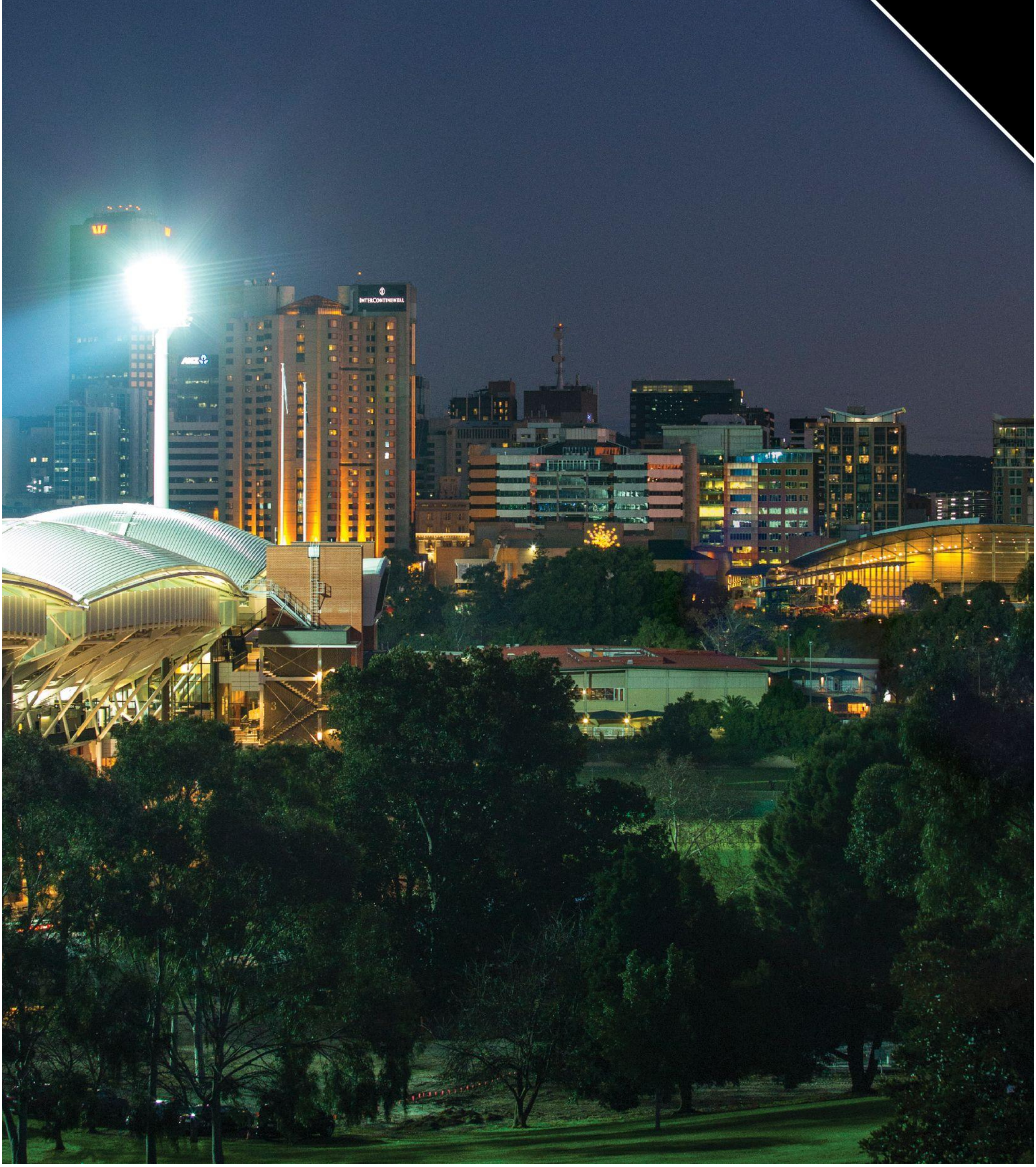
Attachment 20.34

SA Power Networks: Flexible load strategy

October 2014



Flexible load strategy

V1.0

23 October 2014

SA Power Networks

www.sapowernetworks.com.au

Contents

SIGNATURES

The following Stakeholders have reviewed and accepted the details within this document. Any changes to the document may only be made with the formal agreement of the signatories.

Approver	Position	Signature	Date
Mark Vincent	Manager Network Investment Strategy		2/10/14
James Bennett	Manager Regulation		2/10/14

CHANGE HISTORY

Version	Date	Author	Comments
V0.1	06/01/14	AJvV	First Draft for review
V0.2	23/05/14	AJvV	Prepare draft for reset
Final Draft	26/06/14	AJvV	Feedback included – submitted for sign off
V0.9	18/07/14	MV	Amendments based on JB feedback
V1.0	23/09/14	MV	Minor amendments. Final version for submission with Regulatory Proposal

1 BACKGROUND

The term 'flexible loads' is applied to electrical loads on the network that customers may be able to operate at different times, with minimal, if any, loss of amenity. Historically, load control applied to flexible loads has been a powerful tool used by the electricity industry to improve utilisation throughout the electricity supply chain by moving (predominantly) hot water storage loads into off peak times (historically overnight). In more recent times, SA Power Networks has, owing to significant penetration of air conditioning in SA (estimated to be over 90%), been undertaking trials of direct load control (DLC) of air conditioning units. This was to assess the potential benefits from deferred capacity upgrades through increased utilisation of existing infrastructure[1]. However, since the commencement of that work, the industry has seen a dramatic shift in the environment, particularly in relation to the take-up of solar photovoltaics (PV).

In response to increasing electricity prices and generous government incentives for small scale renewable, more and more residential, commercial and industrial customers have been investing in onsite (embedded) generation. Whilst to some extent mitigating the impact of peak demand growth, this dramatic uptake of renewable generation has significantly increased the range of power flows that the network must be able to support and the volatility of those power flows, particularly in the low voltage network. The network must now be able to support both the peak demands seen on the network in the evening on hot summer days as well as the negative flows experienced at solar noon on mild days when solar PV systems are providing peak output (refer to Figure 1). Significant demand transients can also occur in such networks as clouds cross the sun and reduce solar output. In combination, these effects can make it impossible for voltage levels within the LV network to be maintained within prescribed standards without upgrades of conductor, transformers or more complex control algorithms and equipment.

