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INSTITUTE FOR SUSTAINABLE FUTURES

BREAKING THE SOLAR GRIDLOCK: POTENTIAL BENEFITS OF INSTALLING CONCENTRATING SOLAR THERMAL POWER AT CONSTRAINED LOCATIONS IN THE NEM

EXECUTIVE SUMMARY

2013

AUSTELA Australian Solar Thermal Energy Association

Centre for Energy and Environmental Markets

UNSW THE UNIVERSITY OF NEW SOUTH WALES SYDNEY • AUSTRALIA

ERGON ENERGY

Breaking the solar gridlock. Potential benefits of installing concentrating solar thermal power at constrained locations in the NEM

AUTHORS
Jay Rutovitz[1], Juergen Peterseim[1], Ben Elliston[2], Stephen Harris[1], Steve Mohr[1], Keith Lovegrove[3], Andrew Want[4], Edward Langham[1], Iain MacGill[2]

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Institute for Sustainable Futures, UTS[1],
The Centre for Energy and Environmental Markets, UNSW[2] and
The Australian Solar Thermal Energy Association (AUSTELA)[4]

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Left photo: 20MWe Gemasolar tower plant with 15hr storage in Seville, Spain.
Source: http://www.torresolenergy.com/EPORTAL_IMGS/GENERAL/SENERV2/IMG2-cw4e41253840d81/gemasolar-plant-june2011-2b.jpg

Right photo: 280MWe Solana CSP plant with 6hr storage in Arizona, USA.
Source: http://guntherportfolio.com/2013/01/abengoa-solar-solana-generating-station-sortie/

THE CONSORTIUM

The consortium brings together ISF's expertise in decentralised energy, intelligent network solutions, and renewable energy analysis, CEEM's expertise in energy market dynamics and solar capabilities, and AUSTELA's firsthand knowledge of solar thermal technologies, project development and markets. IT Power (Australia)[3] provided expert advice on CSP.

The Institute for Sustainable Futures (ISF) is part of the University of Technology, Sydney, and was formed in 1997 to work with industry, government and the community on applied research projects that aim to create change towards a sustainable future. ISF has a research focus on the market benefits of large scale decentralised energy deployment in the Australian National Electricity Market. **http://www.uts.edu.au/**

The Centre for Energy and Environmental Markets (CEEM) is an interdisciplinary research Centre housed in the Faculty of Engineering and Australian School of Business within the University of NSW that focusses on market-driven transition of the energy sector. **http://www.ceem.unsw.edu.au/**

AUSTELA is the industry body solely dedicated to concentrating solar thermal power (CSP) generation in Australia. Composed of some of the leading national and international solar thermal industry participants, AUSTELA's membership is open to organisations involved in the development of solar thermal power systems on a large scale to supplement or replace existing power requirements in Australia, whether in the electricity sector or in other industry sectors. **http://austela.com.au/**

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Data supplied by the network operators and other parties and used in the formulation of this report has been compiled and assessed in good faith, but may be incomplete and is subject to errors and to change over time as the network situation changes, load projections are amended and operational and technical matters affect network performance and investment. Such changes are likely to have occurred through the period of this research and prior to publication of this report. The network operators and other parties are not responsible for any analysis and conclusions drawn from data they have provided, nor for any network information presented, which is the responsibility of the authors alone.

REVIEW

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INSTITUTE FOR SUSTAINABLE FUTURES
University of Technology, Sydney
PO Box 123, Broadway, NSW, 2007
www.isf.edu.au

Abbreviations

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARENA	Australian Renewable Energy Agency
AUSTELA	Australian Solar Thermal Association
BOM	Bureau of Meteorology
CEEM	Centre for Energy and Environmental Markets
CSP	Concentrating Solar Power
DANCE	Dynamic Avoidable Network Costs Evaluation
DNI	Direct Normal Irradiance
GIS	Geographic Information System
GW	Gigawatt
IFC	Indicative Firm Capacity
ISF	Institute for Sustainable Futures
kWh	Kilowatt hour
kVA	Kilovolt Ampere
LCOE	Levelised Cost of Electricity
MJ	Megajoule
MW	Megawatt
MWh	Megawatt hour
NEM	National Electricity Market
TES	Thermal Energy Storage

EXECUTIVE SUMMARY

This study was undertaken to quantify the potential benefits of installing concentrating solar thermal power (CSP) generation at constrained network locations in the Australian national electricity market (NEM). The primary objectives were to identify and map locations where CSP could provide cost-effective network support services, quantify the potential effect of network support payments on the business case for CSP, and engage network service providers regarding the potential for utilisation of CSP as an alternative to network augmentation.

