# Demand Management Investigation Report

## Sydney Inner Metropolitan Area

## November 2009

## Disclaimer

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### Summary

This report describes investigations undertaken during 2007 and 2008 into the Demand Management (DM) requirements and opportunities in the Sydney Inner Metropolitan Area.

The investigations found that there appear to be sufficient cost-effective options likely to be achievable to form a combined demand management and network strategy to achieve the objectives of the Inner Metropolitan Strategy.

Since that work was completed, a number of factors have led to some changes in the expected DM requirements. Nevertheless, the conclusions of this report remain valid. The balance of this report considers the DM requirements as they were when the study was undertaken.


### Issue

Projections of electricity demand in the Sydney Inner Metropolitan Area indicate that there will be a need for additional bulk supply in summer 2012/13. The currently proposed network solution is the augmentation of the TransGrid 330kV supply to the Sydney Inner Metropolitan Area. A demand management investigation has been undertaken to identify and review the potential options for reducing demand in the target area as a means of optimising the timing of the additional supply.

### Demand Management Requirements

A public consultation paper was published in June 2007. It identified the region supplied by the system of interest and estimated that a reduction of demand of approximately 75MVA would be required to continue to meet the applicable reliability criteria in summer 2012/13. The background to this need is more fully described in that document "Demand Management Options Consultation - Sydney Inner Metropolitan Area", which is available on EnergyAustralia's website at www.energy.com.au/dm.

Since the publication of the consultation paper, several changes have occurred which impact the demand management requirements. These include changes to the size and distribution of electricity demand forecast for 2012/13 and 2013/14 and changes to the expected cost of the proposed supply side project.

On this revised basis, detailed load flow analysis of the system indicated that a reduction in peak demand of 49MVA would be sufficient to meet the reliability criteria during summer 2012/13. Because of the nature of load flows in such an interconnected system, the actual amount varies depending on the location of the reductions, pattern of electricity generation and several other factors.

The forecast demand grows by about 100MVA each year thereafter. In addition, other projects will result in changes in the network configuration. As a result, a greater demand reduction would be required to ensure the reliability criteria are met in summer 2013/14.

The peak demand in this area typically occurs on hot summer weekdays between about 12 noon and 6pm. Historically, high demands in the Energy Australia area supplied from Sydney North, Sydney South, Beaconsfield West and Haymarket 330/132kV Substations have only been reached infrequently and for short periods [1] :

| Year | Top 50 MW | Top 100 MW |
|---|---|---|
| 2005/06 | 1 days, 4 hrs total | 2 days, 7 hrs total |
| 2006/07 | 1 days, 0.5 hrs total | 2 days, 3 hrs total |
| 2007/08 | 1 days, 2.5 hrs total | 2 days, 9 hrs total |
| 2008/09 | 4 days, 8.5hrs total | 6 days, 21.5 hrs total |

The expected cost of the project to augment 330kV supply to the Sydney Inner Metropolitan Area has also increased, and is currently estimated to cost around $400 million. These changes in requirements have been taken into account in formulating the following investigation findings.

## Demand Management Investigation

### General Approach

The overall investigation approach was to identify a broad range of potentially cost-effective DM options, analyse each of the options and their potential impact, practicality and cost, then shortlist the ones that might form a part of a feasible portfolio of projects.

To ensure the consideration of the widest range of options, we undertook a public consultation process, reviewed previous and planned projects by both TransGrid and EnergyAustralia, conducted internal brainstorming sessions and commissioned a consultant review of the data developed by the Demand Management and Planning (DM&P) project.

For each option, we identified both technical demand reduction measures and potential implementation options and then analysed each opportunity to determine the likely effect on the Inner Metropolitan peak demand and the overall cost to TransGrid / EnergyAustralia.

Based on these estimates, we developed potentially successful combinations of projects and identified the most promising feasible options for development.

### Public Consultation

The public consultation was initiated by the publication of a “Demand Management Options Consultation Paper” in June 2007. We received 23 formal responses and six less formal registrations of interest. We also engaged in a large number of discussions to gather additional detail and information about the options suggested.

Each suggestion received is dealt with in the report below, and is summarised in the Appendix.

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[1] As the past three summers have been mild, maximum demands have been moderate. In these circumstances, demands often approach the seasonal maximum more frequently than would otherwise be the case.

### Demand Management and Planning Project Review

CRA International were engaged to undertake an independent review of the information developed under the DM&P project as it stood at the time and to relate it to the geography and demand reduction characteristics of the Inner Metro project. The CRA report was finalised in November 2007 and will be published in company with this report.

It found that the DM&P data suggested that significant, practical and potentially cost effective options existed to achieve effective demand reductions of up to 118MVA at a cost of $14m, or 167MVA at a cost of $26m. In each case the dominant option is the use of existing diesel standby generators – comprising 50MVA of the total. Other significant contributions were from power factor correction, load shifting, and commercial energy efficiency.

In some cases, the DM&P data did not provide the necessary information to make a full analysis. In particular there was very little data on the likely acceptance or uptake rates by customers and the data did not enable a proper evaluation of the impact on the Inner Metro system from power factor correction. These issues have been taken more fully into account in the subsequent investigation and analysis.

Since the CRA report was completed, the Demand Management and Planning Project has been completed and additional information has been able to be included in the considerations for this investigation.

## Demand Management Options and Analysis

### Customer Power Factor Correction

Power factor is a fundamental characteristic of electrical loads. It is the ratio of real power consumed (kW) to apparent power (kVA) and ranges from zero to one. Poor power factor means that larger capacity supplies are required to produce the same amount of work. Poor power factor can be corrected using equipment connected at customers' switchboards. The same strategy is commonly used within networks, for example at zone substations. Improving the power factor of customers' loads can lead to a reduction in the requirements of the supply system depending on how it interacts with other elements. The impact on the network is not simply the sum of the impacts at customer level. The NSW Supply and Installation Rules require that customers maintain the power factor at their point of connection to the network at better than 0.9. Many customers' installations do not meet this level.

In the case of the Inner Metro supply area, there is a large quantity of correction within the network system itself, particularly in the CBD zone substations and at various points in the subtransmission network. Modelling of the network has shown that there are some benefits to customer power factor correction in most locations except the Sydney CBD.

CRA's review of the DM&P data suggested that 41.6MVA of demand reduction would be available from customer power factor correction (excluding the CBD). However, this estimate is based on the effect measured at the customer connection point, not on the network as a whole (network modelling was outside their scope). Further, the DM&P data did not contain the necessary information for CRA to estimate the amount of correction (in MVAr) that would be involved so even an approximation of the network impact would have been difficult.

Three respondents to the consultation process suggested power factor correction would be viable means of reducing peak demand. One response included a proposal to achieve at least 10MVA of reduction (as measured at customer connections) at a cost of $1.33m. Another suggested an auditbased program with power factor correction as a part, while the third included power factor correction as one element of a site-specific retrofit program that would achieve about 2MVA of site demand reduction at a cost of $2.8m.

We have re-analysed recent billing data for all large customers in the inner metro region and estimated the reasonable technical potential for improvement of customer power factor to be 232MVAr. This assumes that standard sized correction units are installed at all those customers outside the Sydney CBD with power factor below 0.9 – a total of almost 2000 installations.

Because customers' load patterns do not correspond perfectly with the system peak loads, not all of this will be available at the time of peak load on the system. We estimated a diversity factor of 80%, leaving an upper potential effective 185MVAr of correction at time of system peak. CRA estimated a coincident diversity factor of 75%, as did SKM in their original study for the DM&P Project.

EnergyAustralia has undertaken several customer power factor correction programs in locations where network demand management opportunities existed. The approach included the establishment of bulk contracts for the supply and installation of suitable equipment, and an approach to customers offering facilitation and discounted prices for equipment to be installed. Prices ensured that paybacks to customers were less than 2 years.