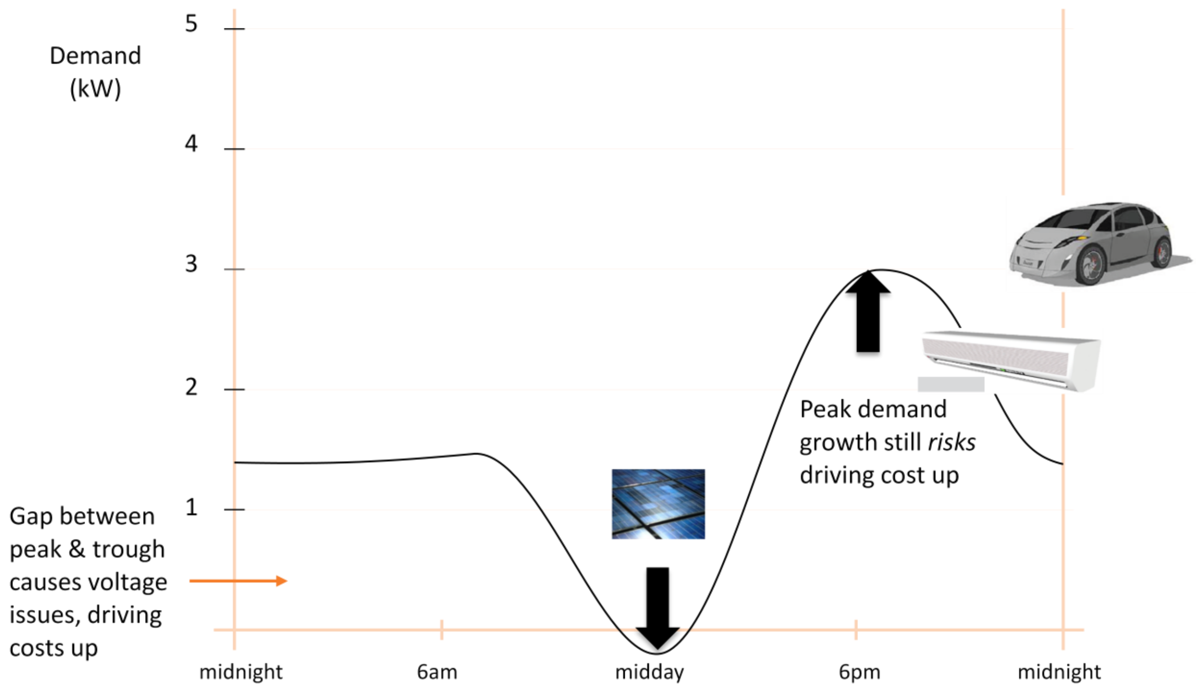


Figure 1. Illustration of peak demand and new "off peak"

[1] Refer to http://www.sapowernetworks.com.au/centric/industry/our_network/demand_management.jsp

Within this environment, significant potential exists for flexible loads to improve the network load factor[2] and thus manage this increasing range and volatility of demand. Such loads may be utilised not only to reduce network peaks, thus avoiding or deferring investment in network upgrades, but also to fill 'troughs' in demand, thereby enabling greater renewable integration within the network without the need to undertake costly remediation work to manage voltage compliance issues.

2 SCOPE OF THIS DOCUMENT

This strategy primarily focuses on the potential use of flexible loads commonly used by residential and small business customers as a means of improving network utilisation.

Our large commercial and industrial customers have had long term exposure to demand based electricity tariffs, often have in-house expertise, and electricity is often a material component of their total expenditure. Due to these factors we tend to see more efficient utilisation of the network by our larger customers.

It should also be noted that during the assessment of non-network solutions as part of the regulatory investment test for Distribution (RIT-D) process, larger commercial and industrial customers are considered as a possibility to negotiate a load curtailment agreement with in lieu of an upgrade, and so these opportunities are pursued through established business processes.

It is in the LV network where the existing and future issue of peak demand and quality of supply needs to be addressed most urgently and one of the greatest opportunities to achieve this is through residential and small business customers becoming more informed active participants in the network.

This strategy sets out a roadmap for partnering with our customers to leverage flexible loads to improve the network load factor and thus broadly reduce network costs. A particular focus is placed on those appliances that are widely recognised to be the largest and/or most flexible loads used by small market customers, being:

1. Electric hot water (including heat pumps) and underfloor heating;
2. Air-conditioning;
3. Battery storage;
4. Electric vehicles; and
5. Pool pumps.

[2] The ratio of peak to average demand.

3 STRATEGIC INITIATIVES

With respect to the leverage of flexible loads to reduce network costs, there are two key approaches that can be taken:

1. **Locational based strategies:** aimed at deferring or reducing network investment that would otherwise be required in a specific area to address an existing or near-term network issue[3]; and
2. **Broad-based strategies:** aimed at improving the load factor across the entire network with a view to deferring long-term network upgrades in areas that do not yet have existing capacity constraints or voltage issues, but in which issues may arise in the longer term.

With respect to locational-based strategies, SA Power Networks has been pursuing opportunities in this regard for some time and has implemented a range of strategies which are described in our *Demand Side Engagement Document*[4]. There is no 'one size fits all' approach that can be taken to addressing locational issues and consideration will be given to the range of potential options as part of the process described in that document. Furthermore, despite the expanding range of potential solutions, at current price points, traditional network upgrades and augmentations remain the most efficient solutions in most circumstances.

Nonetheless, within the next regulatory period, SA Power Networks proposes to continue to explore and trial a variety of locational based strategies. These will be funded by the AER's Demand Management and Embedded Generation Incentive Scheme (DMEGIS).

However, in additional to these trial locational based strategies, a range of broad based strategies are proposed to be undertaken within the next regulatory period to either:

- Support a general improvement in load factor across the network; and/or
- Improve the economics of future locational based strategies.

The broad strategies proposed are as follow:

1. **Customer education and cost reflective tariffs**: Promoting the take-up of cost reflective tariffs at the point of sale of large appliances and providing customers with information on how to efficiently utilise the network.
2. **Promote take-up of product:** Promoting the take-up of customer side energy technologies that has the potential to improve the utilisation and operation of the network.
3. **Promote AS4755[5] adoption:** supporting the mandating of AS4755 for electric vehicles, battery storage and air conditioning to support greater take-up of energy management systems and more cost-effective application of locational direct load control.
4. **Traditional controlled load:** Reconfiguration of our management of off peak hot water and other controlled loads to address the new midday 'off-peak'; and
5. **Direct Load Control foundations:** Initiatives to reduce the costs of direct load control as a non-network solution.

These are described in more detail in the following sections of the strategy. Table 1 on page 16 summarises the applicability of the various strategies with respect to key appliances.

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[3] Being either a capacity constraint – whereby projected demand is greater than network capacity; or a power quality issue – generally resulting in customers' voltage levels falling outside of compliance for some periods.

[4] Refer: http://www.sapowernetworks.com.au/centric/industry/our_network/annual_network_plans/demand_side_engagement_document.jsp

[5] AS4755-2007 standard (Framework for demand response capabilities and supporting technologies for electrical products)

3.1 Customer education and cost reflective tariffs

For discretionary high energy loads a lot can be done simply through educating small customers and providing them with a financial incentive to manage their own load through customer controlled timers and/or behavioural change.

Capacity based tariffs (as those proposed to be implemented in SA) provide customers with a lower energy rate as some of that rate is put into a capacity charge. Therefore, if a customer can manage their capacity during peak hours, they can benefit from this lower rate. In particular loads such as pool pumps and electric vehicles can improve a customer's load factor if their usage were managed appropriately and the network utilisation benefit from this can be shared with customers in the form of reduced power bills.

