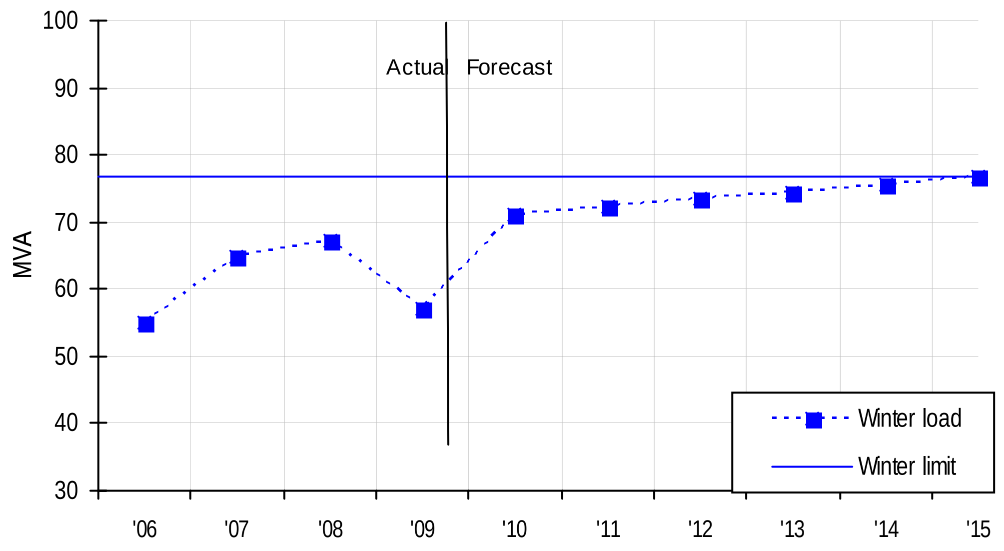
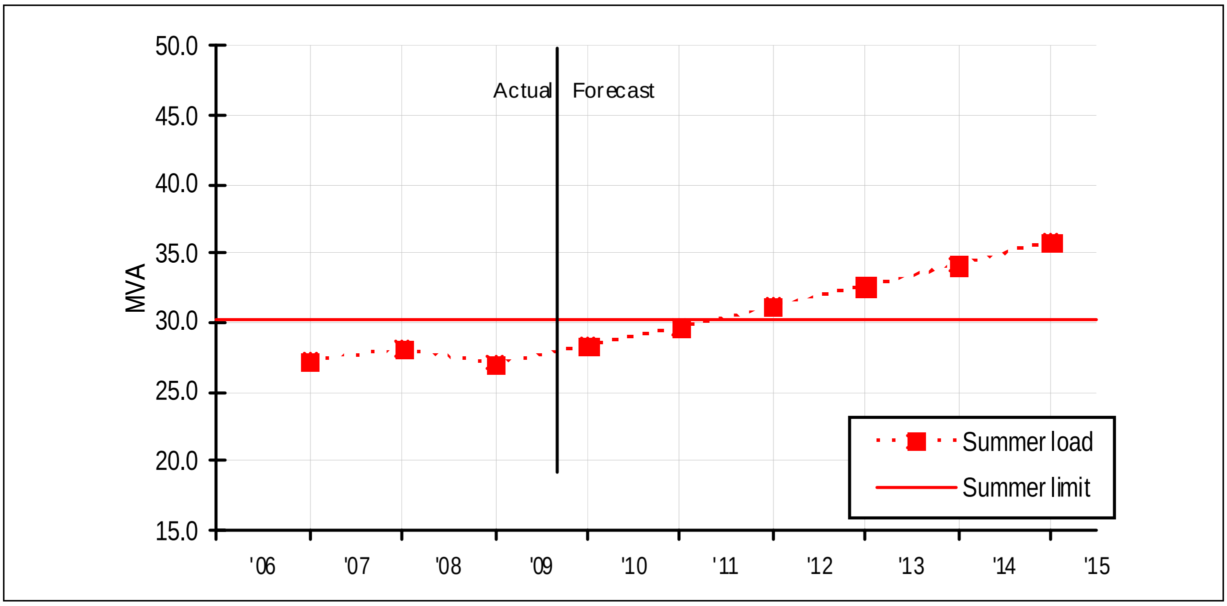