Using this method, EnergyAustralia's experience suggests that participation rates of up to 70% can be achieved – leading to a reasonably expected potential of 130MVAr. EnergyAustralia's modelling suggests that this level of correction, distributed according to the location of the customers where opportunities exist, would be equivalent to a distributed reduction in system peak demand of approximately 23MVA. Based on EnergyAustralia's experience with several smaller customer power factor correction programs, implementation costs for such a program are estimated at $2m.

Experience with earlier programs suggests that there is some natural degradation in PFC effect over time, but that it would be limited to no more than 5% per year. In the context of this program, that would not be a significant impact.

Note that 2009/10 capacity charges in relevant EnergyAustralia network tariffs have been significantly reduced, reducing the payback achieved through implementation of PFC. Additional subsidies may be required in order to make PFC more attractive to customers if these rates persist.

### Load Curtailment, Standby Generation and Load Shifting

*Load Curtailment* is the temporary reduction of a customer's load in response to a request. This might be achieved through stopping or reducing production or a process, shutting down non-essential activities or by supplying some or all of their load from an alternative source. Where the entire load was temporarily removed, this could be called an interruptible load.

*Standby Generators* are a special case of Load Curtailment. Small generators, usually diesel fuelled, are located at sites to provide backup power in the event of a network interruption. In some cases, these can be used in response to a call to remove some or all of a site's load from the network. In rare cases, these generators can also supply surplus power back into the grid to offset other customers' loads.

*Load Shifting* is a further variation where the load curtailed during the 'call' period is made up at a later time. This is achieved by 'shifting' the timing of activities so they fall outside of the peak periods. This might include starting a shift early so that the work ends before the peak period starts or changing the order of work so the energy intensive activities occur outside the 'call' period.

These measures are dealt with together as they share the common element of being a temporary change in load in response to a call that would be issued at a time when network peak demand was expected to occur. Such approaches could be helpful in the case of the inner metro network since the occurrences of peak demand are infrequent and of relatively short duration. In addition, because the network is designed to a standard that allows the peak load to be supplied even after two major failures, it would not be necessary to call such load reductions unless a first contingency outage had occurred. This further reduces the likelihood of a call being required.

The DM&P Project carried out a trial of enrolling and dispatching demand reductions and standby generation. It achieved approximately 15MVA of peak load reduction from seven sites at a cost of $44,025. The project report stated that this remarkably low cost was due to the project being characterised as a test, and would be unlikely to be repeated in a commercial program.

By contrast, another demonstration project under the DM&P project that sought to demonstrate dispatchable load reduction measures in a particular geographic location failed to demonstrate any achievable reductions at all.

Under the DM&P Project, several feasibility studies and analysis reports related to standby generation as a demand management measure were prepared. These include:

- Three feasibility studies by E-Connect of specific standby generator projects identifying options and costs of making effective use of them for demand management;
- A report by SKM on the options for use of standby generators that can supply only part of the host building load;
- a study by Holmes Air Sciences of the likely air quality impacts of the simultaneous use of 115 standby generators in the Sydney CBD totalling 40MW;
- A summary report by SKM covering all of the information assembled by the DM&P project on standby generator use.

This summary report considered the results of all the DM&P reports and concluded that the most appropriate means of achieving effective demand reductions would be by converting existing installations to SCTT (synchronise-close-transfer-trip) operation. They considered it might be possible to achieve a demand reduction in the Inner Metro area of up to 86MVA at a cost of $28.6m by this means ($330/kVA). This cost excluded any costs associated with dealing with air quality concerns.

The CRA report identified this segment as the largest contributor to all their scenarios, primarily because of the assumption that a very high proportion of existing standby generators would be willing to dispatch at low cost. The DM&P Project found some significant concerns regarding air quality from such a strategy if applied in the Sydney CBD that would result in substantially higher costs for those sites or possibly their prohibition. On this basis, CBD based generators were excluded from the practical scenarios in the CRA analysis. Based on customers stated willingness to consider participating in a network support program, CRA found the DM&P data suggested that 50MVA of demand reduction might be economically possible from the use of standby generators. They also identified 12MVA of dispatchable load curtailment or shifting opportunities that might form part of a cost effective strategy.

Ten respondents to the consultation suggested the use of some form of dispatchable load reduction. Three of these focussed on residential customers and these are discussed separately below. Two respondents each suggested that aggregation of opportunities in the inner metro area could provide over 100MVA of dispatchable load reduction or standby generation. The remaining submissions were from end user sites that had been identified in the DM&P data and confirmed their willingness to participate. Submissions from these parties were for up to 30MVA of generation capacity. Some respondents provided prices but requested confidentiality.

EnergyAustralia has executed two standby generator based demand management projects. These provided small amounts of demand reduction (0.8MVA and 0.4MVA) from individual sites. Costs for these were approximately $140/kVA and $170/kVA plus $340-$450/MVA per hour of dispatch.

Recent experience in negotiating network support contracts for dispatchable demand reductions from existing facilities has yielded prices ranging from $50 to $350 per kVA for a single season, plus $2000-$5000/MVA per hour of dispatch. This suggests a reasonably wide range of prices might apply to different opportunities.

TransGrid also secured 100MVA of dispatchable load reduction and small standby generation for summer 2008/09 as part of their portfolio of DM strategies for the 500kV upgrade project. Some of this portfolio is located in the inner metro area.

There are concerns about the viability of a significant proportion of the existing standby generation fleet. These include concerns about urban air quality impacts (noted above - especially in the CBD), technical suitability and reliability of some of the existing plant and willingness of owners to participate. We have assumed for this analysis that customers are unlikely to be willing to accept interruptions to their supply in order to provide network support. This means that normal standby generators would need to have synchronising equipment (SCTT) fitted at extra cost, making only the largest of these cost competitive. Reflecting the potential air quality concerns, we have limited the participation of standby generation in this analysis to 15MVA in the Sydney CBD.

Based on EnergyAustralia's experience and the information from its investigations, it is evident that there are a large range of possible costs for such projects. EnergyAustralia believes that the best way to allow for price discovery and to select the most cost competitive providers is an open market acquisition process. EnergyAustralia therefore expects that proposals for provision of this measure will be obtained using a Request for Proposal (RFP) process.

A detailed cost model has been developed based on the CRA modelling of the DM&P data. This cost model has been used to assess the likely contribution of this segment to various scenarios. Taking all these factors into account, allowing for a small amount of load curtailment and a project management and facilitation overhead of 10%, we have estimated that it should be possible to achieve a reduction of up to 50MVA at a cost of about $12m.

### Conventional Residential Load Control (Off Peak Hot Water)

EnergyAustralia offers off peak tariffs for hard wired loads where supply is only available outside peak times under two basic arrangements. Off Peak 1 tariff supply is only available overnight. Off Peak 2 tariff supply is usually available most of the day except during the evening peak period. Since the period of the peak demand in the inner metro area is between midday and 6:00pm, supply would be available to Off Peak 2 customers during most of this period.

The control system for the majority of customers on controlled load tariffs is via a centrally controlled signalling system, so it may be possible to adjust switching times on critical peak days in the event of a first contingency outage. This would be satisfactory under the terms of the tariff, which provides for supply to be 'usually available for sixteen hours including more than 6 hours between 8pm and 7am and more than 4 hours between 7am and 5pm'.

Within the inner metro area there are approximately 42,000 customers connected to off peak 2 supply. In the vast majority of cases, this supply is used for water heating. A proportion of these customers are connected via local time-switches rather than by remote control devices, there are some sites where the load has been removed and there are potentially some sites where the control relays have failed and are no longer switching off. Allowing for these, we estimate that 85% of available sites would be effective in reducing demand.

Based on diversified load profiles for water heaters on Off Peak 2, EnergyAustralia estimates that between midday and 6:00 pm, these appliances contribute about 200W each to the peak demand. This suggests the availability of a demand reduction of approximately 7MVA.

The preferred approach to accessing this demand reduction is for EnergyAustralia to use a revised switching schedule on critical days. The cost to implement this change would be minimal – limited only to the cost of developing and establishing the appropriate control structures, programming the controllers and providing the necessary customer support arrangements. For the purposes of this analysis the cost of this approach was estimated to be less than $20,000.