In general this is true for other large appliances such as dishwashers and washing machines, but as these tend to be less energy intensive the value proposition is not as compelling and the effort and/or impact on amenity of altering the use of those appliances to outside of peak times is unlikely to provide the same net benefit. Nonetheless, a customer that elects to take up a cost reflective tariff could benefit from exercising similar control over these appliances if the are willing to do so – for example, by delaying start times to non peak hours or away from times when other large appliances (eg. air conditioning) are in use).

3.1.1 Strategic development

Through a customer education program those customers most likely to benefit from small changes in their behaviour or that are in the process of making an investment decision will be presented with information to help improve their own load factor and reduce their impact on the network. This will be done through a general education campaign and through directly engaging with suppliers, consumer interest groups and other industry players in South Australia.

Through providing suppliers such as pool pump installers and car dealerships with education material and incentives they will be able to help customers improve their usage of the network and make use of an alternative tariff to save on their electricity bills. At the same time they will be equipped to deal with the enquiries they are like to receive with regards to the cost reflective tariffs for new investments in energy technology (such as electric vehicles, energy storage systems and solar PV).

3.1.2 Success measures

- ✓ Take-up of cost reflective tariffs
- ✓ 3rd parties willingness and effectiveness in communicating opportunities
- ✓ Customers reporting an increased ability to manage their electricity bills
- ✓ Reduced customer enquiries due to suppliers being able to field questions

3.2 Promote take up of product

Electric vehicles, pool pumps, electric hot water systems and energy storage systems have the potential to improve the utilisation of our network through adding additional energy consumption during off peak times without impacting negatively on peak demand. In the case of electric vehicles and storage, these devices can go a step further and reduce peak demand through discharging into the network during peak times. They can also play a key role in addressing power quality issues in the LV network.

Current pricing structures and community understanding may be imposing barriers to the take-up and/or effective use of these appliances. This prevents these appliances from being utilised when both the individual customer and community could potentially benefit from it.

In addition, in 2009 the South Australian government put in place a requirement for plumbers to install what was deemed low-emission water heaters, such as high efficiency gas, solar or electric heat pump systems in lieu of element hot water systems widely used in households in South Australia prior to this. In 2014 this was amended to allow the installation of small and medium size electric water heaters in houses which are not connected to reticulated gas[6]. Larger systems installed in such houses are required to be low-emission types (eg. solar, high efficiency gas or electric heat pump systems). However, with the significant take up of solar PV and prevalent use of wind energy as generation in South Australia large systems are no longer necessarily a high-emissions option.

3.2.1 Strategic development

As described in section 3.2.1 we will be promoting the take up of these technologies in conjunction with the capacity tariff (and existing controlled load tariffs) throughout SA to provide customers with the financial incentive to utilise these energy intensive appliances in such a way that reduce their own cost and the cost of the community.

Although limited take up of electric vehicles and energy storage systems are predicted over the next 5 years (in part owing to the lack of products and incentives for these available in SA market), with the introduction of capacity based tariffs for small business and residential customers it is forecast up to 300,000 residential battery storage units will be sold in SA over the next 20 years[7].

In the future, once a critical mass has been built up, we may offer additional incentives to some of these customers in exchange for some level of control of their unit – this could be either to peak lop or to help us manage voltage issues.

We will also be working with the state government to review the restriction on large element hot water systems that holds the potential to provide greater integration of renewable energy into the distribution network.

3.2.2 Success measures

- ✓ Take up of electric vehicles, pools, electric hot water and energy storage
- ✓ Improvements in network utilisation

[6] https://www.sa.gov.au/topics/water-energy-and-environment/energy/saving-energy-at-home/household-appliances-and-other-energy-users/water-heating/water-heater-installation-requirements

[7] Energeia forecast 2014

3.3 Promote AS4755 adoption

Electric vehicles and battery storage systems present a significant potential risk to the operation of our network. In particular these technologies have the potential to add to the peak demand on the network if unmanaged. Standards such as AS4755-2007 are an important step towards enabling a future in which new loads such as electric vehicles and battery storage systems can be effectively integrated into the electricity supply chain, enabling customers to readily take advantage of the cost reflective prices envisioned by regulatory reviews such as Power of Choice. AS4755 also provides low cost options for direct load control to address localised constrains as it reduces the complexity of retro-fitting load control devices to customer equipment.

In the absence of an AS4755 interface the installation cost of a load control device could be as much as $125, often needing to be installed by a certified technician in order to retain the warranty of the appliance. The actual load control device can easily be double the cost it needs to be (as much as $50 extra per device) to accommodate the additional components and configurations required to be able to be retrofitted to a number of different appliance makes and models. Having an AS4755 interface would reduce the device cost and take away the need for certified skilled labour during the installation process, reducing the cost of direct load control of, for instance, air conditioning in constrained areas by around $100 per kVA[8].

3.3.1 Strategic development

SA Power Networks intends to continue to promote the mandating of AS4755 for large appliances such as air conditioning, electric vehicles and battery storage systems. Although introducing this standard for other large appliance such as electric hot water and pool pumps will provide some benefits, these devices tend to already have existing load control capabilities (generally via a time switch) that can be leveraged.

We also intend to establish systems and processes to capture where AS4755 compliant appliances are installed as this information will be of value when quantifying and targeting the demand response available in a constrained area. A critical mass of AS4755 appliances will need to be installed before having a material impact on the cost effectiveness of a direct load control based non-network solution in a particular area, which is unlikely to occur over the next 5 years, however the program to promote and capturing this information is planned to start during the initial years of the 2015-20 regulatory control period.

3.3.2 Success measures

- ✓ Mandating of AS4755 interface
- ✓ % AC, EV and battery storage systems with AS4755 interface
- ✓ Effective systems and processes in place to capture location of appliances with AS4755 interface

[8] See Appendix B for case studies

3.4 Traditional controlled load

SA Power Networks currently has over 300,000 off peak hot water storage loads throughout the distribution network. At 2kW to 4kW capacity per unit this equates to over 900MW of load. Through static time switches, this load is set to come on around 11pm and is given an 8hr window to operate within[9].

This timing made sense within the context of historic load profiles on the transmission and distribution networks, however, in more recent times, due to the large penetration of solar in our network, a new 'off peak' time has been created in the middle of the day with distribution feeders sometimes acting as generators over this period. As described in the introduction to this document, this causes problems in the static LV network that was not designed to deal with the large fluctuation between peak load in the late afternoons during heatwaves and local small scale generation in the middle of the day on mild days. In particular these fluctuations create power quality issues and in some cases, as the network was primarily designed to deal with high load times, the inverters of small scale solar systems are forced to shut down during these times as voltage levels become unacceptably high.

The 'solar sponge'

Hot water load has a significant potential to absorb some of the output from solar PV, provided that it can be redirected to this new off peak time[10], however the load characteristics of hot water fluctuate with ambient temperature and it is not always possible to predict how much load will be on the system if load is simply redirected to this time in a static manner (such as through changing the timer setting). One possibility to manage this issue is to control this load dynamically through control algorithms that make allowances for the variation in temperature and season. Such algorithms could be applied locally, or potentially remotely, if telecommunications were available to the meter. Dynamic control, however, comes at a cost and the gains from this control might not be enough to justify this additional cost.