Chart of actual / expected demand vs supply capacity at Caringbah zone

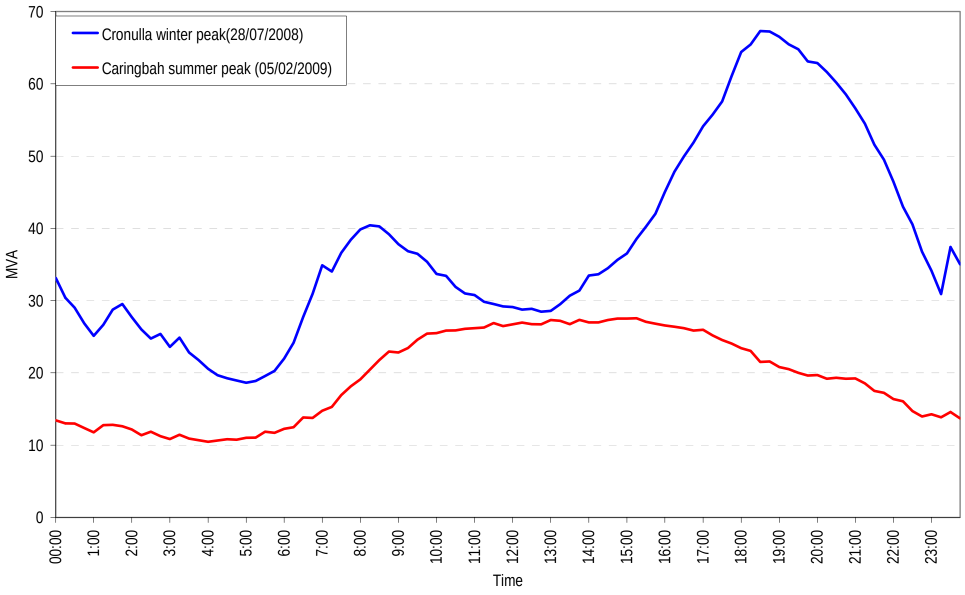


The revised peak demand reduction requirement in both zones is shown in the table below.

DM requirement based on latest load forecast				
Summer	2011/12	2012/13	2013/14	2014/15
DM requirement in Caringbah zone (MVA)	2.2	3.2	4.2	5.3
Winter	2012	2013	2014	2015
DM requirement in Cronulla zone (MVA)	Not required			
DM requirement after up to 4MVA load transfer from Caringbah to Cronulla in 2011				
Winter	2012	2013	2014	2015
DM requirement in Cronulla (MVA) in winter	-	1.1	2.2	3.3

Cronulla and Caringbah Peak Day Load Profiles

The following charts show the Cronulla and Caringbah peak load profiles. The load profiles suggest that residential loads dominate the winter daily peak demand in Cronulla and commercial loads dominate the summer daily peak demand in Caringbah. DM solutions would need to be effective on days between 5:30pm to 8:30pm in winter and 12:30pm to 4:30pm in summer. The load profiles of the top 10 days for each season in Appendix A show that the load profiles are quite consistent.



Demand Management Investigation

The overall investigation approach was to identify potential DM options in both Cronulla and Caringbah, 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 undertook a public consultation and six submissions have been received. We reviewed existing investigation reports from the Demand Management and Planning Project (DMPP) in both areas. We collected and analysed recent energy usage information. 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 and calculated the impact on the zone substation load, 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
- Relocatable generators
- Energy storage system
- Biogas-fired cogeneration system
- Customers' standby diesel generator
- Commercial lighting upgrades and fixed dimming unit
- Commercial air conditioning (HVAC) system upgrade
- Residential and commercial energy efficiency (EE) program
- Control of air conditioner, pool pumps, noncritical loads and commercial lighting

Demand Management Options and Analysis

Power factor correction (PFC)

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 2008/09, we identified that five customers in Caringbah and four customers in Cronulla had power factors that could be improved. The estimated potential demand reduction effective at zone substation level is about 400kVA in summer in Caringbah and 34kVA in winter in Cronulla. From our experience, the estimated cost of the program would be about $68,800.

Relocatable generators

EnergyAustralia has used relocatable generators to provide reliable temporary load reductions in other area. The estimated cost of installing one 1MVA generator for one season would be $534,000. The estimated cost of installing two 1MVA generators for one season would be $695,000.

Energy storage system

Two respondents to our consultation paper suggested they could offer peak shaving in the targeted area by deploying battery energy storage system. The technology is Zinc Bromide flow battery system in modular form and sodium sulphur battery. Based on available information, the estimated cost to EnergyAustralia would be more than $2,400/kVA. We did not pursue this option any further.

Biogas-fired cogeneration system

One respondent to our Consultation Paper suggested they could offer their biogas-fired cogeneration system and install power factor correction equipment at two sites in the target area. Both sites are connected to Cronulla zone substation. Based on the latest peak load profiles, we estimated that peak demand reduction is about 350kVA by using biogas-fired cogeneration system. The estimated cost would be $70,000, or $200/kVA.

The potential peak load reduction from installing power factor correction was very limited due to the operating pattern of the nominated sites. Over the past year, the sites have been consuming energy for very limited periods and the likelihood that this would coincide with peak demand periods is very low. The effectiveness of this option in reducing winter peak demand was assessed as negligible.

