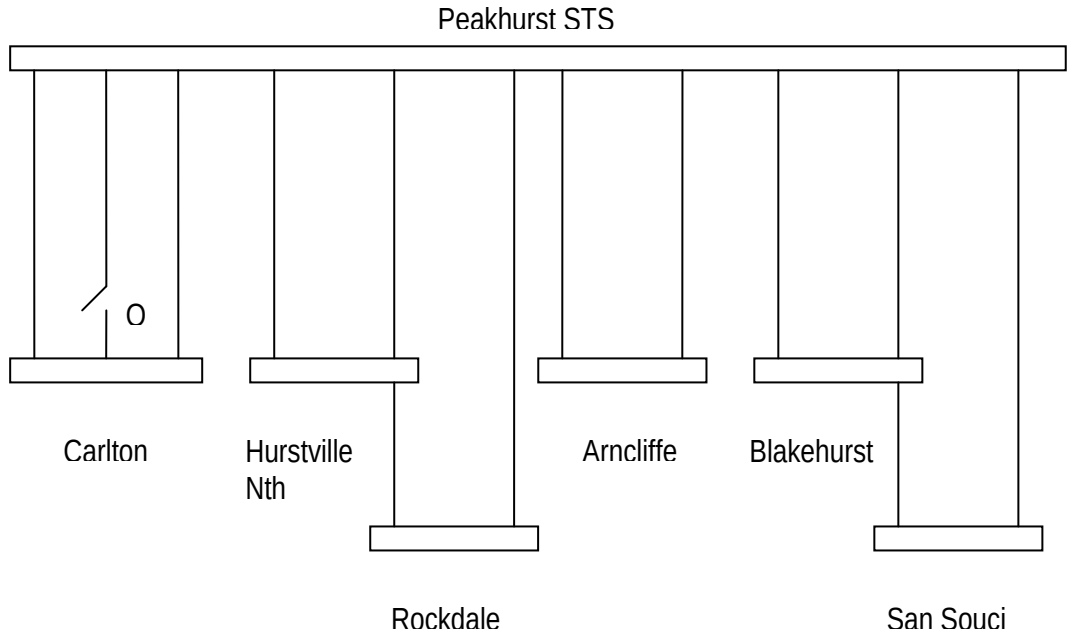
DEMAND MANAGEMENT SCREENING TEST

Eastern St George Area

Current Supply Arrangements

The Eastern St George Area consists of six zone substations - Arncliffe, Blakehurst, Carlton, Hurstville North, Rockdale and Sans Souci. All these substations are supplied at 33kV by Peakhurst subtransmission substation (STS) as per the schematic below:



These substations supply an area roughly bounded by the M5 in the north, Botany Bay in the east, King Georges Rd in the west, and the Georges River in the south. This incorporates all of Rockdale City Council, and the eastern parts of Kogarah Council and Hurstville City Council.

The driving capacity limitations are the acceptable loading limits of the zone substations, which are generally determined by the 33kV feeder capacities.

Supply Capacity and Demand Forecast

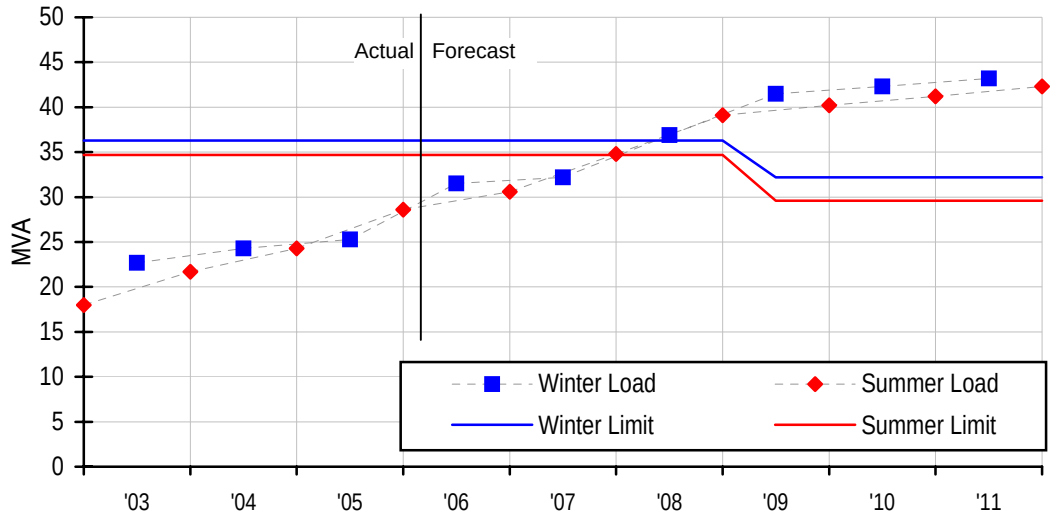
The main loads are a mix of residential, commercial and light industrials. Load has been steadily growing for almost a decade but we have been able to address the problem by transferring the load between zone substations. This is not an option for solving the problems in the future.

