

Demand Management Investigation Report

Gwawley Bay and Engadine Zone

Summary

EnergyAustralia carried out an investigation of demand management (DM) options in the Gwawley Bay and Engadine areas in 2009. The aim was to determine if there were cost effective demand management measures that could defer the need for \$29.2m and \$48.1m investments in Gwawley Bay and Engadine respectively of converting both existing zone substation from 33/11kV to 132/11kV, while maintaining network performance at the required level from winter 2011 to winter 2014. This report concludes that cost effective demand management option is available.

Screening Test Outcomes

A DM screening test (DMST) completed in May 2009 concluded that to achieve one year deferral of proposed Gwawley Bay investment we would need to implement demand reduction of 0.1MVA before winter 2011 in Port Hacking STS. The cost saving from this deferral would be \$2.2m. For two year deferral, we need to implement demand reduction of 2.4MVA before winter 2012. The cost saving from this deferral would be \$4.3m.

To achieve one year deferral of proposed Engadine investment we would need to implement demand reduction of 24.2MVA before winter 2013 on 132kV feeder network. The cost saving from this deferral would be \$3.8m. For two year deferral, we need to implement demand reduction of 29.2MVA before winter 2014. The cost saving from this deferral would be \$7.3m.

DM Requirement

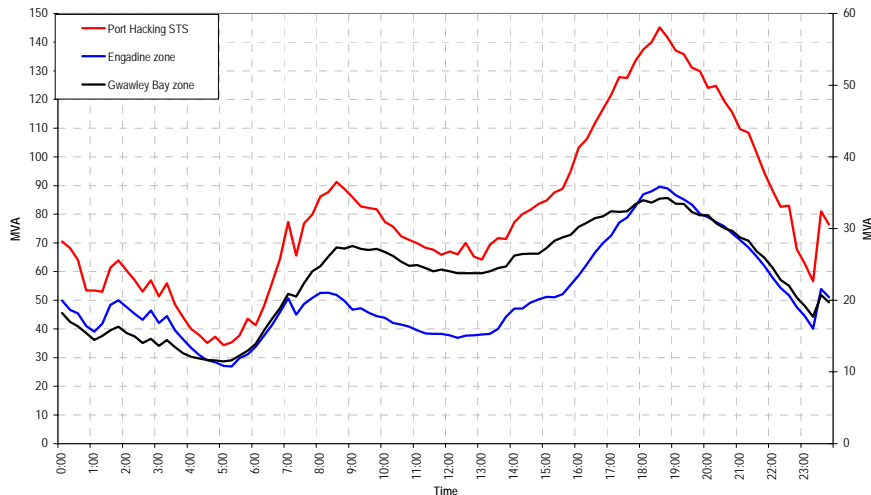
To ensure that the forecast peak load does not exceed the planning design limit, it would be necessary to reduce load at Port Hacking STS and 132kV feeder by the amounts shown in the table below.

Year	2010	2011	2012	2013	2014
DM requirement (MVA) @ Port Hacking STS	-	0.1	2.4	n/a	n/a
Cost savings of Gwawley Bay investment		\$2.2m	\$4.3m		
DM requirement (MVA) @ 132kV Feeder	9.9	14.6	19.3	24.2	29.2
Cost savings of Engadine investment	\$4.2m	\$8.1m	\$11.8m	\$15.2m	\$18.4m

The new Gwawley Bay zone substation project would be completed in August 2012 and can not be deferred further due to aged asset issue. The proposed Engadine solution is scheduled to be commissioned by October 2012. If this solution was to ensure loads stayed within planning designing limits in winter 2010, it would have been needed three years earlier. The value of avoided distribution costs has been based on this hypothetical project with the same cost, but cash flows advanced to meet the required need.

Winter Peak Day Load Profiles

The following charts show the winter peak load profiles in the targeted areas on July 28, 2008. The load profiles suggest that residential loads dominate the winter peak demand. DM solutions would need to be effective between 5:30pm to 8:30pm in winter. The load profiles of the top 10 days for winter season in targeted areas 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 reviewed existing investigation reports from the Demand Management and Planning Project (DMPP) in Port Hacking area. 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 amount of load above design limit. 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
- Embedded power generation
- Commercial lighting upgrades and fixed dimming unit
- Commercial air conditioning (HVAC) system upgrade

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 2008/09, we identified that twenty customers had poor power factor within Port Hacking area. The estimated potential demand reduction effective at zone substation level is about 202kVA in winter. From our experience, the estimated cost of facilitating the program is about \$92,000.

Relocatable generators

EnergyAustralia has used relocatable generators to provide reliable temporary load reductions in other areas. A potentially suitable location is needed that is to install four 1.25MVA generators. This would

give 4MVA demand reduction in total. The estimated cost to EnergyAustralia would be approximately \$1.3m or \$325/kVA.

