



Pre-Feasibility Study for a Solar Power Precinct

Final Report

Prepared for

NSW Department of Environment, Climate Change and Water

Prepared by

AECOM Australia Pty Ltd

Level 11, 44 Market Street, Sydney NSW 2000, PO Box Q410, QVB Post Office NSW 1230, Australia T +61 2 8295 3600 F +61 2 9262 5060 www.aecom.com

ABN 20 093 846 925

17 December 2010

60149060

This report was prepared by AECOM Australia Pty Ltd solely for the use of the Department of Environment, Climate Change and Water NSW (DECCW) in good faith exercising all due care and attention, but no representation or warranty, express or implied, is made as to the relevance, accuracy, completeness or fitness for purpose of this document in respect of any particular user's circumstances. AECOM Australia Pty Ltd undertakes no duty to or accepts any responsibility to any third party who may rely upon this document. Users of this document should satisfy themselves concerning its application to, and where necessary seek expert advice in respect of, their situation. The views expressed within are not necessarily the views of DECCW and may not represent DECCW policy.

Quality Information

Document Pre-Feasibility Study for a Solar Power Precinct

Ref 60149060

Date 17 December 2010

Prepared by Katie Feeney, Dominic Kua, Jeremy Balding and Robin Goodhand

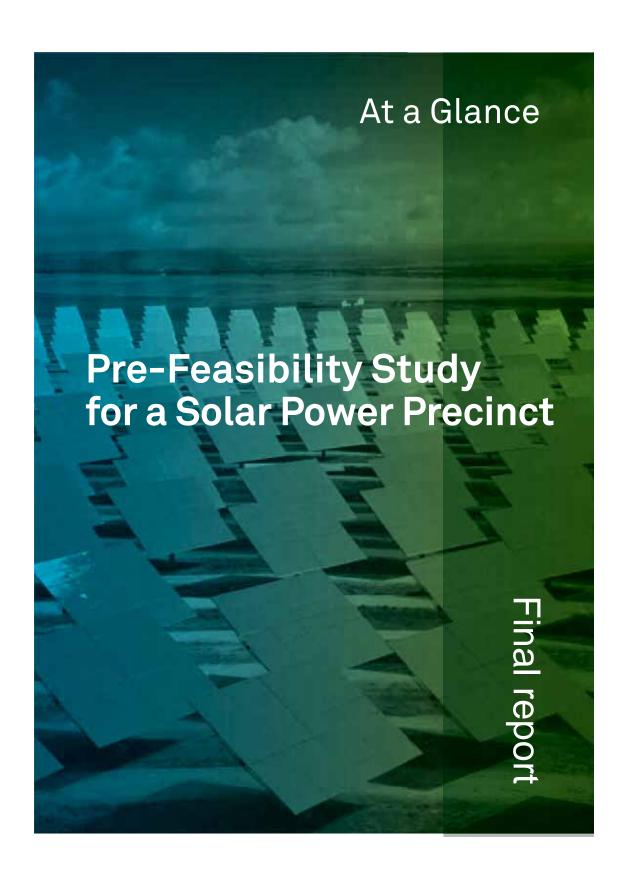
Reviewed by Peter Wood and David Adams

Revision History

Povision	Revision	D	Authorised		
Revision	Date	Details	Name/Position	Signature	
A	26-Mar-2010	Progress Report	Peter Wood Director - Energy, Renewables & Carbon Management	Original signed	
В	30-Apr-2010	Draft Report	Peter Wood Director - Energy, Renewables & Carbon Management	Original signed	
С	31-May- 2010	Final Report	Peter Wood Director - Energy, Renewables & Carbon Management	Original signed	
D	25-Jun-2010	Final Report	Peter Wood Director - Energy, Renewables & Carbon Management	Original signed	
E	23-Jul-2010	Final Report	Peter Wood Director - Energy, Renewables & Carbon Management	Original signed	
F	17-Dec-2010	Revised Final Report	Peter Wood Director - Energy, Renewables & Carbon Management	Par.	

Table of Contents

At a G	lance		i
Execu	tive Sumn	nary	iii
Glossa	ary		xiv
1.0	Introd	uction	1
	1.1	Background	1
	1.2	Objectives	1
	1.3	Scope and Deliverables	2
	1.4	Document Structure	2
2.0	Metho	odology	3
	2.1	Overview	3
	2.2	Phase 1: Technical and Environmental	3
	Feasik	pility	3
	2.16	Phase 2: Economics	9
	2.17	Phase 3: Risk Assessment and Role for Government	9
	2.18	Phase 4: Summary	9
3.0	Techn	ical Assessment	11
	3.1	Technology	11
	3.2	Summary of Area Selection Process	11
	3.3	Detailed Technical Assessment	13
	3.4	Summary	18
4.0	Econo	omic Feasibility	19
	4.1	Introduction	19
	4.2	Methodology	19
	4.3	Levelised Cost of Electricity	21
	4.4	Feasibility assessment	27
	4.5	Cost Sensitivity	30
5.0		Assessment	35
6.0		of Government	40
0.0	6.1	Introduction	40
	6.2	Economic Benefits	40
	6.3	Types of Assistance	43
	6.4	Summary	49
7.0	Refere		51
7.0	recicie	511000	01
Apper	ndix A		A
	Area s	selection process	A
Annor	ndiv B		В
Apper		ed factor assessment	В
	Detaile	eu lactor assessment	D
Apper	ndix C		C
	Solar	technology characteristics	C
Δ	D		Б
Apper			D
	ı ransı	mission components	D
Apper	ndix E		E
		Normal Radiation	E
Apper			F
	l'echn	ology and area matrices	F



At a Glance

The NSW State Plan commits NSW to playing its part in reducing Australia's greenhouse gas emissions to 60% below 2000 levels by 2050. To achieve this, the share of the NSW energy mix coming from renewable sources will need to grow substantially. The National Renewable Energy Target commits Australia to source 20% of its energy from renewable sources by 2020. This study is part of NSW Government's investigations into whether dedicated solar development areas in NSW would help grow solar investment.

This study aims to:

- Determine the feasibility of large scale solar projects in NSW and to test the concept that the co-location of solar plants into a precinct to facilitate sharing of infrastructure may expedite financial viability;
- Identify potential areas for solar precincts in NSW;
- Compare different solar technologies; and
- Identify whether there is a role for Government to support large scale solar projects.

This study considered five types of technology: thin film photovoltaic, mono-crystalline photovoltaic, solar trough, solar tower and a solar trough gas hybrid. Five areas were selected to assess the feasibility of a solar precinct in NSW: Broken Hill, Darlington Point, Dubbo, Moree and Tamworth. Key conclusions are set out below.

Is a solar precinct feasible?

A solar precinct is technically feasible at all five of the areas considered in detail as part of this study. However, there is variation in levelised costs between each of the five areas and the technologies. The high capital costs of solar technology remain the most significant factor affecting the feasibility of solar electricity generation. Other area specific factors such as land prices and transport costs are relatively insignificant as a proportion of total costs. Water costs are also relatively insignificant but the availability of water is an important issue. Delivered gas prices are an important factor for solar-gas hybrid technology.

The most significant technical issue is the connection and integration of large scale solar capacity to the electricity network. Importantly, with the exception of Darlington point, it was technically feasible to connect a 1,000MW precinct to the TransGrid network without significant network strengthening. However, there may be some regulatory challenges as solar power stations are presently regarded by the market rules as intermittent and currently there are no mechanisms for re-designating solar generation as conventional dispatchable generation.

How does a 250 MW plant compare with a 1,000 MW precinct?

The benefit of developing a precinct as opposed to a standalone plant is very area specific and highly dependent on the existing transmission infrastructure. Nonetheless, there are non-financial benefits of a precinct over a standalone plant such as reduced risk and uncertainty, easier environment and planning approvals, increased viability of onsite manufacturing and additional jobs creation. Whilst not having a significant direct impact on project costs, these benefits may in turn lead to better financing terms for developers and facilitate quicker development of large scale solar projects. Sensitivity analysis showed that improved financing can reduce the levelised cost by 6-7%.

What is the most feasible area?

Of the five areas considered, Broken Hill appears the most favourable location for a 250 MW plant due to high levels of solar resource and minimal additional transmission infrastructure required to connect a 250 MW plant. The high cost of the additional transmission infrastructure required for a 1,000MW precinct make a Broken Hill precinct less favourable. Moree is the most favourable area for a 1,000 MW precinct as the additional transmission costs compared to other areas are outweighed by higher electricity production as a result of higher solar resource.

What is the most feasible technology?

Of the technologies modelled, solar trough gas hybrids currently have the lowest levelised cost for all areas with the exception of Moree. Solar tower systems are forecast to provide the lowest levelised costs of the solar-only technologies considered. The inclusion of thermal storage to a solar tower plant or precinct may allow electricity to be scheduled for dispatch at peak periods where it can be sold for a higher price.

Both PV technologies considered were forecast to have levelised costs of electricity higher than the solar thermal options.

17 December 2010

When might large scale solar projects become financially viable?

Compared to new entrant gas generators, solar trough gas hybrid plants, and to a lesser extent, solar tower plants do not appear to become cost competitive for around 15 to 20 years. However, this timing is dependent on REC prices and the introduction of CPRS. The inclusion of thermal storage to solar tower plants may improve financial viability such that tower may become cost competitive under CPRS within 5 to 10 years. Thin film and mono-crystalline photovoltaic technology does not appear to be financially viable in the foreseeable future without significant cost reductions or efficiency improvements.

What are the key factors affecting financial viability?

The most significant factors affecting financial viability of a large scale solar project are the high capital costs of solar electricity generation and the current uncertainty about future revenues. The price trajectory of solar technology over the next 5 to 10 years, as well as more certainty about REC prices and a CPRS, will be significant in determining when financial viability is achieved.

What might be role for the NSW Government?

Large upfront capital costs, combined with high transaction costs, a long gestation period from early development to construction commencement, uncertainty about future revenues and technology risk, make financing of large scale solar projects difficult. These issues may prevent industry developing a large scale solar project in NSW in the foreseeable future. By providing assistance, the Government could bring forward the development of large scale solar projects in NSW.

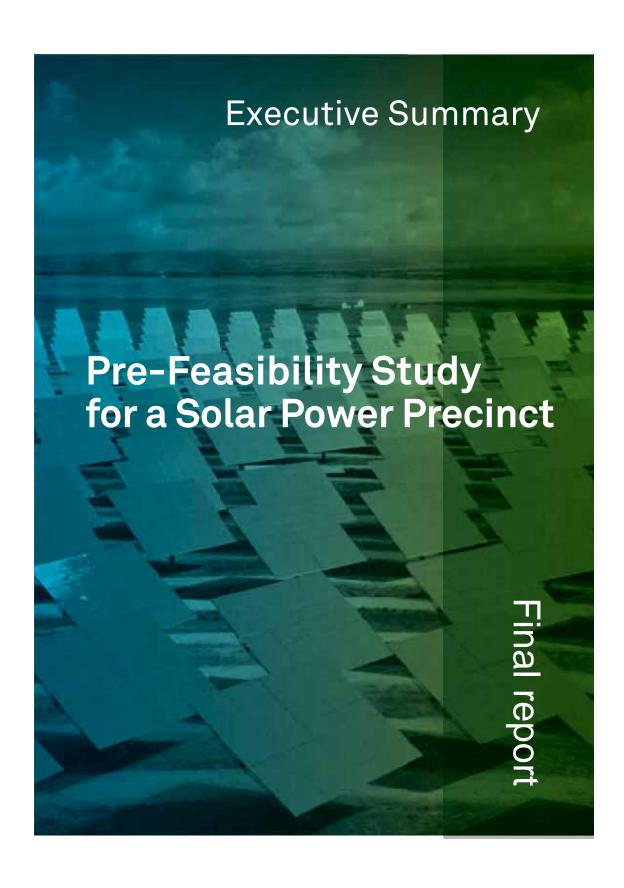
The solar industry is still a relatively new market and, despite good solar resource, Australia has lagged behind in industry development. Establishing a solar plant or precinct will promote the development of the Australian solar industry and generate employment opportunities. By supporting a project of this size, Australia may be better positioned to become a global leader in solar technologies and local production of such technologies should significantly reduce their cost in Australia. In addition, by bringing forward the development of large scale solar projects, the Government will enhance greenhouse gas reductions, helping to achieve the NSW State Plan commitment to play its part in reducing Australia's greenhouse gas emissions to 60% below 2000 levels by 2050 and meeting the national Renewable Energy Target to source 20% of its energy from renewables by 2020.

Any potential role of government should focus around reducing transaction costs and gestation period (through the provision of a pre-approved site and access to key infrastructure such as transmission, water and gas); provision of capital funding (through upfront grant, debt or equity); or improving certainty over revenue streams (through a Power Purchase Agreement). In essence, both capital funding and PPAs will improve investor and developer confidence and will be beneficial in bringing forward the development of large solar projects in NSW. A PPA allows any assistance to be spread over a 20 to 30 year time horizon and reduces the risk that the project will not deliver the expected quantities of solar energy generation. However, the PPA is more expensive to government than an upfront capital grant (by around \$75m-\$115m) because it is cheaper for government to borrow money than a private developer. On their own, measures to reduce transaction costs are unlikely to be enough of an incentive to bridge the financial viability gap. However, government may wish to supplement any capital funding or PPA with support to industry to facilitate easier permitting and access to infrastructure.

Next steps

This study is a pre-feasibility study to test the concept of developing large scale solar precincts as well as identify some of the best areas and technologies in NSW for large scale solar projects. Whilst large scale solar projects may not be financially feasible at the moment, there are some potentially large economic benefits for society in terms of reduced greenhouse gas emissions and industry generation that may warrant Government playing a role in bringing forward the development of large scale solar projects. The magnitude of these benefits is highly dependent on the area and technology under consideration, as well as the level of government assistance and the extent to which it advances the large scale solar industry in NSW. Once a specific area and technology are selected it will be important to undertake:

- A more detailed feasibility study;
- A full economic appraisal to quantify the economic benefits and assess the economic viability of any proposed government assistance; and
- Develop a roadmap to maximise the benefits from supply chain and industrial development.



Executive Summary

Background and Objectives

The NSW State Plan commits NSW to playing its part in reducing Australia's greenhouse gas emissions to 60% below 2000 levels by 2050. To achieve this, the share of the NSW energy mix coming from renewable sources will need to grow substantially.

In the same way that the NSW Government is facilitating wind investment through the establishment of wind renewable energy precincts, this study is part of NSW Government's investigations into whether dedicated solar development areas in NSW would help grow solar investment.

In this context, AECOM's study aims to:

- Determine the feasibility of large scale solar projects in NSW and to test the concept that
 the co-location of solar plants into a precinct to facilitate sharing of infrastructure may expedite
 financial viability;
- Identify potential areas for solar precincts in NSW;
- · Compare different solar technologies; and
- Identify whether there is a role for Government to support large scale solar projects.

Technologies considered

For the purposes of this study a solar precinct is defined as the co-location of solar plants into a precinct to facilitate sharing of infrastructure, particularly access to the electricity network. A precinct could involve up to 1,000 MW of generation capacity including:

- Solar photovoltaic (PV) technology (thin film and mono-crystalline have been considered in this study);
- Solar thermal technology (trough and tower have been considered in this study); and/or
- Solar-gas hybrids (solar trough gas hybrid has been considered in this study).

Areas considered

This study is a pre-feasibility study to examine the concept of a solar precinct and, as such, does not involve identification of a specific land allotment area for development. For the purpose of this study an area is defined as general locations within approximately a 20km radius of a town. A preliminary list of sixteen potentially suitable areas in NSW for a solar precinct development was determined using geospatial analysis of factors such as solar resource, transmission access and land availability. Preliminary quantitative analysis of these factors yielded high level estimates of electricity generation and project costs for each area. The sixteen areas were ranked based on an estimated cost per MWh basis and a qualitative evaluation of environmental, water and land issues. A shortlist of five areas was then selected for more detailed analysis of the trade-offs between feasibility factors.

The five areas selected for further analysis were:

- Broken Hill;
- Darlington Point;
- Dubbo;
- Moree; and
- Tamworth.

Approach

There are a number of area specific factors that affect the feasibility of a solar precinct as set out in **Figure E.1**. This study assessed each of these factors for the five identified areas in addition to forecast solar technology capital costs. Whilst this analysis is sufficient for this pre-feasibility study to test the concept of large scale solar precincts and compare areas, more detailed analysis would be required for the identification and development of a specific site.

17 December 2010

Figure E.1 Area feasibility factors



Figure E.2 shows the five selected areas including solar resource, transmission infrastructure and gas pipelines. The areas have been chosen to represent a range of characteristics to explore the different tradeoffs. For example, Broken Hill has very good solar resource, access to a 220kV transmission line, but poor access to water or gas. Darlington Point has lower solar resource but access to a 330kV transmission line and good access to gas. Key characteristics of each of the selected areas are summarised in **Table E.1.1**.

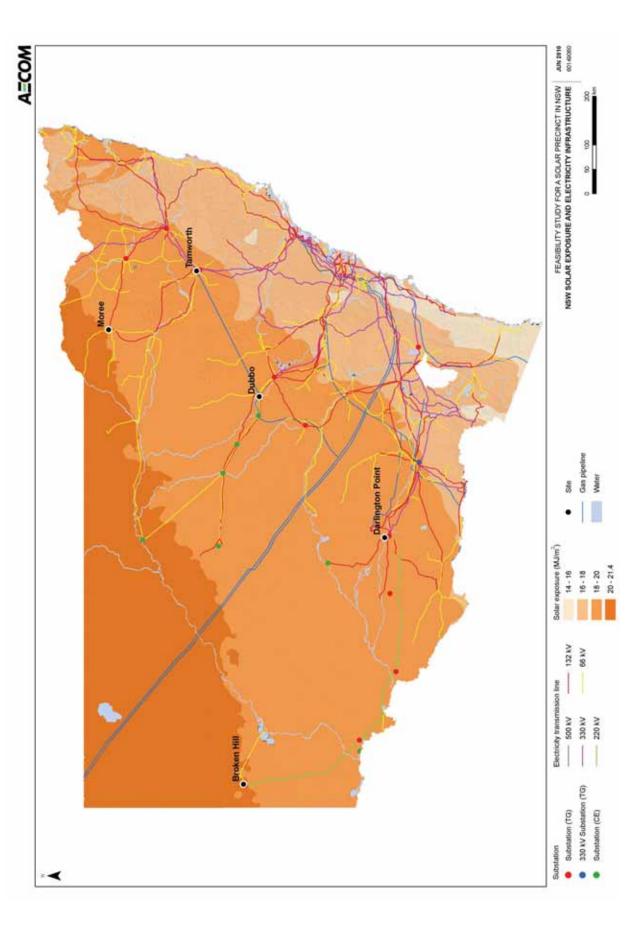
Table E.1.1 Summary of area characteristics

Area	Solar Resource	Access to transmission infrastructure	Access to water	Access to gas	Land prices
Broken Hill	Excellent	Good transmission line access - proximity to 220kV line	Poor	Poor	Lower land values
Darlington Point	Good	Excellent transmission line access - proximity to 330kV line	Good	Excellent (proximity to gas pipeline)	Lower land values
Dubbo	Good	Good	Good	Good (proximity to gas pipeline)	Higher land values
Moree	Excellent	Poor -proximity to 132kV line	Poor	Poor	Higher land values
Tamworth	Good	Excellent transmission line access - proximity to 330kV line	Poor	Good (proximity to gas pipeline)	Higher land values

Source AECOM

17 December 2010 iv

Figure E.2 Study areas, solar resource, transmission lines and gas pipelines



Study Findings

This study sought to answer a number of questions, including:

- Is a solar precinct feasible?
- How does a 250MW plant compare with a 1,000 MW precinct?
- Where is a suitable area for a solar precinct?
- What is a feasible technology?
- When might large scale solar projects become financially viable?
- What are the key factors affecting financial viability?
- What is the role of Government?

Is a solar precinct feasible?

A solar precinct is technically feasible at all five of the areas considered in detail as part of this study. However, there is variation in levelised costs between each of the five areas and financial viability is dependent on factors such as the area and technology chosen, as well as factors beyond a developers control such as the introduction of CPRS or REC prices.

This study shows that a solar precinct, defined as up to 1,000 MW of generation capacity to facilitate sharing of infrastructure, is technically feasible at all five of the areas considered in detail as part of this study.

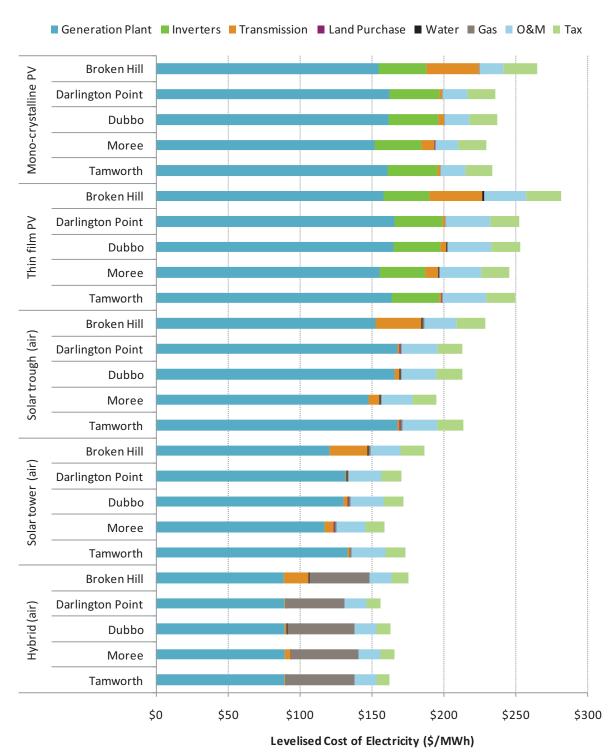
However, there is variation in levelised costs between each of the five areas and financial viability is dependent on factors such as the area and technology chosen, as well as factors beyond a developers control such as the introduction of CPRS or REC prices. **Figure E.3** shows the components of levelised cost for each area and technology for a 1,000 MW precinct with construction commencing in the financial year ended June 2015.

The high capital costs of solar technology remain the most significant factor affecting the feasibility of solar electricity generation; local solar resource and transmission infrastructure costs also play an important part in determining the relative merit of potential areas. Existing suitable transmission infrastructure is significant in lowering capital costs compared to other areas. Other area specific factors such as land prices are relatively insignificant as a proportion of total costs. Water costs are also relatively insignificant but the availability of water is an important issue. None of the areas considered are believed to have sufficient available water resource for wet cooling of solar thermal precincts. Delivered gas prices are an important factor for solar-gas hybrid technology, as is evident by the results showing Darlington Point as the area with the lowest gas prices and the most suitable area of those considered for a 250 MW hybrid plant. There are a range of other site specific factors that will influence the feasibility of a solar plant or precinct such as transport costs. However, as this study does not look at specific sites it is not possible to include these. It has been assumed that a site would be selected with good access to transport. In addition, these other costs are likely to be a small proportion of the total costs so will not significantly affect the levelised cost model.

The most important technical issue is connection and integration of large scale solar capacity to the electricity network. Importantly, with the exception of Darlington Point, it was technically feasible to connect a 1,000MW precinct to the TransGrid network without significant network strengthening. However, there may be some regulatory challenges as solar power stations are presently regarded by the market rules as intermittent because they have limited or no energy storage capability and cannot be relied on individually to contribute to the secure supply of electricity. There are no mechanisms for re-designating solar and other renewable generation as conventional dispatchable generation because the Rules lack a definition of intermittency and designate intermittent generators solely by type. Addressing this, and other regulatory challenges, will assist in the penetration of solar generation into the electricity supply market.

17 December 2010

Figure E.3 Components of levelised cost of electricity – 1,000 MW precinct (2015 construction commencement)



Source AECOM

17 December 2010 vii

How does a 250 MW plant compare with a 1,000 MW precinct?