A summary of capacity and demand for each zone substation is given below.

At **Arncliffe** the rating of the 33kV feeders limits the acceptable load on the substation to 34.7MVA in summer and 36.3MVA winter. In 2005 the summer and winter peak demands at Arncliffe were 24.3 and 25.3MVA respectively. The forecast peak demand and acceptable load levels at Arncliffe are shown in the chart below. It

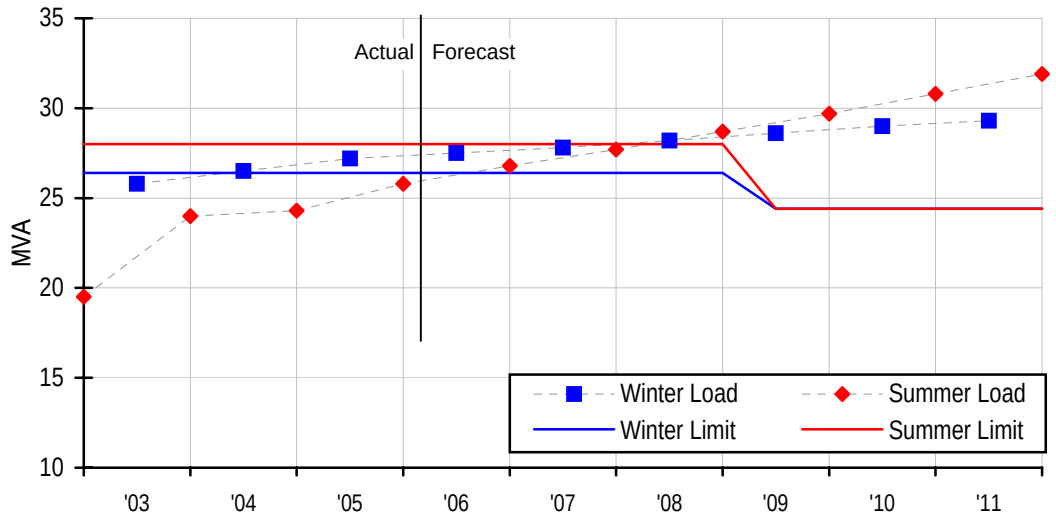
shows that the acceptable loading level will be exceeded by 0.1MVA in summer 2007/08 and 0.3MVA in winter 2008. In summer 2008/09 this will rise to 4.4MVA. In compliance with new licence condition requirements, acceptable loading limits will be reduced after 1 July 2009. Accordingly, forecast peak demand will be above the acceptable loading level by 9.2MVA in winter 2009, and 10.6MVA in summer 2009/2010.

Chart of actual / expected demand vs supply capacity at Arncliffe



At **Blakehurst** the rating of the 33kV feeders limits the acceptable load on the substation to 28.0MVA in summer and 26.4MVA in winter. In 2005 the summer & winter peak demands at Blakehurst were 24.3 & 27.2MVA respectively. The forecast peak demand and acceptable load levels at Blakehurst are shown in the chart below.