Customer standby diesel generators

The DMPP report identified that two customers in the target area had diesel standby generators. The capacities of the generators are 310kVA (Cummins Onan 1998) and 250kVA (PetBow 1970), while the site summer peak load is 570kVA and 820kVA. Both generators are used for essential services only, and serviced and tested on a monthly basis. Adequate fuel is kept on site and additional fuel is available at short notice. There is no synchronising equipment in place. Due to the age of both engines, significant work is needed to examine and potentially re-wire essential and non-essential loads connected to the generator. So we would expect to modify main switchboard and install SCTT equipment. Based on our previous projects, the modification cost of main switchboard is very high and the generator capacity is not large enough to justify the cost, so we did not pursue this option any further.

Commercial lighting upgrade and fixed dimming units

From reviewing DMPP investigation reports, we identified some commercial customers who may have the potential to reduce their peak demand by modifying their lighting system. We subdivided them into three categories - installing motion detectors, installing voltage reduction units (dimming devices) and upgrading light fittings to efficient T5 fittings. We assumed that customers would require financial support for these projects to meet their investment criteria.

Based on our own cost analysis, we estimated that the program would cost EA up to $175,000. The potential peak demand reduction is expected to be about 180kVA. Eight customers would be involved in this program.

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. Nine customers were identified with potential DM options, which could reduce peak demand by 230kVA. The technology includes using electronic expansion valve on chillier, installing new energy efficient chillers, controlling ventilation fans by CO sensors in car park, variable speed controller for pumps and fans etc. The estimated cost is about $345,700. We did not pursue this option any further.

Residential and commercial energy efficiency (EE) program

One respondent to our Consultation Paper suggested they could reduce peak demand in the targeted areas. The proposed technology include roof-top solar photovoltaic system, solar hot water system, ceiling insulation, low-flow showerhead retrofits, CFLs and EE halogen retrofits, fuel switching strategies, A/C load shifting, EE appliances promotion and behaviour change campaigns etc. Because of the limited experience available for this type of project, there is a wide band of uncertainty regarding the effective demand reduction. Based on available information, we have assessed the potential peak demand reduction at about 1.5MVA in Cronulla and 1.2MVA in Caringbah area. The total proposed cost to EA would be about $1.21m and $1.31m respectively.

Control of air conditioner, pool pumps, noncritical loads and commercial lightings

One respondent to our Consultation Paper suggested they could shift peak load in the targeted area by two solutions. Solution one comprises wireless network base stations and wireless relay units which jointly provide an end to end demand response load management system. The radio system will control air conditioner and pool & spa pumps, outdoor lighting, plus any other noncritical loads that will cover commercial and residential customers. Solution two is reducing power usage of commercial gas discharge lighting using a lighting control unit. The proponent could not provide data to demonstrate the effective demand reduction available, and there is little documented experience to draw on. Our estimate of the prospective demand reduction is necessarily quite uncertain, but it appears that in any case it would be small – less than 1MVA total. Based on available cost information, we estimated the total cost is over $2,262/kVA for the first option and $1,223/kVA for the second. Due to the high cost and small impact for this project, we did not pursue these options further.

Summary of Project Cost and Load Reduction

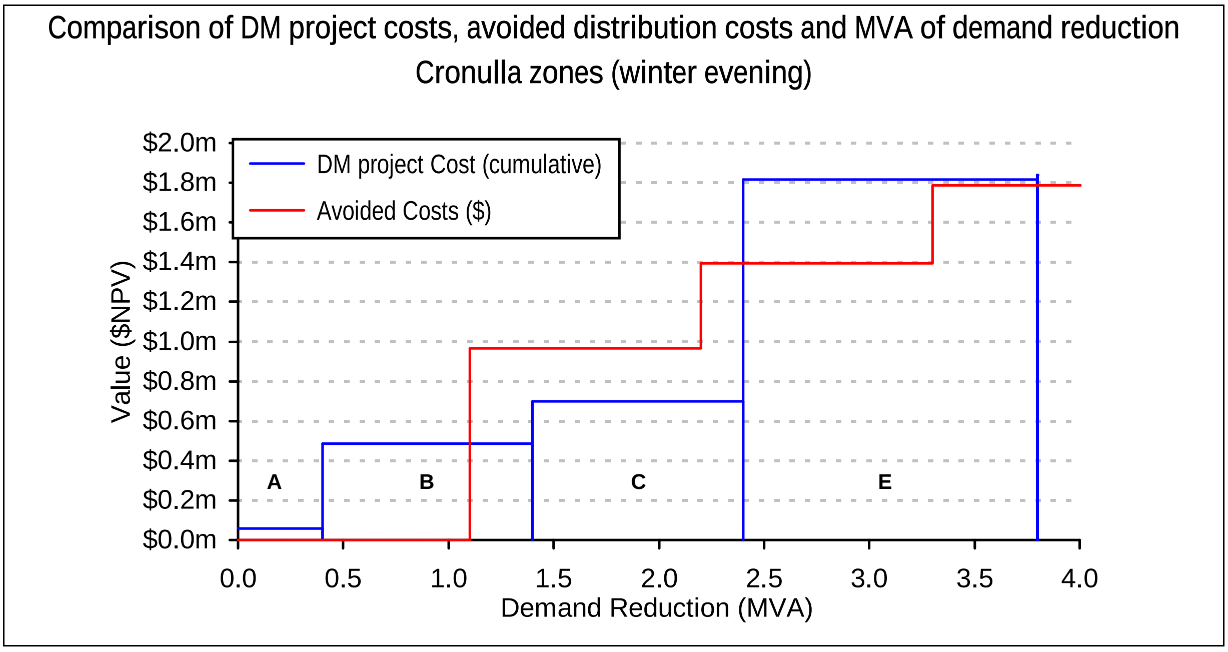
Based on our investigations, we have summarised the estimated size and cost of identified DM options.