Other issues: high overnight ramp rates

In the past, mechanical time switches have been used to establish the windows of operation of controlled load and this lead to natural diversity as the mechanical time switches tends to drift. However, in recent times these switches have been incorporated in electronic meters instead. With just over 100,000 of these systems now on electronic time switches less prone to drifting come online at the same time, a significant ramp rate of just over 200MW increase is seen in the electricity market overnight causing a spot price spike in South Australia. This has lead to the 5min between 11pm and 11.05pm consistently becoming one of the most expensive in South Australia.

This provides another incentive for reprogramming hot water time switches, but again a trade off between this short term solution and the opportunities presented by implementing more strategic dynamic control needs to be considered.

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[9] In some other states, dynamic control is available via 'ripple control systems' and/or smart meters, however in South Australia, a change to the timer settings requires a physical visit to the site and reprogramming of the time switch.
[10] Refer appendix C.

3.4.1 Strategic development

As described above, hot water storage loads act as thermal storage and by diverting some of this load to the peak output times of the installed solar systems the gap between high load and high generation can be reduced. This in turn could make it easier for static LV networks to operate within agreed supply standards whilst also harnessing the full potential of solar energy that might otherwise have been prevented from being generated by voltages exceeding inverter over-voltage settings.

However, changing the way hot water storage loads operate could potentially have an impact on customer useability. A balance must be established to ensure that customers do not run out of hot water, but equally, that there is still some ability to absorb energy during the day. Great care must be taken when selecting new operating times for hot water systems.

As outlined in the Smarter Network Strategy, part of our investigations into options to improve the reliability of our network in worst served areas will involve undertaking a micro-grid trial that integrates local generation, storage and load control. A dynamic load control trial for electric hot water systems is being planned as part of this trial to examine the trade off between controllability and cost. This trial will also consider the use of less intelligent control algorithms that are not reliant on communications (for example, automatic initiation of controlled load in a premises when an over-voltage situation is detected) to compare efficacy with more complex approaches.

In the short term, in order to avoid exacerbating the price spike in the NEM, all new meter equipment with controlled load functionality will be delivered with a revised standard program to change the switching time to 11:45pm with a second program with a switching time of 00:30am with an overall heating period of six hours. This standard program will incorporate a 45 minute randomisation of the switching time to introduce diversity into the actual start of the load control.

Further to this an additional program of work will be undertaken to visit and update the meter program at up to 27,000 customer sites to reflect the switching parameters of the revised standard programs to address the spot price spikes observed in SA.

More broadly, we propose to encourage hot water loads to move to the time of lowest demand on the residential network when PV output is at its highest. This will involve new tariff offerings, and may involve discussions on market energy pricing for hot water controlled load profile customers. In particular, we propose to develop optional tariffs aimed at:

- heat pumps, encouraging less energy use during higher daytime temperatures, still being under SA Power Networks' control and not contributing to network peak demands;
- under-floor heating with expanded off-peak hours but not contributing to network peaks;
- new time clock arrangements for storage heating; and
- depending upon the outcome of the trials discussed above, new dynamic arrangements to control load for those customers with a smart meter.

These arrangements should result in a more efficient network which can receive more renewable energy from customers, whilst in some cases using less energy (eg heat pumps). It will be a challenge for some segments of the energy industry to consider hot water as an efficient day-time load which can also increase the amount of renewable energy able to be received by the current network.

3.4.2 Success measures

- ✓ Reduction in demand spike in the NEM at 11pm
- ✓ Determination of optimal approach to future management of controlled load (static, local dynamic or remote dynamic)
- ✓ Reduced power quality issues arising from solar PV
- ✓ Increased output from installed solar systems

3.5 Direct load control

SA Power Networks have undertaken extensive trials of air conditioning control since 2005. The majority of the trials involved the retrofitting of a control device on air conditioner compressor units that is capable of cycling the compressor. Much of the learning obtained from these trials was around the refinement of our customer support and messaging, back office systems required to coordinate the cycling of compressors, telecommunications requirements and the range of different customer equipment and preferences. It also became apparent that the voluntary take up rate and demand response per air conditioner is highly dependent on demographics, location and housing stock[11].

Cost modelling undertaken by SA Power Networks[12] in the past has been based on retrofitting devices to air conditioning, and to date these cost have not been competitive in comparison with traditional network upgrades. However, significant opportunities exist to reduce these costs in the future through the mandating of a standard AS4755 interface (as discussed in section 3.3) and the leveraging of smart meters as a communication gateway to such devices.

The cost of a back office system and associated telecommunications to undertake a load control program can also be a significant barrier to progress when considered in isolation, as the first start up of such a program needs to cover this cost (not knowing if direct load control will be employed else where in the network).

Appendix B provides a number of case studies that illustrate why DLC only solutions are generally uneconomic when all costs are considered, but how they can begin to become economic if existing infrastructure and capabilities such as smart meters, AS4755 interfaces and supporting telecommunications and systems are already in place.

3.5.1 Strategic development

As with most non network solutions, rural and remote areas are prime candidates for DLC as the network cost is high and the load to be supplied or managed generally smaller, therefore more money is available to fund incentives on a per kVA basis.

Although SA Power Networks will gain most from targeting DLC incentives at customers in constrained areas, we also expect that more broadly customers will react to our proposed cost-reflective tariffs by utilising load control technologies themselves beyond specific DLC incentives provided by us. Retailers and third party demand response aggregators may also seek to offer incentives in non-constrained areas to extract market benefits.

Historical interval data captured by smart meters will help identify customers that are more likely to add significant load to the local network during peak times or has the capacity to soak up excess generation during the day and through a targeted recruitment and implementation program will lead to a lower cost response. This will also have an impact on the operational requirements such as telecommunications and customer support as a smaller participation base will need to be supported for the same demand response level.

Further to this, modern meter management systems (MMS) come equipped with load control packages and the cost of a load control program can be reduced significantly by leveraging off of this

[11] Refer to section 4.3.3.5 of Demand Management Program Interim Report 3 – June 2010 (http://www.sapowernetworks.com.au/public/download.jsp?id=11891) for discussion on expected peak demand reduction

[12] KEMA Limited, ETSA Utilities, Socio Economic Assessment of Smart Metering and DLC for South Australia, Rev 1.0, 17th August 2008.

capability and utilising the telecommunications potentially already at a customer's premises due to their smart meter installation.

A strategy whereby an estimate of the demand response capability can be determined prior to the roll-out of a load control program, and ideally, where specific customers with higher potential discretionary loads can be targeted, would significantly reduce the barriers to DLC. Leveraging smart meter data and infrastructure can reduce the cost of direct load control of air conditioning in constrained areas by over $200 per kVA[13]. However, relying on smart metering will be heavily dependent on a critical mass of smart metering (installed by SA Power Networks or third parties) and the capabilities of the meter management system and is therefore not expected to come into play until the 2020-25 regulatory control period.

On this basis, no specific work is proposed within the 2015 – 2020 period to further investigate DLC opportunities beyond those normally undertaken as part of the consideration of non-network solutions for network augmentation projects. Opportunities may arise in the 2020 – 2025 period once further supporting infrastructure and capabilities are in place.