Concentrating solar thermal power electricity generation has been in commercial operation at utility scale for over 20 years. By the third quarter of 2013, there was 3GW of installed CSP capacity worldwide and close to another 2.5GW under construction (SolarPACES 2013). However, despite excellent solar resources and considerable research and development expertise in CSP, Australia, to date, has only deployed one demonstration plant. The Australian market is very challenging, with a gap between current estimates of the levelised cost of electricity (LCOE) from CSP and likely revenue for grid-connected systems, of between $100/MWh for large systems, to more than $200/MWh for smaller systems (Lovegrove et al. 2012).

Little attention has been paid to the potential for CSP systems to alleviate grid-constraints in electricity networks. Australia’s electricity network experienced a dramatic increase in capital investment over the last six years, with over $45 billion in electricity network infrastructure planned for the period 2010 to 2015 alone.

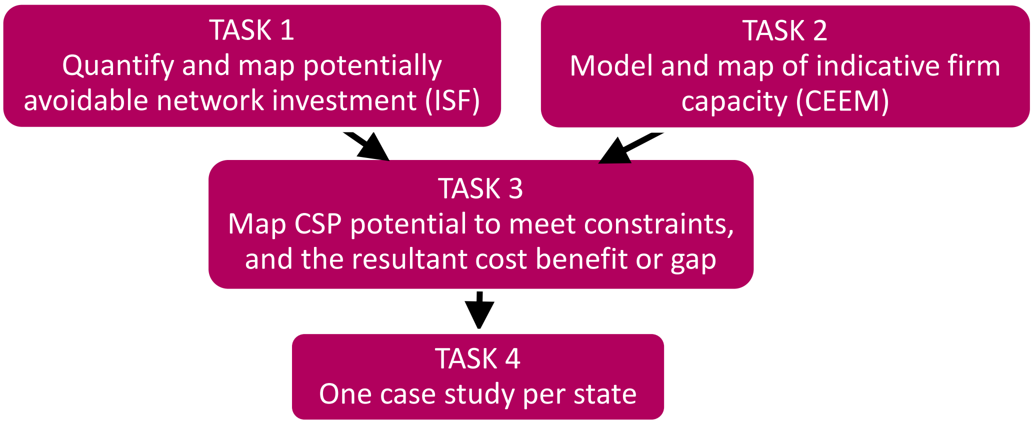
The fact that CSP may be developed with or without storage, at a variety of scales, and may be hybridized – for example with biomass or natural gas – means grid integration is relatively straightforward, in comparison with some other renewable energy options. Further, the potential network services offered by CSP are both reliable and flexible.

The central premise of this study is that rather than continuing to invest, by default, in increasing the capacity of a transmission and distribution network system designed for centralised power generation to meet growing peak demand, facilitating distributed generation or demand reduction options may provide cost effective alternatives. Increasing the deployment of these decentralised energy options, and CSP in particular, could concurrently enable greater deployment of renewable energy in the electricity system, and reduce total system greenhouse gas emissions.

Methodology

The project had four main components, as shown in Figure 1. Task 1 was to quantify and map potentially avoidable network investment, using the Dynamic Avoidable Network Costs Evaluation model (DANCE) developed by the Institute for Sustainable Futures (ISF) at the University of Technology, Sydney, according to location and expected constraint year. The main inputs are data about proposed network investment, forecast electricity demand, peak day demand profiles, and firm capacity at constrained assets in the electricity network. These are mapped for the distribution areas or connection points where distributed energy could potentially alleviate the constraint.