1) DM options in Cronulla area

	DM options in Cronulla	Peak Load Reduction	Total Cost to EA ($NPV)	Cost to EA ($/kVA)	No. of Customers Involved	Time for Implementation
A	Biogas-fired cogeneration plant	0.35MVA	$70,000	$200	1	0.5 - 1 year
B	Relocatable generator	1MVA	$0.43m	$430	1	1 - 2 years

C	Relocatable generator (2nd one)	1MVA	$0.330m	$330	1	1 - 2 years
D	Power factor correction	0.03MVA	$22,600	$666	4	0.5 - 1 year
E	Residential& commercial EE program	1.45MVA	$1.217m	$839	> 5,500	1 - 2 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 in Cronulla area. Stacking the options from lowest relative cost to highest shows that there appear to be sufficient cost-effective demand reduction options to achieve a deferral.

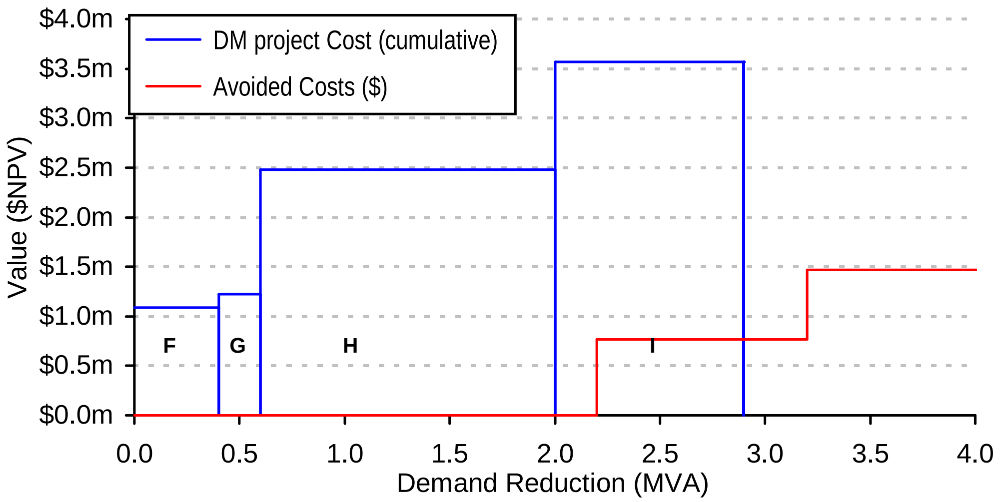


2) DM options in Caringbah area

	DM options in Caringbah	Peak Load Reduction	Total Cost to EA ($NPV)	Cost to EA ($/kVA)	No. of Customers Involved	Time for Implementation
F	Power factor correction	0.4MVA	$46,200	$116	5	0.5 - 1 year
G	Commercial lighting upgrade	0.14MVA	$134,000	$957	4	1 – 2 years
H	Residential and commercial EE program	1.19MVA	$1.32m	$1,109	> 1,400	1 - 2 years
I	Fix dimming for commercial lights	0.86MVA	$1.09m	$1,267	> 150	1 - 2 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 in Caringbah area. Stacking the options from lowest relative cost to highest shows that there are not enough cost-effective demand reduction options to achieve a deferral.

Comparison of DM project costs, avoided distribution costs and MVA of demand reduction Caringbah zones (summer daytime)



DM Strategy Analysis and Options

The supply side solution includes installing a 3rd transformer at Cronulla zone and transferring 4MVA of load from Caringbah to Cronulla zone. The table below shows the calculated present value (PV) of the DM cost and the avoided distribution cost (ADC) for several potential DM strategies.