### Temporary Network Support Embedded Generation

EnergyAustralia has used temporary network support generation facilities on four previous occasions and is currently developing several projects. These consist of modular diesel fuelled generators that can be located at any suitable site within the network to reduce the demand on the relevant 11kV feeders and zone substations. Central control enables them to be operated for short periods when required.

The generators are usually deployed in installations of up to 5MVA. Within the inner metro area there are many locations where suitable sites could be found that would enable effective, dispatchable demand reductions. The amount of generation that could be deployed in this way is essentially unlimited, but for the purposes of this analysis, we have proposed a reasonable upper limit of 100MVA, or 20 installations.

One respondent to the public consultation offered bio-diesel fuelled embedded generation. They suggested they could provide 10 – 20 MVA of peak reduction capacity. Confidentiality was requested with respect to costs.

Based on previous experience and prices for leased generators established at tender, we estimate the cost of providing each 5MVA module to be $1.25m for a one season deployment, or $2.5m to cover two successive summers. Running costs are approximately $2,000 per hour of run time – covering both fuel and marginal maintenance costs.

Temporary network support generators have previously been procured by EnergyAustralia under period supply contracts established through competitive tender. Using this method, EnergyAustralia has identified, investigated and procured suitable generator sites. Other tasks, such as earthing design and construction, electrical connections, and fencing have also been procured by EnergyAustralia.

### Network Support from Existing Embedded Generators

There are several power generation facilities embedded in the EnergyAustralia network within the inner metro area. Although these may operate during peak periods, their operating characteristics, future plans and business drivers are unknown and there are no contractual relationships between the operators and the network relating to these factors. Because of this, when network capacity requirements are planned, it is assumed that they are at liberty to choose not to generate during peak periods.

It may be possible to establish network support agreements with such embedded generators that would ensure that, as far as practicable, their generation was at full output at times when the network might reach peak demand. This could include modifications to operating practices, controls and maintenance scheduling. It may require non-optimal dispatch of the generator or some technical upgrades to improve resilience and reliability of the generator at key times.

This opportunity is limited to significant generators whose performance is explicitly considered in network planning. Smaller generators are implicitly included through the forecasting process at the level of generation they exhibited on past peak days – effectively assuming their performance will replicate past experience. New generators that were not envisaged at the time of the forecast could also be considered as representing legitimate incremental reductions of demand provided their performance could be expected to be adequately reliable and suitable contracts agreed.

We have identified a potential 25MVA of embedded generation located in relevant areas that would provide an effective demand reduction on the transmission system supplying the inner metro area.

In order to be part of a demand management solution, embedded generators would need to satisfy the necessary reliability expectations for network support. Only those that were not included in the base forecasts this project is based on would be eligible. For the purpose of this analysis, we have estimated the likely average cost of negotiating suitable agreements at $60,000 per MVA. Procurement is expected to be via use of an RFP.

### Cogeneration in Commercial Buildings

Cogeneration is the production of more than one form of energy from a single process. In this context, it is usually the production of electricity from a combustion engine and the effective use of the waste heat. An opportunity that has received much attention recently is the use of natural gas fired engines (or small gas turbines) coupled to waste heat boilers and absorption chillers to produce chilled water for air conditioning in commercial buildings. Typically, these are dedicated to a single building, but proposals for supplying groups of buildings are appearing recently.

Several forces are at play making this type of investment more attractive than it has been in the past. These include changes in price relativity between electricity and natural gas, expected increases in electricity costs due to greenhouse abatement measures, the desire for building owners to achieve high green building ratings, the emergence of capable commercial intermediaries, and the improvement in availability and cost of equipment.

Where cogeneration facilities can be relied upon to operate reliably during periods of high network demand they can provide an effective reduction. Multiple small units are preferable to small numbers of large facilities, because a probabilistic approach can be taken to the likely availability of a certain amount of the support at any time. With large units, the consequences of an unplanned outage of a single facility can be significant.

Commercial building loads drive the peak demand of the Inner Metro area. These are strongly affected by cooling loads. Commercial cogeneration facilities that both removed the cooling load (by using waste heat fired absorption chilling) and generated local electricity would be very effective in reducing demand at the necessary times.

In their Sydney 2030 vision, the City of Sydney has proposed a precinct based approach using multiple installations to serve a chilled water distribution network while generating electricity locally for distribution to buildings in the City. Under this vision, intervention would begin in 2010 with a target of achieving 25MW of generation by 2015.

The DM&P project commissioned a report from the Institute of Sustainable Futures that suggested a technical potential of 70MVA for cogeneration in Sydney that would cost about $1350/kVA to realise. Of this total, 24MVA was in non-industrial locations. Perhaps because its focus was on currently available opportunities, the DM&P investigators identified few commercial cogeneration opportunities.

Similarly, the CRA report identified a technical potential for reductions from "embedded generation" of 37MVA that included cogeneration, but at very high cost. This category provided a negligible contribution to all of CRA's commercial scenarios.

However, the DM&P project did subsidise two commercial cogeneration projects, which have subsequently been installed, and two residential cogeneration projects. In one case, the project is now operating successfully and some of the commercial information has been made available. The demand reduction impact of the project is estimated at about 2.7MVA and the subsidy provided by the DM&P project was $400,000 or $150/kVA.

In response to the public consultation process, we received several submissions on cogeneration and have continued discussions with several of these respondents to clarify the potential opportunities. Submissions suggested potentials ranging from multiple projects totalling 150MW to single projects of less than 1MW.

One respondent suggested they might be able to achieve 14MW of commercial cogeneration at a support cost of $300/kVA. Another suggested a potential for up to 23MVA with support of $4.1m, or $180/kVA. Analysis of other proposals EnergyAustralia is aware of suggests a wide range of subsidy costs ranging from $180 to $1000 per kVA.

Other responses and discussions have suggested that there are significant opportunities arising in this area due to a range of pressures. It is also evident that there are some uncertainties and potential barriers to the wider deployment of commercial cogeneration beyond financial issues.

The development timeframes for this type of project are relatively long and involve bringing together a number of parties to secure a project. For this reason, we believe that a program approach would be the most likely to encourage new commercial cogeneration at reasonable cost, and the commercial building sector offers a consistent and repeatable approach that could constitute a significant opportunity with relatively consistent cost structures.

Such a program would target cogeneration installations in commercial buildings of between 300kW and 5MW. While the details of such a program would be discussed further with industry, it was proposed to be a facilitated program which was open to applications on a first-come-first-served basis for an extended period leading up to the requirement date.

Based on the information EnergyAustralia has received, discussion with proponents and EnergyAustralia's own exploration of this opportunity, we believe it is reasonable to expect development of new cogeneration opportunities in commercial buildings could feasibly lead to reductions of up to 30MVA at a cost of $6,000,000.

### Large Industrial Cogeneration

Two large industrial cogeneration opportunities have been identified in the target area. Where industrial users require large quantities of process heat, cogeneration is an alternative to separate generation of steam (usually in gas or coal fired boilers) and electricity drawn from the grid. Because the heat would otherwise be generated from gas or coal, there is no additional offset of electrical demand like there is from displacement of cooling demand in commercial buildings.

If such a project were able to provide sufficient confidence of reliable operation during the key peak demand periods on the network, it would be an effective method of reducing demand on the network.

The two opportunities were identified by the DM&P project, and by respondents to the public consultation process. This has enabled us to assess the nature and indicative support cost of the projects. The expected demand reductions and indicative support costs are tabulated below. Note that some options are mutually exclusive.

| Demand Reduction | Support Cost | $/kVA |
|---|---|---|
| 25MVA | $11m | $440 |
| 58MVA | $19m | $330 |
| 134MVA | Confidential | |

As noted above, there is a higher risk with very large projects being part of a demand reduction portfolio as the consequences of one project being unavailable can severely compromise the overall portfolio. Providing sufficient alternative reductions to back up such a large single element may be uneconomic. Further, since these are very significant projects involving several players, there would be substantial implementation and timing risks to be overcome.