Figure 1: Methodology overview



Task 2 was to quantify the likelihood of CSP being able to generate during peak load periods at different locations in the NEM. The model, developed by the Centre for Energy and Environmental Markets (CEEM) at the University of New South Wales, assigns an indicative firm capacity (IFC) to each location, essentially an estimate of the probability that CSP would be generating during the most acute summer and winter peak network constraint periods. The IFC is calculated by selecting twenty-one of the highest peak demand events for each state in each of the defined peak time periods during 2009, 2010, and 2011. The model examined whether CSP with different amounts of storage, from 0 to 15 hours, would have been generating during the peak event. The IFC assigned at each location is the average value of modelled output for the specific plant configuration for the defined period (for example, summer afternoon).

Task 3 integrates the output from Tasks 1 and 2 to identify locations where CSP may provide cost effective network support, and identifies appropriate plant capacities and configurations. For modelling purposes, CSP is defined as being able to meet a network constraint when the IFC at the location for the time and season is above 80%, and a CSP plant of capacity equal to the maximum projected network constraint could be physically connected at the appropriate connection point. The cost effectiveness of CSP replacing network augmentation is assessed by comparing the CSP plant's LCOE to potential revenue, including a calculated network support payment. Different CSP plant configurations are assessed, ranging from the minimum size plant to alleviate the constraint, to the maximum size able to be connected without requiring network augmentation to export energy. The configurations include the assessment of varying amounts of thermal energy storage (TES). A reduction of 4% per year was included in the modelling of CSP capital costs to allow for the projected learning curve for CSP, a mid-range amongst estimates for likely cost reduction.

The proposed network investment is reduced by 20% prior to calculating the network support payment, reflecting the fact that electricity generation (of any type) cannot replicate the certainty offered by wires and poles. This also means the total societal cost of meeting network constraints is reduced by 20%. Note, however, that the comparison of CSP installation to other non-network solutions is not considered in this study.

Task 4 involved undertaking five case studies at constrained locations in Queensland, New South Wales, Victoria and South Australia, in consultation with the relevant network service provider.

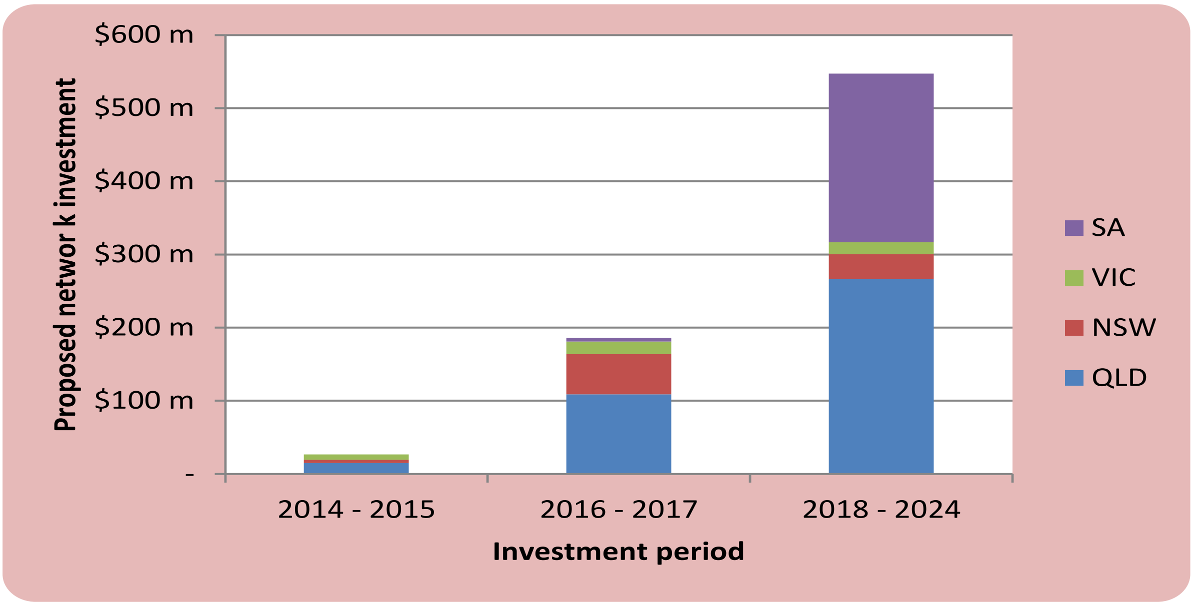
Results – potentially avoidable network investment