The benefit of developing a precinct as opposed to a standalone plant is very area specific and highly dependent on the existing transmission infrastructure. Nonetheless, there are non-financial benefits of a precinct over a standalone plant such as reduced risk and uncertainty, easier environment and planning approvals, increased viability of onsite manufacturing and additional jobs creation. Whilst not having a significant direct impact on project costs, these benefits may in turn lead to better financing terms for developers and facilitate quicker development of large scale solar projects. Sensitivity analysis showed that improved financing can reduce the levelised cost by 6-7%

Table E.1.2 compares the levelised cost of electricity for a 1,000 MW precinct to a standalone 250 MW plant at each area after adjusting for the projected declines in capital costs during development of a 1,000 MW precinct due to the later construction date of some stages in the precinct. Percentages show the relative levelised cost difference between a 1,000 MW precinct and a 250 MW plant.

Table E.1.2 Levelised cost of electricity (\$/MWh) for 250 MW plant and 1,000 MW precinct with percentage difference from 250 MW plant (2015 construction commencement)

Technology Broken Hill		Darlington Point	Dubbo	Moree	Tamworth				
	250 MW Plant								
Mono-crystalline PV	\$225	\$234	\$241	\$247	\$232				
Thin film PV	\$244	\$252	\$258	\$264	\$249				
Solar trough (air)	\$196	\$213	\$217	\$211	\$213				
Solar tower (air)	\$159	\$171	\$176	\$172	\$173				
Hybrid (air)	\$158	\$156	\$165	\$175	\$162				
		1,000 MW Pr	recinct						
Mono-crystalline PV	\$265 (+17%)	\$236 (+1%)	\$237 (-2%)	\$229 (-7%)	\$234 (+1%)				
Thin film PV	\$281 (+15%)	\$252 (0%)	\$253 (-2%)	\$245 (-7%)	\$249 (+0%)				
Solar trough (air)	\$229 (+17%)	\$213 (+0%)	\$213 (-2%)	\$195 (-8%)	\$213 (+0%)				
Solar tower (air)	\$186 (+17%)	\$171 (0%)	\$172 (-2%)	\$159 (-8%)	\$173 (+0%)				
Hybrid (air)	\$175 (+11%)	\$156 (+0%)	\$163 (-1%)	\$166 (-5%)	\$163 (+0%)				

Source AECOM

Table E.1.2 shows that developing a 1,000 MW precinct results in higher levelised costs (10-17%) for all technologies at Broken Hill, no changes in levelised cost at Darlington Point and Tamworth, marginally lower costs at Dubbo (2%), and significantly lower costs at Moree (5-8%).

These differences are primarily a result of the additional cost of increasing transmission infrastructure capacity from that suitable for a 250 MW plant to that suitable for a 1,000 MW precinct. With the exception of Broken Hill, all locations considered have a reduced cost of transmission infrastructure per MWp for a 1,000 MW precinct compared to a 250 MW plant. However, the magnitude of transmission connection costs at Darlington Point, Tamworth and Dubbo is small as a proportion of total costs and the reductions do not manifest as significant differences in the levelised cost. Transmission connection costs at Moree are a larger proportion of total costs so the reduced cost of transmission for a 1000MW precinct has a greater impact on the levelised cost.

Transmission infrastructure is generally the largest cost of development after the solar generating technology itself. Therefore the benefits of developing a precinct as opposed to a standalone plant are highly dependent on the existing transmission infrastructure, what level of additional transmission capacity enhancements are required, as well as the magnitude of transmission costs as a proportion of total project costs.

Whilst a precinct may not have a significant impact on the levelised cost, there are further benefits associated with developing a 1,000 MW precinct as opposed to a 250 MW standalone plant. As each plant within a precinct is successfully developed, commissioned and operated, potential risks (as discussed in **Section 5.0**) to subsequent plants within the precinct may be mitigated. In addition, a precinct will require only one environment and planning approval, there are potential for reduced transport and other site specific costs, and an increase in the viability of onsite manufacturing and additional jobs creation. Whilst not having a significant direct impact on project costs, these benefits may in turn lead to better financing terms for developers and facilitate quicker development of large scale solar projects. Sensitivity analysis showed that improved financing can reduce the levelised cost by 6-7%.

17 December 2010 vii

A Scale Efficient Network Extension (SENE) type agreement, which allows for the large transmission costs to be spread across a number of plants, will be most beneficial in areas where significant infrastructure upgrade is required. In addition, by reducing the costs of the first plant, a SENE type agreement may induce investors into the market earlier than otherwise, particularly in the early stages of large scale solar development when commercial viability is marginal.

What is the most feasible area?

Of the five areas considered, Broken Hill appears the most favourable location for a 250 MW plant due to high levels of solar resource and minimal additional transmission infrastructure required to connect a 250 MW plant. However, there is significant additional transmission infrastructure required for a 1,000 MW precinct at Broken Hill. Moree is the most favourable area for a 1,000 MW precinct of the areas considered. Although transmission infrastructure costs are higher at Moree than those at Darlington Point, Dubbo and Tamworth, this additional cost is outweighed by higher electricity production as a result of better solar resource.

The levelised costs set out in **Table E.1.2** show that of the five areas considered in detail, Broken Hill is the best area for a 250 MW standalone plant across all of the solar technologies considered, but higher gas prices make it less attractive for a solar-gas hybrid plant. This is mainly due to the higher solar resource available at Broken Hill and low transmission infrastructure costs for a standalone 250 MW plant. Moree is the preferred area among those considered in this study for a 1,000 MW precinct. This is a result of the high level of solar resource and corresponding electricity production outweighing the additional transmission infrastructure costs for this area. However, Darlington Point is preferred over Moree for a solar-gas hybrid precinct. Darlington Point, Dubbo and Tamworth all have similar levelised costs for all the technologies considered. This is a reflection of the similar levels of solar resource at each of these areas and similar transmission infrastructure capital costs.

What is the most feasible technology?

Solar trough gas hybrids currently have the lowest levelised cost for all areas with the exception of Moree. Solar tower systems are forecast to provide the lowest levelised costs of the solar-only technologies considered. Both PV technologies considered were forecast to have levelised costs of electricity higher than the solar thermal options.

There are significant variations in the modelled levelised cost of electricity between the different technologies considered. Solar trough gas hybrids result in the lowest levelised cost of electricity for all areas with the exception of Moree, primarily due to a greater proportional increase in electricity production than increase in capital and operating costs for hybridisation of the solar trough plant. However, it is worth noting that while the use of gas to co-fire a solar thermal plant improves the financial viability of a solar thermal plant, it is not the most cost effective use of gas and does not generate all of the economic benefits from pure solar technologies such as reductions in greenhouse gas emissions and industry development.

Solar tower systems are forecast to provide the lowest levelised costs of the solar-only technologies considered. In addition, the inclusion of thermal storage to solar tower plants may allow scheduled dispatch into the market where it can be sold for a higher price. However, this technology is relatively new and untested at the scale proposed. Both PV technologies considered were forecast to have higher levelised costs of electricity than the solar thermal options. A 250 MW plant or 1,000 MW precinct, using either thin-film or mono-crystalline PV, does not appear to be financially viable in the foreseeable future at any of the five areas considered without significant cost reductions or efficiency improvements

When might large scale solar projects become financially viable?

Compared to new entrant gas generators, solar trough gas hybrid plants, and to a lesser extent, pure solar tower plants do not appear to become cost competitive for around 15 to 20 years. However, this timing is dependent on REC prices and the introduction of CPRS and adopted emission reduction target. Higher REC prices or a more aggressive CPRS emission reduction target would act to bring forward solar feasibility through price convergence with conventional gas fired generation. Thin film and mono-crystalline photovoltaic technology does not appear to be financially viable in the foreseeable future without significant cost reductions or efficiency improvements.

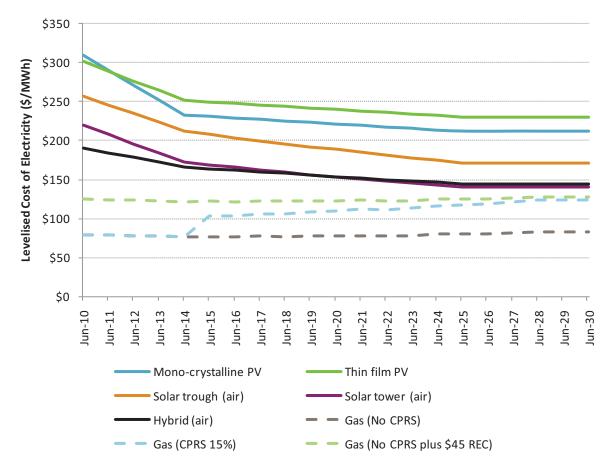
Figure E.4 shows levelised costs of electricity by year of commencement of construction for a 250 MW plant at Broken Hill for each of the solar technologies considered. Other areas and 1,000 MW precincts show a similar trend of cost declines. Also shown is an average of open cycle gas turbine (OCGT) and combined cycle gas turbine (CCGT) new entrant costs, against which solar generation will likely be competing in the electricity market.

Compared to new entrant gas generators, solar trough gas hybrid generation, and to a lesser extent, solar tower plants do not appear to become cost competitive for around 15 to 20 years. However, this timing is dependent on

17 December 2010 ix

REC prices and the introduction of CPRS and adopted emission reduction target. Higher REC prices or a more aggressive CPRS emission reduction target would act to bring forward solar feasibility through price convergence with conventional gas fired generation. The levelised costs produced by this study are conservative estimates; competitive pressures may result in different outcomes in the market.

Figure E.4 Levelised cost of electricity for 250 MW standalone plant at Broken Hill and new entrant gas energy prices by year of construction



Source AECOM

The inclusion of thermal storage for solar tower would result in a higher levelised cost due to the additional cost of the storage technology and increased field size. However, this may be outweighed by the ability to command a higher price for electricity that can be scheduled for dispatch into the market during periods of peak demand. The inclusion of storage may accelerate the point at which the levelised costs for tower becomes cost competitive against new entrant OCGT plants.

17 December 2010

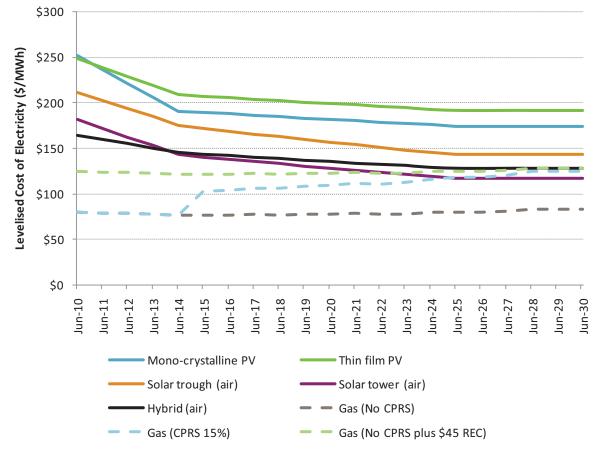
What are the key factors affecting financial viability?

The most significant factors affecting financial viability of both a standalone plant and a larger precinct are the high capital costs of solar electricity generation and the current uncertainty about future revenues. The price trajectory of solar technology over the next 5-10 years, as well as more certainty of REC prices and a CPRS, will be significant in determining when financial viability is achieved.

As illustrated in **Figure E.3**, the differences in cost per MWh are largely as a result of differing capital costs of generation equipment for each technology and different transmission infrastructure requirements at each location. As such, significant reductions in technology capital costs will have a much greater impact on feasibility compared to reductions of other cost elements. The price trajectory of solar technology over the next 5 to 10 years will be significant in determining if and when financial viability is achieved. This is illustrated in **Figure E.5**, which shows levelised costs for a 250MW plant at Broken Hill with a 20% decrease in current technology capital costs assumptions. Compared to new entrant gas generators, hybrid solar trough generation, and to a lesser extent, pure solar tower plants are forecast to become cost competitive within 10 to 15 years.

Figure E.5 also highlights the importance of RECs and CPRS in financial viability. In order for solar generation to be financially viable it needs to be competitive with other new electricity generation entrants. RECs and a CPRS reduce the price differential, increasing solar generation's competitiveness. However, the current uncertainty in both of these markets will make it more challenging for any developer to secure a long term Power Purchase Agreement (PPA).

Figure E.5 Levelised cost of electricity for 250 MW standalone plant at Broken Hill and new entrant gas energy prices by year of construction – 20% decrease in technology capital cost



Source AECOM

17 December 2010 xi

What might be role for the NSW Government?

Large upfront capital costs, combined with high transaction costs, a long gestation period from early development to construction commencement, uncertainty about future revenues, and technology risk, make financing of large scale solar projects difficult. These issues may prevent industry developing a large scale solar project in NSW in the foreseeable future.

By providing assistance, the Government could bring forward the development of large scale solar projects in NSW. This will benefit society in terms of carbon emission reductions and the potential for industry development in

Any potential role of government should focus around reducing transaction costs and gestation period through the provision of: a pre-approved site and access to key infrastructure such as transmission, water and gas; capital funding through upfront grant, debt or equity; or improved certainty over revenue streams through a PPA. In essence, both capital funding and PPAs will improve investor and developer confidence and will be beneficial in bringing forward the development of large solar projects in NSW. A PPA allows any assistance to be spread over a 20 – 30 year time horizon and reduces the risk that the project will not deliver the expected quantities of solar energy generation. However, the PPA is more expensive to government because it is cheaper for government to borrow money than a private developer. On their own, measures to reduce transaction costs are unlikely to be enough of an incentive to bridge the financial viability gap. However, government may wish to supplement any capital funding or PPA with support to industry to facilitate easier permitting and access to infrastructure.

Whilst it is clear that solar will play an important part of the future supply of electricity the timing of this is uncertain. This study shows that large scale solar projects are unlikely to be financially viable for the next 10-20 years and it is hard to see a developer making financial investments in large scale solar power plants in the short term. There is much uncertainty in the market around both capital costs and potential revenue sources.

In addition, a large scale solar project requires infrastructure (transmission, gas, water), land and environmental and planning approvals which while not a significant proportion of the total cost provide further risk and uncertainty around a proposed project, particularly in terms of the gestation period from early development to construction commencement.

The role of government in providing assistance to bring forward the development of large scale solar projects depends on the extent of benefits to society and if they outweigh the costs of assistance. The main benefits to society from the advancement of large scale solar projects in NSW include:

Carbon emission reductions

By bringing forward the development of large scale solar projects, the Government will enhance greenhouse gas reductions. The magnitude of these benefits depends on the technology, area and how many years the project is brought forward. If the Government were to bring forward investment of a solar thermal tower precinct by 10-15 years at Moree, the most favourable area, this would generate greenhouse gas emission savings of around 3.2 (10 years) to 4.8 (15 years) million tCO2-e. This is a reduction of 5-7% of current greenhouse gas emissions from electricity in NSW and will go a significant way to achieving the NSW State Plan commitment to play its part in reducing Australia's greenhouse gas emissions to 60% below 2000 levels by 2050 and meeting the national Renewable Energy Target to source 20% of its energy from renewables by 2020.

Industry development in Australia

The solar industry is still a relatively new market and, despite good solar resource, Australia has lagged behind in industry development. Establishing a solar plant or precinct will promote the development of the Australian solar industry and generate employment opportunities. Whilst, the employment impact will be dependent on the technology and site chosen, overall, solar technology plants, particularly photovoltaic, generate significantly more jobs than OCGT and CCGT plants for construction. For example, construction employment for a 1,000 MW solar PV precinct is around 10,000 full time equivalent (FTE) compared to around 5,000 for solar thermal and 1,000 for OCGT. During operation, photovoltaic technology does not require significant maintenance so employment is limited. Solar thermal technology generates around 20% more operational employment than OCGT and CCGT plants. Employment is higher if onsite manufacturing occurs.

In addition, by supporting a project of this size, Australia may be better positioned to become a global leader in solar technologies and local production of such technologies should significantly reduce their cost in Australia.

The potential roles for government are wide ranging. As discussed above, the main barriers in the large scale solar industry are focused around the large upfront capital cost requirements, long-term financial uncertainty and the high

17 December 2010 xii

transaction costs (e.g. access to grid, planning and environmental approvals). Any potential role of government should focus around addressing these issues and generally fall into the following three categories:

- Reducing transaction costs and gestation period through providing a pre-approved site and provision of access to key infrastructure such as transmission, water and gas;
- Capital funding through upfront grant, debt or equity; and
- Improved certainty over revenue streams through a PPA.

Measures to reduce transaction costs and gestation periods reduce the risks and uncertainty, facilitating the early engagement of debt providers and financiers. However, given the large financial viability gap that currently exists in the market, on its own this is unlikely to be enough to induce investors into the market.

Capital funding significantly reduces the levelised cost, making solar energy sources competitive with traditional sources and reducing the amount of upfront capital required. It can be structured as a grant, debt or equity providing flexibility for the Government to recoup some of its money.

A PPA will provide certainty over future revenue streams for a developer, making it easier for developers to access cheaper financing. In addition, it does not require large upfront funding from the Government, allowing any assistance to be spread over a 20 to 30 year time horizon, and reduces the risk that the project will not deliver the expected quantities of solar energy generation. However, the PPA is more expensive to government than an upfront capital grant (by around \$80m-\$100m) because it is cheaper for government to borrow money than a private developer.

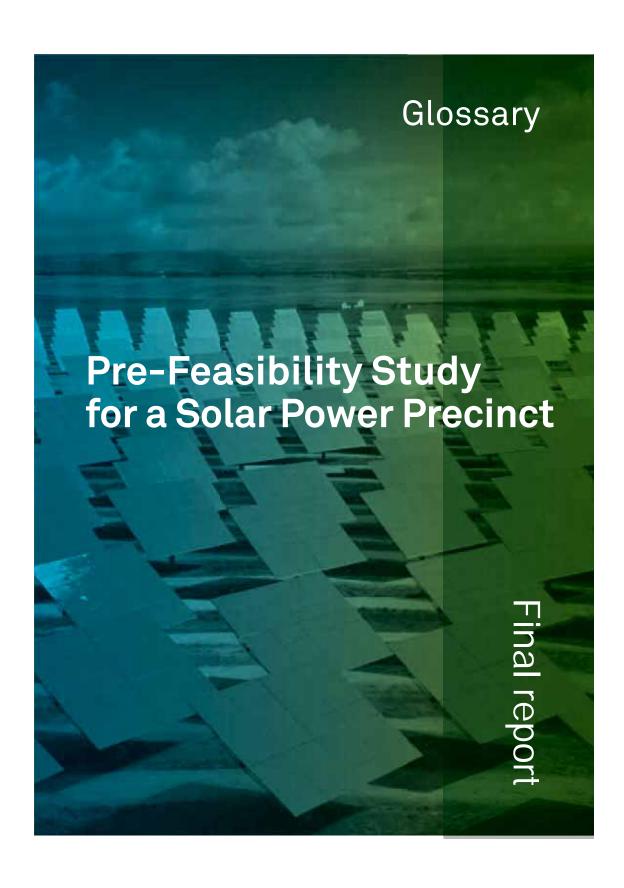
In essence, both capital funding and PPAs will improve investor and developer confidence and will be beneficial in bringing forward the development of large solar projects in NSW. A PPA allows any assistance to be spread over a 20 – 30 year time horizon and reduces the risk that the project will not deliver the expected quantities of solar energy generation. However, the PPA is more expensive to government than an upfront capital grant (by around \$75m-\$115m) because it is cheaper for government to borrow money than a private developer. On their own, measures to reduce transaction costs are unlikely to be enough of an incentive to bridge the financial viability gap. However, government may wish to supplement any capital funding or PPA with support to industry to facilitate easier permitting and access to infrastructure.

Next Steps

This study is a pre-feasibility study to test the concept of developing large scale solar precincts as well as identify some of the best areas and technologies in NSW for large scale solar projects. Whilst large scale solar projects may not be financially feasible at the moment, there are some potentially large economic benefits for society in terms of reduced greenhouse gas emissions and industry generation that may warrant Government playing a role in bringing forward the development of large scale solar projects. The magnitude of these benefits is highly dependent on the area and technology under consideration, as well as the level of government assistance and the extent to which it advances the large scale solar industry in NSW. Once a specific area and technology are selected it will be important to undertake:

- A more detailed feasibility study;
- A full economic appraisal to quantify the economic benefits and assess the economic viability of any proposed government assistance; and
- Develop a roadmap to maximise the benefits from supply chain and industrial development.

17 December 2010 xiii



Glossary

AC Alternating current

AEMC Australian Energy Market Commission

AEMO Australian Energy Market Operator

Albedo Reflectivity (of the environment)

AUD Australian dollars

BoM Bureau of Meteorology

CB Circuit breaker

CCGT Combined cycle gas turbine

CEI Clean Energy Initiative

CLFR Compact Linear Fresnel Reflector

CO₂-e Carbon dioxide equivalent

CPRS Carbon Pollution Reduction Scheme

CPV Concentrated photovoltaic

DC Direct current

DECCW NSW Department of Environment, Climate Change and Water

EEC Endangered ecological community

Embedded load Load located at the solar precinct

EP&A Act Environmental Planning and Approvals Act 1979

EPBC Act Environment Protection and Biodiversity Conservation Act 1999

EPC Engineering, procurement and construction

GIS Geographic information services

GJ Gigajoule (1 billion joules)
GW Gigawatt (1 billion watts)

ha Hectare

HTF Heat transfer fluid
HV High voltage

Inverter Power electronic device that converts DC power into AC power

ISEGS Ivanpah Solar Electric Generating System

joule The standard unit of energy

kL Kilolitre (1000 litres) kV Kilovolt (1000 volts)

LCOE Levelised cost of electricity

LPMA NSW Land and Property Management Authority

17 December 2010 xiv

LV Low voltage ML Megalitre

MVA Mega-volt-ampere

MW Megawatt (1 million watts)

MWh Megawatt-hour

MWp Megawatt-peak (solar panel/array installed power rating at standard test conditions)

NASA National Aeronautics and Space Administration

NEM National Electricity Market

NES National Environmental Significance

NREL National Renewable Energy Laboratory, U.S. Department of Energy

O&M Operations and maintenance

Parasitic load Energy requirements to operate solar energy plant (e.g. fans & motors) that offset the gross

energy generated

PPA Power purchase agreement
PPP Purchasing power parity

PV Photovoltaic

PVsyst Solar PV systems modelling software

REC Renewable Energy Certificate

SAM Solar Advisor Model software package developed for NREL

SEPP State Environmental Planning Policy (Major Development) 2005

SFP Solar Flagships Program

Solar precinct Pre-permitted area for large-scale solar plants and ideally symbiotic load co-located within a

region to facilitate infrastructure sharing and access to the electricity network

STG Steam turbine generator

String "String" of solar panels connected in series to increase output voltage to match inverter

requirements

Symbiotic load See embedded load

TJ Terajoule (1 trillion joules)

TNSP Transmission network service provider

TRNSYS Software package to simulate performance of thermal energy systems

USD United States dollars

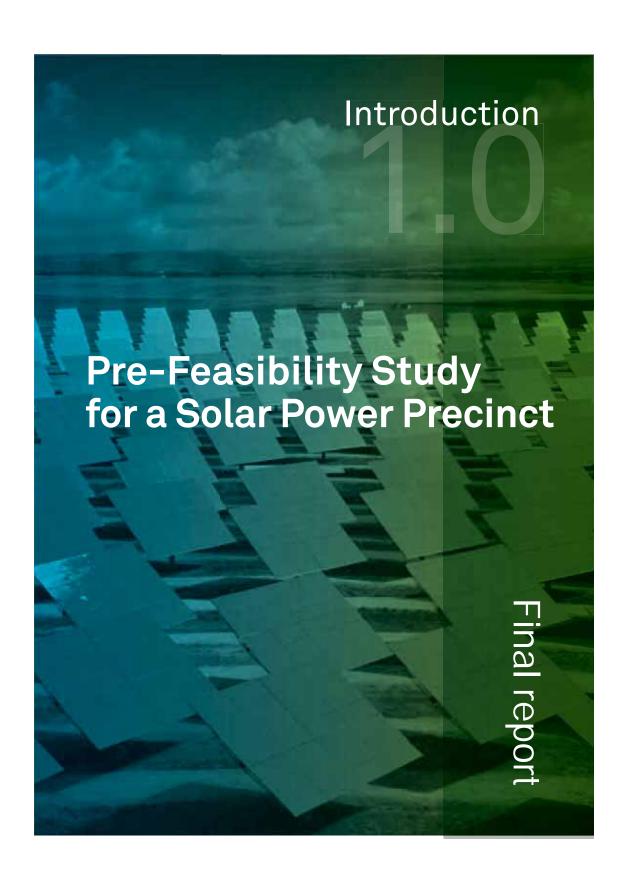
WACC Weighted average cost of capital

Watt A unit of power defined as one joule per second

WSA Water Services Agreement

WTP Water treatment plant

17 December 2010 xv



Introduction

1.0 Introduction

1.1 Background

"Climate change is one of the greatest environmental and economic challenges facing all of us. We have been an international pioneer in greenhouse gas trading and a driving force in the establishment of a national emissions trading scheme. Our focus is to support clean energy and the "low carbon' jobs needed to deliver climate change solutions and prepare for unavoidable changes in climate." NSW State Plan 2010

Electricity generation currently accounts for 38% of all NSW greenhouse gas emissions and is growing on average by about 2% each year. Demand for electricity will continue to rise as both population and the economy grow. Without changes to the way electricity is generated, transmitted and used, current emissions from electricity of 63 million tonnes of carbon dioxide equivalent (CO₂-e) are expected to increase to over 105 million tonnes CO₂-e by 2050¹. It is likely that a carbon price would be introduced at some point well before 2050, however the longer it is deferred, the greater the economic cost of meeting the State's emissions reduction target.