Procurement of large industrial cogeneration schemes could be via direct negotiation with proponents, or via an RFP type process. Continuing discussions with the proponents would be required to identify the necessary milestones and provide the necessary confidence that the projects will be available when needed, and to understand the actual level of support required.

### Commercial Building Energy Efficiency

Improving energy efficiency or managing energy use so that it occurs outside peak periods can provide reductions in peak demand. Commercial building loads are a significant contributor to the Inner Metro region load, and improvements in the dominant areas of lighting and air conditioning provide a relatively repeatable opportunity.

Reductions in lighting loads resulting from changes to more efficient equipment provide reliable reductions in peak demands. In contrast, many efficiency improvements in air conditioning or building controls provide reductions in overall energy use, but do not reduce demands significantly on peak days. Thermal storage can provide an opportunity to reduce peak demand by shifting load from peak to off peak periods. However, experience has shown that often this is less effective on peak days as the storage volume is normally sized for average rather than extreme weather conditions.

CRA found that some of the commercial building energy efficiency opportunities identified in the DM&P project data would be expected to form part of a cost effective portfolio. While the technical potential of this area was found to be high, much of this was at high cost. On the other hand, some 14MVA of the opportunities identified were said to be commercially viable without financial support. CRA assumed that these projects, if not implemented previously, would require some support to encourage customer acceptance. Including these “free” opportunities, CRA found that the DM&P data suggested a potential for a coincident reduction of 15MVA at a cost of $1.8m, or 21MVA for $3.3m.

The DM&P project also undertook demonstration projects in innovative HVAC (heating, ventilation and air conditioning) and lighting; commissioned validation reviews for efficiency opportunities identified in the site studies; and completed a customer survey to gauge responses to the site reports and willingness to implement projects. They found that it was frequently difficult to convince building owners to invest even in opportunities with reasonable paybacks and that substantial facilitation was usually required to bring these opportunities to fruition in addition to financial support.

A review of a selection of the DM&P site studies, which form the basis of the DM&P data, was undertaken by SKM. It found that the ‘level 1’ site studies overestimated the demand reductions available from energy efficiency projects by an average of almost 50% and underestimated costs by an average of 30%.

A survey by the Institute of Sustainable Futures found that the majority (89%) of those who responded to the survey had implemented at least some of the most cost-effective opportunities identified by the DM&P. The response level was only 22%, so these results may be representative of those most interested in the area. Findings from many studies have also identified implementation barriers relating to split incentives and tenant – landlord issues as common in commercial buildings.

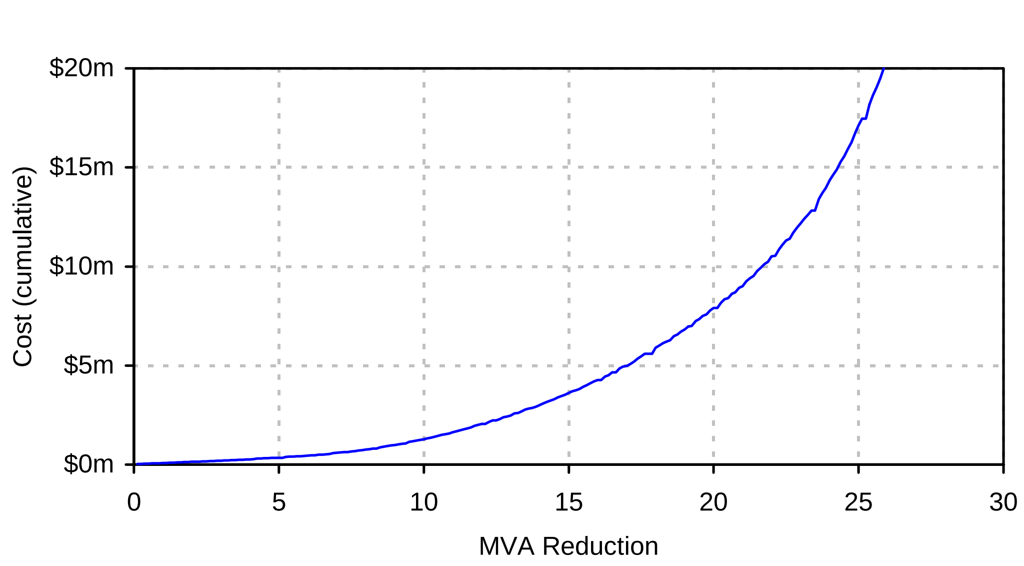
The DM&P project identified thermal storage as the most cost effective innovative HVAC approach and found that small reductions appeared possible, at costs ranging from $240 to $400 per kVA.

Several respondents to the public consultation suggested initiatives in the area of energy efficiency. Some reflected opportunities already identified by the DM&P project. One suggested a commercial lighting project might offer up to 16MVA of demand reduction. Another suggested a program involving audits and follow-up with implementation assistance and suggested that 3MVA might be achieved. Both submissions requested confidentiality with respect to pricing.

EnergyAustralia previously carried out a commercial building energy efficiency project at Brookvale / Dee Why area, using a standard offer approach at $200/kVA. The project generated firm offers for over 1200kVA of demand reductions. However, only 252kVA was actually delivered and the overall project cost was about $115,000 or $450/kVA. The main successful contributions came from lighting upgrades. Several projects that were proposed and accepted for funding did not proceed, including most of the air conditioning related projects. Project management and facilitation costs comprised half the total cost due to the low success rate of the proponents in completing successful demand reductions.

In 2002, EnergyAustralia upgraded the lighting in six floors of a building it occupied in the Sydney CBD. The project achieved a reduction of 78kW (a 35% reduction) with an overall project payback of 3.2 years. Some building occupiers may be willing to accept such a return, however many have indicated they would not. Reducing this payback to 3 years would have required a subsidy of $160/kVA, while reducing it to 2 years would have cost $866/kVA.

EnergyAustralia has re-analysed the data from the DM&P project assuming an average 50% acceptance rate of opportunities would represent the market potential of a DM program in this area and assuming half of the most cost-effective would have already been undertaken independently. Because facilitation appears to be critical in achieving success in this area, an effective implementation method is thought to be some form of standing offer, open for a period of time and involving a level of project support and facilitation. Incorporating a cost for both financial and project support in the model, and added a 10% project overhead for overall project management and marketing, gives the results shown in the chart below. This suggests that some of the lower cost commercial building energy efficiency opportunities would be sufficiently cost effective to form part of a portfolio of effective DM measures.