Embedded power generation

EnergyAustralia has used embedded generators in other areas as a successful DM option. The embedded generation would need to operate in winter early evening to coincide with winter peak demand if the load approached the available capacity. From winter 2008 load analysis, we concluded that 99.7% of the time power generation was over 14.5MVA in peak period (5:30pm to 8:30pm) and 76.6% of the time power generation was over 18MVA. A key task is to sign a Network Support Agreement with the customer to ensure the landfill gas power system generates and exports 18MVA with all necessary facility modification to the EnergyAustralia grid between 5:30pm and 8:30pm peak period in winter 2013. The impact of 18MVA power generation at 33kV grid would be 21MVA at 132kV level. The estimated cost would be approximately \$1.5m for one winter season contract and \$5m for four winter season contract.

Commercial lighting upgrade and fixed dimming units

From 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 motion detect sensor, installing voltage reduction unit (dimming devices) and upgrading light fitting to efficient T5 fittings. Different customers have different investment criteria. To implement the lighting projects, customers require a subsidy that varies from site to site due to different investment criteria.

Based on our own cost analysis, we estimated that the program would cost EA up to \$239,600, with a potential peak demand reduction of about 227kVA. We would target ten customers and assume five customers will 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. Five customers were identified with potential DM options, which could reduce peak demand by 40kVA. The estimated cost is about \$84,100.

Summary of Project Cost and Load Reduction

Based on our investigations, we have summarised below the estimated size and cost of each identified DM option:

DM options	Peak Load Reduction	Total Cost to EA (\$NPV)	Cost to EA (\$/kVA)	Customers Involved	Time for Implementation
Embedded generator (5 year)	21MVA	\$6m	\$57	1	0.5 - 1 year
Embedded generator (4 years)	21MVA	\$5m	\$60	1	0.5 - 1 year
Embedded generator (3 years)	21MVA	\$4m	\$64	1	0.5 - 1 year
Embedded generator (1 year)	21MVA	\$1.5m	\$71	1	0.5 - 1 year
Relocatable genset	4MVA	\$1.3m	\$325	1	0.5 - 1 year
Power factor correction	0.2MVA	\$92,000	\$455	20	0.5 - 1 year
Commercial lighting upgrade	0.2MVA	\$239,600	\$1,054	10	1 – 2 years
HVAC upgrade	0.04MVA	\$84,100	\$2,156	5	1 – 2 years

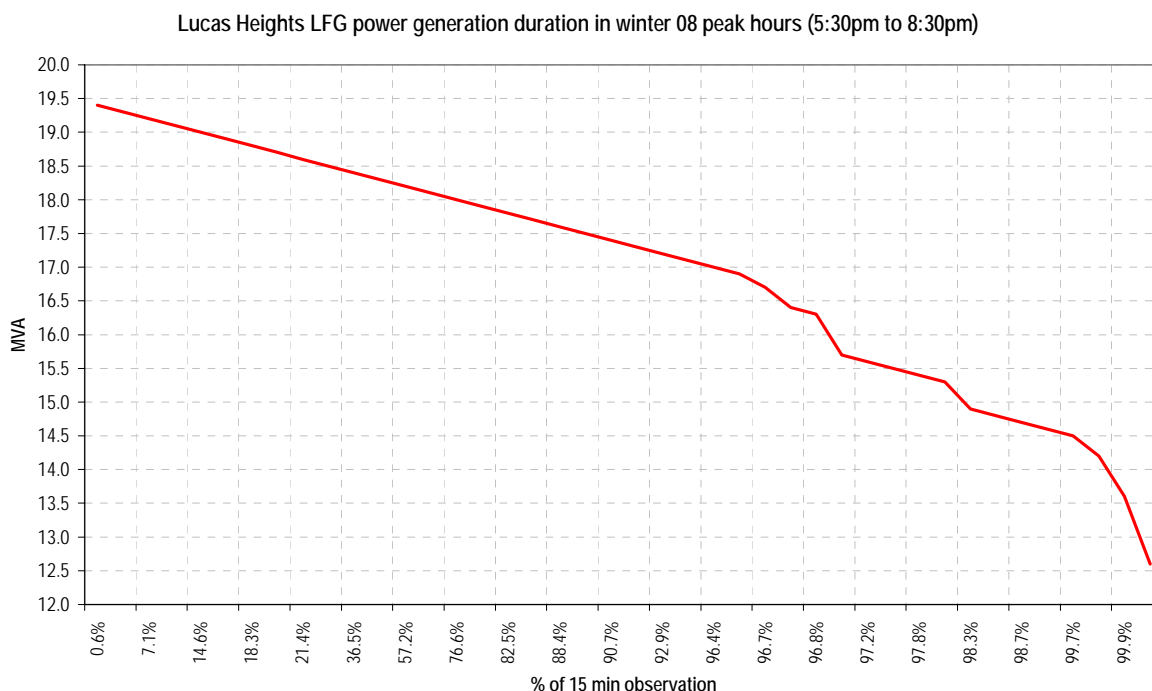
Feasible Options

On the basis of this analysis, we found that embedded power generation, relocatable generator and power factor program options could achieve sufficient demand reductions for Gwawley Bay and Engadine investment cost savings.