Chart of actual / expected demand vs supply capacity at Blakehurst

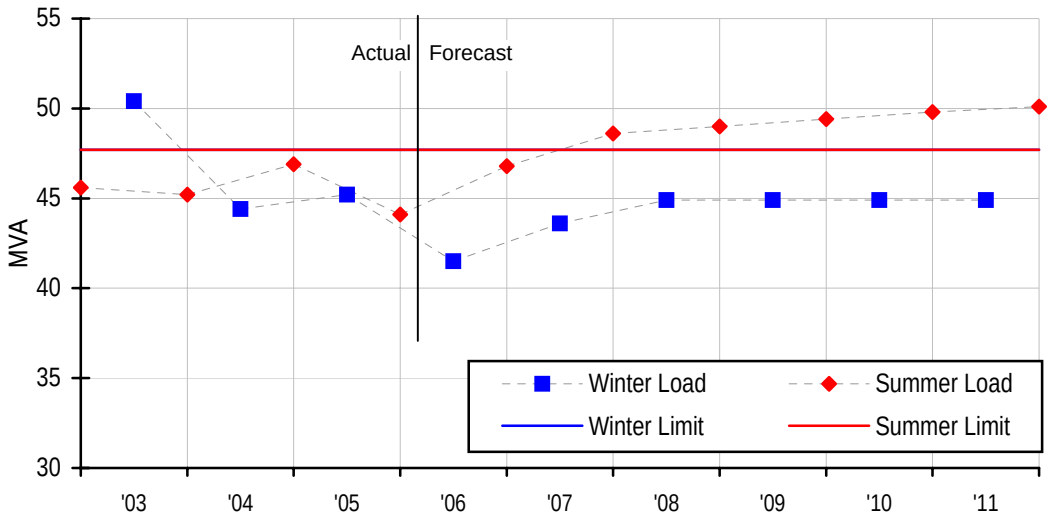


We forecast that the acceptable load levels will be exceeded by 1.1MVA in winter 2006 and 1.4MVA in winter 2007. In summer 2008/09, the forecast load will be 0.7MVA more than the acceptable level. In compliance with new licence condition requirements, acceptable loading limits will be reduced after 1 July 2009. Load is

forecast to be 4.2MVA above this reduced level in winter 2009, and 5.3MVA above in summer 2009/2010.

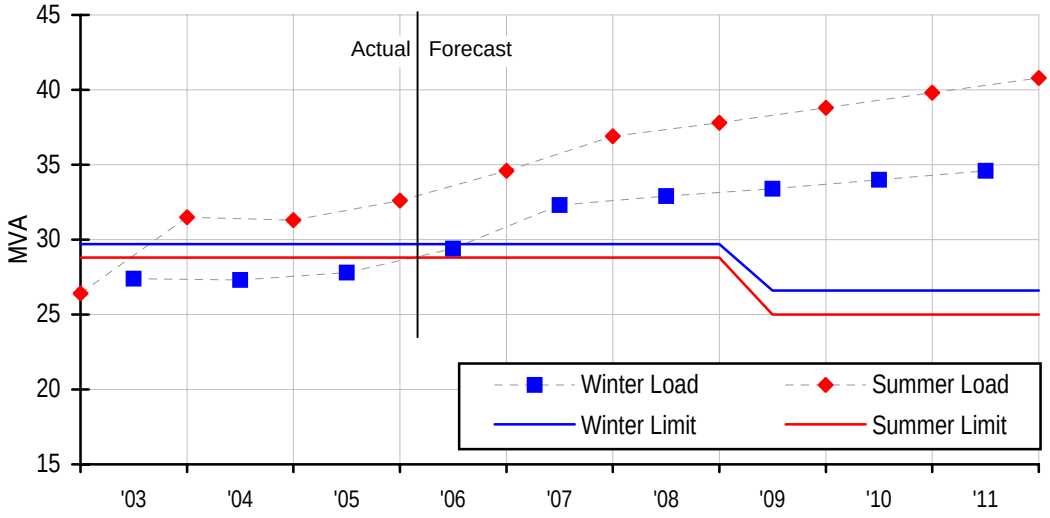
At **Carlton** the rating of the 33/11kV transformers limits acceptable loads to 47.7MVA in both summer and winter. In 2005 the summer & winter peak demands at Carlton were 46.9 & 45.2MVA respectively. We forecast that the acceptable load level will be exceeded by 1.1MVA in summer 2007/2008, 1.5MVA in summer 2008/2009 and 2MVA in summer 2009/2010. Regardless of demand, Carlton must be replaced by 2010 because the equipment is approaching the end of its life, at an estimated cost of $45m.