The NSW State Plan commits NSW to playing its part in reducing Australia's greenhouse gas emissions to 60% below 2000 levels by 2050. To achieve this, the share of the NSW energy mix coming from renewable sources will need to grow substantially. The national Renewable Energy Target commits Australia to source 20% of its energy from renewables by 2020. To achieve the targeted emissions reductions in the decades after 2020, it is reasonable to assume that renewables would continue to grow, especially as carbon prices rise.

In the same way that the NSW Government is facilitating wind investment through the establishment of wind renewable energy precincts, this study is part of NSW Government's investigations into whether dedicated solar development areas in NSW would help grow solar investment.

This study has been issued by NSW Department of Environment, Climate Change and Water (DECCW), to be overseen by a Steering Committee consisting of the Clinton Climate Initiative, Transgrid, Industry & Investment NSW, NSW Department of Planning and the Land and Property Management Authority (LPMA).

1.2 Objectives

This pre-feasibility study determines the economic, technical and environmental feasibility of large scale solar precincts at one or more areas in NSW. This study:

- Informs the NSW Government how best to develop a large-scale solar industry in NSW;
- Determines the feasibility of solar precincts;
- Selects potential areas for solar precincts (subject to feasibility being demonstrated); and
- Highlights the key measures, risks and issues for the NSW Government in the development and implementation of solar precincts.

¹ Data provided by NSW DECCW

1.3 Scope and Deliverables

For the purposes of this study a solar precinct is defined as the co-location of solar plants into a precinct to facilitate sharing of infrastructure, particularly access to the electricity network. A precinct could involve up to 1,000 MW of generation capacity including one or a combination of:

- Solar photovoltaic (PV);
- Solar thermal technology; and/or
- Solar-gas hybrids.

This study is a pre-feasibility study to examine the concept of a solar precinct and as such, does not involve identification of a specific land allotment area for development. For the purpose of this study an area is defined as general locations within approximately a 20km radius of a town.

The key deliverables from the study are:

- An assessment of the technical and environmental feasibility of a 1,000 MW solar precinct in selected areas within NSW:
- 2) An assessment of the project economics and cost-effectiveness of the precinct, comparing the levelised cost of solar plants within the precinct against optimally scaled stand-alone plants (up to around 250 MW) and the likely timeframe for independently financially viable solar plants;
- 3) A risk assessment of all factors material to precinct viability in each area;
- A ranking of potential areas for a solar precinct, based on the technical, environmental and economic feasibility and the risk assessment; and
- 5) Identification of a business model and key measures required for successful development of the precinct.

1.4 Document Structure

The remainder of this document is structured as follows:

Chapter 2 sets out the approach to the study.

Chapter 3 summarises the three stage technical feasibility assessment.

Chapter 4 assesses the economics of each technology at each area.

Chapter 5 assesses project risks.

Chapter 6 considers the role for government.

Chapter 7 lists references.

Appendix A presents the detailed process used to select five areas.

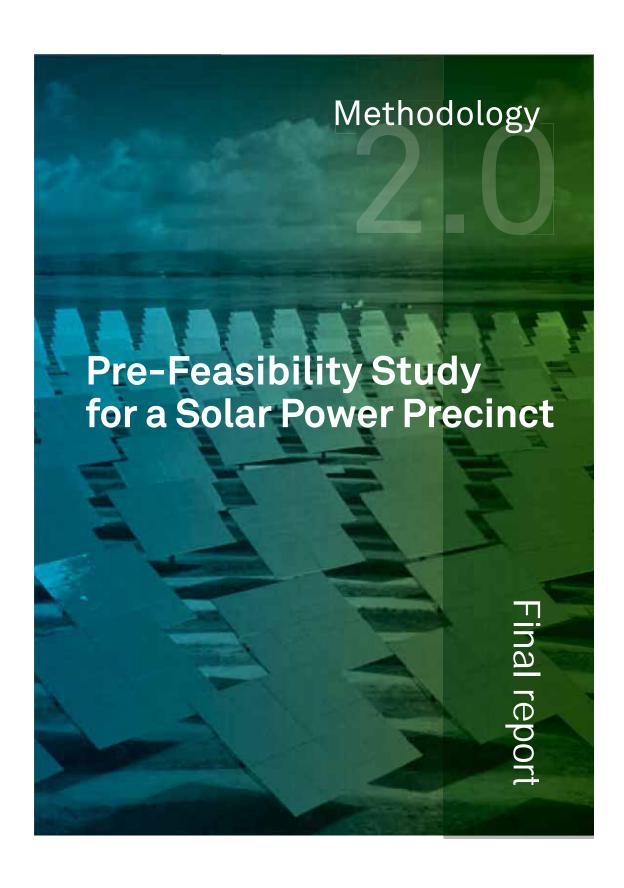
Appendix B presents the detailed technical assessment of the five areas including information on technology selection, technology costs, energy generation, transmission connections costs, land requirements, water requirements, gas requirements, and planning and environmental approvals.

Appendix C presents detailed solar technology characteristics.

Appendix D presents transmission component costs.

Appendix E presents Direct Normal Radiation graphs for each area.

Appendix F presents summary technology and area matrices.



2.0 Methodology

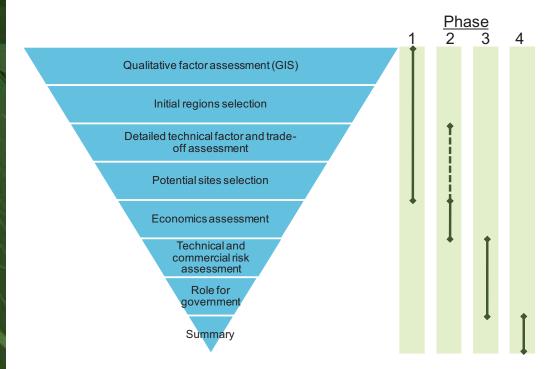
2.1 Overview

The assessment of solar precinct feasibility followed a four stage process as shown in Figure 2.1:

- Phase 1: Technical and environmental feasibility.
- Phase 2: Economics and cost effectiveness.
- Phase 3: Risk assessment, business models and role for government.
- Phase 4: Summary and recommendations.

Each of these phases is discussed below.

Figure 2.1 Overview of approach



2.2 Phase 1: Technical and Environmental Feasibility

There are three objectives of this Phase:

- To identify up to five suitable areas in NSW for a solar precinct.
- To assess the technical feasibility of a 250 MW and 1,000 MW solar precinct in selected areas within NSW.
- To consider whether the precinct could include one or a combination of solar photovoltaic (PV); solar thermal technology; and/or solar-gas hybrids.

This study is a pre-feasibility study to test the concept of a solar precinct. This study does not involve identification of specific sites and for the purpose of this study an area is defined as general locations within approximately a 20 km radius of a town.

This study does not specify what mix of technologies should be in the precinct rather, developers will decide which technology is the more feasible. Instead this study considers each technology separately within the precinct.

2.2.1 Feasibility Factors

There are a number of factors that affect the feasibility of a solar precinct as set out in Figure 2.2.

Figure 2.2 Feasibility factors



Solar resource

The amount of solar energy available directly affects the electrical yield of a solar power plant, and therefore its viability. The amount of solar energy reaching the Earth's surface is generally lower for higher latitudes, so in Australia the solar resource generally improves towards the north of the country. However the solar resource is also strongly affected by long-term weather patterns (cloud cover), atmospheric conditions (for example dust and pollution levels) as well as the physical characteristics and topology of the Earth's surface. AECOM used NASA satellite derived solar resource data to compare areas on a common basis due to the wide area averaged format of the data being broadly consistent with the size of the broad areas of study and because long-term averaged data for the global, direct, diffuse and albedo solar resource components were readily available in a format suitable for integration with the modelling software. AECOM also reviewed satellite derived global solar resource data and ground instrument measured solar resource data from the Australian Bureau of Meteorology for comparative analysis.

Transmission and distribution infrastructure

At 250 MW or more, the proposed solar generation plant will require connection to the transmission network. Constructing the solar plant relatively close to existing high voltage transmission lines or substations would reduce the extent of transmission upgrading required and therefore improve plant feasibility.

Land availability

The solar resource is fairly diffuse and hence large scale solar generation plants require large areas of land to harvest the solar energy. The amount of land and gradient of land also varies between the different types of technologies. Solar thermal plants typically require between 2 to 6 hectares of flat land per MW depending on technology and configuration. Solar PV requires a minimum land area of 1 to 3.5 hectares per MW depending on technology. Solar PV yields will improve with larger land areas and with tracking arrays. Solar PV is less sensitive to land gradient, and a north facing slope can be beneficial for reducing shading.

Water requirements

Access to water is required for general cleaning and maintenance of all the technologies to be considered in this study. In addition, solar thermal plants have the option of using water cooling for the steam turbine generator (STG), which would require a long term, secure and reliable water supply. Water supply can be problematic in inland Australia, and the report has concluded that water cooling option for a solar thermal plant for the scale of capacity being considered by this project is not an option.

Gas

Solar thermal plants require small quantities of gas for heat transfer fluid (HTF) freeze protection and standby ancillary operations. Another option for solar thermal power generation is the use of much larger quantities of gas for hybrid cofiring to either improve the steam cycle efficiency or for the use in a standalone boiler for raising steam for the steam turbine generator when the solar based electrical output of the plant decreases. For this "hybrid" co-firing option, proximity to a gas pipeline is necessary and area evaluation will require review of gas availability and logistics.

Environmental

At 250 MW or more the proposed solar generation plant will occupy a significant area. It will be important to avoid areas of high environmental value that may cause constraints to development.

Planning

Both the 250 MW and 1,000 MW plants will require planning approvals. Local conditions will affect approvals, particularly any environmental issues and the degree of community support and acceptance.

Scope for embedded (symbiotic) load

If there are opportunities for embedded load around the precinct this could potentially reduce the amount of transmission capacity required and therefore cost.

Scope for industry development

There may be scope for the solar precinct to provide opportunities to support industry development.

Selecting favourable areas is a trade off between all of the factors discussed above. For example, Broken Hill has high solar resource, but does not have ready access to high capacity transmission infrastructure. This study aims to assess the different tradeoffs to identify favourable areas and assess feasibility at these areas. The factors also vary for the different technologies (e.g. water and possibly gas are more important for solar thermal technologies).

AECOM, with assistance from the steering committee, grouped the factors into primary and secondary factors, as set out in **Table 2.1**. Primary factors are core to the assessment. Secondary factors are important considerations in the five shortlisted areas.

There are a range of other factors that will influence the feasibility of a solar plant or precinct such as transport costs. However, as this study does not look at specific sites it is not possible to include these. It has been assumed that a site would be selected with good access to transport. In addition, these other costs are likely to be a small proportion of the total costs so will not significantly affect the levelised cost model.

Table 2.1 Feasibility factors

Prir	Primary Factors		Secondary factors		
•	Solar resource	•	Planning		
•	Transmission and distribution infrastructure	•	Scope for embedded (symbiotic) load		
•	Land availability, topography and cost	•	Scope for industry development		
•	Water requirements				
•	Gas				
•	Environmental factors				

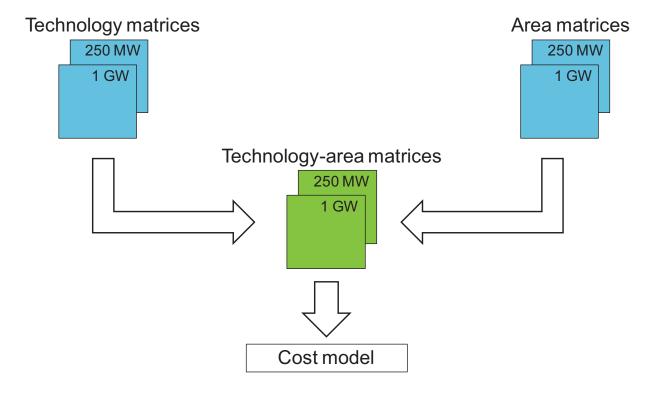
2.2.2 Technology-Area Matrices

Assessing technical feasibility involves collecting technology specific information (such as costs, efficiency, land requirements, water requirements) and combining this with area specific information (such as solar resource, distance from transmission and distribution infrastructure, availability and price of land). AECOM has developed technology and area matrices that are combined to assess areas and feed into the cost model in Phase 2. This analysis was undertaken for both a 250 MW plant and a 1,000 MW plant. Technology and area factors were examined in parallel to capture any trade-offs between them.

Figure 2.3 sets out the approach used to assess the technical feasibility. In summary:

- Technology matrices list characteristics related to a particular type of technology;
- Area matrices list characteristics related to a specific area; and
- Technology-area matrices combine these characteristics to determine technical feasibility of a particular technology and a particular area.

Figure 2.3 Approach to Phase 1



2.2.3 Technology Matrices

The precinct could include one or a combination of solar photovoltaic (PV); solar thermal technology; and/or solar-gas hybrids. **Table 2.2** sets out the information collected for each technology considered in this study. A completed table is presented **Appendix F**.

Table 2.2 Technology matrix

Characteristics	Units		Technology		
		PV	Solar Thermal	Gas Hybrid	
Land requirements					
	2.3 ha / MW				
Land size	р				
Total hectares (250 MW)	ha				
Total hectares (1000 MW)	ha				
Water requirements					
Operations	ML / MWp				
Feed water	ML / MWp / year				
Gas requirements					
Operations	GJ / MWp				
Technology cost					
Total Technology cost	\$ / Wp				
Annual maintenance costs					
Total annual maintenance	\$ / MWp				
Major periodic maintenance					
Frequency	Years				

2.3.1 Area Matrices

To ensure all suitable areas within NSW were considered AECOM undertook a three stage filter approach:

- Stage 1: Qualitative factor assessment using GIS to identify potential areas;
- Stage 2: Preliminary quantitative factor assessment to select up to five areas; and
- Stage 3: More detailed assessment of shortlisted five areas.

Stage 1: Qualitative factor assessment using GIS

Stage 1 involved the use of spatial analysis to identify a long list of areas with a mix of solar resource, transmission connection capability, land availability, water availability and gas connection capability, though not necessarily all in the same area

Stage 2: Preliminary quantitative factor assessment

Stage 2 involved a basic quantitative factor assessment using rules of thumb for the primary factors to identify five areas for a more detailed technical assessment. **Table 2.3** sets out an area matrix demonstrating the type of information collected for each potential area. A completed table is presented in **Appendix F**.

Table 2.3 Area matrix

Area Characteristics	Areas						
Area Gharacteristics	Area 1	Area 2	Area	Area N			
Coordinates							
Weather							
Average daily insolation							
Generation							
Capacity factor							
Transmission							
Distance to substation							
Distance to 330kV line							
Total cost							
Cost per watt							
Land cost							
Water cost							
Gas							
Distance to pipeline							
Total cost							
Environmental factors							
Heritage sites							
Mining leases							
Wetlands							

The key step is combining the technology and area matrices to assess the technical feasibility at each area. **Table 2.4** sets out an example technology-area matrix. For Stage 2, a high level quantitative assessment was made using rule of thumb to identify the tradeoffs between the different factors and identify the five areas to be selected for more detailed analysis.

Table 2.4 Technology-area matrix

Area	Technology	Energy Generation	Technology cost	T&D cost	&	Water cost & availability	Environm ent	Feasi bility
Area 1	PV							
	Solar thermal							
	Gas hybrid							
Area 2	PV							
	Solar thermal							
	Gas hybrid							
Area 3	PV							
	Solar thermal							
	Gas hybrid							
Area N	PV							
	Solar thermal							
	Gas hybrid							

AECOM prepared the technology and area matrices and held a workshop with the Steering Committee to complete this process and shortlist five areas.

Stage 3: Detailed factor assessment

Stage 3 involves a more detailed assessment of all factors for the five areas to assess technical feasibility and feed into the economic assessment of this study.

2.4 Phase 2: Economics

The objective of Phase 2 was to assess the economics and cost-effectiveness of the precincts, comparing the levelised cost of solar plants within the precinct against optimally scaled stand-alone plants (up to around 250 MW) and the likely timeframe for independent financially viable solar plants.

Phase 2 was split into three tasks:

- Calculation of levelised costs;
- Estimation of potential revenue; and
- Comparison of aggregated and disaggregated areas.

2.4.1 Calculation of Levelised Costs

Levelised costs were calculated using a spreadsheet model that used the following inputs:

- Capital costs;
- · Operating costs; and
- Weighted average cost of capital (WACC).

The WACC is discussed in Section 4.2.2.

2.4.2 Estimation of timing of commercial feasibility

Levelised costs were calculated for a range of construction commencement years to be compared against the forecast price of new entrants using conventional generation technology. Inputs included:

- The long run marginal cost of open cycle and combined cycle gas turbine plant; and
- Carbon Pollution Reduction Scheme (CPRS) impacts.

2.4.3 Comparison of Aggregated and Disaggregated Areas

This task brings together the outputs of previous modelling to assess the economic feasibility of solar precincts. The modelled price was used to:

- Determine the most attractive areas for development of a solar precinct;
- Assess the cost-effectiveness of a solar precinct compared to a similar capacity made up of a number of standalone plants; and
- Determine the likely timeframe for economic feasibility.

Sensitivity testing was also conducted on a few key factors such as electricity generation and capital costs.

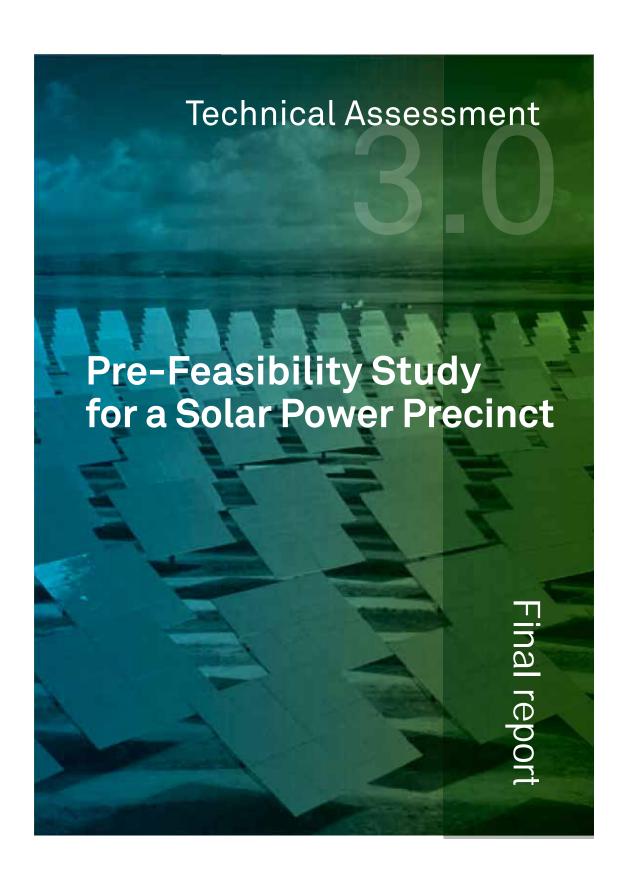
2.5 Phase 3: Risk Assessment and Role for Government

The third phase of the project identified and assessed the risks to feasibility, looked at the most appropriate role for the NSW Government to address risks where appropriate and reviewed possible business models to aid the development of the precinct. A key output of this stage is the analysis of options for support by the NSW Government to facilitate the development of solar precinct(s).

2.6 Phase 4: Summary

Phase 4 summarised the previous phases in terms of:

- Project economics of the precincts, comparing the levelised cost of solar plants within the precinct against standalone plants;
- Potential areas for a solar precinct, based on the technical, environmental and economic feasibility and the risk assessment; and
- Identification of a business model and key measures required for successful development of the precinct.



3.0 Technical Assessment

3.1 Technology

There are two principal types of solar technologies:

- Solar photovoltaic (Solar PV) technologies that convert sunlight directly into electricity; and
- Solar thermal technologies that focus sunlight to create heat to produce steam that is used indirectly to generate electricity using steam turbiness.

This study focuses on two types of solar PV, namely mono-crystalline and thin film, and two types of solar thermal, namely trough and tower. It also considers the potential for "hybridising' solar thermal by gas co-firing. These technologies were selected for inclusion in this study because they represent a range of differences in terms of manufacturing processes, costs and efficiencies. For more information on the selection of these technologies see **Section B.1** of **Appendix B**.

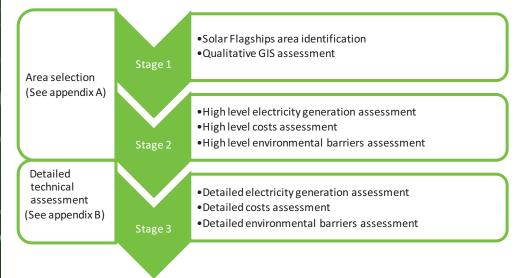
3.2 Summary of Area Selection Process

As discussed in **Section 2.2**, AECOM used a 3 stage process to identify five areas on which to assess technical feasibility:

- Stage 1: Qualitative factor assessment using GIS;
- Stage 2: Preliminary quantitative factor assessment to identify five areas for technical assessment; and
- Stage 3: Detailed technical assessment for five areas.

Stages 1 and 2 are to identify the five areas for more detailed analysis. Full details of Stages 1 and 2 can be found in **Appendix A**. Stage 3 is a more detailed technical assessment of the five areas identified in stage 2. Full details of stage 3 can be found in **Appendix B**.

Figure 3.1 Area selection process



3.2.1 Stage 1: Qualitative Factor Assessment

Stage 1 consisted of a qualitative factor assessment using GIS mapping to identify potential areas for a solar precinct and was also informed by project locations as identified by Solar Flagships proponents². Sixteen areas, as set out in **Table 3.1**, were identified after assessment of the following key factors:

- Solar resource;
- Transmission line access proximity and capacity of the line;
- Proximity to the gas pipeline;
- Land value; and
- Proximity to a major surface water source.