3.5.2 Success measures

- ✓ Reduction in estimated $/kVA for DLC
- ✓ Continued assessment of DLC as a non network solution
- ✓ Implementation of DLC as a niche solution
- ✓ Capability in place to 'mine' interval data for opportunities
- ✓ Targeted recruitment considered during evaluation of DLC as a non-network solutions

3.6 Summary

Through the initiatives listed in this section, we aim to partner with our customers to unlock the potential of flexible loads as a way to improve the utilisation and operation of our changing network. Table 1 on the following page summarises the application of these initiatives by appliance. This is described in more detail in Appendix A.

[13] See Appendix B for case studies

Table 1. Appliance summary

Appliance	Load size in SA (2014)	Total size[14]	Hours of operation	Current issues	Possible solutions	Promote AS4755 adoption	Customer education & cost reflective tariffs	Reprogram time switch	Direct load control	Promote take up of product
Electric hot water & underfloor heating	Number of units: 300k Average capacity: 2kW to 4kW Average daily energy: between 3kWh and 9kWh (depending on weather conditions)	900MW	11pm – 7am with an optional boost in the afternoon	NEM spike at 11pm	Possible sponge for solar output during the day			✓	✓	✓
Air conditioning	Number of units: 800k Average capacity: 2kW to 10kW Average daily energy: between 10kWh and 50kWh (during hot spells)	3,200MW	4pm – 9pm during hot weather	Primary driver of peak demand in network	Tool to address capacity constrains in local areas through dynamic load control (subject to RIT-D)	✓	✓		✓	
Battery storage	Number of units: 0 Average capacity: 1kW to 5kW Average energy: 5kWh to 20kWh	N/A	N/A	Very little incentive to invest in storage, high cost of storage	Flexible load/supply that can address power quality, reliability and capacity constrains in local areas	✓	✓			✓
Electric Vehicles	Number of units: 160 Average capacity: 1kW to 3kW Average daily energy: 10kWh to 15kWh	<1MW	Likely overnight	Could add to peak demand if unmanaged	Can improve network utilisation by adding an additional flexible load	✓	✓			✓
Pool Pumps	Number of units: 50k Average capacity: 1.5kW Average daily energy: between 5kWh and 20kWh (depending on season and customer preference)	75MW	4 – 12hrs a day	No incentive to run pool pumps outside of peak hours	Can provide relieve during peak by moving pool pump load outside of these hours		✓			

[14] For comparison only, diversity between appliances not taken into consideration

APPENDIX A – ROADMAP BY APPLIANCE

This appendix sets out a roadmap by appliance for the application of the initiatives described in the previous section. It also includes a cost estimate for the implementation of this strategy.

Air conditioning

Table 0-1: Air conditioning load control solutions roadmap

Reset Period	Strategic Development
Current Period (2014 – 2015)	Complete analysis of outcomes from Direct Load Control trials.
Period 2 (2015 – 2020)	Promote and monitor the take up of AS4755 interfaces for air conditioning.
Period 3 (2020 – 2025)	Continue to promote and monitor the take up of AS4755 interfaces for air conditioning. Leverage smart meters to identify largest customer loads in constrained areas.

Considerations

During the detailed strategy development for this appliance, the following issues will need to be considered:

- Viability of other non-network solutions
- Local demographics and housing stock

Hot water & underfloor heating

Table 0-2: Hot water load control solutions roadmap

Reset Period	Strategic Development
Current Period (2014 – 2015)	Modelling of hot water load as a potential power quality solution. Targeted implementation of randomised start times for hot water systems to address overnight ramp rate.
Period 2 (2015 – 2020)	Implementation of new load window for all new or altered installations. Retrospective shifting of load window for a subset of existing installations. Trialing of dynamic hot water load control leveraging smart meter capabilities. Promoting of hot water systems.
Period 3 (2020 – 2025)	Roll out of dynamic hot water load control in power quality problem areas.

Considerations

During the detailed strategy development for this appliance, the following issues will need to be considered:

- Impact of changes on customer useability of equipment
- Impact of changes on market and retailers
- Impact on smart meter requirements

Electric Vehicles

Table 0-3: Electric Vehicle load control solutions roadmap

Reset Period	Strategic Development
Current Period (2014 – 2015)	Set up systems and processes to monitor EV connections.
Period 2 (2015 – 2020)	Mandate notification and tariff change of all new EV connections. Promote and monitor the take up of AS4755 interfaces for plug in electric vehicles.
Period 3 (2020 – 2025)	Continue to promote and monitor the take up of AS4755 interfaces for plug in electric vehicles.

Considerations

During the detailed strategy development for this appliance, the following issues will need to be considered:

- Impact of charging on neighbouring customers
- Unwanted peaks during off peak periods
- Size of charging load

Storage

Table 0-4: Storage roadmap

Reset Period	Strategic Development
Current Period (2014 – 2015)	Monitor the development of battery storage applications for small business and residential customers.
Period 2 (2015 – 2020)	Mandate capacity tariff for all new battery storage connections. Promote and monitor the take up of AS4755 interfaces for battery storage.
Period 3 (2020 – 2025)	Continue to promote and monitor the take up of AS4755 interfaces for battery storage.

Considerations

During the detailed strategy development for this appliance, the following issues will need to be considered:

- Impact of battery systems on the reliable and safe operation of the network
- Utilisation of customer battery systems as a non-network solution once a critical mass has been achieved
- How battery systems can be optimised with respect to tariff signals

Pool pumps

Table 0-5: Pool pump load control solutions roadmap

Reset Period	Strategic Development
Current Period (2014 – 2015)	
Period 2 (2015 – 2020)	Promote capacity tariff for pool pump connections through pool pump suppliers. Promote reprogramming of time switches to operate pool pumps during off peak times.
Period 3 (2020 – 2025)	Continue to promote capacity tariff through pool pump suppliers.

Considerations

During the detailed strategy development for this appliance, the following issues will need to be considered:

- Health impacts of change in customer behaviour
- Overlap of pool usage with hot days
- Diversity of pool & pool pump use with other large appliances on extreme days

Program cost 2015-20

Table 0-6: Cost estimate for program implementation

	Total 15-20 ($,000)	2015	2016	2017	2018	2019
Capex						
Program management and project office (2 FTE)	$1,950	$390	$390	$390	$390	$390
Education and support material	$390	$150	$150	$30	$30	$30
Reprogram hot water timers	$600	$200	$200	$200	-	-
Develop systems and processes	$500[15]	$250	$250	-	-	-
Total	**$3,440**	**$990**	**$990**	**$620**	**$420**	**$420**
Opex						
System administration (1 FTE)	$487.5	$97.5	$97.5	$97.5	$97.5	$97.5
Advertising campaign to promote appliances	$500	$100	$100	$100	$100	$100
Establish load control module in MMS	N/A[16]	-	-	-	-	-
Dynamic hot water trial	N/A[17]	-	-	-	-	-
Total	**$987.5**	**$197.5**	**$197.5**	**$197.5**	**$197.5**	**$197.5**

[15] Cost based on solar PV database and process establishment
[16] Included in Tariff and Metering Business Case
[17] Included in micro-grid proposal

APPENDIX B – DLC CASE STUDIES

Case study 1 – Small country substation

The Williamstown Substation is part of the Barossa 33,000 V (33kV) electricity distribution system. The Substation is operated at 33kV stepped down to 11kV and has two 11kV feeder exits that supply the local residential load. There are approximately 1,100 customers in the surrounding suburbs supplied from the Williamstown Substation.