A total of 92 constraints, or constrained areas, were identified in non-metropolitan areas in the NEM during this research, either from public network planning documents or information supplied directly by the network operators. In two states, Queensland and South Australia, constraints were only examined in areas with direct normal insolation (DNI) likely to be sufficient for CSP to operate economically, while in Victoria and New South Wales all non-metropolitan constraints were mapped where possible. The high number of constraints in Victoria reflects the fact that use of data from public information allowed easy inclusion of all the identified non-metropolitan constraints, so low DNI areas were included, and is not because the network is more constrained.

Approximately $0.8 billion of potentially avoidable network augmentation has been identified across the NEM in areas with suitable solar irradiance for installation of CSP (defined here as average DNI which is more than 21 MJ/m^2/day). This is broken down by time period and state in Figure 2. There is a further $0.5 billion of potentially avoidable network expenditure which has been identified in areas with DNI below 21 MJ/m^2/day.

Most of the investment occurs in the period from 2016 onwards. This reflects the fact that maximum demand forecasts were reduced significantly during 2012, with the result that proposed growth-related augmentation has in many cases been deferred. It is important to stress that proposed investment changes as demand forecasts change, as different non-network solutions come into play, and as reliability criteria are adjusted. Thus the investment identified here is a snapshot of expectations at the present time.

Figure 2: Potentially avoidable network investment in areas with average daily DNI > 21 MJ/m^2



Results – indicative firm capacity

The modelling showed that IFCs in excess of 80% can be achieved in all seasons and most locations. Very little storage is required to reliably meet summer afternoon and evening peaks in most areas of the NEM. In winter, IFC is less due to the lower solar resource, but high IFCs can still be reached by increasing storage levels.

Figure 3: Indicative firm capacity summer afternoon (5 and 10 hours storage)