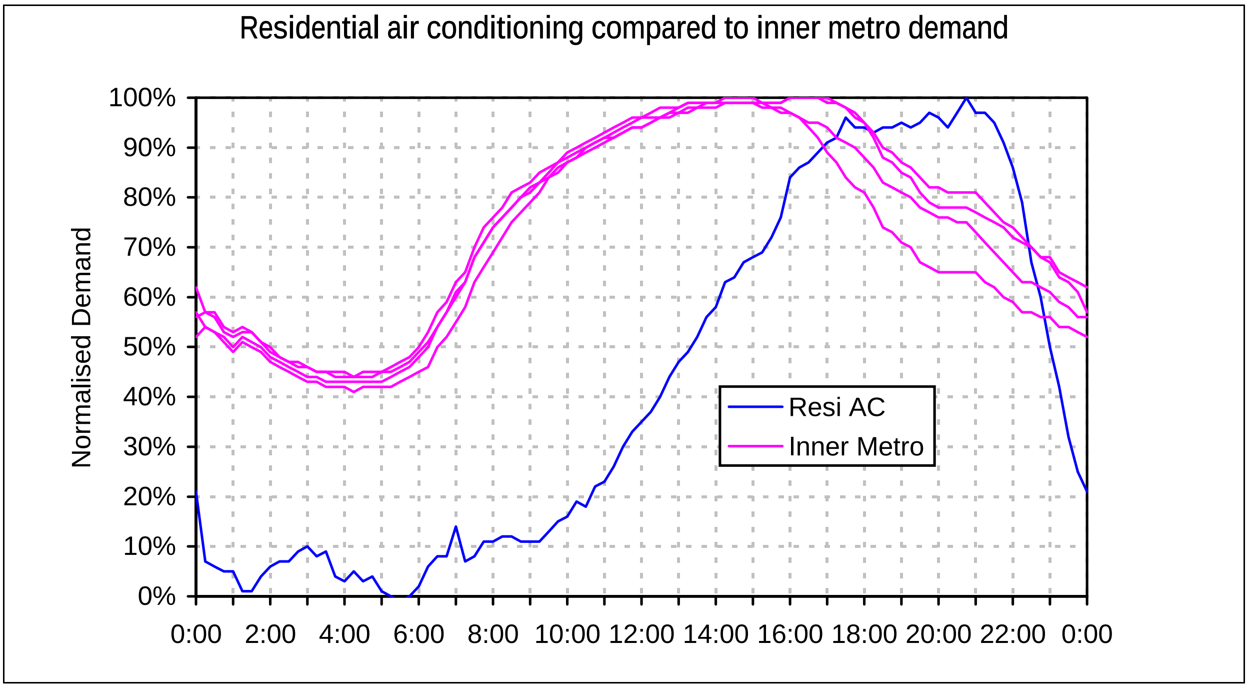

## New Residential Load Control

Control of residential water heating load has been practiced in NSW for many years as an effective means of reducing peak demands. Recently, various approaches to controlling other loads have been proposed that respond to the growing need in some areas to deal with summer load peaks. The main targets have been air conditioning and pool pumps because these represent significantly sized loads that are commonly used during peak summer periods.

For air conditioning, the approach has usually been to cycle the units on and off for relatively short periods. Where the units would have otherwise been running at full capacity, this can lead to a reduction in demand. For pool pumps, the approach is to prevent their operation during peak times, usually by controlling the supply to the pump.

Residential air conditioner cycling has been successfully used in the USA, although circumstances in the USA are somewhat different to those in Australia. Recent trials have been undertaken in Australia in Adelaide, Brisbane, Perth and western Sydney at various sizes and levels of maturity. The trials have generally shown that it is possible to reduce the air conditioner demand without unduly affecting customers' comfort levels. However, the trials have not extended to determining the cost of a large rollout program.

The inner metro load profile shows a peak that is substantially flat from 12 noon to 6:00pm on working weekdays. Network load profiles from residential areas show loads on hot days rising throughout the day and peaking in the evening. On similar, but cooler, days the profile is different primarily because air conditioning is not in use. The difference between the two profiles is a good representation of the diversified residential air conditioning load. This is compared to inner metro load profiles on peak days in the chart below.




This shows that the overlap between these profiles is imperfect. A reduction in the residential air conditioning profile that reduced its peak by 10MVA would result in a reduction of between 5.5 and 6.4MVA in the inner metro peak.

Much of the inner metro region is coastal and enjoys a relatively milder climate, resulting in lower levels of air conditioning ownership than in areas where trials of air conditioner trials have been undertaken. We estimate there are approximately 318,000 residential air conditioners in the inner metro region (based on ABS data). Trials in Australia have shown participation rates of around 10% limited by a combination of suitability and willingness. Reductions from cycling have been demonstrated of the order of 0.5kW per participating unit. There is some risk that participation rates in a full rollout would be lower than in trials. In addition, the trials targeted larger, typically ducted systems, meaning average reductions across a large rollout might be lower than 0.5kW. This suggests an upper bound of expectation from a residential air conditioner program of about 15MVA, resulting in between 7.7 and 9.6MVA of effective impact on the inner metro region.

One respondent to the public consultation suggested a program using remote control devices to cycle residential air conditioners. They estimated a program involving 102,000 participants might reduce peak demand by 153MW at a confidential price.

Another respondent suggested control of air conditioners as a component of a wider ranging program, but could provide only general observations about possible savings and costs.

Estimates based on reports from field trials undertaken by Energex in 2007/08 suggest a program cost of $1500 per participant, using currently available technologies. Based on the available information, we estimate a residential air conditioning cycling program addressing all 780,000 customers in the inner metro area would cost about $22m and yield an effective reduction in inner metro demand of 9.6MVA.

Pool pumps are typically operated using simple time switches to control operation. Research suggests many are used more often and for longer than necessary. There have been some historical attempts to use conventional load control (off peak tariff) techniques with pool pumps, with limited success.

EnergyAustralia conducted a trial of changing pool pump usage as part of a program assisting customers to save under time-of-use pricing. Data from this program suggests the average diversified demand of a pool pump over the inner metro peak period of 12 noon to 6:00pm is 0.32kW. Based on data collected by Sydney Water, there are about 35,000 pools in the inner metro area. This would imply a contribution of 11MVA to the inner metro peak.

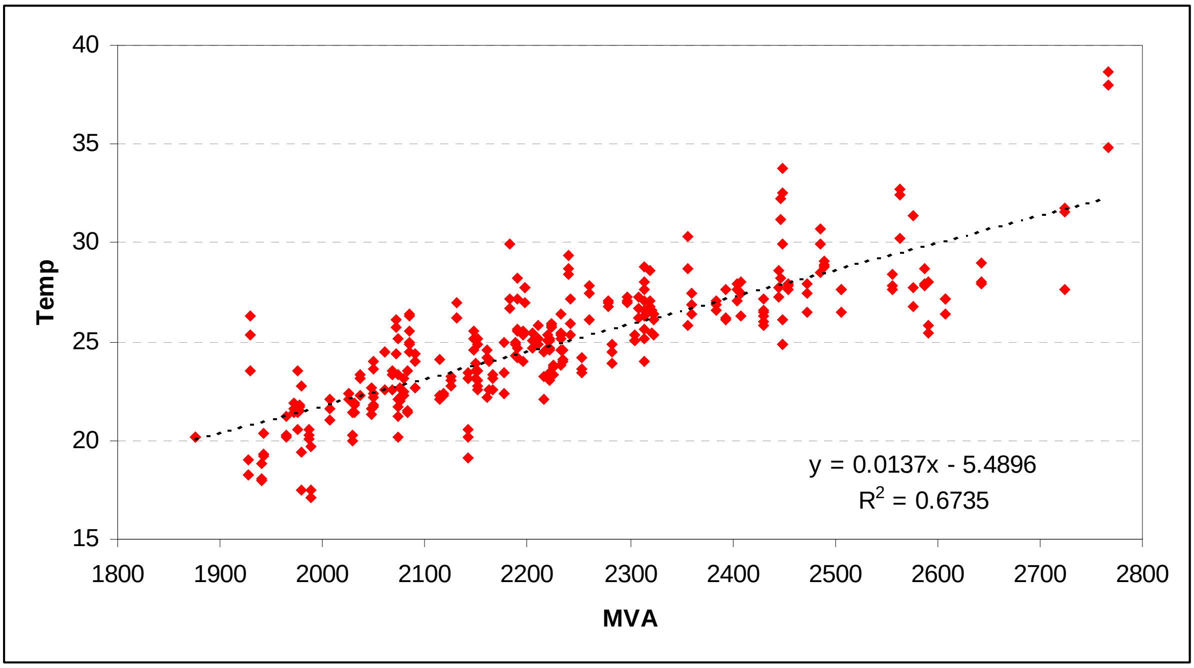
There is a range of issues that affect pool pump controls, including interactions with chlorination and cleaning functions, and restrictions on after hours use due to noise concerns.

One respondent to the public consultation suggested a system of controlling pool pumps using temperature sensors, which would inhibit operation whenever temperature exceeded a predetermined trigger level. They estimated the cost of the control devices, installation and incentives at a confidential cost. They assumed an average pool pump load of 2kW and a population of 180,000 pools in Sydney.

Another respondent suggested control of pool pumps as a component of a wider ranging program, suggesting a population of 40,000 pools and an average pool pump load of 1kW but did not provide any clear view of costs.