Table 3.1 16 areas identified in qualitative factor assessment

•	Armidale	Darlington Point	Nyngan
•	Balranald	• Dubbo	Tamworth
•	Bourke	• Hay	Wagga Wagga
•	Broken Hill	Inverell	Wellington
•	Buronga	Lake George	
•	Cobar	Moree	

3.2.2 Stage 2: Preliminary Quantitative Factor Assessment

This section provides an overview of the selection process undertaken to identify five areas on which to perform more detailed analysis. Further explanation of this process is presented in **Appendix A**.

A basic quantitative factor assessment was undertaken in Stage 2 on the sixteen areas identified in Stage 1 to shortlist five areas. The assessment included preliminary analysis of:

- Electricity generation (MWh);
- Costs (including transmission, land, water and gas); and
- Environmental barriers.

As a result of Stage 2, the sixteen areas were ranked based on electricity generation and cost analysis. Qualitative environmental, water and land issues were also included for consideration in the selection of the five areas.

A workshop was held to discuss these results and finalise the selection of five areas. The results showed that the top five ranked areas, in terms of cost per MWh, are clustered in the north east largely due to better insolation from latitude effects and relatively low transmission costs to connect at 330kV. However, the differences between areas were small in terms of cost per MWh and selection based purely on cost per MWh would exclude consideration of non financial factors such as land gradient and water availability. As such, the final selection of the five areas to be analysed in more detail was based on the following criteria in order to capture trade-offs between feasibility factors and conduct more detailed analysis on a variety of scenarios:

- Geographic spread;
- Land gradient;
- Water availability;
- · Gas availability for hybrid plant; and
- Distance to transmission network to illustrate costs of connection.

² Note AECOM was only given broad locations and no other details of the solar flagship proponents.

Based on the above criteria, the following areas were selected for more detailed assessment:

- Broken Hill;
- Darlington Point;
- Dubbo;
- Moree: and
- Tamworth.

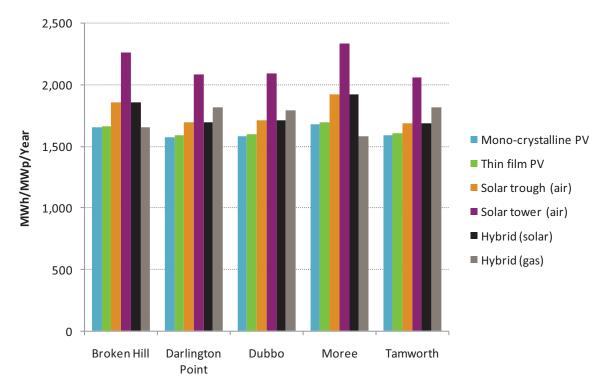
3.3 Detailed Technical Assessment

This section provides an overview of the detailed technical assessment of the five areas identified in Stage 2. Further detail is presented in **Appendix B**.

3.3.1 Generation Potential

The electrical output of a solar plant is a function of both solar technology characteristics and area specific characteristics such as the latitude, longitude, altitude, ambient temperature and wind speed as well as the global, direct, diffuse and albedo components of the solar resource. To enable the generation potential of the areas to be compared on a common basis AECOM developed generic system designs for each of the solar technologies and then undertook detailed solar generation modelling to estimate annual electricity production per MWp of installed capacity. **Figure 3.2** compares energy generation potential (MWh / MWp / year) between each of the five areas under consideration and each of the different technologies. For the hybrid generation the solar and gas generation components are shown separately, where the proportion of gas generation is based upon output smoothing and extended generation in to the shoulder periods. Energy storage was not evaluated as a core part of this study, enabling the comparison of technologies on a common basis such that both photovoltaic and thermal technologies dispatch into the same electricity market.

Figure 3.2 Energy generation by area and by technology (MWh/MWp/year)



Source AECOM

Note The black hybrid column in the chart above illustrates the solar component of the hybrid generation and needs to be added to the grey or blue columns to obtain the combined output of the hybrid plant.

Figure 3.2 illustrates that of the areas considered, Moree has the highest electricity generation potential, followed by Broken Hill, whilst Darlington Point, Dubbo and Tamworth produce similar levels of electricity per MWp. The areas have different resource characteristics, in particular, differences in the ambient temperature and direct normal irradiation significantly influence the performance of the various technologies between areas. Solar thermal technologies rely on solar concentration to operate and hence their performance significantly improves in areas with high levels of direct irradiation such as Moree and Broken Hill. Although the solar resource is greater at Moree and Broken Hill relative to Darlington Point, Dubbo and Tamworth, the higher ambient and operating temperature affects the efficiency of solar PV panels such that there is only a relatively small improvement in their performance at these areas compared to the performance change with the solar thermal technologies.

The generation potential of the solar plant is sensitive to the long term solar resource. There are limitations with the solar resource data sets available and there is some discrepency between the NASA and BoM satellite data sources and further discrepancy between satellite and ground based solar data sets assessed in this study. Hence the magnitude of the global, direct and diffuse components of the solar resource at the areas are subject to some uncertainty. Once a preferred site for a precinct is identified, it is recommended that suitably calibrated instruments for measuring meteorological data and the global, direct, diffuse and albedo optical components of the solar resource be established at the site to facilitate the technology selection and technical design of the plant. Precinct site-specific high quality solar data sets will reduce project development gestation time, facilitate improved investor confidence in the project, and may result in more favourable financing terms and conditions thereby reducing the levelised cost of electricity.

As discussed in **Section B.3** of **Appendix B**, the electricity generation potential per MWp is also sensitive to the technical characteristics and modelling assumptions used to define the generic solar technology system configurations required to enable areas to be compared on a common basis. The sensitivity of the levelised cost of electricity to generation potential is assessed in **section 4.51**.

3.3.2 Transmission and Distribution Infrastructure

AECOM undertook an assessment of the costs of connection to transmission networks for each area. The cost of connection is highly area specific and dependent on the existing infrastructure. Efficient connection of a 1,000 MW precinct requires access to connection voltages of at least 330 kV. A 250 MW plant could be efficiently connected to a 220 kV system. Connections to the 132kV system are possible, but are no less expensive than higher voltages, require more plant and have technical limitations in terms of power transfer.

The simplest and cheapest method for new connections is to connect to an existing substation. Alternatively, a connection may be made to an existing transmission line by establishment of a new substation in its vicinity. The decision to do either is largely driven by whichever requires the least amount of new transmission line to be built for connection to the grid.

Of the five areas, Darlington Point and Tamworth are within a few kilometres of 330 kV substations which have capacity for connections of 1,000 MW. Dubbo is 46 km from the Wellington 330 kV substation which also has capacity for 1,000 MW connections. Moree is not near a substation, so the cheapest option for both 250 MW and 1,000 MW is to connect to the existing 330 kV transmission line between Armidale and Dumaresq. This will require about 140 km of new 330 kV transmission line as well as construction of a new 330 kV substation.

A 250MW plant may be readily connected to the existing 220 kV substation at Broken Hill. A 1,000 MW precinct at Broken Hill however would require construction of over 500 km of new 330 kV transmission line for connection to the Darlington Point substation.

Table 3.2 summarises the cost of transmission connection at each area. Darlington Point and Tamworth, both within a few kilometres of a 330 kV line have low connection costs, whilst Dubbo it is somewhat more expensive due to the need for construction of 46 km of transmission line to Wellington. Moree is the most expensive for a 250 MW plant due to the length of new transmission line required. Broken Hill, has a relatively low connection cost for a 250 MW plant due to the presence of an existing 220 kV line. However, costs increase substantially for the 1,000 MW precinct due to the need for a 330 kV connection.

With the exception of Broken Hill, all areas receive economies of scale in transmission connection costs for a 1,000 MW precinct compared to a 250 MW plant. In terms of staging of the precinct build out, the optimal timing depends on if and when, a 330 kV line is required. This in turn depends on the existing transmission infrastructure and is highly area dependent.

Table 3.2 Transmission costs by area

Area	250MW (Total Cost)	1,000MW (Total Cost)	250MW (\$/MW)	1,000MW (\$/MW)	Economies of scale
Broken Hill	\$22.6m	\$585.5m	\$91,000	\$585,000	×
Darlington Point	\$15.6m	\$27.6m	\$62,000	\$28,000	✓
Dubbo	\$48.4m	\$60.4m	\$193,000	\$60,000	✓
Moree	\$138.3m	\$150.3m	\$553,000	\$150,000	√√
Tamworth	\$13.0m	\$25.0m	\$52,000	\$25,000	√

The connection costs developed in this study only consider the direct costs of connection to the TransGrid network, such as lines, substation extensions and minor local upgrades. However, connecting new generation into the grid will alter power flows and potentially create generation and load constraints, either for the new generator or other generators and consumers in the market. Under the current electricity market rules the generation proponent would need to pay the costs of deep system upgrades required as a result of its connection. Of the five areas considered, Darlington Point is likely to need significant network strengthening for a 1,000 MW precinct. The impact would be reduced if the proposed TransGrid SA-NSW "SNI" (Central Route) Interconnector goes ahead.

The integration of large scale solar capacity to the electricity network faces regulatory challenges. The three dominant challenges of integrating large scale renewable energy into the power system include:

- Allocation of the cost and risk of grid extensions;
- Accommodation of intermittent renewable generation; and
- Achieving technical compliance under the National Electricity Rules (NER).

The proposed Rule change "Scale Efficient Network Extension" (SENE) is intended to address the first challenge by sharing the cost of connection between the first and subsequent proponents in a particular region. The accommodation of wind farms into the electricity system may aid the acceptance of the technical characteristics of other types of renewable energy including solar, as the amount of wind capacity increases to meet Large-scale Renewable Energy Target requirements.

Currently solar power would normally be designated as intermittent generation by type under the Rules. There are no mechanisms for re-designating solar and other renewable generation as conventional dispatchable generation because the Rules lack a definition of intermittency and designate intermittent generators solely by type. Addressing this, and other regulatory challenges, will assist in the penetration of solar generation into the electricity supply market.

3.3.3 Land Availability

Generation at a scale as large as a solar precinct requires significant areas of land to harvest solar energy. The land requirements vary depending on the details of the specific technology. There is a trade off between minimising land area and cabling/piping requirements by placing solar collectors closer together and placing solar collectors further apart to maximise generation potential (the closer solar collectors are placed together the more they shade each other). Other land factors such as gradient and aspect must also be considered as they influence generation output.

To compare areas on a common basis generic layouts for each technology were developed assuming flat land. As illustrated in **Table 3.3**, land requirements vary by solar technology, with mono-crystalline PV requiring the least amount of land at around 1 hectare per MW and solar thermal between 2.5-3.5 hectares per MW.

Table 3.3 Land requirements (hectares)

Technology	Area per MW	Total Area (ha)		
	(ha / MW)	250 MW	1 GW	
Mono-crystalline PV	1.04	260	1035	
Thin film PV	3.3	830	3322	
Solar trough	2.4	600	2400	
Solar tower	3.5	875	3500	
Hybrid	2.4	600	2400	

Source AECOM

Total precinct land costs are a product of the land requirements for each technology and local land values. **Figure 3.3** summarises the total land costs for each technology at each area. Regional centres such as Moree, Dubbo and Tamworth have relatively high land values compared to Broken Hill and Darlington Point resulting in higher total land costs for a given technology. Whilst total land costs vary by technology and area, the total costs are not significant in terms of total project capital costs and therefore do not have a significant impact on levelised costs of generation. It is anticipated that developers will investigate a number of land purchase arrangements in order to reduce acquisition costs; however these costs are likely to remain in the same order of magnitude as presented in **Figure 3.3**.

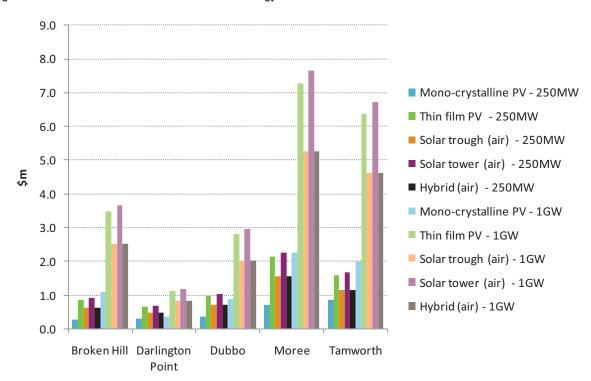


Figure 3.3 Total area land costs for each area and technology

Source AECOM

3.3.4 Water Requirements

A solar power plant requires water for a number of purposes including surface cleaning and dust control. Solar thermal plants have additional water requirements for the generation steam cycle and, if so designed, large volumes of water for wet cooling to improve steam cycle efficiency. The combination of these functions necessitates access to a reliable supply of water.

Areas of NSW with high levels of solar insolation are typically further inland and in arid regions and often experience prolonged drought conditions. As a result, securing a reliable water supply capable of delivering the quantities required for water cooling of a solar thermal plant at any of the areas considered is unlikely to be possible. **Table 3.4** summarises the annual water requirements for each technology.

Table 3.4 Annual water requirements (ML)

Size of plant	Mono-crystalline PV	Thin film PV	Solar trough, tower and Hybrid (air cooled)
250 MW	89	276	190
1,000 MW	357	1,102	760

Source AECOM

Potential augmentations to supply sufficient water for cleaning, steam cycle (thermal only) and if possible, water cooling, were developed based on analysis of water availability and local supply. **Table 3.5** summarises the preferred option selected for each area. Depending on the area, water is supplied from river extraction, groundwater or town supply, and is piped and treated for use at the precinct.

The analysis revealed it is unlikely that water cooling is feasible for a 1,000 MW plant at any of the areas considered; Tamworth and Dubbo may be able to support a 250 MW plant with water cooling. As such, water cooled solar thermal generation has not been considered as part of this study.

Table 3.5 Preferred water option for each area

Area	Preferred option
Broken Hill Town supply (may not be feasible for 1,000 MW precinct)	
Darlington Point	Purchase river extraction licence, treat and pump
Dubbo	River extraction, pipeline and treatment plant
Moree	Groundwater supply, pipeline and treatment plant
Tamworth	River extraction, pipeline and treatment plant

3.3.5 Gas

Solar thermal technology requires small quantities of gas for freeze protection of the heat transfer fluid and standby ancillary operations. Another option for solar thermal generation is the use of gas for hybridisation to either improve the steam cycle efficiency or for the use in a standalone boiler for raising steam during periods of low solar generation. Gas is not required for mono-crystalline and thin film PV technologies.

The availability and price of gas depend on the volume required, supply profile and the distance from the nearest gas pipeline; proximity to a gas pipeline is therefore advantageous for feasibility. Gas will have a cheaper unit price if required in large volumes for hybrid generation, although gas pipelines would need to be constructed for precincts not located close to existing pipelines. **Table 3.6** summarises the assumed delivered gas prices. Darlington Point may provide the cheapest access to gas as it is close to the NSW-Victoria gas pipeline. Gas prices have been costed as delivered price per GJ.

Table 3.6 Final delivered gas cost for a solar thermal plant (\$/GJ)

	Broken Hill	Darlington Point	Dubbo	Moree	Tamworth
Road delivery	13.0	9.2	11.8	13.0	11.8
Piped delivery (hybrid only)	7.2	6.4	7.4	8.4	7.4

Source AECOM

3.3.6 Environmental

As noted, a solar plant of 250 MW or more will occupy a significant area of land. It will be important to avoid areas of high environmental value that may cause constraints to development. AECOM considered major environmental constraints at each of the five areas. Whilst environmental constraints are present in each of the areas, these constraints do not necessarily preclude any area from hosting a solar precinct.

3.3.7 Embedded Load

AECOM considered two types of embedded load – firstly, load within the local region and secondly, potential load within the precinct itself. Any embedded load reduces the size and therefore cost of network connections –from the transmission network to the edge of the precinct and within the precinct itself, respectively.

Of the five areas considered, Dubbo and Tamworth have the greatest local loads which may reduce the costs of transmission. However, both of these sites have relatively low transmission costs. Preliminary research and communication with local councils has not identified any significant loads that might be co-located in precincts. However, if the components for solar generation, such as PV panels, are manufactured at plants co-located within solar precincts there are many potential benefits, including:

- Local load reduces the need for transmission connection;
- Local manufacturing reduces transport costs and damage to delicate components; and
- Development of industry in regional areas where employment costs are lower.

Benefits of local manufacturing have not been included because the scope depends on the particular technology chosen. Once a technology and area is identified, a roadmap should be developed to maximise these benefits.

3.3.8 Capital Costs of Technology and Construction Staging

Whilst it is generally accepted that capital costs for all solar technologies are likely to decline with time, there is a significant degree of uncertainty around future capital costs for solar technology, particularly for the less mature solar thermal technologies.

In addition to future price uncertainty, there is also a range around currently quoted prices. AECOM has made assumptions on current solar technology capital costs based on previous experience, published reports and information from project developers where available. **Table 3.7** shows the assumed capital costs in 2010 and assumed reduction in capital costs. These are acknowledged to be conservative assumptions and sensitivity analysis using alternate capital costs is presented in **Section 4.5**.

Table 3.7	Generation technology	capital cost assumptions (2010\$)
I able 3.1	Generation technology	(capital cost assumptions (20 log)

Technology	Current Capital Cost	Forecast Capital Cost	Construction Period
Mono-crystalline PV	\$5.0/W	50% panel cost decrease by 2014 then 1% p.a. real price decrease thereafter	2 years (250MW) 8 years (1,000MW)
Thin film PV	\$4.6/W	50% panel cost decrease by 2014 then 1% p.a. real price decrease thereafter	2 years (250MW) 8 years (1,000MW)
Solar trough	\$4.8/W	20% decrease by 2014 then further 25% decrease by 2025	2 years (250MW) 8 years (1,000MW)
Solar tower	\$4.9/W	25% decrease by 2014 then further 25% decrease by 2025	2 years (250MW) 8 years (1,000MW)
Hybrid	\$5.1/W	As per solar trough	2 years (250MW) 8 years (1,000MW)

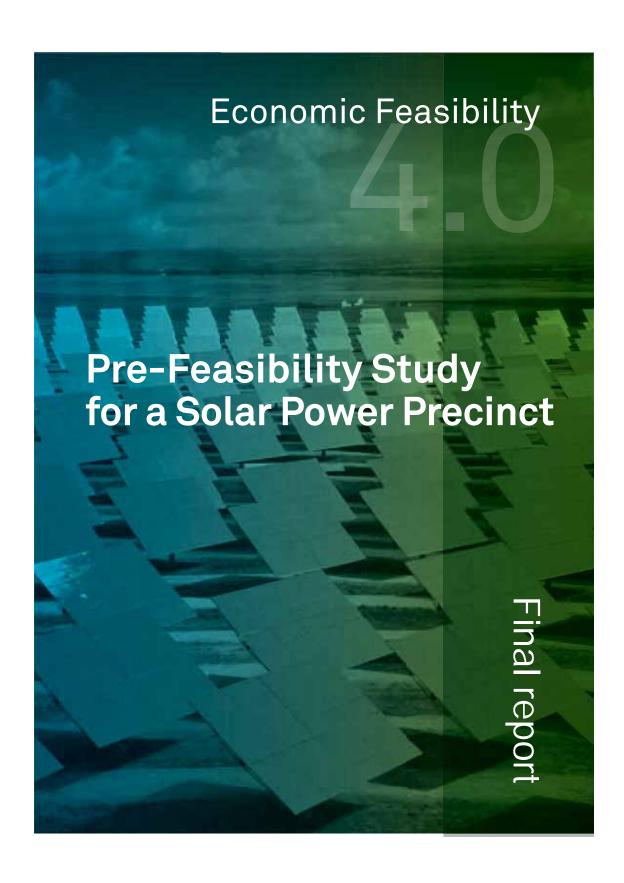
Source AECOM

Most existing solar generation technology has been deployed in relatively small scale developments compared to that required for a 1,000 MW precinct or even a 250 MW plant. As such, there is the potential for economies of scale as volumes increase and the industry moves along the learning curve. AECOM expects economies of scale to be realised in scaling up deployment from the current small scale developments to a 250 MW plant, but then no significant further economies of scale between 250 MW and 1,000 MW total capacity. This is a conservative assumption as there are very few existing solar plants with capacity greater than 50 MW, let alone at the 250 MW and 1,000 MW scale proposed for this project. Significant economies of scale beyond 250 MW may exist, however these will only become apparent following the construction and commission of multiple large scale solar plants.

Construction of a 250 MW plant has been assumed to take two years and be phased such that half of the final capacity is available for electricity generation by the start of the second year of construction. This is a simplistic assumption that has been made to maintain a consistent base for comparison between different technologies. Capital costs are assumed to be set at the commencement of construction with no decrease during the construction period. A 1,000 MW precinct has been assumed to be constructed over an eight year period with similar gradual increases in available generation capacity each year. However, a 1,000 MW precinct has been assumed to be built in four separate stages so that each stage is able to take advantage of lower prices at the start of construction for that stage as per the declines shown in **Table 3.7**.

3.4 Summary

The high capital costs of solar technology remain the most significant factor affecting the feasibility of solar electricity generation, whilst local solar resource and transmission infrastructure costs play an important part in determining the relative merit of potential areas. Existing suitable transmission infrastructure is significant in lowering capital costs compared to other areas. Other area specific factors such as land prices are relatively insignificant as a proportion of total costs. Water costs are also relatively insignificant but the availability of water is an important issue. None of the areas considered are believed to have sufficient available water resource for wet cooling of solar thermal plants. Delivered gas prices are an important factor for solar-gas hybrid technology, as is evident by the results showing Darlington Point as the area with the lowest gas prices and the most suitable area of those considered for a 250 MW hybrid plant.



4.0 Economic Feasibility

Introduction

To assess the relative cost effectiveness of the various technologies and areas under consideration, AECOM has estimated electricity generation costs and revenues for each option and compared generation costs on a per MWh basis.

This is analogous to the price per MWh of a long term power purchase agreement (PPA) required to ensure the financial viability of the precinct, also known as the levelised cost of electricity (LCOE).

The key issues affecting the levelised cost of electricity for a solar precinct are:

- Capital costs of generation and transmission infrastructure;
- Operating and maintenance expenses including the purchase of water and gas;
- Total dispatched electricity (a product of both local solar insolation and technology efficiency;
- The timing of expenditure and revenue; and
- Project financing costs.

The methodology developed by AECOM to estimate the required levelised cost for financial viability is discussed in Section 4.2 and the results are presented in Section 4.3. Technology and area options with a lower estimated levelised cost are financially preferable to those that require a higher levelised

AECOM has undertaken sensitivity analysis to test how the required electricity price responds to changes in key variables. This is discussed in Section 4.4.

4.2 Methodology

AECOM has developed a discounted cash flow model to estimate the price required by a new entrant to the electricity generation market.

Project cash flows have been evaluated for each year of the economic life of the plant, with costs and revenues in future years discounted to equivalent present values using an estimate of the cost of capital for the project.

As the electricity sale price is both an input into the calculation of the project revenues and the value to be determined by the modelling process, an iterative calculation process is used to determine the electricity sale price required to produce an internal rate of return for the project equal to the cost of capital. This represents the lowest viable electricity price, or levelised cost of electricity, for that project.

The model is simpler than would actually be used for financing purposes and does not consider changes to debt gearing ratios over the life of the asset or other such strategies that can be used to maximise returns on equity. As such, levelised cost estimates may be considered to be conservative and actual levelised costs may potentially be lower than those estimated.

4.2.1 Cashflows

Net project cash flows are calculated from the sum of individual revenue and expenditure items for each year of the economic life of the asset.

Revenues

Revenue from electricity sales is equal to electricity production in each year multiplied by the sale price in that year. Total annual electricity production varies by area and technology. Electricity prices are assumed to be indexed to inflation to maintain a constant real value.

Imputation credits paid to investors to prevent double taxation are included in the net project cashflow as a revenue item reflecting their value to equity investors.