Chart of actual / expected demand vs supply capacity at Carlton



At **Hurstville Nth** the 33kV feeders limit acceptable loading to 28.8MVA in summer and 29.7MVA in winter. In 2005 the summer & winter peak demands at Hurstville Nth were 31.3 & 27.8MVA respectively.

Chart of actual / expected demand vs supply capacity at Hurstville Nth

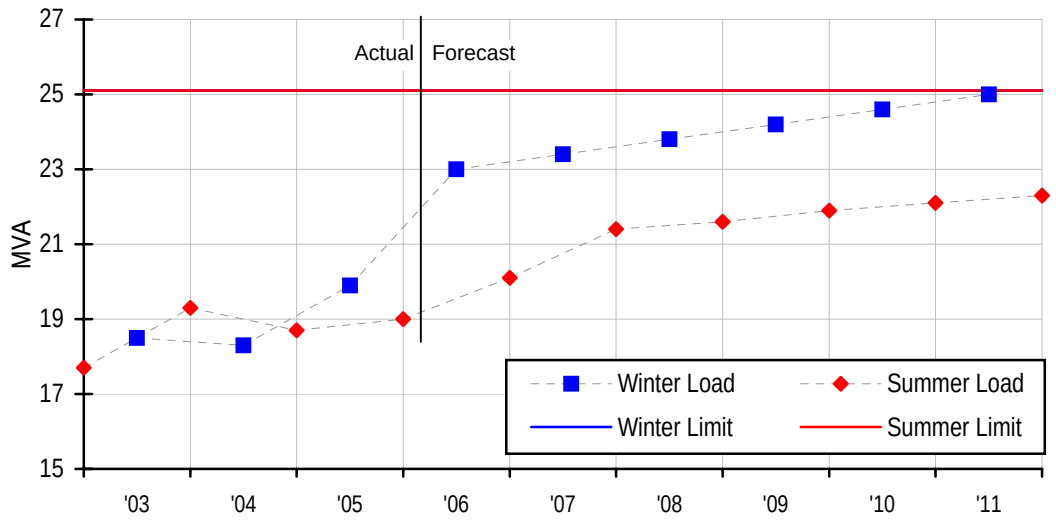


We forecast that the peak demand will be 5.8MVA above the acceptable level in summer 2006/2007 and 2.6MVA above in winter 2007. In compliance with new

licence condition requirements, acceptable loading limits will be reduced after 1 July 2009. Peak demand is forecast to be 6.8MVA above this reduced level in winter 2009, and 13.8MVA above in summer 2009/2010.

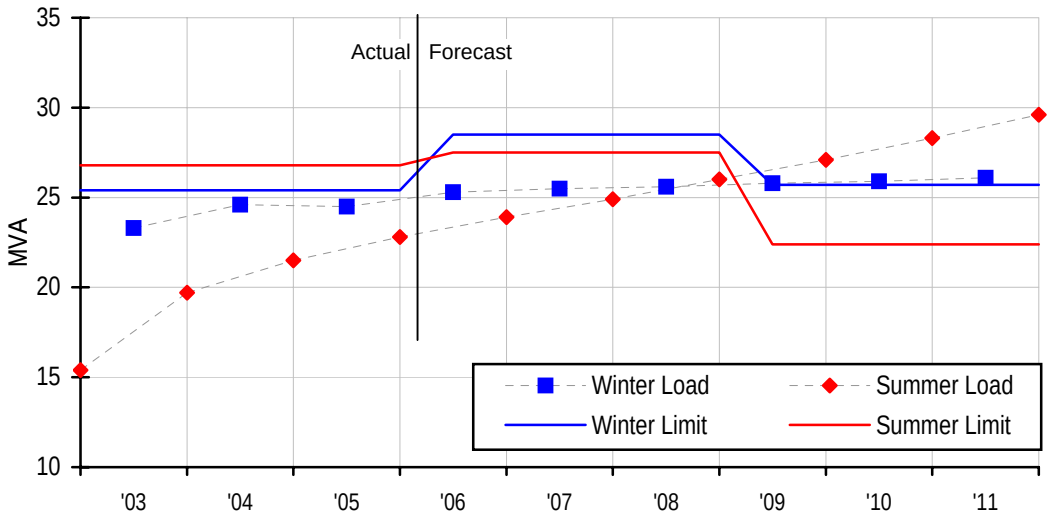
At **Rockdale** it is forecast that capacity will be sufficient to meet demand up to and beyond 2010.