An analysis of the correlation of temperature with demand in the inner metro area showed that while there is a clear relationship between temperature and load, the correlation was certainly not a good enough proxy to form the basis of an effective control strategy.

The chart below shows the correlation between air temperature and inner metro load at 12:00, 14:00 and 15:30 during the 2005/06 summer. Weekends and public holidays have been removed as the much lower loads on these days results in an even less accurate correlation. It shows that, to avoid even the highest few load points, the trigger temperature would need to be at 27 degrees. This would result in the pool pumps being disconnected very frequently and often at inappropriate times.




A pool pump control strategy might form a reasonable adjunct to a residential air conditioner cycling program at marginal cost. Assuming a similar (10%) take up rate, this would add about 1MVA reduction with limited additional costs relating to the installation of the control device and additional customer incentives. As a combined program, we estimate an effective impact of 11MVA at a cost of $23m.

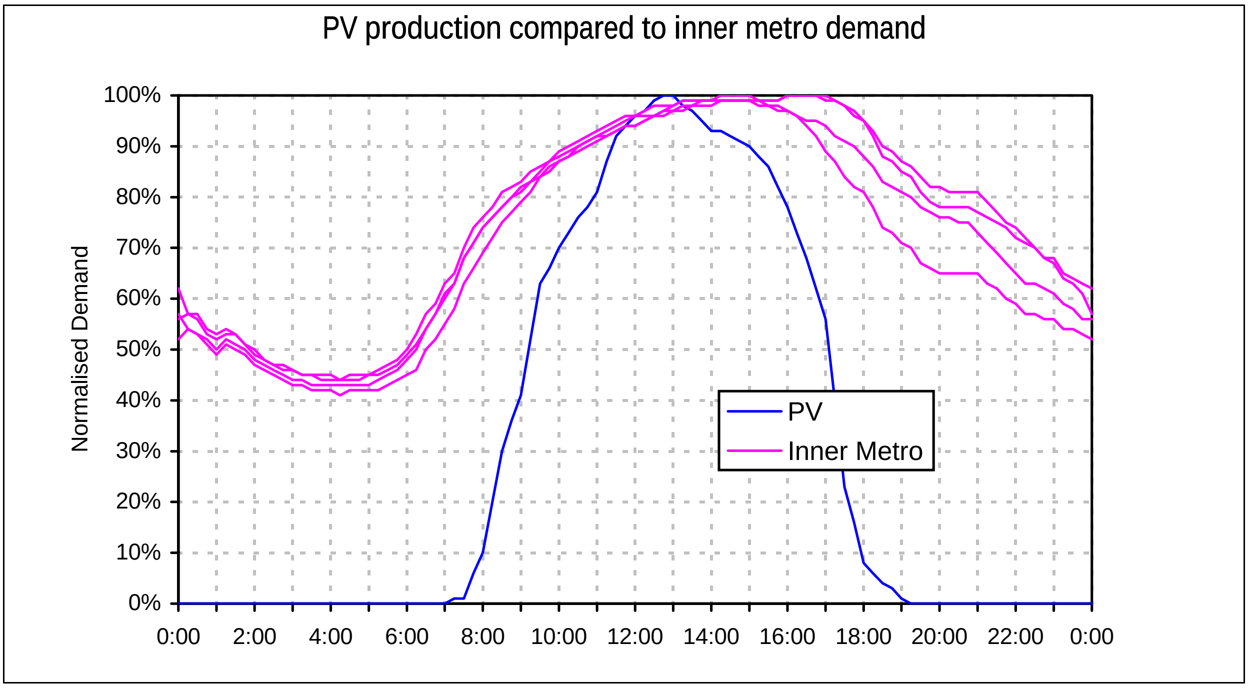
## Solar Photovoltaic Generation

Photovoltaic (PV) cells convert solar energy into electricity. The integration of PV installations into electricity systems has often been cited as a means to reduce peak demands in summer, as it is assumed their production profile coincides with peak demand driven by air conditioning loads.

PV can be readily installed on rooftops or in other open spaces and despite the typically small unit sizes, the theoretical potential in the inner metro is large. For example, if every residential dwelling in the inner metro was able to install a 1kW peak rated PV system (about 10m$^2$), that would result in over 750MW of PV generation.

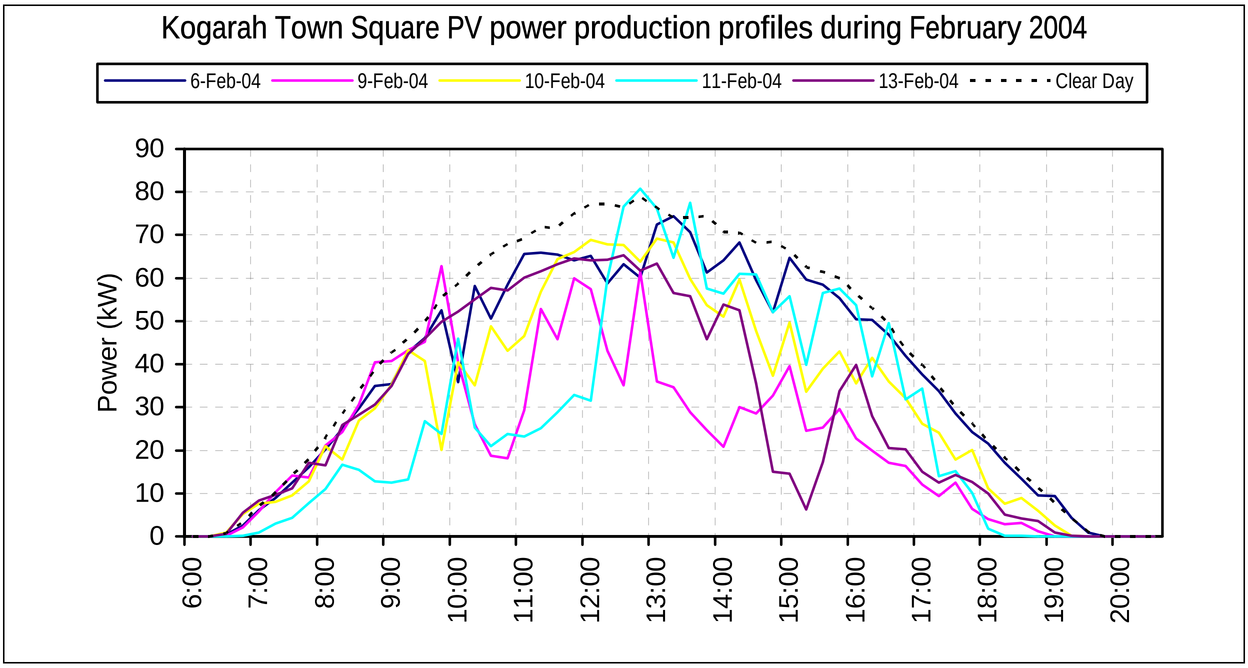
While PV installation sizes are usually quoted in terms of their rated panel capacity in kW, actual system production is somewhat less than this amount. Based on monitored data from 28 installations in Newington, the maximum observed diversified output per 1kWp array on a high load summer day (1 Feb 2005) was 0.68kW, and the output declines to approximately 0.1kVA at 6:00pm.

The peak of the inner metro load profile occurs between 12:00 noon and 6:00pm. Even on sunny days, PV production shows a marked drop off from the peak at 1:00pm (summer time) to 6:00pm, as shown in the chart below. On cloudy days, production levels are much lower. In determining the level of coincidence and reliability of PV driven peak reductions for the inner metro area, both timing and cloudiness must be considered.




On the top 10 load days of summer 2008/09, the daily sun hours (a measure of cloudiness) varied from a high of 13 (fully sunny) to a low of 7.1 (with observations showing 7/8 cloud cover at 9am and 5/8 at 3pm). Only three of the top ten days showed close to fully clear skies.