Project capital costs for each technology and area are provided as an output of the technology and area matrices. Capital costs have been assumed to be incurred evenly over the duration of

17 December 2010 19 construction. Residual values for transmission infrastructure and inverters are considered if these assets have an economic life beyond that of the generation plant.

Operating expenses include fixed operating costs, which are a function of plant capacity regardless of output, and variable operating costs, which are assumed to be a function of generation output. Fixed costs may include annual connection and licensing fees for electricity transmission, insurances, staff, water supply and gas supply (if co-fired) and any fixed component of maintenance. Variable operating expenses include maintenance, consumables and the variable components of water and gas (if necessary) that are consumed as part of the electricity generation process.

Taxable income is calculated as total revenue less operating expenses, interest payments and asset depreciation. Tax losses in prior years are considered in calculating tax payable. This is an important consideration for projects with large up-front capital requirements prior to receiving any revenue, as initial negative taxable income due to debt interest payments may cause sufficient tax losses to ensure no income tax is payable in the early years of a project and hence, improve the overall project viability. A corporate tax rate of 30% has been applied to taxable income.

Interest payments on debt are considered when calculating tax payments, but are not included in the net project cashflow as the applied discount factor includes returns to debt holders.

4.2.2 Cost of Capital

The cost of capital represents the cost of funding the project and includes the cost of both debt and equity funds. It represents the rate of return that the same allocation of capital could be expected to achieve on an alternative investment of similar risk. For an investment to be worthwhile, the expected return must be greater than the cost of capital consumed.

AECOM has assumed that all projects under consideration would be funded by a mix of debt and equity, with a gearing (debt ratio) of 60%.

Cost of Debt

The required rate of return to debt holders is the nominal risk free rate plus a debt margin. The risk free rate has been estimated as 5.72% based on the average Australian Government 10 year nominal bond rate from January 1998 to December 2007 (pre financial crisis). Whilst Government bond rates in May 2010 have averaged around 5.5%, it is more appropriate to use a long term average for this study as the developments being evaluated may not be financed until many years into the future at an unknown debt rate, for which the longer term average rate may be a better indicator.

A debt margin of 2% has been assumed. This value may be considered low in the current financial climate, but is an appropriate long-term assumption representing the debt margin over the life of the asset and is consistent with the value used in similar applications, including ACIL Tasman's (2009) study into new entry generation costs in the national electricity market.

The resulting cost of project debt is 7.72% p.a.

Cost of Equity

The required return on equity is similar in concept to the required debt return, in that a premium is applied to the risk free rate. The equity premium for a new electricity generation plant is taken to be the equity market risk premium, multiplied by β , which is a parameter representing the risk of electricity generation relative to the market as a whole. A value for β above one implies the investment has higher risk than the average market risk, whilst a value of β below one implies lower risk. β value can be estimated from stock market data. A β value of 1.1 has been assumed, based on the average value for electricity generating firms with a gearing ratio of 60% as reported by Allen Consulting Group (2009). A market risk premium of 6% has been applied, consistent with that used by both ACIL Tasman and Allen Consulting.

The resulting cost of equity is 12.32%.

Weighted Average Cost of Capital

AECOM has used a post-tax nominal Weighted Average Cost of Capital (WACC) to represent the cost of capital faced by a firm entering the electricity generation market and to discount future cash flows to present values. Whilst there are a variety of alternative WACC definitions available, AECOM has adopted the "vanilla WACC" as shown in **Equation 1**.

Equation 1 WACC

$$WACC = r_e \frac{E}{V} + r_d \frac{D}{V}$$

Where

 $r_e = required return to equity holders$

 r_d = required return to debt holders

E = value of equity

D = value of debt

 $V = value \ of \ assets$

AECOM believes that this definition is the most appropriate formulation for estimating the cost of capital for investment in electricity generation assets. As noted by Officer (2005):

The "Vanilla WACC" is more accurate for finite life investments than alternative formulations because of the tax effect and cross product effects of taxation and depreciation. The taxes applicable to the company or entity can be accurately identified when they occur in the net cash flows.

The resulting WACC is 9.6% (post tax nominal).

4.3 Levelised Cost of Electricity

The levelised cost results are presented for construction beginning in the financial year ending June 2015. 2015 was selected to present the results as this was considered the earliest feasible start for any large scale solar project. The CPRS is currently scheduled to be in place around 2015 and there are long lead times from early development through to construction. In addition, the estimates of future costs and revenue are more uncertain the further forward a time period is considered. Whilst the results for 2015 are presented below, the model calculates levelised cost for commencement in each year and this is presented in **Section 4.4.4**. The levelised cost results for the 1,000 MW precinct presented below assume a single developer for the precinct unless otherwise stated.

4.3.1 Levelised Cost of Electricity for a 250MW Plant

Table 4.1 shows estimated levelised costs per MWh for a 250 MW plant. Levelised costs range from \$162 per MWh for a solar thermal hybrid plant at Darlington Point to \$270 per MWh for a thin-film PV plant at Moree. Broken Hill has the lowest levelised costs for all solar only technologies. Solar thermal hybrid plant offers the lowest levelised cost for all areas, followed by solar tower, solar trough, mono-crystalline PV and thin-film PV.

Table 4.1 Base case levelised cost of electricity (\$/MWh) for a 250MW plant- 2015 construction commencement

Technology	Broken Hill	Darlington Point	Dubbo	Moree	Tamworth
Mono-crystalline PV	\$231	\$240	\$247	\$252	\$238
Thin film PV	\$250	\$259	\$265	\$270	\$255
Solar trough (air)	\$208	\$226	\$230	\$222	\$225
Solar tower (air)	\$169	\$181	\$186	\$181	\$183
Hybrid (air)	\$164	\$162	\$171	\$181	\$168

Source A ECOM

4.3.2 Levelised Cost of Electricity for a 1,000 MW Precinct

Table 4.2 shows estimated levelised costs per MWh for a 1,000 MW precinct. The results have been presented for three scenarios to reflect how a precinct may work in practice:

- A 1,000 MW precinct assumes one developer for the whole plant or an infrastructure sharing agreement (such as a SENE type agreement for transmission) to share the costs across all four plants;
- First 250 MW stage of 1,000 MW precinct assumes four individual developers; and
- Last 250 MW stage of 1,000 MW precinct assumes four individual developers.

Table 4.2 Base case levelised cost of electricity (\$/MWh) for a 1000 MW precinct – 2015 construction commencement

Technology	Broken Hill	Darlington Point	Dubbo	Moree	Tamworth		
1,000 MW Precinct							
Mono-crystalline PV	\$265	\$236	\$237	\$229	\$234		
Thin film PV	\$281	\$252	\$253	\$245	\$249		
Solar trough (air)	\$229	\$213	\$213	\$195	\$213		
Solar tower (air)	\$186	\$171	\$172	\$159	\$173		
Hybrid (air)	\$175	\$156	\$163	\$166	\$163		
First 2	250 MW stage of 1	,000 MW Precinct	(2015 construction	commencement)			
Mono-crystalline PV	\$356	\$240	\$247	\$253	\$238		
Thin film PV	\$375	\$259	\$265	\$271	\$256		
Solar trough (air)	\$316	\$226	\$230	\$223	\$226		
Solar tower (air)	\$258	\$181	\$186	\$182	\$184		
Hybrid (air)	\$222	\$162	\$171	\$181	\$169		
Last 2	50 MW stage of 1	,000 MW Precinct	(2021 construction	commencement)			
Mono-crystalline PV	\$215	\$225	\$224	\$211	\$224		
Thin film PV	\$234	\$243	\$242	\$228	\$240		
Solar trough (air)	\$181	\$198	\$195	\$174	\$198		
Solar tower (air)	\$148	\$159	\$158	\$142	\$161		
Hybrid (air)	\$150	\$149	\$155	\$155	\$155		

Source AECOM

For the 1,000MW precinct, levelised costs range from \$156 per MWh for a solar thermal hybrid precinct at Darlington Point to \$281 per MWh for a thin-film PV precinct in Broken Hill. For a 1,000MW precinct, Moree has the lowest levelised cost for all solar only technologies. As for the 250MW plant, solar thermal hybrid plant offers the lowest levelised cost for all areas with the exception of Moree, followed by solar tower, solar trough, mono-crystalline PV and thin-film PV. With the exception of Broken Hill, levelised costs for a 1,000 MW precinct are generally lower than those for a 250 MW standalone plant for the same year of commencement of construction.

For the first 250MW plant of a 1,000MW precinct, levelised costs range from \$162 per MWh for a solar thermal hybrid plant at Darlington Point to \$375 per MWh for a thin-film PV plant in Broken Hill. For the last 250MW plant of a 1,000MW precinct, levelised costs range from \$142 per MWh for a solar tower plant at Moree to \$243 per MWh for a thin-film PV plant in Darlington Point. For all areas other than Broken Hill, the levelised costs of the first 250 MW stage essentially match the levelised costs of the standalone 250 MW plant because of similar transmission costs. However for Broken Hill, the large first stage transmission costs for a 1,000 MW precinct are reflected in the higher levelised costs for the first 250 MW stage when compared with the standalone 250 MW plant. For all plants, except Broken Hill, the levelised cost of the last plant is significantly lower than the first plant, reflecting high connection costs of the first plant (particularly transmission connection) as well as reduced capital cost in later periods. In practice, a SENE type agreement would be used to spread the high transmission connection costs over subsequent plants.

Overall, the sharing of infrastructure costs across a number of plants does not have a big impact on the levelised cost because it is such a small proportion of total costs. A SENE type agreement, which allows for the large transmission costs to be spread across a number of plants will be most beneficial in areas where significant infrastructure upgrade is required. In addition, by reducing the costs of the first plant, a SENE type agreement may induce investors into the market earlier than otherwise, particularly in the early stages of large scale solar development when commercial viability is marginal.

4.3.3 Comparison of 250MW Plant with a 1,000MW Precinct

With the exception of Broken Hill, the levelised costs for a 1,000 MW precinct are generally lower than those for a 250 MW standalone plant for the same year of commencement of construction. However, part of this difference is due to slight reductions in capital costs for each stage of construction of the 1,000 MW precinct.

To remove the influence of capital cost reductions, the levelised costs of four separate 250 MW plants were averaged, where the construction of each plant matches the stages of the 1,000 MW precinct. This allows a direct comparison from which to evaluate the benefits or otherwise of developing 1,000 MW precinct compared to 250 MW stand alone plants. **Table 4.3** shows the results for a 1,000 MW precinct compared to the average levelised cost for a 250 MW plant.

Table 4.3	Levelised cost of electricity (\$/MWh) for 250 MW standalone plant and 1,000 MW precinct - 201	5 construction commencement
I UDIC T.O	Levelised cost of electricity (will will for 200 lift standardie plant and 1,000 lift predict - 201	5 construction committencement

Technology	Broken Hill	Darlington Point	Dubbo	Moree	Tamworth		
250 MW Plant							
Mono-crystalline PV	\$225	\$234	\$241	\$247	\$232		
Thin film PV	\$244	\$252	\$258	\$264	\$249		
Solar trough (air)	\$196	\$213	\$217	\$211	\$213		
Solar tower (air)	\$159	\$171	\$176	\$172	\$173		
Hybrid (air)	\$158	\$156	\$165	\$175	\$162		
		1,000 MW Pr	ecinct				
Mono-crystalline PV	\$265 (+17%)	\$236 (+1%)	\$237 (-2%)	\$229 (-7%)	\$234 (+1%)		
Thin film PV	\$281 (+15%)	\$252 (0%)	\$253 (-2%)	\$245 (-7%)	\$249 (+0%)		
Solar trough (air)	\$229 (+17%)	\$213 (+0%)	\$213 (-2%)	\$195 (-8%)	\$213 (+0%)		
Solar tower (air)	\$186 (+17%)	\$171 (0%)	\$172 (-2%)	\$159 (-8%)	\$173 (+0%)		
Hybrid (air)	\$175 (+11%)	\$156 (+0%)	\$163 (-1%)	\$166 (-5%)	\$163 (+0%)		

Source AECOM

Table 4.3 shows that developing a 1,000 MW precinct results in higher levelised costs (11-17%) for all technologies at Broken Hill, no changes in levelised cost at Darlington Point and Tamworth, marginally lower costs at Dubbo (1-2%), and significantly lower costs at Moree (5-8%). These differences are primarily a result of the additional cost of transmission infrastructure to increasing capacity from that suitable for a 250 MW plant to that suitable for a 1,000 MW precinct. With the exception of Broken Hill, all locations considered have a reduced cost of transmission infrastructure per MWp for a 1,000 MW precinct compared to a 250 MW plant. However, the magnitude of these costs at Darlington Point, Tamworth and Dubbo is small as a proportion of total costs and does not show up as significant differences in the levelised cost. As illustrated in **Figure 4.1** and **Figure 4.2**, transmission costs at Moree are a larger proportion of total costs so the reduced cost of transmission for a 1000MW precinct has a bigger impact on the levelised cost.

Transmission infrastructure is generally the largest cost of development after the solar generating technology itself. Therefore the benefits of developing a precinct as opposed to a standalone plant are highly dependent on the existing transmission infrastructure, and at what level of additional capacity enhancements are required to the existing transmission infrastructure, as well as the magnitude of transmission costs as a proportion of total project costs.

In addition to the cost differences shown in **Table 4.3**, there may be further benefits associated with developing a 1,000 MW precinct as opposed to a 250 MW standalone plant. As each plant within a precinct is developed, commissioned and successfully operating, potential risks (as discussed in **Section 5.0**) to subsequent plants within the precinct may be mitigated. In addition, a precinct will require only one environmental and planning approval, there are potential for reduced transport and other site specific costs, and an increase in the viability of onsite manufacturing and additional jobs creation. Whilst not having a significant direct impact on project costs, these benefits may in turn lead to better financing terms for developers and facilitate quicker development of large scale solar projects. The impact of this on levelised electricity costs has been examined in **Section 4.5.6** and shows potential reductions in levelised costs of 6-7%.

4.3.4 Breakdown of levelised cost of electricity

Differences in cost per MWh are largely as a result of differing capital costs of generation equipment for each technology and different transmission infrastructure requirements at each location.

Figure 4.1 and **Figure 4.2** show levelised cost apportioned between each cost item for a 250 MW plant and 1,000 MW precinct respectively, with construction commencing in 2015.

Figure 4.1 Components of levelised cost of electricity – 250 MW plant (2015 construction commencement)

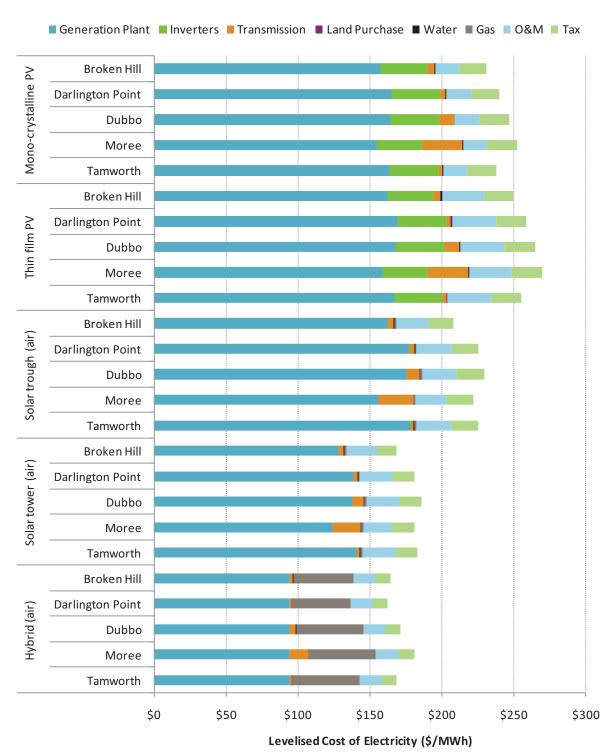
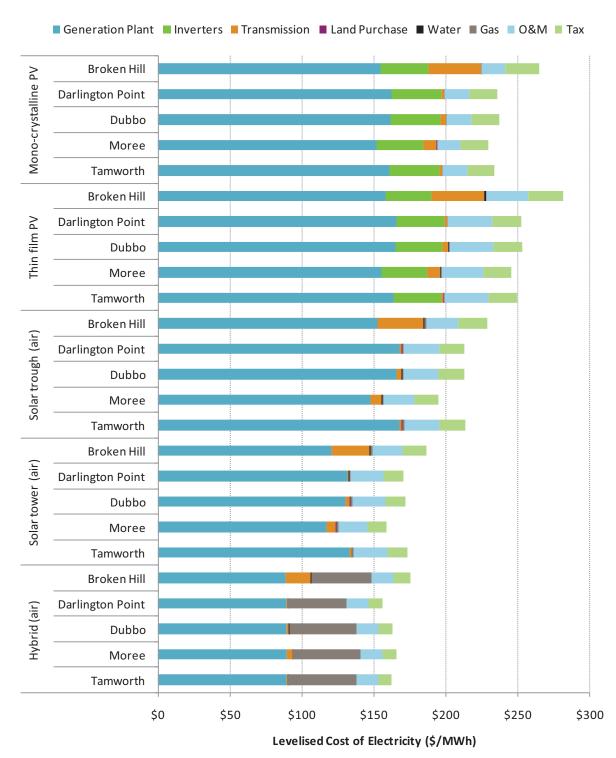
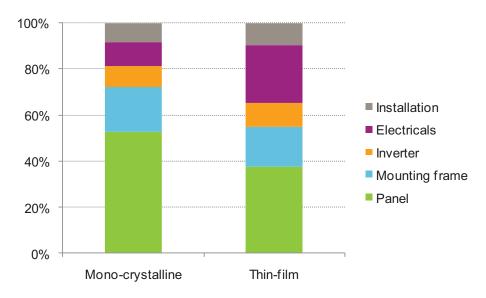


Figure 4.2 Components of levelised cost of electricity - 1,000 MW precinct (2015 construction commencement)



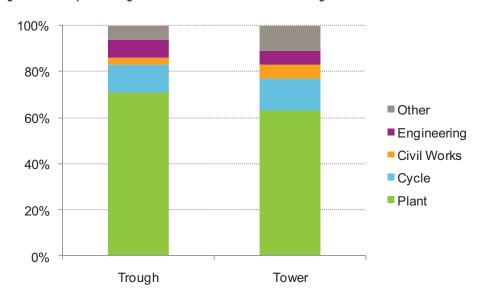
It can be seen in **Figure 4.1** and **Figure 4.2** that the electricity generation plant capital costs are the most significant component of levelised costs at all locations, representing around 60-80% of levelised costs for solar only generation and a slightly lower proportion for hybrid generation. **Figure 4.3** and **Figure 4.4** highlight the main components of generation costs for each technology. For all technologies, the core plant makes up the largest proportion of costs. As such, policies aimed at reducing other cost components, such as construction costs, will not have a significant impact on the levelised cost.

Figure 4.3 Components of generation costs for PV technologies



Source AECOM

Figure 4.4 Components of generation costs for solar thermal technologies



Source Sargent & Lundy (2003)

4.4 Feasibility assessment

4.4.1 New Entrant Generation Costs

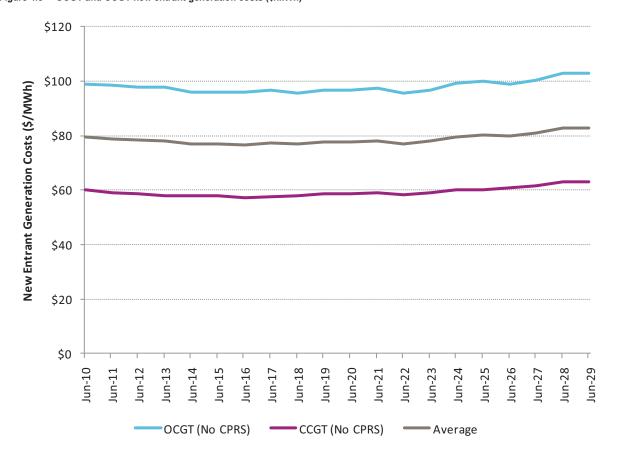
To assess the relative cost effectiveness of the various technologies and areas under consideration, AECOM has compared the levelised cost results to the price required for a new entrant generator utilising conventional generation technology.

The Australian Energy Market Operator (AEMO) commissioned a report on new entrant generation costs, which gives prices for new entrants in various locations around Australia, from 2009-10 until 2028-29 (ACIL Tasman, 2009).

AECOM has used the published LRMC for both a combined cycle gas turbine (CCGT) and an open cycle gas turbine (OCGT) generators in North-Central New South Wales as a point of comparison. CCGT will typically be used to provide base load whereas OCGT will be used to meet peak demand. In reality, most of the solar technologies under consideration will be competing in a market between the two prices.

Figure 4.5 shows the forecast new entrant generation costs for both OCGT and CCGT generators. The forecast generation cost is around \$60/MWh for CCGT and around \$100/MWh for OCGT. Both remain relatively stable over time. As solar is likely to compete in the market between the two prices, the average cost of OCGT and CCGT has been used to compare with solar generation.

Figure 4.5 OCGT and CCGT new entrant generation costs (\$/MWh)



Source ACIL Tasman (2009) with AECOM modifications for 2010 prices

4.4.2 Carbon Pollution Reduction Scheme impacts

The ACIL Tasman (2009) report also publishes new entrant generation costs under a Carbon Pollution Reduction Scheme (CPRS). The ACIL Tasman model assumes the scheme commences in July 2010 (as originally planned) and forecasts permit prices to be \$23/tonne in 2010 rising to \$37/tonne by 2020 in real terms, with between 65-73% being passed through to the market. The ACIL Tasman model forecasts of permit prices are 15% higher than those projected under the Treasury modelling for the CPRS5 scenario (a 5% reduction from 2000 emission levels by 2020).

The Government recently announced (27 April 2010) the CPRS will be taken off the agenda until at least the end of 2012. As such, there is uncertainty over when the CPRS will come into effect. This study assumes that it has been delayed and will come into effect by 2015 and permit prices will be the same as they would have been if the scheme started in 2010. If Government is to meet the targets set prices will need to be at least as much as currently planned and the delay may result in higher prices.

The Copenhagen Accord states that the parties shall enhance their co-operative actions to combat climate change while recognizing the scientific view that an increase in global temperatures should be kept below 2 degrees Celsius. This corresponds to an atmospheric CO₂ concentration of 550 ppm and a 10% reduction in emissions by 2020 for Australia. In addition, the accord also, for the first time, acknowledges that staying below 2 degrees Celsius may not be sufficient and includes a review in 2015 of the need to potentially aim for staying below 1.5 degrees Celsius, or an atmospheric CO₂ concentration of 350 ppm. This suggests that any global agreement on emission reductions may include more stringent targets than the 5% reduction by 2020 in CPRS scenario 5. As such, AECOM has adjusted the ACIL Tasman model to calculate a new entrant generation cost under a CPRS15 scenario (15% reduction from 2000 emission levels by 2020) using the Treasury modelling for permit prices under the CPRS15 scenario (see **Figure 4.6**).

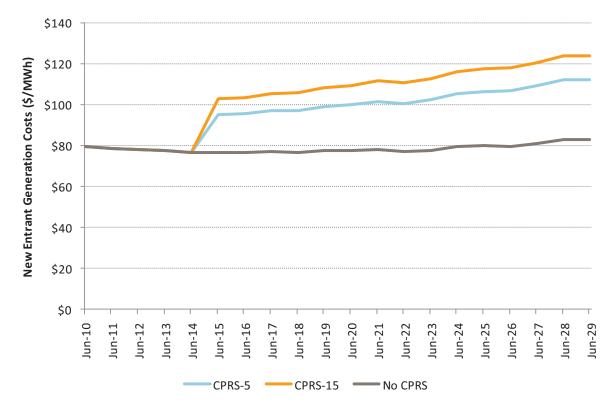


Figure 4.6 OCGT and CCGT new entrant generation costs (\$/MWh) and alternate CPRS scenarios

Source ACIL Tasman (2009) with AECOM modifications for revised CPRS timeline and 2010 prices

4.4.3 Renewable Energy Certificates (RECs)

The sale of Renewable Energy Certificates (RECs) provides an additional revenue stream for the project. One REC is produced for each MWh of renewable electricity produced. Under most circumstances, all electricity produced by a solar plant will be considered to be renewable. However, the use of gas to co-fire a solar thermal plant will reduce the amount of RECs produced per unit of output.