Williamstown Substation consists of one 2.5MVA 33/11kV transformer. The Williamstown Substation has a normal cyclic summer rating of 3.3MVA and a firm delivery capacity of 3.3MVA in 2013/14.

The forecast demand in 2013/14 was 3.6MVA. This meant during peak load conditions, up to 0.3MVA of load may need to have been shed, which would have require the shedding of up to 100 customers. Further to this the load is expected to increase to 3.7MVA in 2014/15 and 3.8MVA in 2015/16. Deferring the upgrade has a financial benefit of $530 per kVA in 2013/14, $430 per kVA in 2014/15 and $360 per kVA in 2015/16[18].

DLC solution

Assuming an airconditioning direct load control program was considered to meet this constraint in order to delay upgrading the network. If a response of 0.7kW was assumed per volunteer over the peak period, this would require over 40% of the customers in the area to enrol in the program in year 1 (and an additional 14% in year 2 and 14% in year 3 if the program is to continue to meet the growing demand). To date the take up rates have varied significantly depending on the demographics of the area, but typically a take up of 5% - 15% has been seen.

For this specific the technical solution it is expected the cost per kVA would be around $333 if the program is ran over 3 years (assuming approximately $289[19] set up cost and $100[20] ongoing cost each year per volunteer). Although the cost of this technical solution seems plausible, this cost does not include any incentives required to onboard volunteers. Considering the high numbers of volunteers required (40% - 68%), this is problematic.

However, if it were assumed that:

- Smart meters with a telecommunications link have already been rolled out to the area and is a sunk cost;
- By leveraging smart meter data and targeting customers with large ariconditioning units (or other large loads), the diversified controllable load per customer could be increased to 1.2kVA[21] and customer support cost could be reduced;
- The price point of DLC devices can be significantly[22] reduced due to standardisation and economies of scale; and
- Reduced installation cost due to having AS4755 appliances.

[18] Refer to Williamstown Reasonableness Test issued in 2011 (http://www.sapowernetworks.com.au/public/download.jsp?id=18843&sstat=259131)
[19] Includes cost of bringing forward the installation of 3G to site by 5 years ($89), the DLC installation cost ($100) and the cost of the DLC device ($100)
[20] Includes ongoing comms cost ($60) and volunteer support ($40)
[21] Assuming an additional 1kVA per volunteer with a 50% diversity factor
[22] Assumed to reduce to $25 per device

Then the constrained will be able to be met with a take-up rate of 25% in year 1 and 40% in year 3 and incentive levels of $300 - $500 per volunteer[23] for each year of the program would be available.

Base $/kVA (not including incentives)	Reduced $/kVA (not including incentives)	Combined reduction in $/kVA (not including incentives)
$333/kVA	$79/kVA	$254/kVA

Reductions due to smart meters only		Reduction due to AS4755 only	
$191/kVA		$108/kVA	
Leverage comms infrastructure	Targeted recruitment	Reduced cost of DLC device	Avoided installation cost
$55/kVA	$158/kVA	$46/kVA	$62/kVA

[23] Depends on which year volunteer is enrolled in the program

Case study 2 – SWER upgrade

The Port Neill SWER is fed from the Tumby Bay Distribution Substation and is part of the Port Lincoln 33,000 V (33 kV) electricity distribution system on the Eyre peninsular. The substation is operated at 33 kV stepped down to 11 kV and has three 11 kV feeder exits that supply the local residential and rural load. There are approximately 2,030 customers in the surrounding area supplied from the Tumby Bay substation.

The Ungarra 11kV feeder from Tumby Bay supplies the Port Neill SWER by 15.3km of 11kV overhead line. The Port Neill SWER consists of three 150 kVA 11/19 kV transformers supplying 226 customers including two three phase loads half way along the 25.4km feeder. To cater for network risks and business needs, SA Power Networks Network Planning considers that transformers are upgraded when the load is forecast to exceed 130% of the normal nameplate rating or a total of 585kVA (195kVA per phase).

The estimated demand in 2013/14 is 607kVA. This will mean during peak load conditions, up to 22kVA of load may need to be shed, which would require the shedding of up to 8 customers. Further to this the load is expected to increase to 637kVA in 2014/15 and 669kVA in 2015/16. Deferring the upgrade has a financial benefit of $1,850 per kVA in 2013/14, $1,050 per kVA in 2014/15 and $708 per kVA in 2015/16[24].

DLC solution

Assuming an airconditioning direct load control program was considered to meet this constrained in order to delay upgrading the network. If a response of 0.7kW was assumed per volunteer over the peak period, this would require 15% of the customers in the area to enrol in the program in year 1 (and an additional 20% in year 2 and 20% in year 3 if the program is to continue to meet the growing demand).

For this specific technical solution it is expected the cost per kVA would be around $386 if the program runs for 3 years (assuming the same set up and ongoing cost per volunteer as case study 1, but with a large amount of volunteers only required for one year). Although the cost of the technical solution is very attractive in comparison to the available benefit, this cost does not include any incentives required to onboard volunteers. Considering the high numbers of volunteers required in year 2 and 3 (35% - 55%), the ramp up during these years and the relatively lower incentives able to be offered ($150 per volunteer), this program is only feasible for delaying the upgrade by one year.

If the same assumptions were applied as per case study 1, then the constrained will be able to be met for the three years considered, with a take-up rate of 9% in year 1 to 32% in year 3 and incentive levels of over $700 per volunteer for each year of the program.

Base $/kVA (not including incentives)	Reduced $/kVA (not including incentives)	Combined reduction in $/kVA (not including incentives)
$386/kVA	$86/kVA	$300/kVA

Reductions due to smart meters only		Reduction due to AS4755 only	
$220/kVA		$138/kVA	
Leverage comms infrastructure	Targeted recruitment	Reduced cost of DLC device	Avoided installation cost
$71/kVA	$178/kVA	$59/kVA	$79/kVA

[24] Port Neill reasonableness test was not publically released

Case study 3 – Urban substation

The Campbelltown and Woodforde Substations form part of the Eastern Suburbs meshed electricity network. Both substations are supplied directly from the 66,000 volt sub-transmission network and operated at 66,000 volts stepped down to 11,000 volts. The Campbelltown Substation contains two 24MVA 66/11kV transformers and the Woodforde Substation contains two 21MVA 66/11kV transformers. The forecast loads for Campbelltown Substation and Woodforde Substations exceed their firm delivery capacities in 2013/14.

The firm delivery capacity of the Campbelltown Substation is limited by the normal capacity of the transformers, being 59.0MVA. The forecast load for the Campbelltown Substation in 2013/14 is 62.2MVA.