The impact of clouds on PV production is also shown in the chart below, taken from the Kogarah Town Centre PV system. These traces show the output from the PV system on the five highest load days at the local zone substation in summer 2004. This also suggests that PV output is often below clear day levels on high load days.




We used diversified solar production data from 28 rooftop PV systems at Newington and actual load data from the four highest peak load days for the inner metro area in 2008/09 to analyse the net coincident impact. We took into account the likely actual diversified production outputs of PV systems, the probability of clear skies on peak days, and the underlying correlation between PV production and inner metro peak demands and assumed installation of 5000 kWp of PV. From EnergyAustralia's assessment, each kWp of installed PV capacity could be expected to lead to a reduction in inner metro peak demand of between 0.1 and 0.6kVA. At least 75% of the time, it would be 0.4kVA or better. While this is a relatively low level of reliability compared to other demand management options, we have used 0.4kVA per kWp for this analysis.

One respondent to the public consultation proposed a PV array of between 100kWp and 300kWp on a public structure. The cost of the PV array was given at $10/W, or $10,000/kWp, yielding an expected cost of $1m for a 100kWp system. The submission proposed a subsidy of $200/kWp. It was not clear how the remaining 80% of the project would be funded.

The DM&P project identified several locations where significant PV systems could be installed on large commercial roofs. CRA assumed an 85% coincidence factor and assessed the subsidy required for cost of these systems to be between $10,000 and $14,000 per kVA.

The Federal Government previously offered rebates for installation of PV systems in residential houses. At the typical cost of $12,000 - $15,000 for a 1 kWp system, the rebate of $8,000 covered more than half the system cost. However, some bulk providers in the marketplace offered residential 1kWp PV systems for as low as $9,500. With the government rebates of $8,000 and a contribution from RECs at $50 each, this could give a net cost of $495 for a 1kWp system on an ideal single-storey house where the household income is less than $100,000.

A new "Solar Credits" scheme has been established to replace the $8,000 rebate, whereby Renewable Energy Certificates (RECs) can be created by small PV system purchasers equal to the annual production over 15 years multiplied by five. For a 1kWp PV system in Sydney, this would be 105 RECs. If RECs were priced at $30 (based on recent spot prices), this would be equivalent to a contribution of $3,150. Since the original $9,500 offer included assignment of the RECs (21 under the current scheme) to the supplier, the net price would be about $6,000. The providers of these systems claim a typical saving to the customer of about $200 per year on their electricity bills.

Rebates and Solar Credits are not available for larger scale commercially sized PV systems.

PV systems remain expensive and require significant subsidies to make them viable. Assuming a program took advantage of the Federal Government's Solar Credit scheme and limited participation to 1.5kWp systems, we estimate a program cost of about $3,500 per installed kWp. Based on the impact assessment for the inner metro, this would be equivalent to $8,750 per kVA. We have assumed for this analysis that this would result in a sufficient additional take-up of PV generation systems to yield at least 1MVA effective demand reduction.

### Innovative Tariffs

EnergyAustralia has undertaken several trials of innovative tariff approaches to assess their effectiveness in encouraging changes of energy use behaviour. In particular, EnergyAustralia has sought to encourage customers to use less power during critical peak periods. The approaches tried to date include time-of-use pricing and critical peak pricing.

Time-of-use pricing has been in place for the majority of business customers for many years. Prices for major customers also include substantial components related to annual peak demand in order to encourage minimisation of peak demands during the system wide peak time of 2:00pm to 8:00pm. With the recent availability of more cost-effective electronic metering solutions, expansion of these price signals to smaller customers has become possible. EnergyAustralia's current policy is that all replacement and new meters have this capability and EnergyAustralia's default network tariff is a time-of-use based price. EnergyAustralia's forecasts of demand include the impact of this steady change.

A more targeted approach was tested with residential customers under the strategic pricing trial. Under this system, volunteer customers were notified of 'critical peak' periods when their price would rise to $1.00 or even $2.00 per kWh for a few critical hours. In exchange, their prices were discounted significantly at all other times. The trial showed that customers made significant reductions in their demand during critical periods.

The trials did not produce sufficiently reliable data to fully assess the impact these reductions might have on a system level load profile such as the inner metro load. The trials were also conducted during relatively mild summer weather and it is difficult to translate the observed response to the level expected on a hot peak day. Using generous assumptions about these effects, a recent review showed that a system wide program offering a dynamic peak price product to all residential customers might result in a reduction of 25MVA at a cost of $24m. A significant cost of such a program would be the cost of replacing meters. At some point in the future, when smart meters have been deployed, this may become a more attractive opportunity. This is not expected to occur until after the need date for the inner metro area.

Another approach often discussed is the concept of Customer Baseline Load tariffs. Instead of penalising usage during critical peak periods, this approach rewards customers for reductions they achieve. It is expected that this may lead to a much larger acceptance rate and improve effectiveness. However no trials of this approach have been completed.

Securing critical peak demand reductions from the commercial sector has been considered using more direct dispatchable approaches. Tariff based approaches are not considered a likely candidate for inclusion in a demand management strategy for the inner metro area.

## Computer Efficiency

The CRA review of the DM&P project data suggested that activating energy star settings and replacing CRT monitors could lead to peak demand reductions of 9.2MVA at a cost of $4,200 per kVA.

EnergyAustralia's review of this sector suggests that the turnover of this type of equipment is about three years. The government is also considering introducing regulations covering labelling and energy usage of computer equipment, and we would expect that this improvement would occur as part of the natural improvement in equipment efficiency prior to 2012.

On this basis we consider that a demand management program in this area would be unlikely to produce an additional demand reduction benefit.

## Residential Efficiency Retrofits

One respondent to the public consultation suggested converting electric hot water systems to gas, heat pump or solar as part of a suite of programs. However they also stated that this element would provide limited reductions in the inner metro peak demand.

EnergyAustralia has undertaken several demand management projects in the residential sector. These have included conversion of incandescent lighting to compact fluorescent and hot water system conversions. However, these have been targeted at winter evening peaks and would have little effect on the inner metro demand. There has been widespread implementation of similar approaches in many areas of the inner metro, commonly by local councils. Also, import controls are now in place for incandescent lamps, lighting MEPS are in place, and incandescent lamps will be subject to retail restrictions later in 2009. EnergyAustralia's analysis of residential efficiency opportunities therefore suggests that they would not form part of a cost-effective demand management solution for the inner metro project.

## Active Harmonic Filters

Active harmonic filters are usually used to resolve power quality issues but should also result in some reduction in site peak demand due to the effective improvement they make in power factor. One respondent to the public consultation suggested the use of active harmonic filters as an effective means of reducing peak demands in commercial buildings and factories. They suggested reductions of 5% to 15% were achievable but did not provide any indication of likely cost.

A trial of an active harmonic filter was undertaken as part of the DM&P project. The unit trialled cost $40,000 and was installed at an 11-floor commercial office building. The data collected from the site before and after installation did not demonstrate any significant difference in peak demand.

While active harmonic filtering may result in benefits, the observable demand reductions were not significant and certainly did not support an estimate of up to 15% reduction. On this basis it is not possible to consider this option as part of a cost-effective demand management portfolio.

## Battery Storage

An effective means of shifting loads from peak periods to off peak periods would be to use rechargeable batteries. A large-scale battery installation could be used in much the same way as an embedded generator to reduce the peak demand by discharging during a critical peak load time, and charging during off peak times. This would have a technical advantage over generators in that there would be no local emissions and low noise, making it easier to identify suitable connection sites.