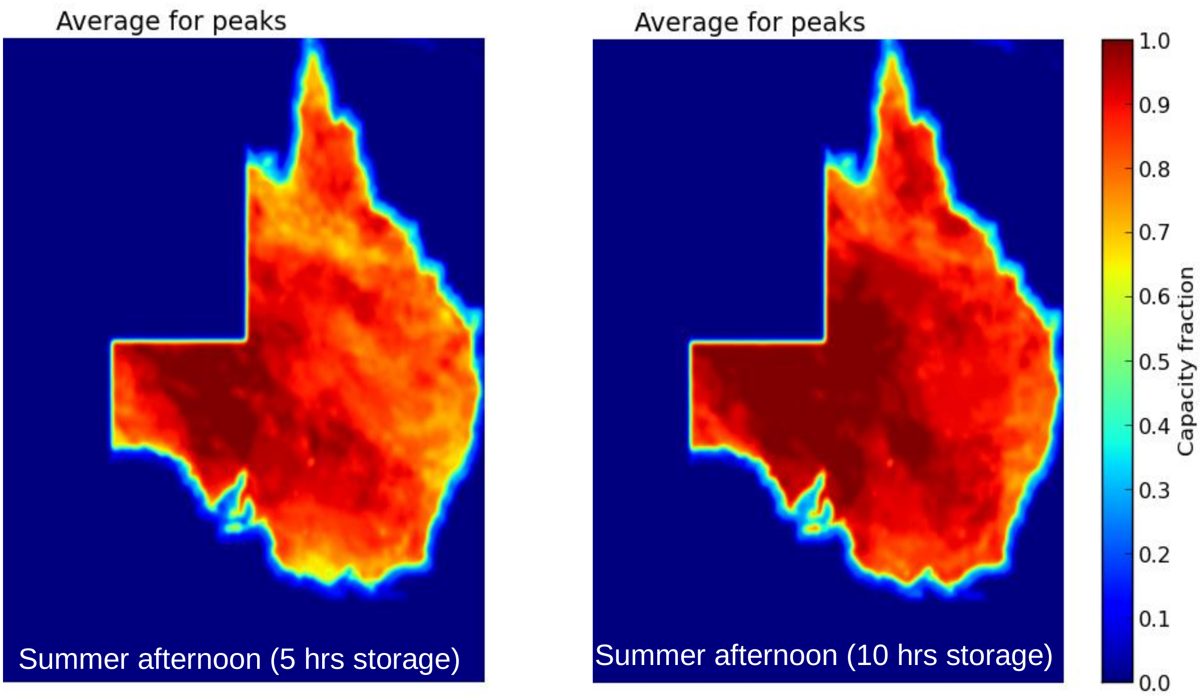


Figure 4: Indicative firm capacity winter evening (0 and 10 hours storage)

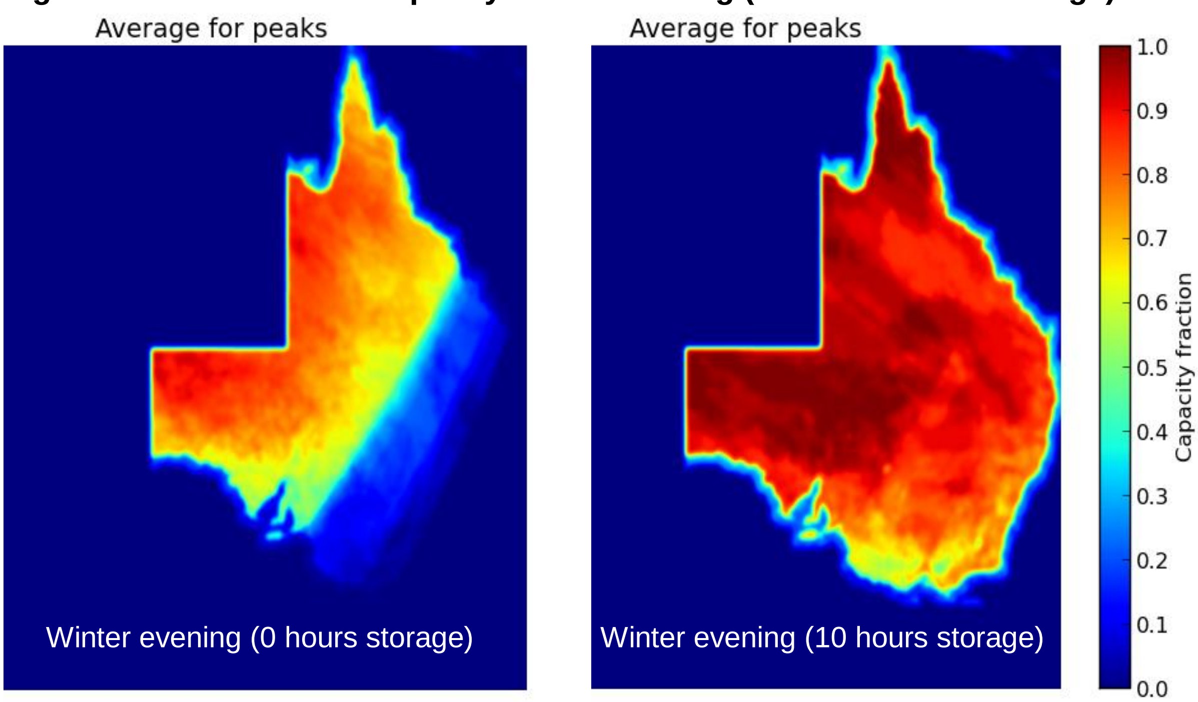


Figure 3 shows two plots of IFC across the NEM during the summer afternoon peak, with 5 and 10 hours of storage. The plots have a number of common features. First, coastal areas have lower values due to the weather systems that generally prevail on the coast. This is also true for tropical northern Queensland, where summers include monsoonal impacts and periods of high rainfall. In winter, Queensland sees higher IFCs because of the absence of monsoonal weather patterns. Second, we find that IFCs are somewhat higher the further west the plant is located (e.g. northern South Australia).