The firm delivery capacity of the Woodforde Substation is limited by the emergency capacity of the transformers and the available ties to adjacent Substation, being 47.9MVA during a single contingency during summer 2013/14. The forecast load for the Woodforde Substation in 2013/14 is 51.6MVA.

Some feeder works are being undertaken to defer the immediate overload of these Substations by transferring load to adjacent Norwood Substation, however these constrains will need to be addressed further in 2013. Further to this the load is expected to increase to xMVA in 2014/15 and yMVA in 2015/16. Deferring the upgrade has a financial benefit of $129 per kVA in 2013/14, $95 per kVA in 2014/15 and $70 per kVA in 2015/16[25].

DLC solution

Assuming an airconditioning direct load control program was considered to meet this constrained in order to delay upgrading the network. If a response of 0.7kW was assumed per volunteer over the peak period, this would require 38% of the customers in the area to enrol in the program in year 1 (and an additional 20% in year 2 and 22% in year 3 if the program is to continue to meet the growing demand).

For this specific technical solution it is expected the cost per kVA would be around $349 if the program runs for 3 years. The technical cost of this solution significantly outweighs the $/kVA benefit available. This cost also does not include any incentives required to onboard volunteers. Considering the high numbers of volunteers required (38% in year 1 to 80% in year 3), this program is not feasible for delaying the upgrade. This is mainly due to the low cost of augmentation in $/kVA terms in densely populated areas.

[25] Refer to Campbelltown and Woodforde RFP issued in 2011 (http://www.sapowernetworks.com.au/public/download.jsp?id=19140&sstat=259164)

Even if the same assumptions were applied as per case study 1, the constrained will require take up rates of 22% in year 1 to 47% in year 3 at a cost of 3 to 4 times the available benefit (not including incentives).

Base $/kVA (not including incentives)	Reduced $/kVA (not including incentives)	Combined reduction in $/kVA (not including incentives)
$349/kVA	$79/kVA	$270/kVA

Reductions due to smart meters only		Reduction due to AS4755 only	
$201/kVA		$119/kVA	
Leverage comms infrastructure	Targeted recruitment	Reduced cost of DLC device	Avoided installation cost
$61/kVA	$166/kVA	$51/kVA	$68/kVA

APPENDIX C – HOT WATER ANALYSIS

Daily hot water load (incl losses) ranges from 1 GWh to 2.5 GWh. When considering the potential of hot water load to act as a sponge for solar PV to address power quality issues the worst load availability would be on a mild day in summer with full sun, after a heat wave has heated up the cold water. Following on from a hot summer's day and night, the state requirement for energy for hot water could be as low as 900 MWh for that day.

Assuming an average heating element size of just over 3kW and customer numbers of just under 300,000, the average run time for hot water in summer is then around one hour. Perfectly shaped, the hot water could still provide a 300 MW of load for 3 hours in peak summer.

The current level of (estimated) PV output on a sunny day is 3.6 GWh. For the highest 3 hours, the energy is 1.35 GWh (with an average peak of 450 MW).

On average around 50% of customers on a feeder would have controllable hot water on a feeder if assuming gas is available or 80% assuming gas is not available. For O/H areas with gas with solar issues (modelled to be around 50% penetration[26]) HW will allow up to 80% of customers to have PV by programming the hot water load to be staggered through the three highest solar PV output hours of the day (i.e. the hot water will cover 30% of the PV output during those hours, therefore reducing the PV output back to a 50% penetration level). In old underground areas with gas with solar issues (modelled to be around 25% penetration) HW will allow up to 55% of customers to have PV.

In areas where there is no gas available (and it is assumed 80% of customers have element hot water systems) these percentages increase to 100% and 75% respectively.

Even though as a state we have enough hot water load to lop the highest 3 hours of our solar generation (as we are not trying to cancel out all solar generation, just the bit that gives us issues), in an LV area it will still depend on the local configuration as to what can be achieved through HW load control.

[26] PSC modelling

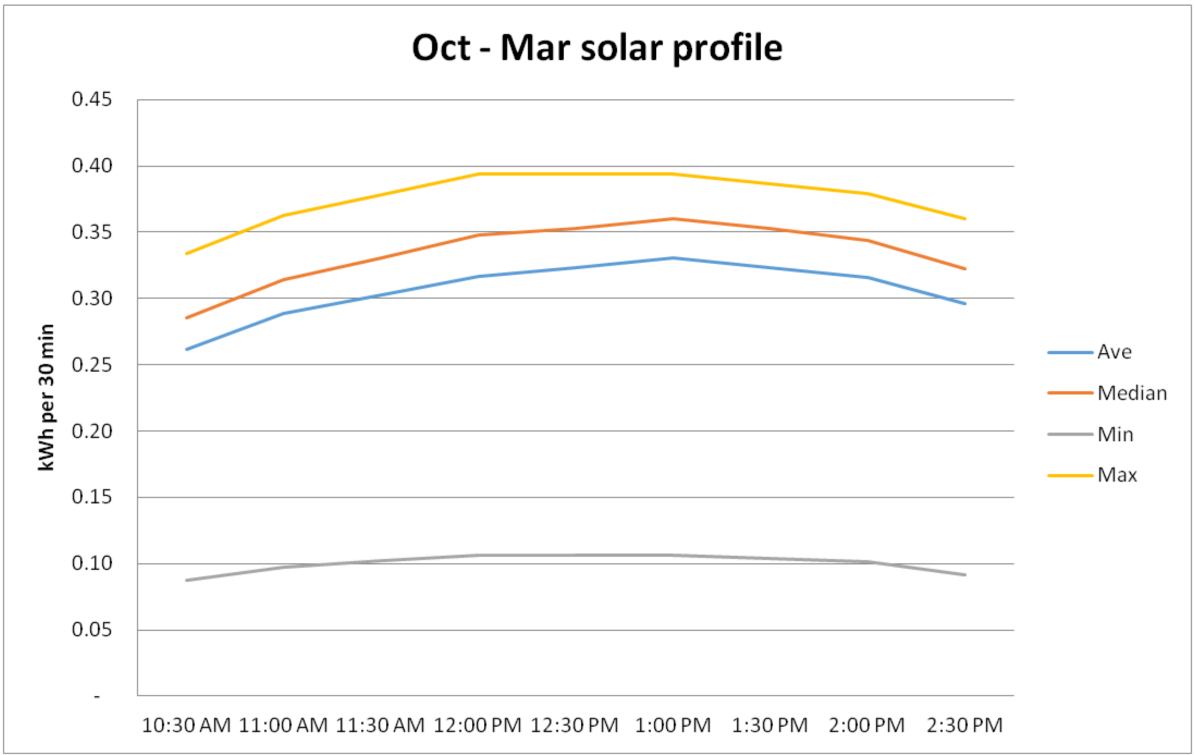


Figure 2. Solar PV output for a 1kW unit over summer during peak solar output window