Chart of actual / expected demand vs supply capacity at Rockdale



At **San Souci** the 11kV transformer connections and switchgear limit the acceptable load to 26.8MVA in summer and 25.4MVA in winter. In 2006 the 11kV switchboard, CTs and transformer tails will be replaced, increasing the acceptable load level to 27.5MVA in summer and 28.5MVA in winter. In 2005 the summer & winter peak demand at San Souci was 21.5 & 24.5MVA respectively. In compliance with new licence condition requirements, acceptable feeder limits will be reduced after 1 July 2009. Forecast peak demand will be 0.1MVA above this reduced level in winter 2009, and 4.7MVA above in summer 2009/2010.

Chart of actual / expected demand vs supply capacity at San Souci



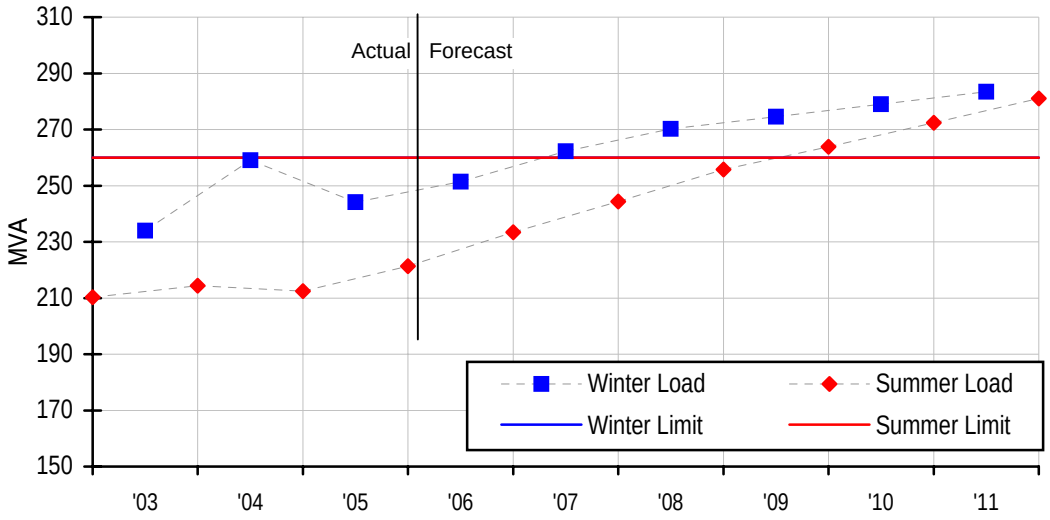
This information is summarised in Table 1 below. It shows the difference between the acceptable loading limit and forecast peak demand for each zone substation in the East St George area, for both summer and winter. In order to avoid or defer the need for a supply side solution, this is the amount by which peak demand would need to be reduced.

Table 1: Demand reduction requirements at zone substations in East St George area (MVA)

Substation	Arncliffe	Blakehurst	Carlton	Hurstville North	Rockdale	Sans Souci	Total
summer 06							0
winter 06		1.1		-	-	-	1.1
summer 07		-		5.8	-	-	5.8
winter 07		1.4		2.6	-	-	4
summer 08	0.1	-	1.1	8.1	-	-	9.3
winter 08	0.3	1.8	-	3.2	-	-	5.3
summer 09	4.4	0.7	1.5	9	-	-	15.6
winter 09	9.2	4.2	-	6.8	-	0.1	20.3
summer 10	10.6	5.3	2	13.8	-	4.7	36.4
winter 10	10	4.6	-	7.4	-	0.2	22.2

At **Peakhurst STS** the 132/33kV transformers limit the acceptable load to 260MVA in summer and winter. In 2005 the summer and winter peak demand at Peakhurst was 212.4 and 244.1MVA respectively. The forecast peak demand will be 2.2MVA above the acceptable level in winter 2007, and 3.9MVA above in summer 2009/2010.