Results for winter evening (the 'worst case' for CSP) are shown in Figure 4. The plot on the left is an extreme case: winter evening results for a plant with no TES. The band across the map shows locations where IFCs are approaching zero simultaneously, as sunset falls within the period of interest (5 to 8pm on winter evenings). Further north on the plot, IFC increases because sunset occurs later. The plot on the right shows the effect of increasing storage to 10 hours, which results in IFCs of 80% and above in most areas.

The CSP model simulated plant output using a simple dispatch strategy, with generation starting at 12pm and continuing as long as possible. In practice, a more sophisticated dispatch strategy would be employed to meet any obligations under a network support contract, as well as considering solar forecasts, demand forecasts, and prevailing market prices. This could achieve much better availability than indicated by the IFC.

Results – cost effects of CSP replacing network augmentation

The results indicate that CSP could avoid the need for network augmentation in 72% of the constrained areas examined, i.e. in 48 locations. Altogether, 93 constraints, or constrained areas, were considered, of which 67 had sufficient information to make a determination. If constraints were limited to only those with solar resources better than 21 MJ/m^2/day DNI, CSP could avoid the need for augmentation at 94% of locations.

Victoria has the lowest percentage of locations where CSP can avoid the requirement for augmentation, essentially because sites with average DNI as low as 13.5 MJ/m^2/day have been included in the overall analysis. The lowest DNI for the sites examined in other states respectively is 20 (QLD), 19.8 (NSW) and 18.9 (SA).

For each location where CSP could indicatively meet the constraint, cost benefit calculations were undertaken. The results for each state are shown in Table 1. Overall, CSP installation was found to have a positive cost benefit in 25% of the constrained locations examined (where DNI > 21 MJ/m^2/day), meaning that a CSP plant operating under a network support contract would have a commercially viable business case, while the cost to energy consumers of meeting constraints is reduced by 20% relative to traditional network augmentation. An additional 36% of constrained locations come close to cost-effectiveness, with a cost gap of less than $20 (that is, overall cost benefit was between -$20 and $0 per MWh), as shown in Table 2.

Altogether, installation of 533MW of CSP at grid constrained locations was found to be cost effective during the next 10 years, and an additional 125MW had a cost benefit between -$20 and $0 per MWh. Across all states, the average plant was 40MW, with 10 hours storage, and the average and lowest LCOE were $202/MWh and $111/MWh respectively.

Table 1: Proportion of grid constrained locations where CSP could indicatively avoid the need for network augmentation

	QLD	NSW	VIC	SA	All states
Number of locations where CSP could indicatively avoid the need for network augmentation	20	7	17	4	**48**
Proportion of all locations	87%	88%	53%	100%	**72%**
Proportion of locations with DNI > 21 MJ/m^2/day	90%	100%	100%	100%	**94%**

Note: Excludes locations with insufficient information

Table 2: Cost benefit of CSP installed at grid constrained locations

	QLD	NSW	VIC	SA	All states
Proportion of cost effective sites	30%	0%	14%	67%	**25%**
Proportion of sites cost benefit > -$20/MWh	45%	17%	14%	67%	**39%**

Note: Only sites with DNI >21 MJ/m^2/day are included

The network support payment was not found to be a crucial factor to CSP plant viability in most locations, although it certainly contributed to the overall cost effectiveness, and made a major contribution in some locations. As the optimisation process generally increased the plant size to the maximum able to be connected, this had the effect of diluting the contribution from the network payment when measured as a value per MWh of plant output. The largest network support payment contribution calculated was $134/MWh (83% of the LCOE at that site), and the average $15/MWh (8% of LCOE). The average value of the network support payment at cost effective sites was somewhat higher, at $31/MWh., contributing an average of 20% of the LCOE.

Results – case studies

Five case studies were undertaken, at locations in each NEM state other than Tasmania, in consultation with Network Service Providers. The results are summarised in Table 3.