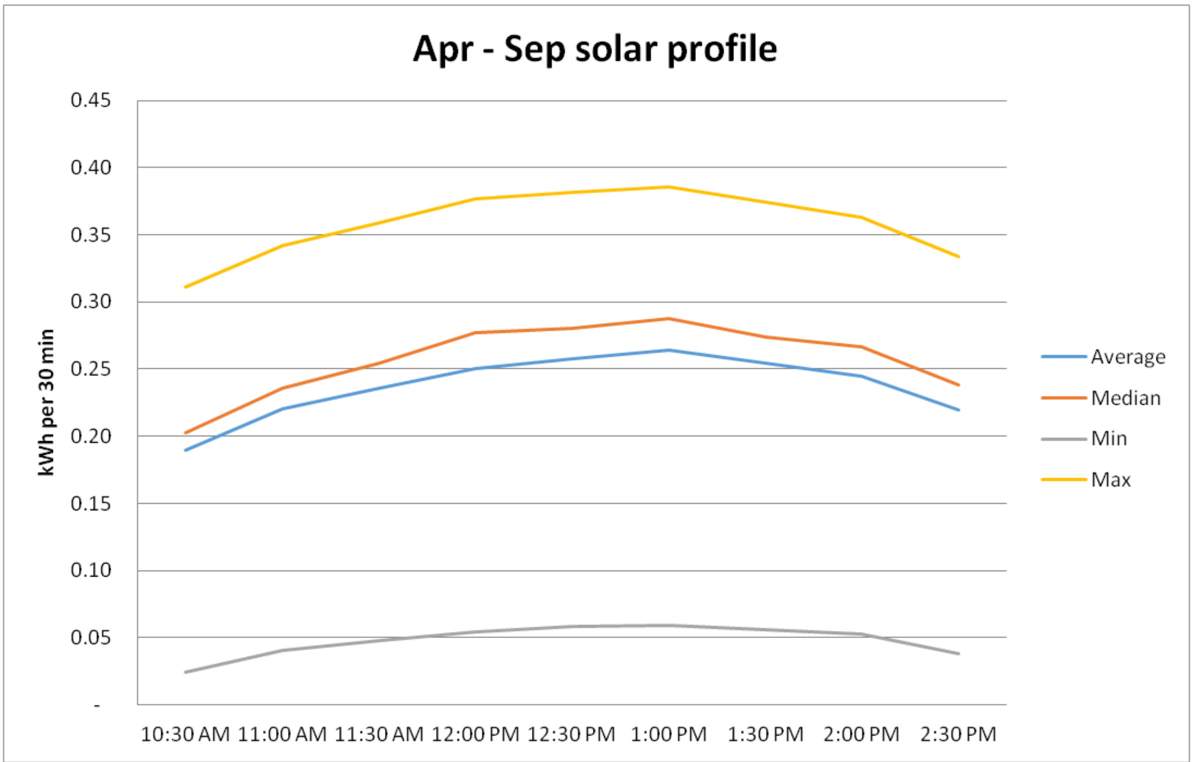
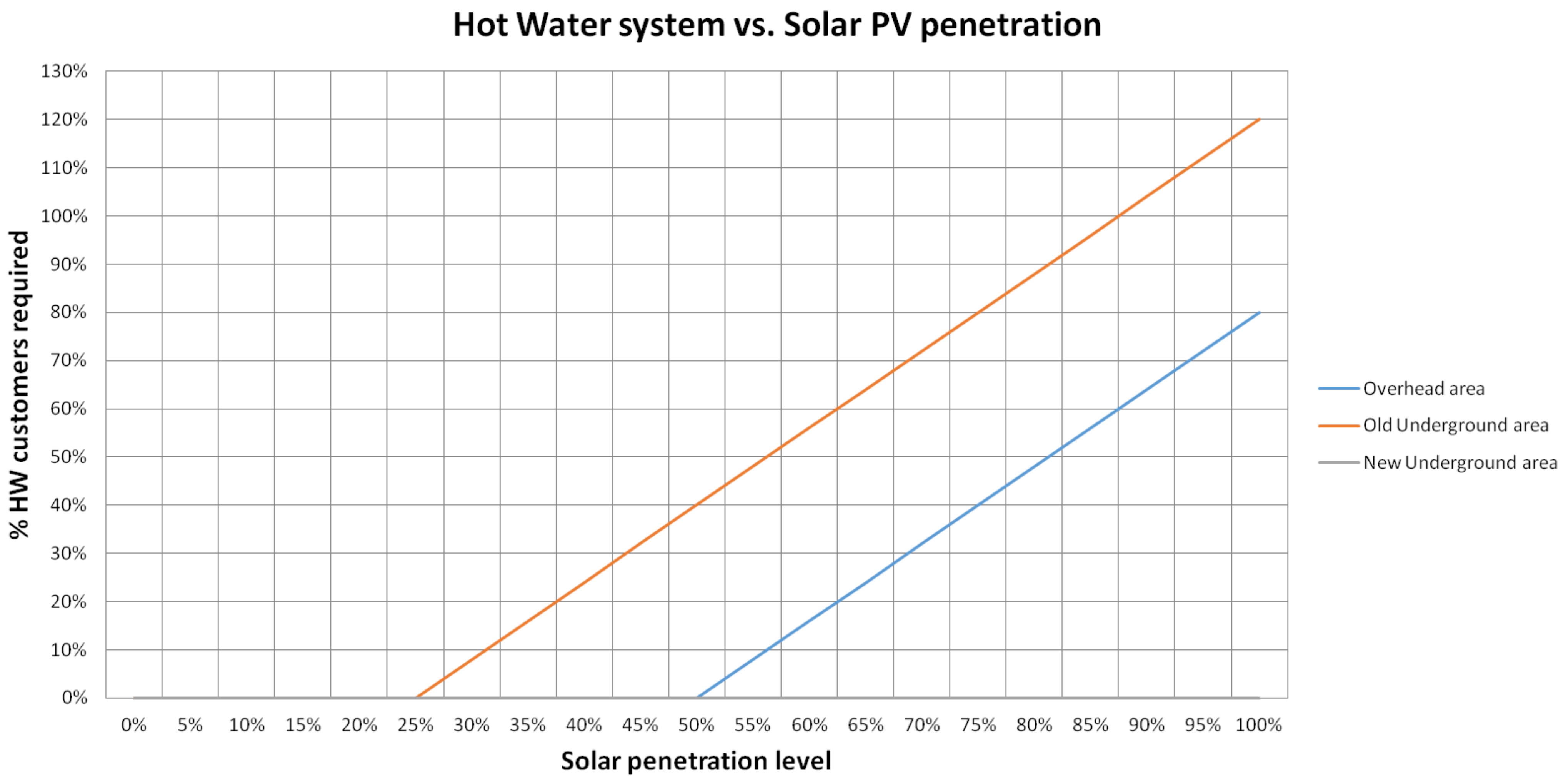


Figure 3. Solar PV output for a 1kW unit over winter during peak solar output window


Hot Water system vs. Solar PV penetration
130%
120%
110%
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
% HW customers required
0%
5%
10%
15%
20%
25%
30%
35%
40%
45%
50%
55%
60%
65%
70%
75%
80%
85%
90%
95%
100%
Solar penetration level
Overhead area
Old Underground area
New Underground area