Chart of actual / expected demand vs supply capacity at Peakhurst STS



Supply Strategy Option

The default supply side solution is to install a new 100MVA 132/11kV zone substation at Kogarah at an approximate cost of $61m. This would reduce loading at Blakehurst, Carlton, Rockdale, Hurstville North, Sans Souci zone substations and at Peakhurst STS. The decision needs to be made by early 2006 to enable commissioning by winter 2009.

Required Demand Management Characteristics

In order to defer the Kogarah zone investment by one year from 2009 to 2010, demand reductions totalling 36.4MVA would need to be implemented before summer 2009/2010. The demand management would need to occur at times of day, seasons and in those locations that would result in each zone substation in the East St George area being loaded within limits. At least 20MVA of this would need to be effective during winter peaks as well.

The value of avoided cost due to a one year deferral would be $4.55m, or approximately $125/kVA.

Existing DM Investigations

An investigation into the demand management potential in the St George & Sutherland areas has been carried out in 2004/05 as part of the Demand Management & Planning Project (DM & P), which is an initiative being undertaken by EnergyAustralia, Transgrid and the NSW Department of Planning. The purpose of the investigation was to identify demand reduction potential via the implementation of power factor correction (PFC), standby generation, interruptible load, fuel switching, and energy efficiency. 125 customer sites were investigated with peak demand ranging from 150kVA to 5MVA.

Based on very generous assumptions, the results for the East St George area are summarised in the table below and include:

- all identified opportunities for standby generators where the generator size was sufficient to support the customer's load, interruptibility opportunities assessed as high or moderately likely to proceed and all load shifting.
- all other opportunities where the notional subsidy required to enable projects to proceed is less than $250/kVA (twice the avoided cost identified for this project).

On this basis, the DM&P project identified that the technical potential for demand reduction could be up to 6MVA. Subsequent work from the DM&P project has suggested that this would be difficult to realise, but it represents the upper bound of reasonable expectations for this area.

Table 2: Demand management opportunities identified in Eastern St George (MVA)

Zone Substation	Season	Standby Generator	PFC	Cooling-Refrigeration	Lighting	Fuel Switching	Interr-uptible	Load Shifting	Total (MVA)
Arncliffe	S	-	0.204	0.020	0.047	-	0.030	1.069	1.4
	W	-	0.175	0.025	0.047	-	0.030	1.069	1.3
Blakehurst	S	0.228	0.053	-	-	-	-	-	0.3
	W	0.228	0.043	0.009	-	-	-	-	0.3
Carlton	S	-	0.705	-	0.066	0.189	0.030	-	1.0
	W	-	0.571	0.024	0.066	0.189	0.030	-	0.9
Hurstville Nth	S	0.578	0.912	-	0.057	-	0.060	0.930	2.5
	W	0.578	0.831	0.100	0.057	-	0.040	0.930	2.5
Rockdale	S	-	0.056	0.030	0.170	-	0.084	0.343	0.7
	W	-	0.051	0.018	0.170	-	0.084	0.343	0.7
San Souci	S	-	0.107	0.030	0.035	-	0.020	-	0.2
	W	-	0.077	0.010	0.035	-	0.020	-	0.1
							Region Total (MVA)	Summer	6.1
								Winter	5.8

The size of the DM requirement is large, representing about 25% of the current demand at the substations concerned, and clearly larger than the technical potential identified by the DM&P project. The relative value of avoided costs, at $125/kVA is moderate, and any DM options would need to provide reductions in both summer and winter. Because of the long lead time required for such a large project, a final decision is needed very soon, and the time available for investigation, development and implementation of DM alternatives is short.

Conclusion

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

However, as noted above in Table 1 the long lead time required to develop and execute the supply solution will mean that loading levels in some areas will be above the design levels needed to meet network reliability targets. Some reduction in peak demand in those intervening years would have value in improving network reliability prior to commissioning of the new substation.

We will develop and propose an appropriate valuation methodology to IPART that will enable us to develop and implement some DM measures to improve network performance in the period leading up to the commissioning of the new zone substation.