No.	Possible DM Strategies	DM PV	ADC PV
1	Biogas-fired cogen DM + 1MVA generator for W 2013 Load transfer in 2011 , deferral of Cronulla 3rd transformer to W 2014	$0.49m	$0.97m
2	Biogas-fired cogen + 1MVA generator in W2013, + 2 gensets in W2014 Load transfer in 2011 , deferral of Cronulla 3rd transformer to W2015	$0.86m	$1.4m
3	PFC program + Energy efficiency program + lighting program S12/13 Load transfer and 3rd transformer installation deferred to S 12/13	$2.34m	$0.76m

By comparing with the present value of demand management cost, we concluded that option two is the most beneficial. This would mean transferring 4MVA from Caringbah to Cronulla in 2011 as planned, negotiating a network support agreement with the biogas-fired cogeneration for winter 2013 & 2014, installing one 1MVA generator in winter 2013 and two 1MVA generators in winter 2014. This would enable the 3rd transformer at Cronulla to be installed later, in time to meet the need in winter 2015.

Feasible Options

Our analysis showed that a combination of an embedded power generator and some relocatable generator options could form a cost effective DM strategy.

- Embedded power generation

Sydney Water currently owns and operates biogas-fired cogeneration facilities in Cronulla Sewage Treatment Plant. The following picture shows that 77% observation of power generation was over 350kVA in winter 09 peak hours (5:30pm to 8:30pm).

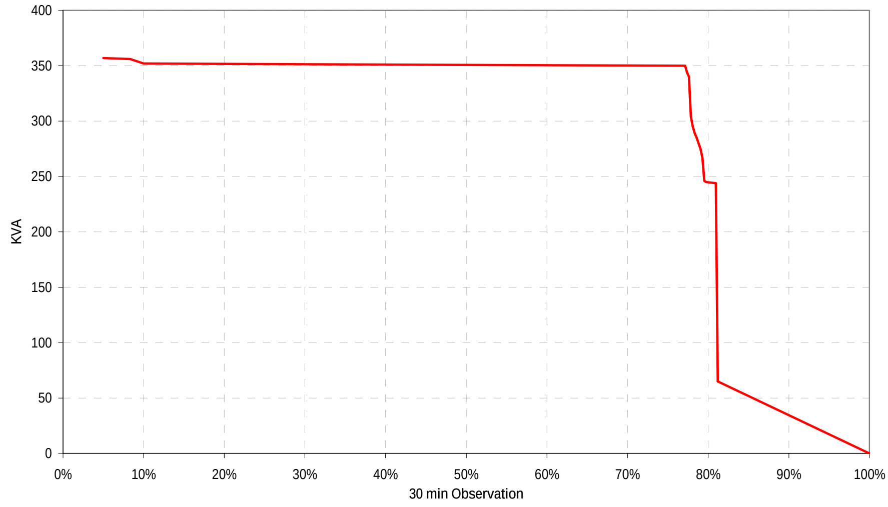


Chart - Sydney Water cogeneration output in winter 09 peak hours (5:30pm to 8:30pm)

The current reverse power protection settings on the generator are designed to limit power output to the load at one particular electrical switchboard. This can be changed, and Sydney Water have undertaken to do this. Sydney Water will complete the upgrade to its facilities by March 2010. The cogeneration system will then be able to supply power to the entire plant and will operate more uniformly at a higher level.

Sydney Water has indicated its willingness to enter into a Network Support Agreement with EnergyAustralia for two seasons. The contract will require Sydney Water to provide network support by ensuring that their biogas-fired generator in Cronulla Sewage Treatment Plant is kept running between the peak hours of 5:30pm and 8:30pm during winter. The agreement would also be conditional on Sydney Water undertaking several improvements to maximise the power output availability and modify the planned maintenance schedule to generate 350kVA or more during the winter peak period.

- Relocatable generator

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, generator control communication and distance to EA's 11kV substation.

The generator would be remotely controlled and monitored via a reliable communications link to the EA Control Room. Then they will automatically synchronise and connect to EA network. The control and communications of gensets will be explored and developed further in next stage.

Based on our experience from similar projects, this option is technically feasible and commercially viable. We plan to lease 1x1MVA generator in winter 2013 and 2x1MVA in winter 2014. The estimated cost based on our current contract would be $534,000 for the first year and $440,000 for the second year. The lower cost in the second year is because the cost for site, design and civil work done for 2013 will not need to be repeated for the second year. There is a potential site available inside the Sydney Water sewage treatment plant, which is away from any residential areas and would not present any noise issues. The winter peak demand on site varies from 0.7MVA to 1.7MVA, so there should be little difficulty absorbing 2MVA into the 11kV network at this location.