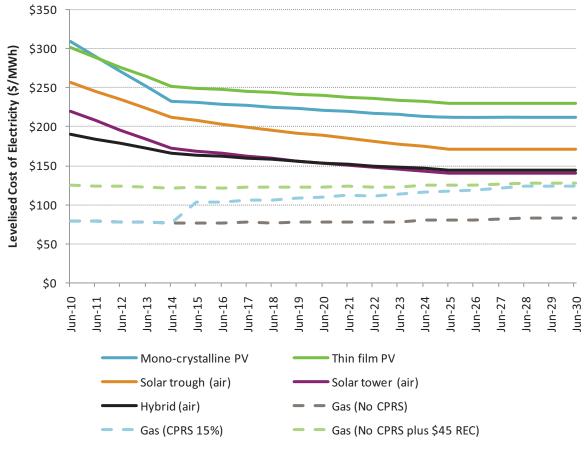
AECOM has not included REC sales as a revenue item in determining the levelised cost of electricity generation but it is an important consideration in the comparison of solar electricity generation and gas fired generation. A price of \$45 (2010\$) per REC has been assumed for the purpose of comparing levelised costs between solar electricity generation and gas fired generation. The overall value of REC revenue will be dependent on the timing of plant construction as the scheme is due to be phased out in 2030. The introduction of a CPRS will also influence REC prices. RECs are designed to represent the price difference between 1 MWh of renewable electricity and 1 MWh of non-renewable electricity. REC prices would be expected to fall on commencement of the CPRS due to the scheme causing an increase in price of non-renewable electricity. As such, the combined price effect of RECs and CPRS will be less than the individual price impact of the two schemes in isolation.

4.4.4 Electricity Generation Price Convergence

The levelised cost of solar generated electricity is expected to decline over time as solar technology capital costs fall. This is in contrast with black energy prices, such as gas, which are expected to rise with the introduction of the CPRS.

Figure 4.7 shows a comparison of levelised cost for each solar technology considered by year of construction commencement for 250 MW standalone plant at Broken Hill compared to the simple average of OCGT and CCGT levelised costs under different CPRS and REC price assumptions. Other areas and precincts show a similar trend in cost declines.

Figure 4.7 Levelised cost of electricity for 250 MW standalone plant at Broken Hill and new entrant gas prices by year of construction



Source AECOM

Figure 4.7 shows that even if a constant real price of \$45 per REC is maintained or a 15% CPRS target is introduced, solar hybrid generation does not appear to become cost competitive for around 20 years. The assumption of a slower pace of solar technology cost reductions prevents other solar technologies from closing the price gap with conventional gas fired generation prior to 2030.

4.5 Cost Sensitivity

Large scale solar electricity generation is a relatively new market and there is considerable uncertainty surrounding future values for a number of key variables. AECOM has used the best available information to produce the price estimates presented in **Section 4.3**. Changes to these underlying assumptions may result in significant variation in the estimated generation costs.

Sensitivity analysis has been undertaken to explore how generation costs may change in response to changes in assumed parameter values.

Key factors for which sensitivity analysis has been undertaken include:

- Solar Electricity Generation;
- Generation technology capital costs;
- Energy storage;
- Transmission infrastructure capital costs and staging; and
- Project financing.

4.5.1 Solar Electricity Generation

The solar generation potential assessed in this study is sensitive to the technical modelling parameters and techniques used to define the solar systems as well as uncertainties in the solar resource. The solar generation potential can be refined with fine tuning of the designs, system models and solar resource datasets, however this is a highly involved and time consuming process. The relative importance and significance of refined and optimised designs on the levelised cost of electricity can be assessed indirectly by sensitivity testing the levelised cost of electricity to changes in the solar generation potential.

Sensitivity of Levelised cost to changes in solar generation potential

The modelling parameters and techniques used in this study are described in **Section B.3** of **Appendix B**. The technical modelling included a number of sensitivity tests to assess the changes in generation potential due to uncertainties in system configuration, modelling parameters and techniques; however the technical modelling sensitivity tests did not encompass the full range of factors that influence the generation potential.

The following scenario illustrates how the levelised cost of electricity changes with an assumed change in generation potential. **Table 4.4** summarises the assumed positive and negative changes in electricity generation potential used to illustrate the impact on the levelised cost of electricity. **Table 4.5** shows the estimated levelised cost of electricity and percentage change relative to the base case in response to the assumed increase in solar generation potential, and **Table 4.6** shows the comparable change for a decrease in solar electricity generation potential.

Table 4.4 Percentage variations applied to the solar generation potential used to test the sensitivity of the levelised cost of electricity to generation potnetial.

Solar Generation Assumption	Mono- crystalline PV	Thin film PV	Solar trough (air)	Solar tower (air)	Hybrid (air) - solar
Upper	10%	10%	30%	30%	30%
Lower	-10%	-10%	-30%	-30%	-30%

Source AECOM (see Section B.3.7 for details of the technical modelling)

Table 4.5 Levelised cost of electricity (\$/MWh) and percentage change from base case – higher solar generation potential (2015 construction commencement)

Technology	Broken Hill	Darlington Point	Dubbo	Moree	Tamworth
		250 MW P	lant		
Mono-crystalline PV	\$210 (-9%)	\$218 (-9%)	\$224 (-9%)	\$229 (-9%)	\$216 (-9%)
Thin film PV	\$227 (-9%)	\$235 (-9%)	\$241 (-9%)	\$246 (-9%)	\$232 (-9%)
Solar trough (air)	\$160 (-23%)	\$174 (-23%)	\$177 (-23%)	\$171 (-23%)	\$173 (-23%)
Solar tower (air)	\$130 (-23%)	\$139 (-23%)	\$143 (-23%)	\$139 (-23%)	\$141 (-23%)
Hybrid (air)	\$136 (-17%)	\$134 (-17%)	\$143 (-17%)	\$150 (-17%)	\$141 (-16%)
		1,000 MW Pr	ecinct		
Mono-crystalline PV	\$241 (-9%)	\$214 (-9%)	\$216 (-9%)	\$209 (-9%)	\$213 (-9%)
Thin film PV	\$256 (-9%)	\$229 (-9%)	\$230 (-9%)	\$223 (-9%)	\$227 (-9%)
Solar trough (air)	\$176 (-23%)	\$164 (-23%)	\$163 (-23%)	\$150 (-23%)	\$164 (-23%)
Solar tower (air)	\$143 (-23%)	\$131 (-23%)	\$132 (-23%)	\$122 (-23%)	\$133 (-23%)
Hybrid (air)	\$145 (-17%)	\$130 (-17%)	\$136 (-16%)	\$139 (-16%)	\$136 (-16%)

Table 4.6 Levelised cost of electricity (\$/MWh) and percentage change from base case – lower solar generation (2015 construction commencement)

Technology	Broken Hill	Darlington Point	Dubbo	Moree	Tamworth					
		250 MW P	lant							
Mono-crystalline PV	\$257 (+11%)	\$267 (+11%)	\$274 (+11%)	\$280 (+11%)	\$264 (+11%)					
Thin film PV	\$277 (+11%)	\$287 (+11%)	\$294 (+11%)	\$300 (+11%)	\$283 (+11%)					
Solar trough (air)	\$297 (+43%)	\$322 (+43%)	\$328 (+43%)	\$317 (+43%)	\$322 (+43%)					
Solar tower (air)	\$241 (+43%)	\$258 (+43%)	\$265 (+43%)	\$259 (+43%)	\$261 (+43%)					
Hybrid (air)	\$216 (+32%)	\$213 (+32%)	\$224 (+31%)	\$238 (+31%)	\$220 (+30%)					
1,000 MW Precinct										
Mono-crystalline PV	\$294 (+11%)	\$262 (+11%)	\$263 (+11%)	\$255 (+11%)	\$260 (+11%)					
Thin film PV	\$313 (+11%)	\$280 (+11%)	\$281 (+11%)	\$273 (+11%)	\$277 (+11%)					
Solar trough (air)	\$327 (+43%)	\$304 (+43%)	\$304 (+43%)	\$278 (+43%)	\$305 (+43%)					
Solar tower (air)	\$266 (+43%)	\$244 (+43%)	\$246 (+43%)	\$227 (+43%)	\$248 (+43%)					
Hybrid (air)	\$232 (+32%)	\$205 (+31%)	\$212 (+30%)	\$217 (+30%)	\$211 (+30%)					

Source AECOM

The percentage change applied to the solar electricity generation potential results in a roughly equal but opposite percentage change in levelised costs for PV technologies only. A non-linear relationship is exhibited for thermal technologies where percentage changes to solar electricity generation potentials do not result in a similar but opposite percentage change in levelised costs. A 10% increase in solar generation potential for PV technologies and a 30% increase for solar thermal technologies are not enough to make either technology cost competitive with conventional generation technology in the short term.

Sensitivity to solar generation potential due to uncertainties in the solar resource

The base case solar generation potentials were calculated for each technology using long term NASA satellite derived solar, temperature and wind resource data. For comparison the generation potential is also calculated using long term Bureau of Meteorology satellite derived resource data, and ground measured temperature and wind resource data. There is significant variation between the solar data sources and these variations are not consistent between areas. The solar technologies respond non-linearly to these differences in datasets, where the solar thermal technologies' generation potential are particularly sensitive to the estimated direct component of the solar resource, where as the PV technologies' efficiency is very sensitive to temperature. The Levelised cost of electricity based on the BoM data and percentage change relative to the NASA base case is shown in **Table 4.7**.

17 December 2010 3⁻

Table 4.7 Levelised cost of electricity (and percentage change relative to base case) based on Solar Generation Potential calculated using Bureau of Meteorology derived solar resource data

Technology	Broken Hill	Darlington Point	Dubbo	Moree	Tamworth				
		250 MW P	lant						
Mono-crystalline PV	\$226 (-2%)	\$237 (-1%)	\$243 (-1%)	\$256 (+2%)	\$237 (0%)				
Thin film PV	\$241 (-3%)	\$253 (-2%)	\$258 (-2%)	\$271 (+0%)	\$252 (-1%)				
Solar trough (air)	\$184 (-11%)	\$197 (-13%)	\$202 (-12%)	\$211 (-5%)	\$205 (-9%)				
Solar tower (air)	\$150 (-11%)	\$158 (-13%)	\$164 (-12%)	\$172 (-5%)	\$166 (-9%)				
Hybrid (air)	\$158 (-4%)	\$156 (-3%)	\$165 (-4%)	\$178 (-2%)	\$164 (-3%)				
1,000 MW Precinct									
Mono-crystalline PV	\$259 (-2%)	\$232 (-1%)	\$234 (-1%)	\$233 (+2%)	\$233 (0%)				
Thin film PV	\$272 (-3%)	\$246 (-2%)	\$247 (-2%)	\$246 (+0%)	\$ (+0%) \$246 (-1%)				
Solar trough (air)	\$203 (-11%)	\$186 (-13%)	\$187 (-12%)	\$185 (-5%)	\$194 (-9%)				
Solar tower (air)	\$165 (-11%)	\$149 (-13%)	\$152 (-12%)	\$151 (-5%)	\$158 (-9%)				
Hybrid (air)	\$169 (-4%)	\$150 (-4%)	\$157 (-4%)	\$163 (-2%)	\$158 (-3%)				

4.5.2 Generation System Capital Costs

Table 4.8 and **Table 4.9** show the percentage change in estimated generation costs per MWh in response to a +/-20% change in baseline technology capital costs. As solar generation capital costs represent a significant proportion of total costs, overall cost per MWh shows significant response to changes in capital costs. The relative change varies between areas and technologies due to the influence of other costs such as transmission infrastructure in the case of Broken Hill or ongoing gas purchase costs for trough hybrid systems. A 20% decrease in the base capital costs assumptions will make hybrid solar trough, and to a lesser extent, pure solar tower plants, competitive with conventional generation technology within 10 to 15 years.

Table 4.8 Levelised cost of electricity (\$/MWh) and percentage change from base case – 20% higher technology capital costs (2015 construction commencement)

Technology	Broken Hill	Darlington Point	Dubbo	Moree	Tamworth				
		250 MW PI	ant						
Mono-crystalline PV	\$273 (+18%)	\$284 (+18%)	\$290 (+18%)	\$293 (+16%)	\$281 (+18%)				
Thin film PV	\$292 (+17%)	\$303 (+17%)	\$309 (+17%)	\$312 (+15%)	\$299 (+17%)				
Solar trough (air)	\$243 (+17%)	\$265 (+17%)	\$268 (+17%)	\$256 (+15%)	\$264 (+17%)				
Solar tower (air)	\$197 (+17%)	\$211 (+17%)	\$216 (+16%)	\$208 (+15%)	\$214 (+17%)				
Hybrid (air)	\$183 (+11%)	\$181 (+12%)	\$190 (+11%)	\$200 (+10%)	\$187 (+11%)				
1,000 MW Precinct									
Mono-crystalline PV	\$306 (+16%)	\$279 (+18%)	\$280 (+18%)	\$270 (+18%)	\$277 (+18%)				
Thin film PV	\$323 (+15%)	\$296 (+17%)	\$296 (+17%)	\$286 (+17%)	\$292 (+17%)				
Solar trough (air)	\$262 (+15%)	\$250 (+17%)	\$249 (+17%)	\$227 (+17%)	\$250 (+17%)				
Solar tower (air)	\$213 (+14%)	\$200 (+17%)	\$201 (+17%)	\$185 (+16%)	\$203 (+17%)				
Hybrid (air)	\$193 (+10%)	\$174 (+11%)	\$181 (+11%)	\$184 (+11%)	\$180 (+11%)				

Source AECOM

Table 4.9 Levelised cost of electricity (\$/MWh) and percentage change from base case – 20% lower generation plant capital costs (2015 construction commencement)

Technology	Broken Hill	Darlington Point	Dubbo	Moree	Tamworth					
		250 MW PI	ant							
Mono-crystalline PV	\$190 (-18%)	\$197 (-18%)	\$203 (-18%)	\$212 (-16%)	\$195 (-18%)					
Thin film PV	\$207 (-17%)	\$214 (-17%)	\$221 (-17%)	\$228 (-15%)	\$211 (-17%)					
Solar trough (air)	\$172 (-17%)	\$187 (-17%)	\$191 (-17%)	\$188 (-15%)	\$186 (-17%)					
Solar tower (air)	\$141 (-17%)	\$150 (-17%)	\$155 (-16%)	\$154 (-15%)	\$152 (-17%)					
Hybrid (air)	\$144 (-12%)	\$142 (-13%)	\$151 (-12%)	\$161 (-11%)	\$148 (-12%)					
1,000 MW Precinct										
Mono-crystalline PV	\$223 (-16%)	\$193 (-18%)	\$194 (-18%)	\$189 (-18%)	\$191 (-18%)					
Thin film PV	\$240 (-15%)	\$209 (-17%)	\$210 (-17%)	\$205 (-17%)	\$207 (-17%)					
Solar trough (air)	\$195 (-15%)	\$176 (-17%)	\$176 (-17%)	\$162 (-17%)	\$176 (-17%)					
Solar tower (air)	\$160 (-14%)	\$142 (-17%)	\$143 (-17%)	\$133 (-16%)	\$144 (-17%)					
Hybrid (air)	\$156 (-11%)	\$137 (-12%)	\$144 (-12%)	\$147 (-12%)	\$143 (-12%)					

4.5.3 Energy Storage

Energy storage was omitted as a core component of this study as this enables the solar PV and solar thermal technologies to dispatch into the same market and be compared on a common basis.

The inclusion of energy storage for solar systems will affect financial viability through two mechanisms:

- Increased capital cost for both the storage technology itself and the associated increased size of solar collectors
- Improved electricity generation and dispatch.

The combination of the above factors may accelerate the point at which the levelised costs for tower becomes cost competitive against new entrant OCGT plants.

4.5.4 Transmission Infrastructure Capital Costs

As shown in **Figure 4.1** and **Figure 4.2**, transmission costs are most significant for a 250 MW standalone plant at Moree and a 1,000 MW precinct at Broken Hill. Excluding transmission infrastructure costs reduces the levelised cost of electricity by between 8-12% for a 250 MW plant at Moree and 11-16% for a 1,000 MW precinct at Broken Hill with smaller reductions of between 3-5% for a 250 MW plant at Dubbo and 3-4% for a 1,000 MW precinct at Moree. For all other areas considered, transmission infrastructure costs are far exceeded by solar electricity generation capital costs, resulting in only minor reductions in levelised costs of electricity when transmission infrastructure costs are excluded.

4.5.5 Transmission Infrastructure Construction Staging

As a 1,000 MW precinct will be built over a number of years and as an aggregate of individual plants within the precinct, there are a number of alternate options for constructing and funding the transmission infrastructure required for the entire 1,000 MW precinct. AECOM has assumed that transmission expansion would be staged efficiently to lower overall precinct transmission costs and that the associated capital and financing costs would be spread across all plants within the precinct. However, alternatives such as incremental expansion of transmission infrastructure for each 250 MW stage or a single build out of all the required transmission infrastructure for the fully developed precinct may be considered.

Incremental expansion of transmission capacity results in a 1-2% lower overall levelised cost for a 1,000 MW precinct at Broken Hill primarily due to the fact that the first 250 MW stage requires minimal transmission infrastructure expansion and so capital expenditure is deferred until the second stage is constructed. The relative insignificance of transmission costs compared to the generation plant capital costs for a 1,000 MW precinct at all locations considered other than Broken Hill, result in insignificant changes in levelised costs as a result of alternative transmission infrastructure staging and funding.

4.5.6 Project Financing

As debt and equity finance are priced differently, the proportion of overall project financing provided as debt, known as the gearing ratio, will influence the levelised cost of electricity. AECOM has assumed a debt gearing of 60%. However, debt providers may be willing to lend a higher proportion of total funding requirements for later developments within a precinct after operational and financial performance of earlier plants has been proven or if suitable performance

guarantees are provided by technology providers. That is, operation risk has been reduced. Higher gearing will reduce the weighted average cost of capital (WACC) and the higher level of debt has tax advantages.

An increase in the debt gearing ratio from 60% to 75% results in a 6-7% reduction in levelised cost for solar only technologies and a 4-5% reduction for hybrid technology.

Conversely, if investor judged the project to be of higher risk for a particular reason (such as credit worthiness of the PPA counterparty or perceived risk associated with large scale deployment of a new technology) a higher return on debt or equitively investments may be required to secure funding.

An increase in debt and equity financing costs to 8.5% and 15% respectively, whilst still maintaining a debt gearing ratio of 60% (resulting in a WACC of 11.1% post tax nominal) would increase levelised costs for solar only technologies by 12-14% and 9-10% for hybrid technology.

4.5.7 Solar Flagships Funding

The Commonwealth Government announced in its May 2009 Budget the establishment of the \$4.5 billion Clean Energy Initiative (CEI). CEI includes the Solar Flagships Program (SFP), which provides up to \$1.5 billion in funding for construction of a total capacity of 1,000 MW, including up to four solar power stations.

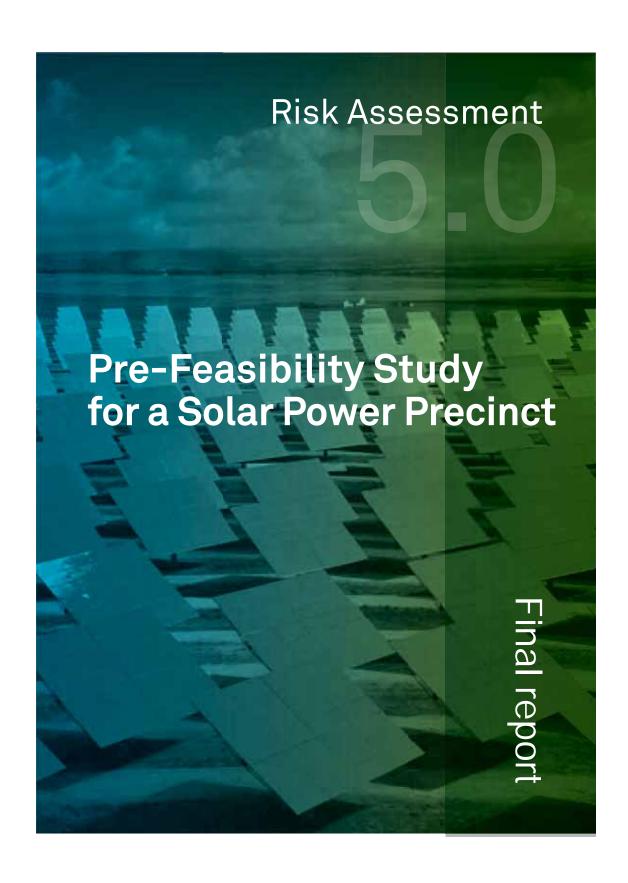
Whilst the funding will not necessarily be divided evenly between all projects supported as part the program, the impact of up-front solar flagships funding on levelised costs has been modelled assuming one quarter (\$375 million) of the total available funding is used to offset first year capital costs.

Table 4.10 shows the resulting levelised costs of electricity and percentage change from base case costs. Levelised costs are lower for 250 MW plants compared to 1,000 MW precincts of the same technology at the same location as the Solar Flagships funding represents a greater proportion of overall development costs.

Table 4.10 Levelised cost of electricity (\$/MWh) and percentage change from base case – Solar Flagships funding (2015 construction commencement)

Technology	Broken Hill	Darlington Point	Dubbo	Moree	Tamworth					
		250 MW P	lant							
Mono-crystalline PV	\$150 (-35%)	\$156 (-35%)	\$163 (-34%)	\$173 (-32%)	\$154 (-35%)					
Thin film PV	\$169 (-32%)	\$175 (-32%)	\$181 (-32%)	\$191 (-29%)	\$172 (-33%)					
Solar trough (air)	\$138 (-34%)	\$149 (-34%)	\$154 (-33%)	\$154 (-30%)	\$149 (-34%)					
Solar tower (air)	\$111 (-34%)	\$119 (-34%)	\$124 (-33%)	\$125 (-31%)	\$120 (-34%)					
Hybrid (air)	\$127 (-23%)	\$125 (-23%)	\$134 (-22%)	\$144 (-21%)	\$131 (-22%)					
1,000 MW Precinct										
Mono-crystalline PV	\$240 (-9%)	\$210 (-11%)	\$211 (-11%)	\$205 (-11%)	\$208 (-11%)					
Thin film PV	\$256 (-9%)	\$226 (-10%)	\$227 (-10%)	\$227 (-10%) \$221 (-10%)						
Solar trough (air)	\$207 (-9%)	\$189 (-11%)	\$189 (-11%)	\$174 (-11%)	\$190 (-11%)					
Solar tower (air)	\$169 (-9%)	\$152 (-11%)	\$153 (-11%)	\$142 (-11%)	\$154 (-11%)					
Hybrid (air)	\$164 (-7%)	\$144 (-7%)	\$152 (-7%)	\$155 (-7%)	\$151 (-7%)					

Source AECOM



5.0 Risk Assessment

The allocation and mitigation of the various risk factors in developing a solar precinct for large scale power generation will be a critical step in successfully progressing the project through feasibility, development, financing, construction and operation. The risk for any particular part of the project should lie with the party most suited to manage that risk. In privately financed projects, as would be expected for a large scale solar plant, it is common for the developer to carry most of the risk but in some things the risk should either lie with other stakeholders or be shared. The early allocation of risk and mitigation thereof can offer tangible benefits for the speed of development and economic viability. It can also increase the appetite for a number of developers and thereby increase competition. Several recent large scale infrastructure projects have become unviable due to the inequitable division of project risk.