Overall, the study found that CSP installed at the case study locations would be able to delay, or avoid entirely, the planned network augmentation in all cases, and provide similar reliability to a traditional network solution in four of the five cases.

Strategies to achieve sufficient reliability varied according to the network requirements at each location. In four locations (two in Queensland, one in New South Wales and one in South Australia), the gas boiler normally installed as part of a CSP plant was modelled as oversized in order to provide emergency backup. Network requirements were to provide on–demand operation at these locations, and there were periods in each year where CSP would not provide sufficient certainty. It is expected that total gas use would be minimal, as the purpose is to provide emergency backup in the event that required network support falls outside of a period when the CSP is generating.

Table 3: Case study overview

	Network operator	Optimum plant MW / TES	Proposed augmentation year and cost	Network payment $/MWh	Net benefit $/MWh
The Riverland, SA (line replacement)	ElectraNet	40MW, 5hrs	2022, $226m	$110	$144
The Riverland SA (line upgrade)	ElectraNet	130MW, 5hrs	2022, $10m	$1	$60
Charleville, Qld	Ergon	20MW, 5hrs	2022, $70m	$6	$16
Wemen, Vic	Powercor	77MW, 5hrs	2021, $12m	$3	$23
Gunnedah supply, NSW (CSP at Moree)	Transgrid	50 MW, 5hrs	2019, $24	**$9**	**-$13**
Millchester, Qld	Ergon	40MW, 15hrs	2017, $46m	**$16**	**-$29**
Gunnedah supply, NSW (CSP at Gunnedah)	Transgrid	50 MW, 5hrs	2019, $30m	**$13**	**-$39**

In the fifth location (Wemen in Victoria), CSP could not provide certainty of generation by the end of the forecast period, as there could be a capacity shortfall for up to 100% of the time during the summer months, and CSP is not suitable for such constant generation. The CSP could reduce the likelihood of a capacity shortfall by 72%, which may be sufficient to defer the investment indefinitely. However, the CSP plant was found to have a positive cost benefit at this location without a network support payment.

The network support payment was not generally found to be a decisive factor in the case study economic outcomes, other than in the Riverland, where the network payment could provide $110/MWh if the investment from the higher cost augmentation was transferred to the CSP. In other cases, the value varied from $1/MWh to $16/MWh.

Conclusions and recommendations

This study confirms that CSP can provide a viable alternative to traditional network augmentation solutions in addressing electricity grid constraints. It supports the hypothesis that CSP has potential to play a significant role in optimising costs in electricity networks with high levels of renewable energy generation capacity. The study did not extend to other types of distributed energy as an alternative to network augmentation, and further research and an options analysis would be useful.

This study identified $0.8 billion of potentially avoidable network investment, and 533MW of cost effective CSP which could be installed at grid constrained locations in the next 10 years. Based on the current emissions intensity of electricity generation in each state, this would reduce greenhouse emissions by an estimated 1.9 million tonnes per year.

Network support payments can play a role in increasing the cost effectiveness of CSP, and such installations can avoid or defer the requirement for network augmentation. The potential for such cost effective installations will change as network forecasts are modified. If CSP and other distributed energy are to compete with traditional network solutions, the availability and accessibility of network information is likely to require improvement. The mapping outputs of this project provide an example of how information could be produced and disseminated to increase industry engagement and drive innovation and investment in developing non-network opportunities to defer augmentation. These outputs can be found at: www.breakingthesolargridlock.net.

A key requirement is for network data to be harmonised, and rules established to enable project proponents easier access to timely data, in formats that support scenario modelling. The Australian Energy Market Commission (AEMC) noted the value of more transparent network planning processes, including data access, in their 2012 review (Australian Energy Market Commission 2012).

While Regulatory Investment tests have provided consistency and rigour in economic analysis of network investments, adjustments may be required in order for the benefits of CSP (and other forms of distributed generation) to be considered appropriately and to enable greater scope for private investment and innovation.

The study supports the contention that CSP can play an important and economically efficient role in Australia’s electricity system.