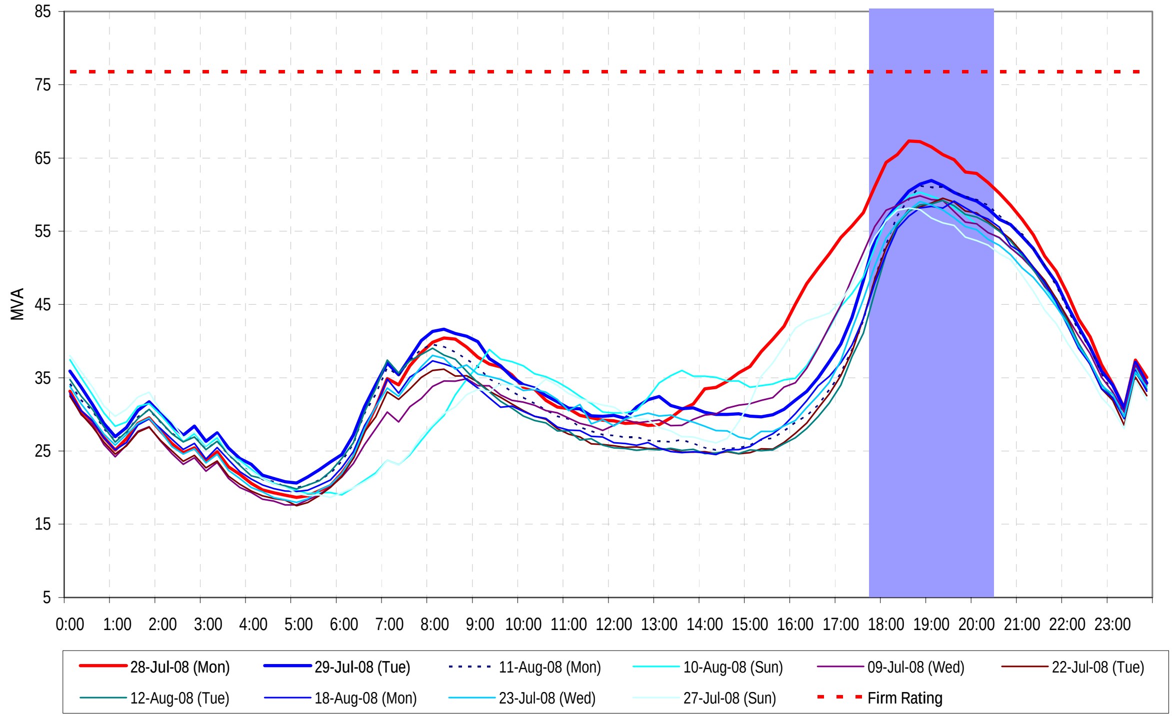
Conclusion

We identified a feasible DM strategy combining the options of using biogas-fired cogeneration and relocatable generator. The combined DM projects are sufficiently large to enable deferral of the need for the proposed installation of a third transformer in Cronulla zone until winter 2015. These options will be developed to enable implementation for winter 2013 and 2014.

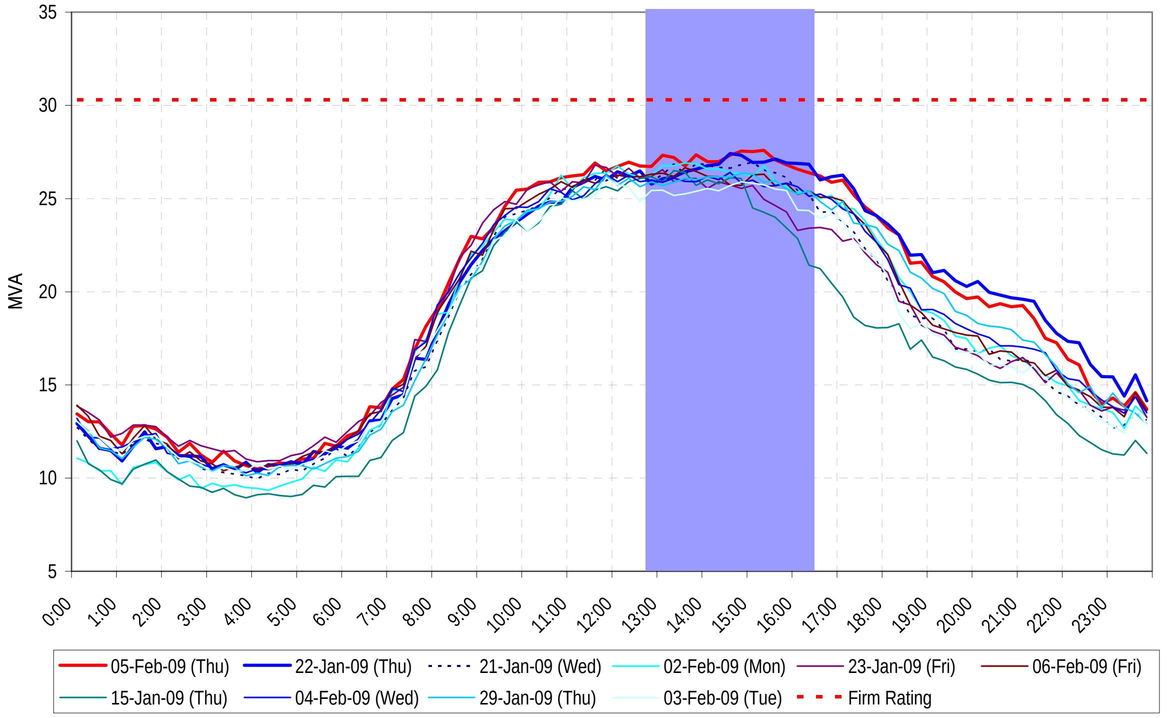
The need for the load transfer (4MVA) from Caringbah to Cronulla cannot be cost effectively deferred and this work should be carried out as scheduled prior November 2011.