The risk matrix as shown in **Table 5.1** below, lists the main risks associated with the development of the precinct itself, however it does not address the many specific and smaller project risks that exist.

Pre-Feasibility Study for a Solar Power Precinct

Table 5.1 Risk matrix

Project area	Risk	Consequence	Likelihood (low, med, high)	Magnitude (low, medium, high)	Owner of risk (inc secondary owner)	Mitigation options	Role for govt?
Power Purchase Agreement (PPA)	Not securing PPA to underpin project viability	Project does not proceed	Med/High	High	Developer	Creditworthy entity to either be an anchor off-taker or underpin the project completely	Possibly
Project Development	Equity financing of project including development cost overrun, interest rate and foreign exchange risk	Project delay	Medium	Med/High	Developer	Reputable and creditworthy. Strong balance sheet. Strong technology partners Hedging	o Z
Financing	Securing of project finance and third party debt	Project does not proceed	Low/Med	High	Developer/(govt)	Minimise early development risk and delay. Secure Power Purchase Agreement or revenue to underpin debt service. Govt financial support.	Possibly
Electricity Market	Reliance on some merchant revenue for non contracted off-take (post operation)	Portion of variable revenue	Medium	Med/High	Developer	Long term electricity price analysis. Hedging.	No
Electricity Market	Material and sustained REC prices decrease (post operation)	Decreased project cash flow, returns and possible debt service default	Low/Med	High	Developer	Long term REC price analysis. Hedging. Cap and collar on REC off take agreement	O _N
Electricity Transmission system	Delay or very costly connection agreement	Project delay or project does not proceed	Low/Med	High	Developer (Govt)	Early engagement and discussions	Yes
Electricity Transmission system	Constraints or future build out issues for staged capacity	Limited plant capacity (MW) and hence revenue	Medium	High	Developer	System studies and discussions with transmission network service provider (TNSP)	ON
Electricity Transmission system	Requirement for new line	Permitting delay and securing of land	Medium	Med/High	Govt	Minimise land owners and early engagement. Closely manage the permitting process	Yes

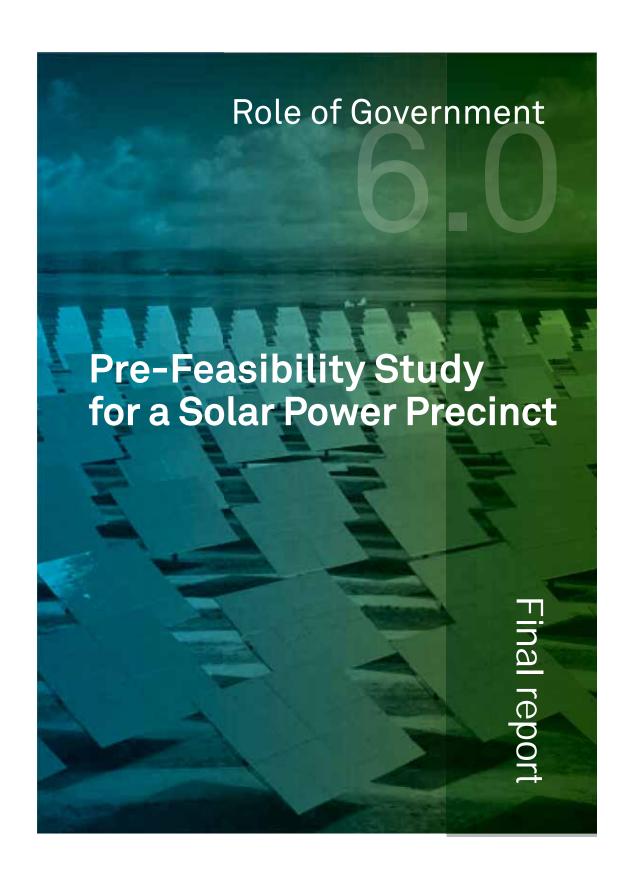
Pre-Feasibility Study for a Solar Power Precinct

Project area	Risk	Consequence	Likelihood	Magnitude	Owner of risk	Mitigation options	Role for
			(low, med, high)	(low, medium, high)	(inc secondary owner)		govt?
Electricity Transmission system	Requirement for code changes due to capacity of plant and non base load operation	Project delay and possibly project not proceeding	Med/High	High	Govt /(developer)	Early engagement with regulator (this issues could affect many developers across NEM)	Yes
Land	permitting	Project delay and possibly project not proceeding	Medium	High	Govt /(developer)	Minimise private landowners. Early engagement with owners and securing options to lease or purchase Start permitting following solar resource assessment	Yes
Water	Permitting or rights	Project delay and possibly project not proceeding	Medium	High	Developer/(Govt)	Early development engagement and in principle water off-take agreement	Yes
Water	Inconsistent quality and volume	Project non performance or reduced output	Low/Med	Med/High	Developer	Use pipeline potable water. If not potable define scope of water quality and design on site water treatment plant. Risk analysis and contractual agreement on volume	°Z
Water	Water price increase	Increased operating costs and decreased returns	Medium	Medium	Developer	Ideally, a Water Services Agreement (WSA) with defined pricing and escalation. If not, risk analysis on future water pricing	No
Water	Permitting for new pipeline	Project delay and possibly project not proceeding	Low/Med	High	Govt /(developer)	Minimise private land owners and early engagement. Closely manage the permitting process	Yes
Gas (Hybrid only)	Availability and security of supply	Decreased revenue	Low/Med	High	Developer	Gas Supply Agreement with appropriate guarantees	No
Gas (Hybrid only)	Price increase	Decreased revenue and project viability	Medium	High	Developer	Gas Supply Agreement with defined pricing structure	No

	Cons	Consequence	Likelihood (low, med, high)	Magnitude (low, medium, high)	Owner of risk (inc secondary owner)	Mitigation options	Role for govt?
Permitting fo	Permitting for new pipeline	Project delay and possibly project not proceeding	Low/Med	High	Govt /(developer)	Minimise private land owners and early engagement. Closely manage the permitting process	Yes
Estimate of solar availability not achieved	ability	Lower than expected production and revenue	Low	Med/High	Govt/(Developer)	Detailed solar monitoring at selected site	Yes³
Unable to secure approvals	ovals	Project does not proceed	Medium	High	Govt	Identification of all approvals necessary, steps involved and estimate of time and cost. Careful management of process	Yes
Underestimate of capital costs	al	Overspend. Potential to affect viability	Medium	Med/High	Developer	Detailed study to estimate costs and contingency and build in sufficient sensitivities into economic/financial model. Ideally EPC contract with appropriate cost penalties	ON O
O&M costs increase from financial model estimate post operation	m 9 post	Potential to affect viability	Medium	Med/High	Developer	Detailed study to estimate costs and contingency and build in sufficient sensitivities into economic/financial model. Ideally well defined O&M agreement appropriate cost penalties	O _N
Technology does not perform as expected ie output, availability, reliability	rform	Decreased revenue and debt service difficulties	Low/Med	Med/High	Developer	Technology provider guarantees for performance. Working plants. Expert support close to plant for first 12 months	ON.

³ Although industry discussions have indicated that banks require at least one year of ground data and given the importance of this most developers may want to undertake monitoring themselves.

Project area	Risk	Consequence	Likelihood (low, med, high)	Magnitude (low, medium, high)	Owner of risk (inc secondary owner)	Mitigation options	Role for govt?
Insurance	Unavailable or too costly to put in place	Project viability and revenues at risk. Project does not proceed	Low	High	Developer	Structure the project such that insurance is obtainable and make sure cover is secured for business interruption	ON
Socio-Political	Resistance of community/agencies to the development	Project delay or project not proceeding	Low	High	Govt/(Developer)	Well structured and planned community/agency consultation programme	Yes
Additional Benefits	Understatement of benefits such as industry development	Under-investment	Medium	Medium	Govt	Strong economics capability	Yes



6.0 Role of Government

6.1 Introduction

Whilst it is clear that solar will play an important part of the future supply of electricity, the timing of this is uncertain. This study shows that large scale solar projects are unlikely to be financially viable for the next 10-20 years and it is hard to see a developer making financial investments in large scale solar power plants in the short term. There is much uncertainty in the market around both capital costs, and how quickly these will fall, and potential revenue sources.

In order for solar generation to be financially viable, it needs to be competitive with other new electricity generation entrants. RECs and CPRS reduce the price differential, increasing solar generation's competitiveness. However, the current uncertainty in both of these markets may be acting as a barrier to large scale solar projects. As well as reducing financial viability, the uncertainty around when CPRS might be introduced, as well as the level of emission reduction targets, will make it harder to secure a long term PPA. A PPA provides certainty to the servicing of project debt and equity returns and makes it easier to secure project finance.

In addition, a large scale solar project requires infrastructure (transmission, gas, water), land and environmental and planning approvals which, while not a significant proportion of the total cost, add further risk and uncertainty around a proposed project, particularly in terms of the transaction costs and gestation period from early development to construction commencement.

The role of government in providing assistance to bring forward the development of large scale solar projects depends on the extent of benefits to society and if they outweigh the costs of assistance. The main benefits to society from the advancement of large scale solar projects in NSW include cleaner energy, and the associated carbon emission reductions, and the potential for industry development in Australia. In addition, this level of solar generation will deliver substantial benefits in terms of the security of energy supply and socio-economic development.

6.2 Economic Benefits

6.2.1 Cleaner Energy

Solar energy produces lower emissions than traditional energy sources. **Table 6.1** sets out the expected greenhouse gas (GHG) emission savings from the different solar technologies at each site for a 250 MW plant and a 1,000 MW precinct. The total GHG emission reductions for a 250 MW solar plant vary between 1.8 and 2.7 million tCO2-e over the life of the plant, dependent on the area and technology and average between 63,000 – 96,000 tCO2-e a year dependent on the area and technology. Moree, the most viable area for a 1,000 MW precinct, would result in GHG emission reductions of around 8.9 to 10.8 million tCO2-e for the solar thermal and hybrid technologies. These avoided emissions are based on a gas generated electricity emission intensity, which is the most likely market for a solar plant to compete against. As gas has much lower emissions intensity than coal this is a conservative estimate of greenhouse gas emission reductions.

By bringing forward the development of large scale solar projects, the Government will enhance greenhouse gas reductions. The magnitude of these benefits depends on how many years the project is brought forward by. If the Government were to bring forward investment of a solar thermal tower precinct by 10-15 years at Moree, the most favourable area, this would generate greenhouse gas emission savings of around 3.2 (10 years) to 4.8 (15 years) million tCO2-e.

This study assumes that a CPRS will be in place by 2015 such that some of these GHG emissions will be captured in the market. However, the CPRS will be a market price reflecting the value of traded carbon emissions rights given the constraints on supply imposed by the

scheme. This, in practice, is often less than the social cost of carbon which seeks to encapsulate the full global cost today of an incremental unit of CO2-e emitted now, calculated by summing the full global cost of the damage it imposes over the whole of its time in the atmosphere.

Table 6.1 Potential greenhouse gas emission reductions ('000 tCO2-e)

	Broken	Hill	Darlingt	on Point	Dubbo		Moree		Tamwor	th
Technology	Life of project	Avg. Annual								
	('000)	('000)	('000)	('000)	('000)	('000)	('000)	('000)	('000)	('000)
				2501	/IW					
Mono-crystalline										
PV	1,838	66	1,756	63	1,763	63	1,874	67	1,768	63
Thin film PV	1,848	66	1,769	63	1,780	64	1,885	67	1,790	64
Solar trough (air)	2,146	77	1,955	70	1,982	71	2,226	79	1,954	70
Solar tower (air)	2,611	93	2,408	86	2,422	86	2,696	96	2,377	85
Hybrid (air)	2,146	77	1,955	70	1,982	71	2,226	79	1,954	70
1,000MW										
Mono-crystalline										
PV	7,286	214	6,960	205	6,991	206	7,428	218	7,008	206
Thin film PV	7,326	215	7,013	206	7,057	208	7,472	220	7,097	209
Solar trough (air)	8,583	252	7,821	230	7,927	233	8,902	262	7,817	230
Solar tower (air)	10,445	307	9,632	283	9,688	285	10,782	317	9,507	280
Hybrid (air)	8,583	252	7,821	230	7,927	233	8,902	262	7,817	230

Source AECOM, based on National Greenhouse Accounts (NGA) Factors, 2010

There is a large body of literature available on the issue of external costs of greenhouse gas emissions. The values vary significantly depending on the approach used and the country in which the analysis is undertaken. International research on the social cost of carbon suggests a figure of around A\$50/tCO2e. The UK Government recently adopted a value of £25.5/tCO2e (2007 prices) that increases by 2% per year to reflect the damage costs of climate change caused by each additional tonne of greenhouse gas emitted (around A\$65 in 2009). This has been made mandatory for all economic appraisals by the UK Government and was endorsed by the OECD. Recent research on the external cost of greenhouse gas emissions for the European Commission recommends a central value of €25 /t CO2e (around A\$50/tCO2e) in 2010 rising to €40/tCO2e (around A\$80/tCO2e) by 2020⁴.

The economic benefits of greenhouse gas reductions will be the difference between the CPRS permits price and the recommended social cost of carbon. As such, the economic benefit is dependent on when a CPRS is introduced and the targets set. **Table 6.2** sets out some different CPRS target scenarios to consider the potential economic benefits. The economic benefits of reductions in GHG emissions from accelerating a solar precinct by 10 years range from \$35 to \$136 million depending on the level of CPRS targets and assuming a social cost of carbon of \$66/tCO2e in 2010 increasing by 2% per annum. This increases to around \$40 to \$170 million if the project is brought forward by 15 years. However, it is important to recognise that the construction of a solar precinct would generate GHG emissions. It has been assumed that these emissions would occur anyway but at a later date. Further work is recommended to assess the GHG emissions from the construction of a solar precinct and hence the net GHG emission reductions from the development of a solar precinct.

-

⁴ Handbook on estimation of external costs in the transport sector, CE Delft, February 2008

Table 6.2 NPV (7% discount rate) for potential economic benefits of greenhouse gas emission reductions from acceleration of large scale solar precinct, assuming a social cost of carbon of \$66/t CO2e in 2010 increasing by 2% per annum

Technology	No CPRS	CPRS 5%	CPRS 15%	
Solar Tower –10 years	\$136m	\$70m	\$43m	
Solar Tower –15 years	\$172m	\$85m	\$49m	
Solar Trough/Hybrid –10 years	\$113m	\$58m	\$35m	
Solar Trough/Hybrid –15 years	\$142m	\$70m	\$40m	

6.2.2 Industry Development

The solar industry is still a relatively new market and, despite good solar resource, Australia has lagged behind in industry development. According to the IEA⁵, countries with high solar resource and expensive electricity will be the first to reach commercial feasibility for solar projects. Whilst Australia has one of the highest solar resources in the world, it has lagged other countries in the solar industry because of the cheap supply of electricity from fossil fuel.

Establishing a solar plant or precinct will promote the development of the Australian solar industry and generate employment opportunities. The employment impact will be dependent on the technology and site chosen. **Table 6.3** sets out employment multipliers estimated for the energy generation industry in a recent study: *The net employment impacts of climate change policies* by Access Economics (2009). Overall, solar technology plants, particularly photovoltaic, generate significantly more jobs than OCGT and CCGT plants for construction. For example, construction employment for a 1,000 MW solar PV precinct is around 10,000 full time equivalent (FTE) compared to around 5,000 for solar thermal and 1,000 for OCGT. During operation, photovoltaic technology does not require significant maintenance so employment is limited. Solar thermal technology generates around 20% more operational employment than OCGT and CCGT plants. Employment is higher if onsite manufacturing occurs.

Whilst **Table 6.3** provides an indication of the likely employment that may result from large scale solar projects, the scope of this will be dependent on the area selected and local skills base. Once an area and technology are selected it will be important to review the local skill base against the type of jobs required and develop a roadmap to maximise employment opportunities.

Table 6.3: Employment generation for different energy generation

	Employment per MW	250 MW	1000 MW	
Construction				
Solar PV	10.17	2542.5	10170	
Solar thermal	4.89	1222.5	4890	
OCGT	0.95	237.5	950	
CCGT	1.28	320	1280	
Operations (annual)				
Solar PV	-	-	-	
Solar thermal	0.15	37.5	150	
OCGT	0.12	30	120	
CCGT	0.12	30	120	

Note Employment is expressed in full time equivalent terms

Source Access Economics (2009)

_

⁵ Technology Roadmap: Solar photovoltaic energy, IEA

6.2.3 Other Benefits

Other benefits that may result from supporting a project of this size include:

- · Australia may be better positioned to become a global leader in solar technologies; and
- Local production of solar technologies, which is viable for projects of this size, should significantly reduce the
 cost of solar technology in Australia, which in turn should increase take up in other markets such as
 residential and commercial buildings and further decrease GHG emissions.

6.2.4 Summary

Whilst this study provides an indication of the likely economic benefits that may result from large scale solar projects, the magnitude of these benefits is highly dependent on the area and technology under consideration, as well as the level of government assistance and the extent to which it advances the large scale solar industry in NSW. Once an area and technology are selected it will be important to undertake:

- A more detailed feasibility study;
- A full economic appraisal to quantify the economic benefits and assess the economic viability of any proposed government assistance; and
- Develop a roadmap to maximise the benefits from supply chain and industrial development.

6.3 Types of Assistance

As discussed above, the main barriers in the large scale solar industry are focused around the uncertainty in capital costs and revenues and the subsequent difficulty in securing financing. Other major barriers are the high transaction costs and long gestation period from early development to construction commencement which exacerbates securing financing. Any potential role of government should focus around addressing these issues. **Table 6.5** sets out some options for different roles government could take which generally fall into the following three categories:

- Reducing transaction costs and gestation period through providing a pre-approved site and provision of access to key infrastructure such as transmission, water and gas;
- Capital funding through upfront grant, debt or equity; and
- Improved certainty over revenue streams through a PPA.

Table 6.4 sets out the costs to government of providing a PPA or an upfront capital grant to make a 1,000 MW solar tower precinct at Moree, the most viable area, financially viable. REC revenue, which was excluded from the levelised costs presented in **Section 4.3**, has been included in the analysis. The amount of assistance required depends on when construction commences and whether a CPRS is in place. The cost to government of providing a PPA is around \$1.1bn if construction commences in 2015 and between \$0.7bn and \$1bn if construction starts in 2020 depending on whether a CPRS exists and the targets set. An upfront capital grant would cost the government around \$1bn if construction started in 2015 and between \$0.7bn and \$0.9bn if construction commenced in 2020, depending on whether a CPRS exists. CPRS has an increasing impact over time due to the increasing permit prices, whilst the impact of RECs diminishes over time as the scheme is phased out in 2030 and REC prices decrease as CPRS permit prices increase. A PPA allows any assistance to be spread over a 20 – 30 year time horizon and reduces the risk that the project will not deliver the expected quantities of solar energy generation. However, the PPA is more expensive to government than an upfront capital grant (by around \$80m-\$100m) because it is cheaper for government to borrow money than a private developer.

Table 6.4: Cost to government of PPA and upfront grant to make a solar tower precinct (1,000MW) at Moree financially viable (2010\$)

	2015			2020		
	No CPRS	CPRS-5	CPRS-15	No CPRS	CPRS-5	CPRS-15
LCOE (\$/MWh)	\$159	\$159	\$159	\$146	\$146	\$146
LCOE (\$/MWh) (including RECs) ⁶	\$129	\$146	\$153	\$125	\$138	\$143
New entrant generation cost (\$/MWh)	\$77	\$95	\$103	\$78	\$100	\$109
PPA gap (\$/MWh)	\$52	\$51	\$50	\$47	\$38	\$33
NPV of Government providing a PPA that makes the project financially viable (7% real discount rate) (\$)	\$1,124m	\$1,102m	\$1088m	\$1,031m	\$821m	\$732m
Upfront government contribution to make the project financially viable (\$) (2010\$)	\$1,009m	\$995m	\$985 m	\$930m	\$738m	\$658m

Note: a REC price of \$45 has been assumed. RECs are due to be phased out by 2030 so the lifetime value of a REC is less than \$45.

⁻

⁶ As discussed in Section 4.4.3, RECs are designed to represent the price difference between 1 MWh of renewable electricity and 1 MWh of non-renewable electricity. REC prices would be expected to fall on commencement of the CPRS due to the scheme causing an increase in price of non-renewable electricity. As such, the combined price effect of RECs and CPRS will be less than the individual price impact of the two schemes in isolation. This effect reduces over time, as the RECs are phased out.