- **Embedded power generation – Signing a Network Support Agreement with Energy Developments Ltd (EDL) for multiple winter seasons**

Energy Developments currently owns and operates landfill gas (LFG) power generation facilities in Lucas Heights. Landfill gas is generated by decomposition of organic matter in refuse tips. It mostly consists of methane and carbon dioxide mixed with water vapour and organic compounds. The substantial methane content of landfill gas enables it to be used as a power generation fuel. There are more than three hundred fifty vertical gas extraction wells on site that extract landfill gas at a reasonably-consistent flow and quality. All the wells are linked by underground pipes to a gas collection facility, where gas processing reduces moisture and filters out fine particles. The processed landfill gas is then used as a fuel in gas engines. The power generation facilities are connected to EA power grid.

The following picture shows that 99.7% observation of power generation was over 14.5MVA in winter 08 peak hours (5:30pm to 8:30pm) and 76.6% observation of power generation was over 18MVA at Lucas Heights LFG site.



EnergyAustralia could enter into a Network Support Agreement with EDL for single season or multiple seasons. The contract requires EDL to provide network support by ensuring that their landfill gas power generation in Lucas Heights is kept running between the peak hours of 5:30pm and 8:30pm during winter. The agreement also involves EDL undertaking several improvements to the generation and control systems and scheduling maintenance works to generate and export 18MVA during winter peak period. Further analysis concluded that the impact of 18MVA power generation at 33kV grid would be 21MVA at 132kV level. The power generation output profiles in winter 2008 are shown in Appendix B.

The different combinations of the identified DM options will have different impact on the investment cost savings. The following table shows the peak demand requirement and cost saving values.

Year	2010	2011	2012	2013	2014
DM requirement (MVA) @ Port Hacking STS	-	0.1	2.4	n/a	n/a
Cost savings of Gwawley Bay investment		\$2.2m	\$4.3m		
DM requirement (MVA) @ 132kV Feeder	9.9	14.6	19.3	24.2	29.2
Cost savings of Engadine investment	\$4.2m	\$8.1m	\$11.8m	\$15.2m	\$18.4m

- 1) If EA have a three year network agreement with EDL covering up to winter 2012, the investment cost savings would be about \$16.1m, which will defer the Gwawley Bay investment by two years. The estimated DM cost would be \$4m for 21MVA. The net savings would be \$12.1m.
- 2) If EA have a four year network agreement with EDL covering up to winter 2013, the investment cost savings would be about \$19.5m, which will defer the Gwawley Bay investment by two years and Engadine investment by one year. The DM option should combine EDL network support agreement (21MVA) and relocatable generator (4MVA). The estimated total DM cost would be \$6.3m for 25MVA. The net savings would be \$13.2m.
- 3) If EA have a five year network agreement with EDL covering up to winter 2014, the investment cost savings would be about \$22.7m, which will defer the Gwawley Bay and Engadine investment by two year. The DM option should combine EDL network support agreement (21MVA) and two relocatable generator sites (2x4MVA) and power factor correction program (0.2MVA). The estimated total DM cost would be \$9.5m for 29.2MVA. The net savings would be \$13.2m.

Option 1) is definitely worth pursuing because of \$12.1m cost savings. The options 2) and 3) are even better because of more cost savings and deferral of investment. But, selection of option 2) or 3) is depended on the price of EDL offer. If power factor correction program were selected, it should be started sooner than later for capturing the peak load reduction benefit earlier.

The new Gwawley Bay zone substation is proposed to be completed before winter 2013. There would be an opportunity to transfer load from Miranda zone to the new Gwawley Bay zone, which would also reduce the demand on the critical part of the 132kV network. Depending on how much load would be transferred, the relocatable generator DM option could be scaled down (or even not required) if 4 to 5MVA load were transferred. This option should be reviewed in 2013 after the load has been transferred.

There is an additional cost savings benefit if EA sign the agreement with EDL because it will also help relieving peak demand for inner metro project in summer 2012/13.

- **Customer power factor correction**

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 202kVA in winter. Total cost of EA to undertake such a program is estimated at \$92,000, including all project management, customer contact and direct costs.