Appendix A: Additional Data

- Top 10 days winter 2008 daily load profiles in Cronulla zone



- Top 10 days summer 2008/09 daily load profiles in Caringbah zone



Appendix B: Public Consultation

EnergyAustralia prepared the Cronulla and Caringbah Demand Management Options Consultation Paper and advertised in the Sydney Morning Herald and St. George & Sutherland Shire Leader in July 2009. 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 September 2009.

The objective of this consultation was to invite responses from industry experts, consultants, manufactures 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 6 submissions

No	Company	Proposed Technology	Suggested kVA demand reduction	Suggested cost	Sites or Clients
1	Sydney Water	PFC Biogas-fired cogeneration	215kVA 450kWe	$366/kVA $100kVA	Pumping station Sewage treatment plant
2	LESS	Ceiling insulation High power factor CFLs EE halogen downlights Fuel switching Emberted standby power saver Behaviour change EE appliances Solar PV Commercial lighting & HVAC	2.48MVA (Cronulla) 2.68MVA (Caringbah)	$490.88/kVA	Households and commercial customers
3	tE	Demand response load management Gas discharge lighting	N/A	$480 per home, and any additional modification cost Plus additional based station infrastructure cost Over $1,000 to $1,500/kW	Households SMEs Commercial customers
4	Zest Energy	ZBB battery energy storage	0.25MW to 4MW	$2,400/kW	N/A
5	ADAPT	Energy storage system	2.5 to 20MVA	N/A	N/A
6	Prime Power Services	Gas-fired generator	1 to 4 MVA		Identified sites

Appendix C: DM Screening Test

DEMAND MANAGEMENT SCREENING TEST

Cronulla Zone Augmentation

Current Supply Arrangements

Cronulla Zone Substation consists of two 45MVA transformers and is supplied via the 132kV feeder 916(3) teed off from feeder 916 linking Sydney South BSP and Kurnell STS. The 132kV feeder 281 from Kirrawee provides back up supply.

Caringbah Zone Substation is equipped with two 33MVA transformers and is supplied by 33kV feeder 745 from Kurnell STS with backup 33kV feeder supply from Port Hacking STS.

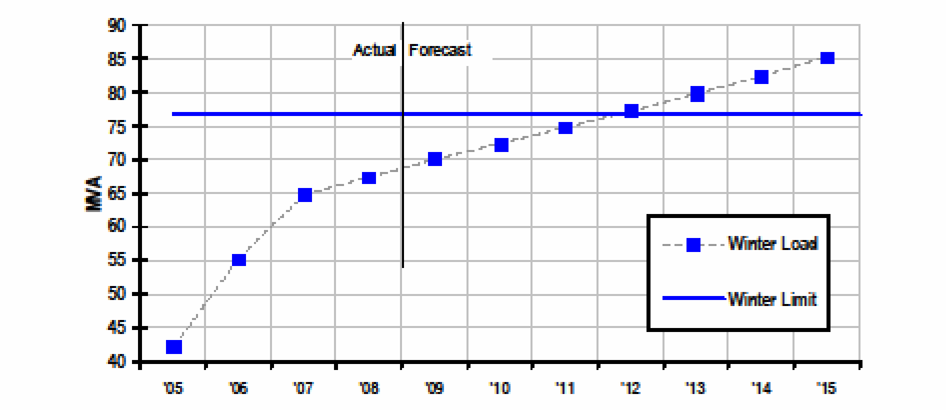
Cronulla and Caringbah Zone Substations are interconnected at 11kV feeder level. These substations are in the Sutherland supply area and supply parts of Cronulla, North Cronulla, Woolooware, Burraneer, Dolans Bay, Port Hacking, Lilli Pilli, Maianbar, Yenabilli, Bundeena, Caringbah, Miranda, Sylvania Waters and Yowie Bay.

Supply Capacity and Demand Forecast

Winter is the critical season for Cronulla Zone Substation. It supplies a mix of residential and commercial customers.