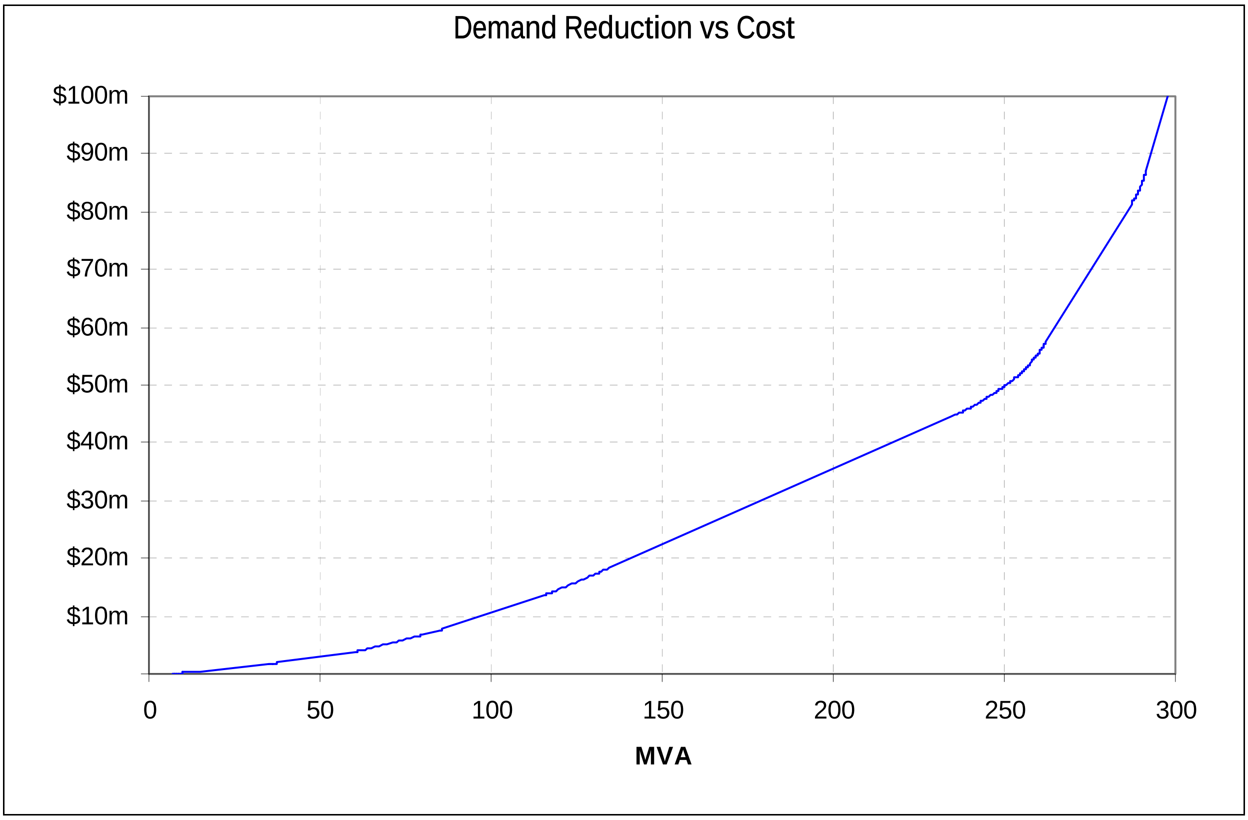
One respondent to the public consultation suggested large-scale battery storage could be developed comprising sixty 1.5MWh batteries. This might provide up to 15MW over the six hour inner metro peak period. The technology suggested is not currently commercially available, so there would be some development risk. Following further discussions, we estimated the contribution to a large-scale project would be more than $2,000 per kVA. At this cost it is very unlikely that such an approach would prove cost-effective, and it would be unreasonable to take on the development risk in this case.

### Summary of broadly indicative DM Project Cost and Load Reduction

Based on this investigation, we have estimated the likely load reduction and the total broadly indicative cost to EnergyAustralia / TransGrid for each of the project opportunities identified as having potential. The following table summarises these results, including our level of confidence that the estimated impact and cost levels can be achieved.

| | Demand Reduction MVA | Broadly Indicative cost | Confidence level |
|---|---|---|---|
| Conventional Residential Load Control (Off Peak Hot Water) | 7 | $20k | High |
| Network Support from Existing Embedded Generators | 25 | $1.5m | Medium |
| Customer Power Factor Correction | 25 | $2m | High |
| Commercial Building Energy Efficiency | Up to 10 | $1.5m | Medium |
| Cogeneration in Commercial Buildings | Up to 30 | $6m | Medium |
| Load Curtailment, Standby Generation and Load Shifting | Up to 50 | $12m | Medium |
| Temporary Network Support Embedded Generation (1 year) | Up to 100 | $25m | High |
| Large Industrial Cogeneration (option 2) | 58 | $20m | Low |
| Large Industrial Cogeneration (option 3) | 25 | $10m | Low |
| Innovative Tariffs | 25 | $25m | Low |
| New Residential Load Control | 11 | $25m | Medium |
| Solar Photovoltaic Generation | 1 | $10m | Medium |
| Computer Efficiency | No additional reduction likely | | |
| Residential Efficiency Retrofits | Not sufficiently effective for inner metro profile | | |
| Active Harmonic Filters | Insufficient evidence of reliable reductions | | |
| Battery Storage | Not sufficiently commercial | | |

Several of the measures are scalable – the amount obtainable will increase if more support is provided. In some cases, there will be fixed project overheads that will be additional to the costs noted above if the projects are scaled down significantly. In addition, the cost of some elements will be higher if two seasons of support are required compared to only one. This enables a more complex analysis to be constructed based on the cost of providing various levels of demand reduction. The following chart shows demand reduction against cost of implementation for various levels of required reduction, with each measure chosen based on its cost, and low likelihood measures excluded.




Based on this analysis, it should be possible to achieve a distributed demand reduction of up to 100MVA for one year at a cost of around $10m. Higher levels of demand reduction are possible, but costs would be expected to increase rapidly.

## Conclusion

Based on this investigation, there appear to be sufficient cost-effective options likely to be achievable to form a combined demand management and network strategy to achieve the objectives of the Inner Metropolitan Strategy.

## Appendix: Public Consultation

Written submissions were received to the Public Consultation Process from the following respondents:

| No | Company | Proposed Technology |
|---|---|---|
| 1 | Amcor Australasia | Industrial cogeneration |
| 2 | AMRS | Nil–will not submit response |
| 3 | APP Corporation | Industrial cogeneration & standby generation |
| 4 | Austracs | Pool pump control using Thermaswitch™ |
| 5 | CBD Energy (Captech) | Power Factor Correction (PFC) |
| 6 | Cogent Energy | Commercial building co/tri-generation |
| 7 | Cundall | Commercial building co/tri-generation |
| 8 | Demand Manager | Commercial building cogeneration |
| 9 | Energy Response | Demand Side Response (standby generators and load shifting) |
| 10 | greenpeak management pty ltd | Leased generators fuelled with biodiesel |
| 11 | Intelligent Energy Solutions | Active Harmonic Filters |
| 12 | JPemberton Consulting / invenergy | Large scale battery storage |
| 13 | Knox Advanced Engineering | Standby generators and cogeneration |
| 14 | Low Energy Supplies & Services (LESS) | EE & fuel switching incl. commercial lighting; PV systems; solar, gas and heat pump HW systems. Load shifting incl. air con., DSR, pool pumps. |
| 15 | Optus | Standby generators |
| 16 | Parsons Brinkerhoff | Energy Efficiency, PFC and Cogeneration |
| 17 | Railcorp | EE various; new HV supply; standby generators |
| 18 | Resource Connections International | Embedded co/tri-generation |
| 19 | SAAB Systems | Direct Load Control System |
| 20 | Sydney Water Corporation | Diesel generators, biogas generators, load shifting |
| 21 | Telstra Corporation | Diesel standby generators and EE measures |
| 22 | True Energy Pty Ltd | Motor soft starters; lighting controls; PFC; cogeneration |
| 23 | UNSW | Photovoltaics (PV) |

The following groups made registrations of interest to the Public Consultation Process but did not submit a written response.

| No | Company |
|---|---|
| 1 | CSR Edmonds |
| 2 | Energy Conservation Systems |
| 3 | Ethnic Communities Council of NSW |
| 4 | Resource Connections |
| 5 | Mapua Institute of Technology |
| 6 | Energeering Pty Ltd |