- **Relocatable generators**

EnergyAustralia has used leased diesel generators in other areas as a successful DM option. Identification of a suitable site is a critical element of this option where generators can be installed

temporarily. During our investigation, we identified several likely locations for the project, and assessed issues of ease of access, noise, exhaust stack installation, fuel refilling, earthing, 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. The generators 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 experiences from 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 \$1.3m for 4MVA installation.

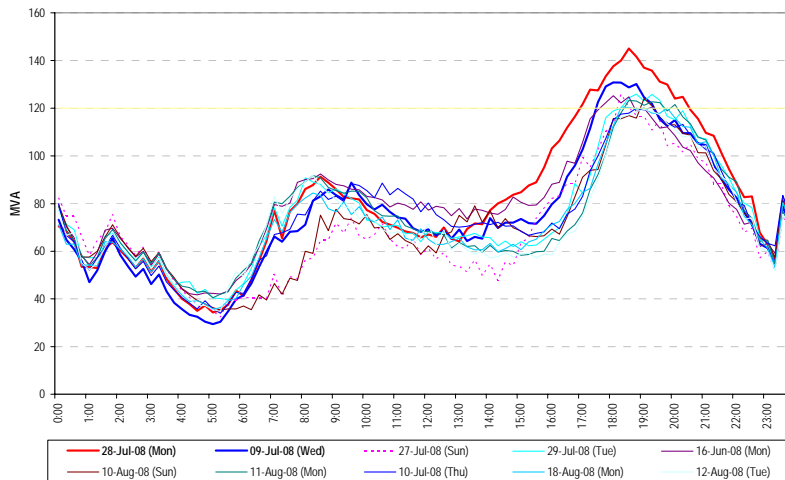
Conclusion

We identified several feasible DM options comprising embedded power generation, relocatable generators and PFC program to provide an evening peak demand relief in the target area. The project is sufficiently large to enable deferral of the proposed investment for one or two years.

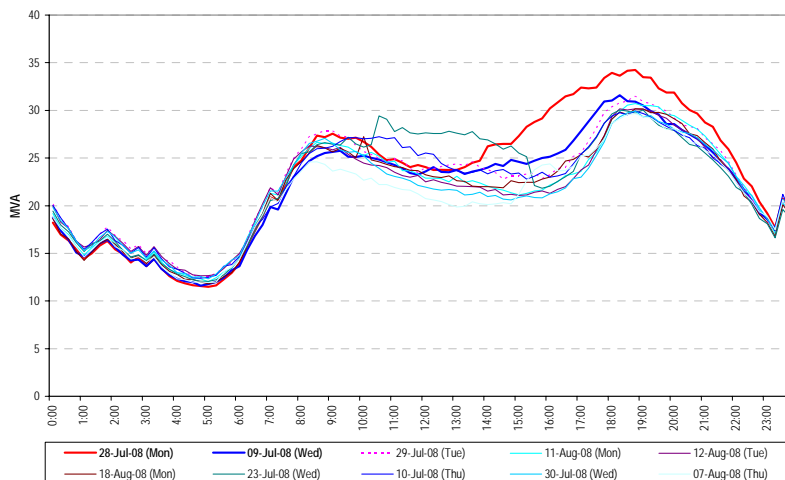
The extra cost saving over \$12m is depending on the EDL offer price. We recommend starting to negotiate with EDL about their offer and develop the DM options to a project offer.

Appendix A: Additional Data

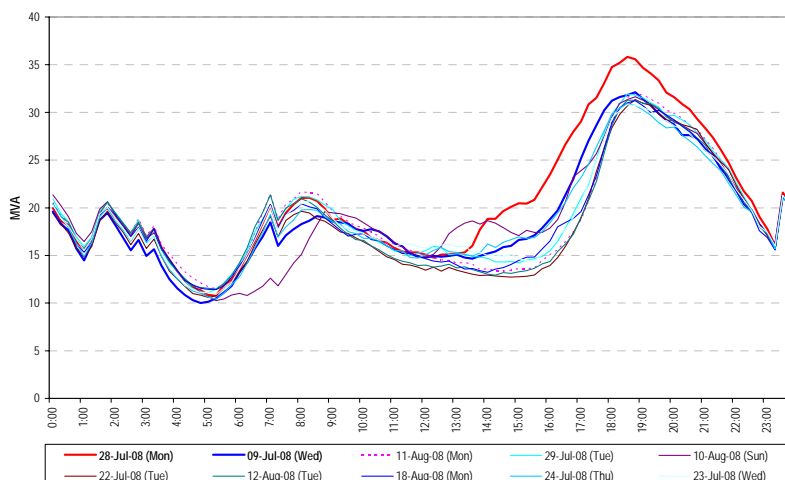
Port Hacking STS – top 10 days load profiles in winter 2008