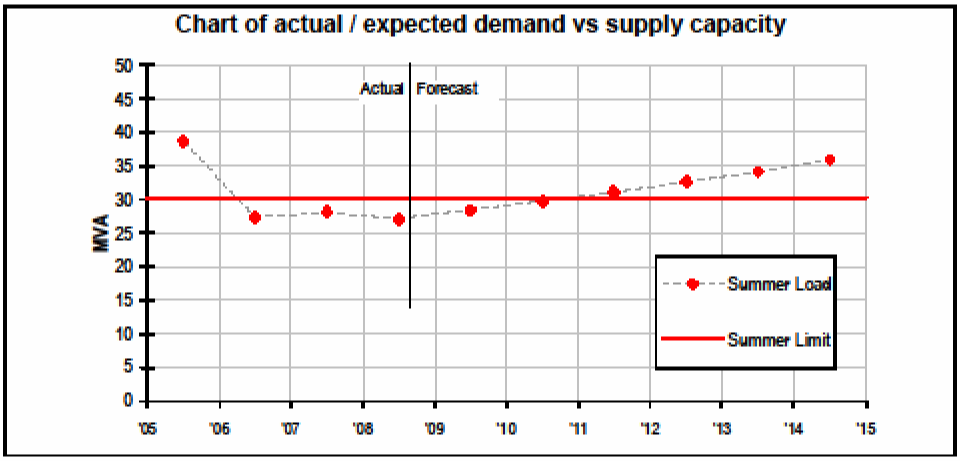
The relevant capacity limit at Cronulla Zone Substation is 76.8MVA in winter. Peak demand was 67.3MVA in winter 2008, and we forecast it would exceed relevant limits by 0.5MVA in winter 2012 rising to 8.4MVA in winter 2015.

Chart of actual / expected demand vs supply capacity



Summer is the critical season for Caringbah Zone Substation. It supplies a mix of residential and commercial customers.

The relevant capacity limit at Caringbah Zone Substation is 30.3MVA in summer. Peak demand was 28.1MVA in summer 2007/08, and we forecast it would exceed relevant limits by 2.4MVA in summer 2012/13 rising to 5.6MVA in summer 2014/15.



Supply Strategy Option

The preferred supply side option is to install a third 50MVA 132/11kV transformer and associated switchgear at Cronulla Zone Substation. This will allow load to be transferred from Caringbah to Cronulla Zone.

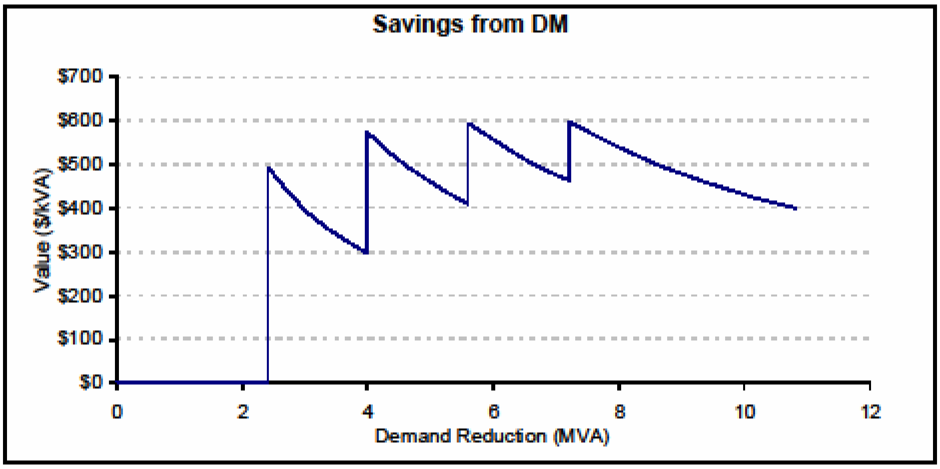
The estimated cost of this project is $16.7m. Commissioning is proposed before winter 2012, with an investment decision date of August 2009.

Required Demand Management Characteristics

If demand could be reduced by 0.5MVA before winter 2012 and 2.4MVA before summer 2012/13, then the proposed investment could be deferred by one year. This represents 3% of total demand on the two zone substations. The savings from this deferral is $1.2m or $494/kVA, which is high.

If demand could be reduced by 3.1MVA by winter 2013 and 4.0MVA by summer 2013/14, then the investment could be deferred by two years. The savings from this deferral is $2.3m or $574/kVA, which is also high.

If demand could be reduced by 5.7MVA by winter 2014 and 5.6MVA by summer 2014/15, then the investment could be deferred by three years. The savings from this deferral is $3.3m or $595/kVA, which is also high.



The Demand Management and Planning Project (DMPP) has identified demand reduction opportunities at over 1000 sites across the Sydney metropolitan area. A search of the DMPP databases has revealed potential demand reductions of 1.88MVA at Caringbah Zone Substation and 273kVA at Cronulla Zone Substation at a subsidy cost of $600/kVA or less.

The demand reduction requirement is moderate in absolute and relative terms, and the deferral value is high. The timeframe before an investment decision must be made is sufficient to fully investigate demand reduction opportunities in the relevant supply area. DMPP databases indicate that over 2MVA of cost effective demand reductions opportunities have been identified in the Cronulla and Caringbah zone areas.

We conclude that it is reasonable to expect that the proposed investment could be deferred via demand reduction options.

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.