Gwawley zone substation – top 10 days load profiles in winter 2008

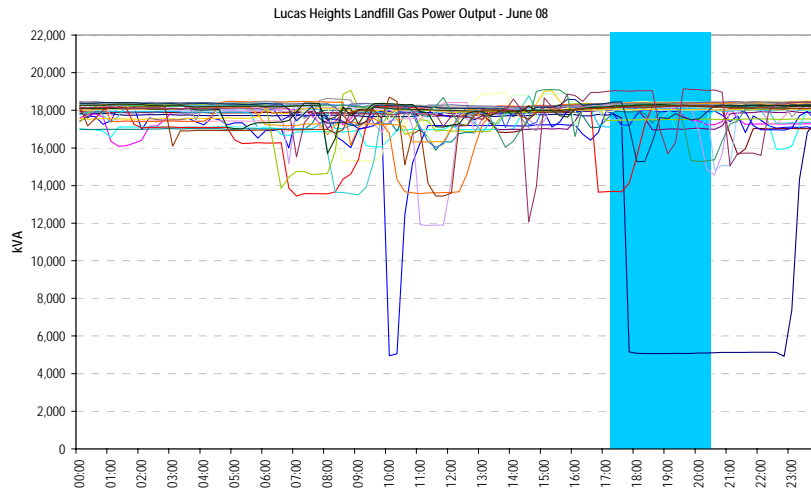


Engadine zone substation – top 10 days load profiles in winter 2008

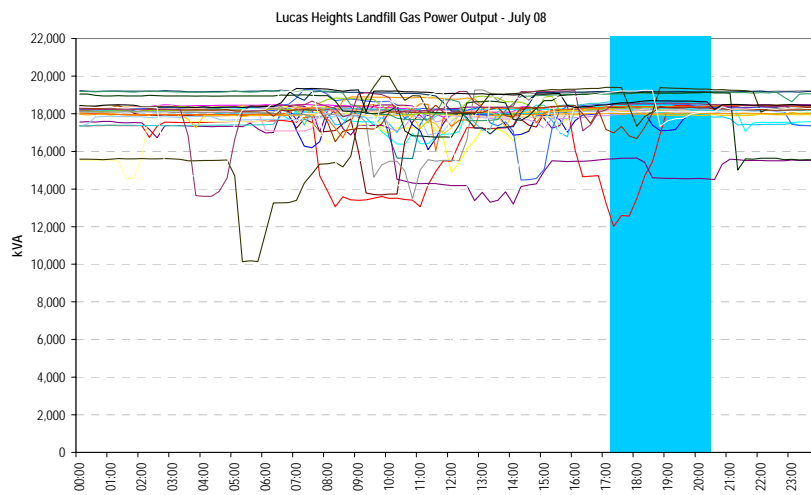


Appendix B: Lucas Heights Landfill Gas (LFG) Power Generation in winter 2008

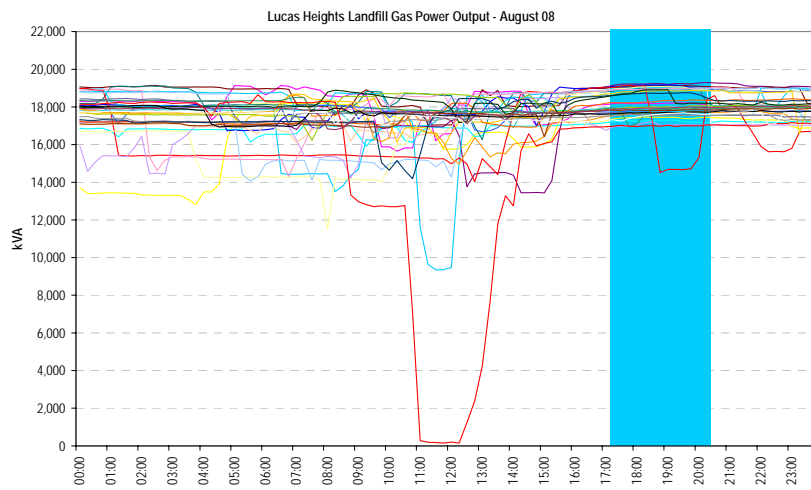
➤ Power output in June 2008



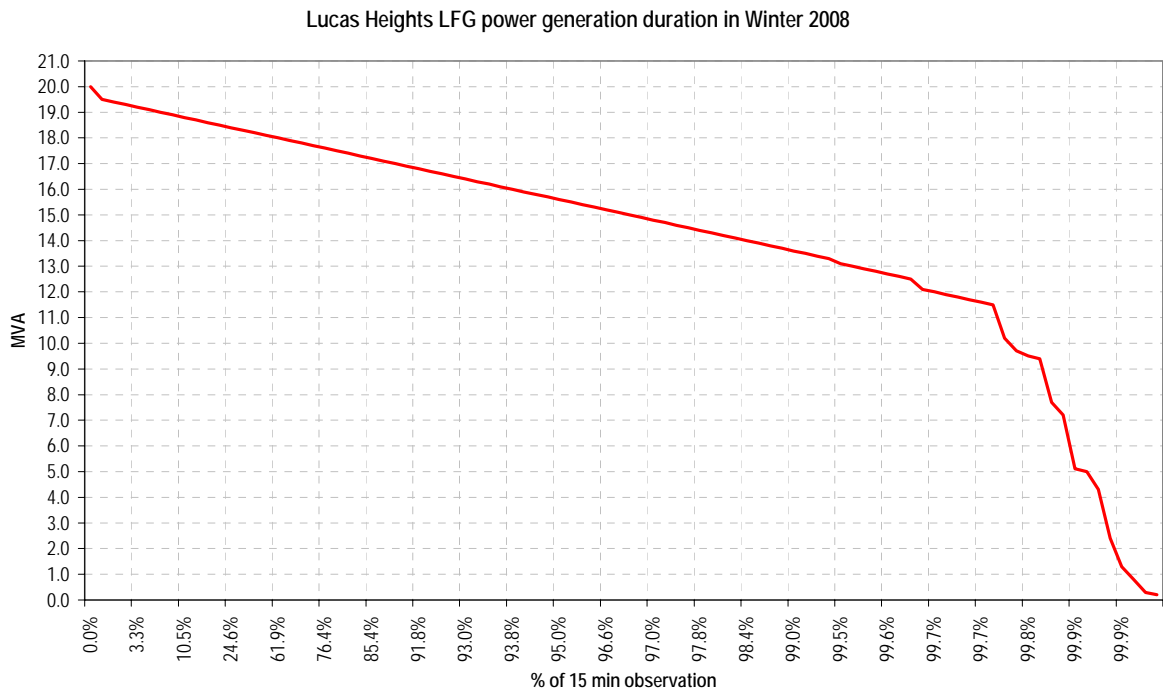
➤ Power output in July 2008



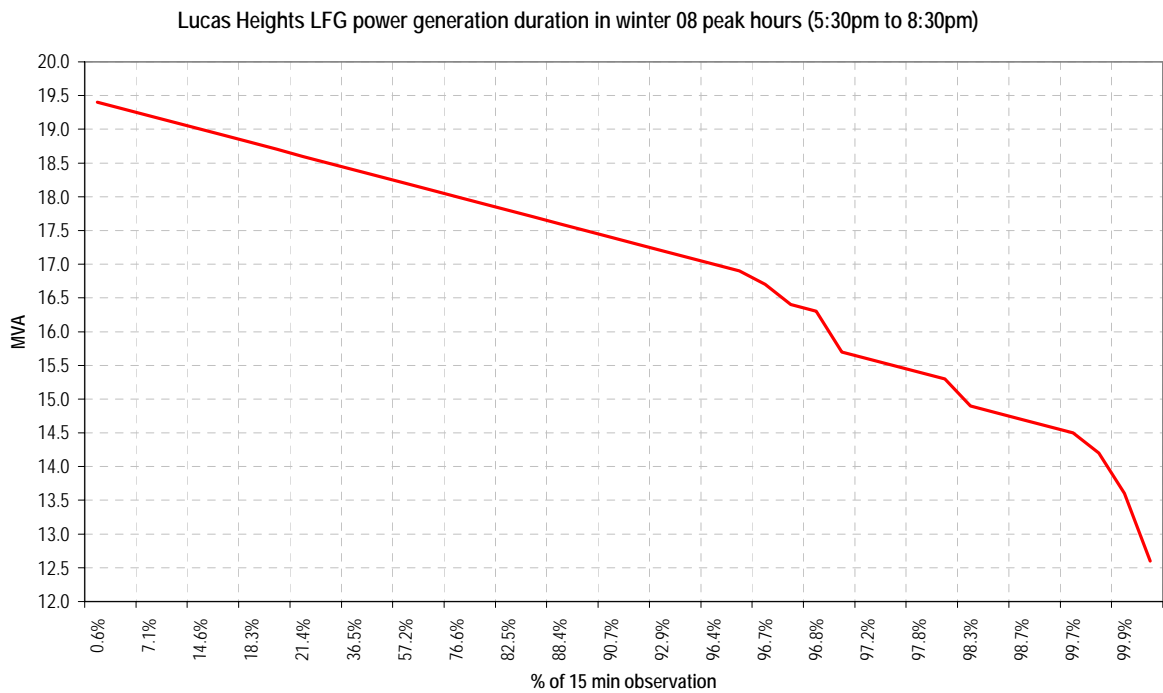
➤ Power output in August 2008



➤ Winter 2008 power generation duration



➤ Winter 2008 power generation duration in peak hours (5:30pm to 8:30pm)



748 via Lucas Heights and Jannali. Due to aged asset issues, Engadine Zone Substation would need to be replaced no later than 2014.

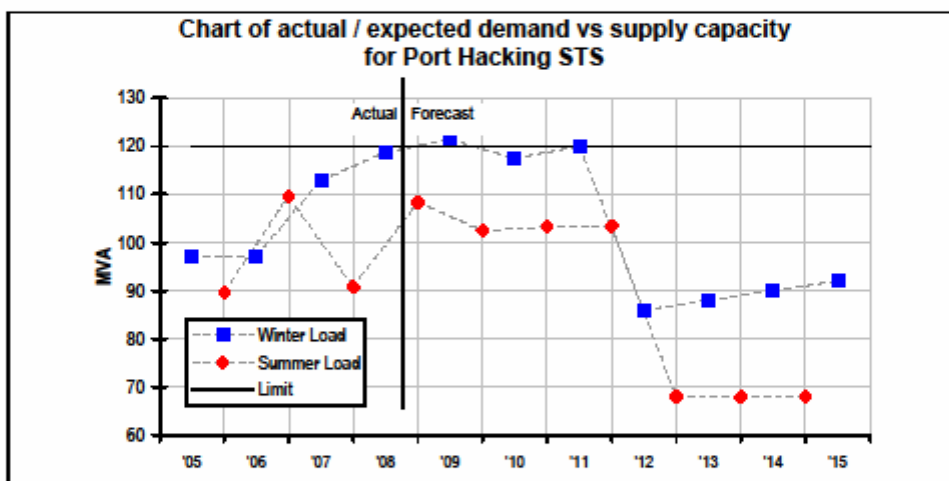
Supply Capacity and Demand Forecast

In the period prior to action being required solely for asset condition issues, there are no forecast load issues at Gwawley Bay zone substation or Engadine zone substation.

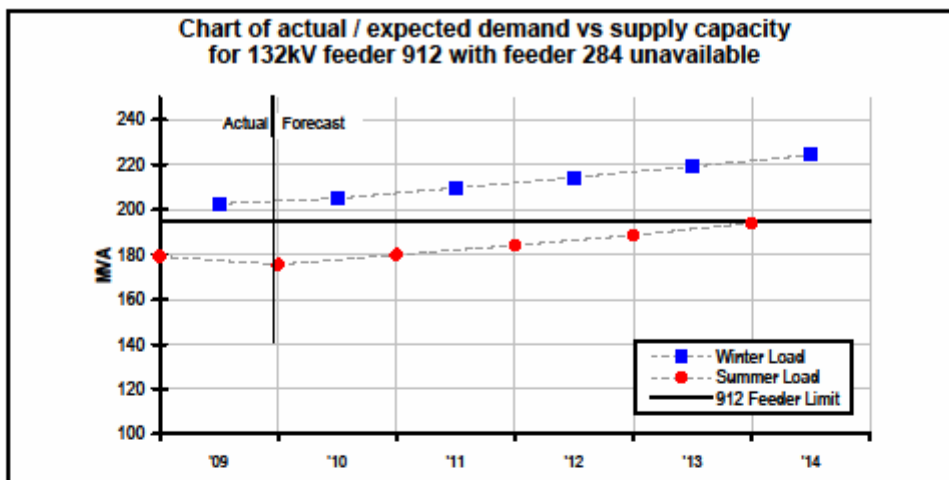
Winter is the critical season for this part of the network.

The relevant capacity limit of Port Hacking STS is 120MVA in both summer and winter. We forecast that demand would exceed capacity by 0.1MVA in winter 2011 and 2.4MVA in winter 2012. However, after 2011 the removal of the Gwawley Bay load to the 132kV system would resolve the load issues.

We forecast that summer demand at Port Hacking STS would be within capacity limits for the foreseeable future.



The relevant capacity limit for the 132kV feeder network supplying Port Hacking STS is 195MVA in summer and winter, limited by the rating of the Port Hacking busbar. The 132kV network is designed so that all load can be supplied when any single element is out of service. The worst case scenario is when feeder 284 is out of service, when the Port Hacking, Menai and SRA Heathcote loads must all be supplied via feeder 912. Under these circumstances, the existing Gwawley Bay and Kirrawee zones would be switched to their alternate supplies. We forecast that, under these conditions, demand would be 24.2MVA more than the feeder capacity in winter 2013, rising to 29.2 in winter 2014.



Supply Strategy Option

The preferred supply side solution is the conversion of both Gwawley Bay Zone Substation and Engadine Zone Substation to 132/11kV operation.

The new Gwawley Bay Zone Substation will be supplied via a tee connection from 132kV feeder 917 and a new 132kV underground feeder from Port Hacking STS. The estimated cost of this investment is \$29.2m. Commissioning is proposed for completion in May 2011. This would reduce the load at Port Hacking STS effectively, but not affect the 132kV feeder issues (since the existing Gwawley Bay zone would not be supplied via feeder 912 if feeder 284 was unavailable).

The new Engadine Zone Substation will connect into reconfigured 132kV feeders 285 & 912. The estimated cost of this investment is \$48.1m. Commissioning is proposed for completion in October 2012. This would reduce the load on the critical elements of the 132kV network and remove the loading issues.

The decision on these investments must be made by June 2009.

Required Demand Management Characteristics

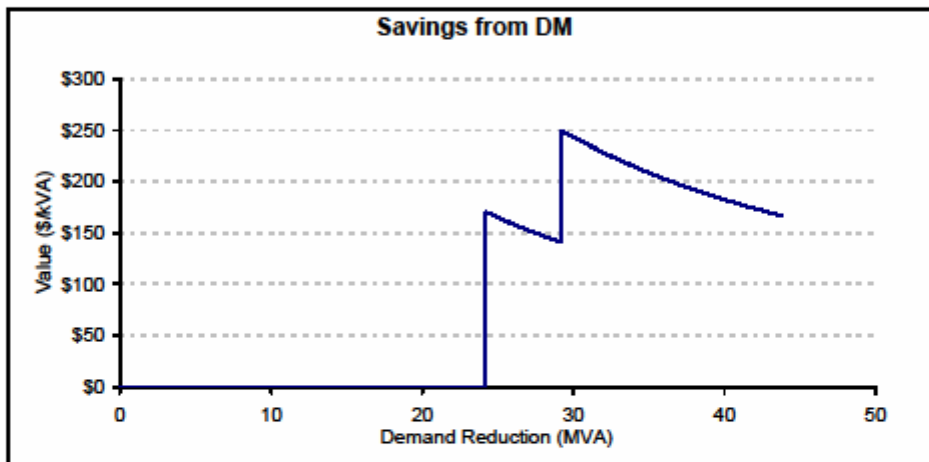
If demand on Port Hacking STS could be reduced by 0.1MVA before winter 2011, then the proposed Gwawley Bay investment could be deferred by one year. The cost saving from this deferral would be \$2.2m, which is very high. Even if a future change in the demand forecast resulted in a demand reduction requirement of up to 1.0MVA, the saving from deferral would be over \$2,000/kVA.

If demand could be reduced by 2.4MVA, the load would be within the design limits in winter 2012. However, the need to retire the 33kV circuit breakers and other equipment in the 33kV supply to Gwawley Bay means that the project would need to be undertaken regardless of load conditions.

If the load on the 132kV feeder network could be reduced by 24.2MVA in winter 2013, the need for proposed Engadine investment could be deferred until winter 2014. The cost saving from this deferral would be \$3.8m or \$160/kVA, which is moderate.

If the load on the 132kV feeder network could be reduced by 29.2MVA in winter 2014, the proposed Engadine investment could be deferred by two years. The cost saving from this deferral would be \$7.3m or \$250/kVA.

The demand reductions would need to address the winter evening peak and could come from Menai, Miranda, Engadine, Lucas Heights or Jannali zone substations, or the SRA Heathcote supply.



The demand reductions required to enable the need for these two investments to be deferred may overlap if the demand reductions from Port Hacking load come from locations that would be supplied by feeder 912 with feeder 284 unavailable.

Reductions in demand at this location may also be beneficial at the transmission level and contribute to the deferral of the proposed Chullora Bulk Supply Point in summer 2012/13. This would be an additional benefit.

There are embedded generators connected to the 33kV system supplied from Port Hacking STS. The combined effect of these generators is equivalent to a reduction of approximately 21MVA. There may be potential to enter into a network support agreement with the owner/operator of these plants.

In addition, assuming the new Gwawley Bay zone substation is completed before winter 2013, there would be an opportunity to transfer load from Miranda zone to the new Gwawley Bay zone, which would also reduce the demand on the critical part of the 132kV network.

The DM requirement to enable deferral of the need for the proposed Gwawley Bay investment to winter 2012 is very small and the benefits are high. It would be expected that such a demand reduction would be readily achieved.

With respect to the proposed Engadine investment, there appears to be significant demand reduction opportunities in the area supplied by Port Hacking STS, and additional cost savings may be attributable at transmission level. It is therefore considered reasonable to expect that demand management could cost effectively defer the need for the proposed supply side project until 2014.

Recommendation

Based on this analysis it is considered reasonable to expect that it may be cost-effective to postpone both of the proposed supply-side solution by implementing demand management strategies. A demand management investigation will be undertaken.