Table 6.5 Comparison of government roles

Type of option	Option	Description	Benefit	Costs
Reduced transaction costs and gestation period	Pre- permitting a site and provision of access to infrastructure	Providing a pre-approved site that has access to transmission, water, gas and other required infrastructure	Eliminating the risk and uncertainty, particularly around the length of time required to get a site ready for development Provides a significant incentive to development Provides and may induce or bring forward development Facilitate the early engagement of debt providers and financiers Provides increased certainty to the financial analysis and sensitivities around this. This helps in increasing the accuracy of the capital, operation and maintenance costs Can be implemented in varying degrees from Government going to market with a site to government facilitating discussions and providing commitments on timeframes (see options below) Government can potentially recoup costs from developers (funding for this work is not the main consideration but the high transaction costs and amount of time it will take and the uncertainty around both of these)	The costs will vary depending on the degree of pre-permitting and the areas. The cost does not vary significantly by technology. Below are the total costs of land, transmission, gas and water connection for each area: Broken Hill \$\$16-17m (250 MW)\$ \$\$16-17m (250 MW)\$ \$\$11-12m (250 MW)\$ \$\$18-19m (16W)\$ Moree \$\$35m (250 MW)\$ \$\$35m (250 MW)\$ \$\$35m (250 MW)\$ \$\$35m (250 MW)\$ \$\$107-111m (16W)\$ \$\$107-111m (16W)\$ \$\$107-111m (16W)\$ \$\$107-111m (16W)\$ Tamworth \$\$10m (250 MW)\$ \$\$16-17m (16W)\$ The majority of this cost is transmission connection costs. These costs exclude the administration and transaction costs of pre-permitting a site which could be large.
	Electricity Transmission system	Engage with relevant network stakeholders during pre-development to advance a connection agreement as far as possible	 Reducing risk and time delays for developer Low cost to government 	Largely transaction and administration costs

ecinct
Power Pr
a Solar F
tudy for
asibility S
Pre-Fe

Type of option	Option	Description	Benefit	efit	Costs
	Electricity Transmission system	Lead discussions with all stakeholders to secure transmission line corridor		Reducing risk and time delays for developer Provides increased certainty to the financial analysis and sensitivities around	Largely transaction and administration costs
			•	Low cost to government	
	Electricity	Engage with regulator and other	•	Reducing risk and time delays for	Largely transaction and administration
	Transmission	stakeholders to deliver a road map,		developer	costs
	system	issues, actions, timing etc for any	•	low cost to government	
•	Land	Secure, consistent with finance	•	Reducing risk and time delays for	Costs vary by area and technology
		requirements, all landholding for the		developer	
		site with draft long term lease	•	Provides increased certainty to the	
		agreements with terms and conditions		financial analysis and sensitivities around this	
	Water	Assist the developer where possible in	•	Reducing risk and time delays for	Largely transaction and administration
		securing a long term water supply		developer	costs
		agreement with acceptable terms and	•	Low cost to government	
1		conditions			
	Water	Secure, consistent with finance	•	Reducing risk and time delays for	 Costs vary by area and technology
		requirements, all land required for the		developer	
		water pipeline corridor, draft long term	•	Provides increased certainty to the	
		lease agreements with terms and		financial analysis and sensitivities around	
		conditions	•	this I ow cost to government	
•	Gas (Hybrid	Secure, consistent with finance	•	Reducing risk and time delays for	Costs vary by area and technology
	only)	requirements, all land required for the		developer	
		gas pipeline corridor, draft long term	•	Provides increased certainty to the	
		lease agreements with terms and		financial analysis and sensitivities around	
		conditions		SIUI	
			•	Low cost to government	

nct
reci
ver F
. Powe
Solar
α
dy for
Study
ollity
easil
Pre-Fe
Ω_

Type of option	Option	Description	Benefit	Costs
	Environment	Deliver a fully permitted site	 Reducing risk and time delays for developer Low cost to government 	 Largely transaction and administration costs
	Socio- Political	Lead the community and associated stakeholder engagement process to gain support and mitigate the risk of objection and delay	 Reducing risk and time delays for developer Low cost to government 	 Largely transaction and administration costs
	Additional Benefits	Develop a road may to ensure local areas maximise opportunities from large scale solar projects	 Prepare local region to maximise benefits from a solar precinct Increased jobs in local regions Minimal costs to government 	 Largely transaction and administration costs
Funding Options	Grant	Government could provide a grant to cover the cost difference between a viable and non-viable project	Sensitivity analysis shows upfront funding significantly reduces the levelised cost, making solar energy competitive with traditional energy sources. This is likely to increase the likelihood of securing a PPA agreement, which in turn increases the likelihood of securing project financing. Reduce the amount of financing required Easy to administer	 Cost depends on area, technology, size of plant and year in which development commences As illustrated in Table 6.4, the cost to government of providing an upfront capital grant to make a solar tower precinct at Moree financially viable is around \$1bn if construction started in 2015 and between \$0.7bn and \$0.9bn if construction commenced in 2020, depending on whether a CPRS exists
	Debt financing support	Government could provide financing support to cover the cost difference between a viable and non-viable project to be repaid in the future when sufficient cash flows become available	 As above for grant Provides government with opportunity to recoup some of funding Provides more certainty Government will recover funding than equity financing discussed below 	 Long term role for government Requires administration
	Equity financing	Government could provide equity into the project to cover the cost difference between a viable and non-viable project	 As above for grant and loan Provides government with opportunity to recoup some of funding Provides government with opportunity to share in upside of project 	 Long term role for government Requires administration Potential conflict of interest for government

Type of option	Option	Description	Benefit	Costs
Improved	PPA	A developer may request Government	Provide certainty over future revenue	 The cost will vary by technology, area,
certainty over		to enter into a long term PPA with a	streams for developer	size of plant and construction
revenue		tariff structure designed to guarantee	 Easier financing for developer 	commencement.
streams		debt service and agreed return on	Cheaper financing for developer (sensitivity	 As illustrated in Table 6.4, the cost to
		equity subject to plant performance	testing shows better financing terms can	government of providing a PPA to make
			reduce the levelised cost by 6-7%)	a solar tower precinct at Moree
		AECOM notes that any decision to	 Flexibility in tariff structure can be utilised 	financially viable is around \$1.1bn if
		enter a PPA model would need to be	to reduce cost to government (e.g.	construction commences in 2015 and
		subject to an appropriate economic	constant PPA which allows Government to	between \$0.7bn and \$1bn if construction
		and financial appraisal	recoup some of expenditure in later years	starts in 2020 depending on whether a
			when solar energy becomes cheaper than	CPRS exists and the targets set.
			traditional energy sources)	 PPA is more expensive to government
			 Does not require a large upfront funding 	than an upfront capital grant because it
			from the Government, allowing any	is cheaper for government to borrow
			assistance to be spread over a 20 – 30	money than a private developer.
			year time horizon, and reduces the risk that	 Long term role for government
			the project will not deliver the expected	 Uncertainty over costs to government
			quantities of solar energy generation.	(dependent on cost of traditional energy
				sources)
				 May distort the energy market

6.4 Summary

Whilst it is clear that solar will play an important part of the future supply of electricity, the timing of this is uncertain. This study shows that large scale solar projects are unlikely to be financially viable for the next 10-20 years and it is hard to see a developer making financial investments in large scale solar power plants in the short term. There is much uncertainty in the market around both capital costs and potential revenue sources.

In addition, a large scale solar project requires infrastructure (transmission, gas, water), land and environmental and planning approvals, which while not a significant proportion of the total cost add further risk and uncertainty around a proposed project, particularly in terms of the gestation period from early development to construction commencement.

The role of government in providing assistance to bring forward the development of large scale solar projects depends on the extent of benefits to society and if they outweigh the costs of assistance. The main benefits to society from the advancement of large scale solar projects in NSW include:

Carbon emission reductions

By bringing forward the development of large scale solar projects, the Government will enhance greenhouse gas reductions. The magnitude of these benefits depends on the technology, area and how many years the project is brought forward. If the Government were to bring forward investment of a solar thermal tower precinct by 10-15 years at Moree, the most favourable area, this would generate greenhouse gas emission savings of around 3.2 (10 years) to 4.8 (15 years) million tCO₂-e. This is a reduction of 5-7% of current greenhouse gas emissions from electricity in NSW and will go a significant way to achieving the NSW State Plan commitment to play its part in reducing Australia's greenhouse gas emissions to 60% below 2000 levels by 2050, and meeting the national Renewable Energy Target to source 20% of its energy from renewables by 2020.

Industry development in Australia

The solar industry is still a relatively new market and, despite good solar resource, Australia has lagged behind in industry development. Establishing a solar plant or precinct will promote the development of the Australian solar industry and generate employment opportunities. Whilst, the employment impact will be dependent on the technology and site chosen, overall, solar technology plants, particularly photovoltaic, generate significantly more jobs than OCGT and CCGT plants for construction. For example, construction employment for a 1,000 MW solar PV precinct is around 10,000 full time equivalent (FTE) compared to around 5,000 for solar thermal and 1,000 for OCGT. During operation, photovoltaic technology does not require significant maintenance so employment is limited. Solar thermal technology generates around 20% more operational employment than OCGT and CCGT plants. Employment is higher if onsite manufacturing occurs.

By supporting a project of this size, Australia may also benefit through improved positioning to become a global leader in solar technologies, and local production generating significant cost reductions of solar technology. Whilst this study provides an indication of the likely economic benefits that may result from large scale solar projects, the magnitude of these benefits is highly dependent on the area and technology under consideration, as well as the level of government assistance and the extent to which it advances the large scale solar industry in NSW. Once an area and technology are selected it will be important to undertake:

- A more detailed feasibility study;
- A full economic appraisal to quantify the economic benefits and assess the economic viability of any proposed government assistance; and
- Develop a roadmap to maximise the benefits from supply chain and industrial development.

The potential roles for government are wide ranging. As discussed above, the main barriers in the large scale solar industry are focused around the large upfront capital cost requirements, long-term financial uncertainty and the high transaction costs (e.g. access to grid, planning and environmental approvals). Any potential role of government should focus around addressing these issues and generally falls into the following three categories:

17 December 2010 49

- Reducing transaction costs and gestation period through providing a pre-approved site and provision of access to key infrastructure such as transmission, water and gas;
- · Capital funding through upfront grant, debt or equity; and
- Improved certainty over revenue streams through a PPA.

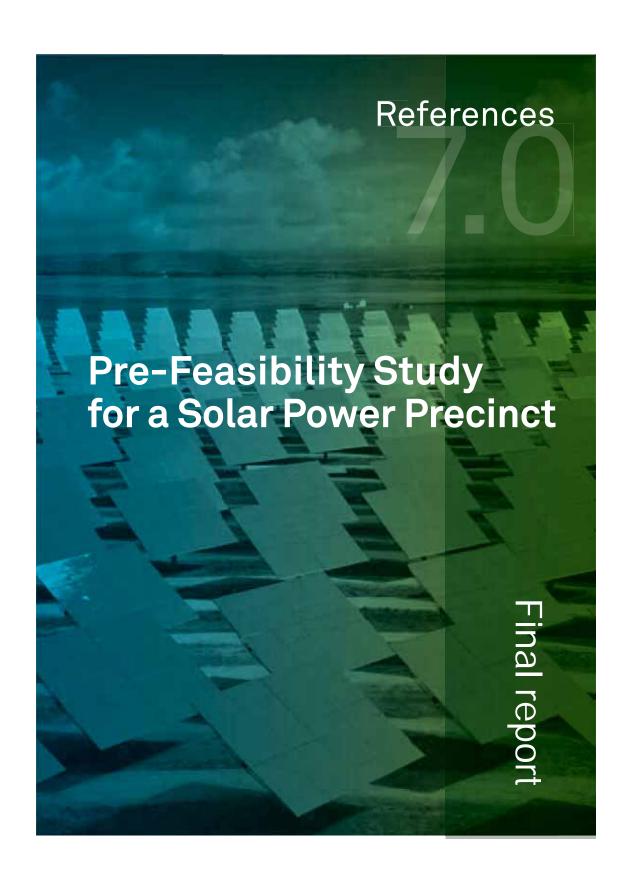
Measures to reduce transaction costs and gestation periods reduce the risks and uncertainty, facilitating the early engagement of debt providers and financiers. This option can be implemented to varying degrees from provision of a fully pre-approved and connected site to a commitment to facilitate discussions with appropriate parties. Government can also potentially recoup some of these costs as developers are more concerned with the time and uncertainty than the costs. However, given the large financial viability gap that currently exists in the market, on its own this is unlikely to be enough to induce investors into the market.

Capital funding significantly reduces the levelised cost, making solar energy sources competitive with traditional sources and reducing the amount of upfront capital required. It can be structured as a grant, debt or equity providing flexibility for the Government to recoup some of its money.

A PPA will provide certainty over future revenue streams for a developer, making it easier for developers to access cheaper financing. It also does not require a large upfront funding from the Government, allowing any assistance to be spread over a 20-30 year time horizon, and reduces the risk that the project will not deliver the expected quantities of solar energy generation. However, the PPA is more expensive to government than an upfront capital grant (by around \$75m-\$115m) because it is cheaper for government to borrow money than a private developer.

In essence, both capital funding and PPA will improve investor and developer confidence and will be beneficial in bringing forward the development of large solar projects in NSW. On their own, measures to reduce transaction costs are unlikely to be enough of an incentive to bridge the financial viability gap. However, government may wish to supplement any capital funding or PPA with support to industry to facilitate easier permitting and access to infrastructure.

17 December 2010 50



7.0 References

Access Economics, 2009. The net employment impacts of climate change policies.

ACIL Tasman, 2009. Fuel resource, new entry and generation costs in the NEM.

AGL, 2009. AGL Natural Gas Plans NSW,

http://www.agl.com.au/Downloads/NSW Gas RegulatedPrices Residential.pdf, accessed April 2010.

The Allen Consulting Group, 2009. WACC Parameters Update for the Purpose of Determining the Maximum Reserve Capacity Price.

Department of Environment, Climate Change and Water, 2010. NPWS Atlas of NSW Wildlife. http://wildlifeatlas.nationalparks.nsw.gov.au/wildlifeatlas/watlas.jsp, accessed December 2009.

Department of Environment, Water, Heritage and the Arts, 2010. Protected Matters Search Tool, http://www.environment.gov.au, accessed December 2009.

Department of Environment, Water, Heritage and the Arts 2010. Australian Wetlands Database. Available: http://www.environment.gov.au/cgi-bin/wetlands/ramsardetails, accessed March 2010.

Delft CE, 2008, Handbook on estimation of external costs in the transport sector. Available: http://ec.europa.eu/transport/sustainable/doc/2008 costs handbook.pdf

Global LNG Info, 2010. World's LNG Liquefaction Plants and Regasification Terminals, http://www.globallnginfo.com/World%20LNG%20Plants%20&%20Terminals.pdf, accessed April 2010.

International Energy Agency (IEA), Technology Roadmap: Solar photovoltaic energy. Available:http://www.iea.org/papers/2010/pv roadmap.pdf

Jemena, 2010. Eastern Gas Pipeline, Transportation Tariffs Effective 1st January 2010 – Reference Tariffs, http://www.jemena.com.au/operations/transmission/egp/ assetDetails/currentTariffs/downloads/EGP %20Public%20Tariffs%202010.pdf, accessed April

Meyer, R, 2009. Concentrated solar power - an overview, http://www.erc.uct.ac.za/seminarscourses/presentations/Meyer 19-08-2009.pdf, accessed March 2010.

Muller-Steinhagen, H, 2008. Solar Thermal Power Plants - On the Way to Commercial Market Introduction, https://www.htri.net/Public/prodsvcs/HMS_Victoria1.pdf, accessed April 2010.

National Native Land Tribunal. http://www.nntt.gov.au, accessed March 2010.

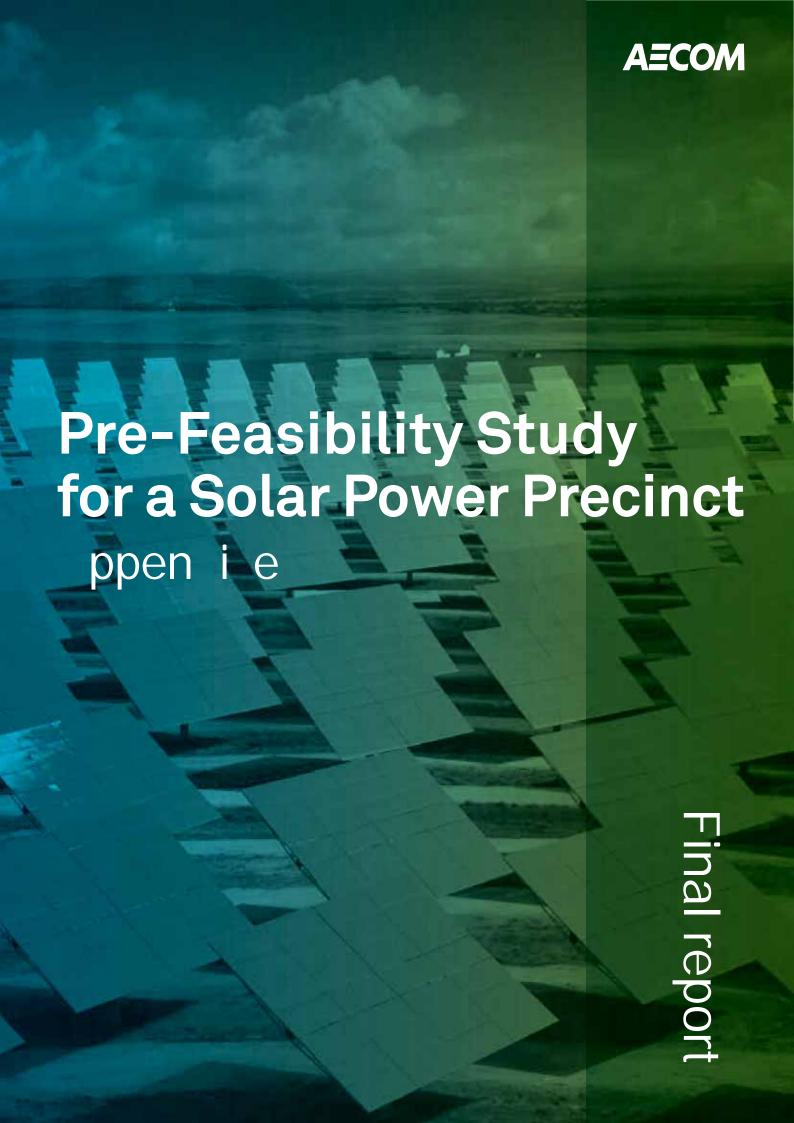
Officer, R.R., 2005. Comments on Draft Guidelines: the Commerce Commission's Approach to Estimating the Cost of Capital.

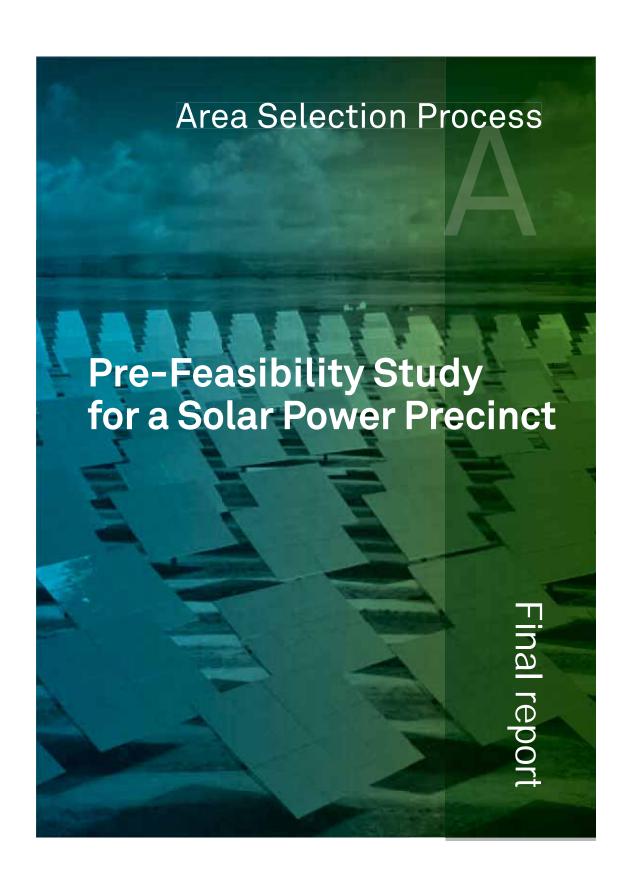
Reuters, 2010. Google develops prototype mirror for solar energy, http://www.reuters.com/article/idUSTRE61P58V20100226, accessed April 2010

Sargent and Lundy, 2003. Assessment of Parabolic Trough and Power Tower Solar Technology Cost and Performance Forecasts, NREL/SR-550-34440.

Woody, T, 2010. A High-Tech Entrepreneur on the Front Lines of Solar, http://www.e360.vale.edu/content/feature.msp?id=2248, accessed April 2010.

17 December 2010





Appendix A Area Selection Process

As set out in **Chapter 3.0**, the selection of five areas on which to conduct detailed analysis was based on the first two stages of AECOM's technical feasibility methodology:

- Stage 1: Qualitative factor assessment using GIS; and
- Stage 2: Preliminary quantitative factor assessment.

A.1 Stage 1: Qualitative factor assessment

The qualitative assessment involved the use of spatial analysis to identify areas with a mix of solar resource, transmission connection capability, land availability, water availability and gas connection capability, though not necessarily all in the same area.

As a starting point, DECCW provided information on areas that were included in Round 1 of the Solar Flagship Scheme. GIS layers for the feasibility factors in **Section 2.2.1** were used to compare areas. **Figure A.1** shows the location of each area and the combined GIS layers.

This process identified 16 potential areas to take forward to the Stage 2 analysis. **Table A.1** sets out a summary of the key factors at each of the 16 potential areas. The selection includes a range of areas to assess the trade-offs between the various factors. For example, Bourke has excellent solar resource, relatively low land values but poor transmission infrastructure.

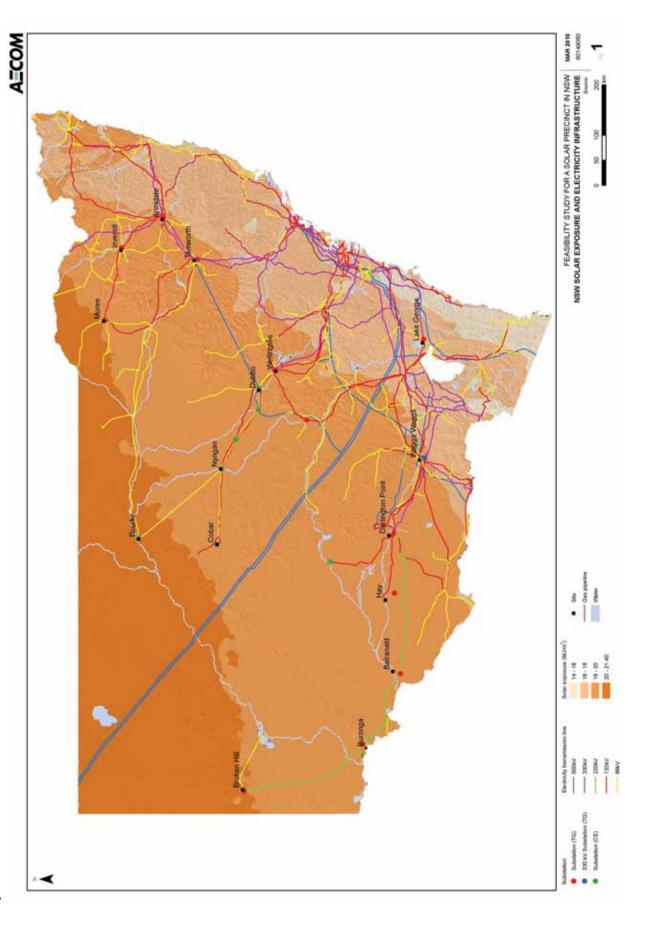
Table A.1 Potential solar precinct areas

Area	Summary
Armidale	Excellent solar resource
	Excellent transmission line access - proximity to 330kV line
	Proximity to gas pipeline
	Regional centre may have high relative land values
Balranald	Excellent solar resource
	Good transmission line access - proximity to 220kV line
Bourke	Superior solar resource
	Poor transmission line access -proximity to 66 kV line
	Regional centre but relatively low land values
Broken Hill	Superior solar resource
	Good transmission line access - proximity to 220kV line
	Not close to a major surface water source
	Regional centre but relatively low land values
Buronga	Excellent solar resource
	Good transmission line access - proximity to 220kV line
Cobar	Excellent solar resource
	Moderate transmission line access - proximity to 132kV line
	Not close to a major surface water source
Darlington Point	Excellent solar resource
	Excellent transmission line access - proximity to 330kV line
	Proximity to gas pipeline
Dubbo	Excellent solar resource
	Moderate transmission line access - proximity to 132kV line
	Proximity to gas pipeline
	Regional centre may have high relative land values

Area	Summary
Hay	Excellent solar resource
	Moderate transmission line access - proximity to 132kV line
Inverell	Excellent solar resource
	Moderate transmission line access - proximity to 132kV line
	Regional centre may have high relative land values
Lake George	Good solar resource
	Excellent transmission line access - proximity to 330kV line
	Proximity to gas pipeline
	Regional centre may have high relative land values
Moree	Excellent solar resource
	Moderate transmission line access - proximity to 132kV line
	Not close to a major surface water source
Nyngan	Excellent solar resource
	Moderate transmission line access - proximity to 132kV line
Tamworth	Excellent solar resource
	Excellent transmission line access - proximity to 330kV line
	Proximity to gas pipeline
	Not close to a major surface water source
	Regional centre may have high relative land values
Wagga Wagga	Excellent solar resource
	Excellent transmission line access - proximity to 330kV line
	Proximity to gas pipeline
	Regional centre may have high relative land values
Wellington	Excellent solar resource
	Excellent transmission line access - proximity to 330kV line

Source AECOM

Figure A.1 Qualitative factor assessment



A.2 Stage 2: Preliminary quantitative factor assessment

Stage 2 involved a basic quantitative factor assessment on the 16 areas identified in Stage 1 to identify five areas for a more detailed technical assessment. The following factors were assessed at a high level for both a 250 MW and a 1,000 MW precinct at each area:

- Solar resource;
- Transmission cost;
- Land availability and cost;
- Water availability and cost;
- Gas availability and cost; and
- Environmental barriers to development.

This assessment was undertaken for mono-crystalline PV, thin film PV and solar trough technologies and draws on technology matrices **Table A.2** and **Table A.3**.

The key assumptions used for this analysis are discussed below.

Table A.2 Technology matrix (250 MW)

	Units	Mono-crystalline PV	Thin film PV	Solar trough
General				
Mounting frame	N/A	Static	Static	Static
Cooling type	Air / water	Air	Air	Air
Land				
Land size	ha / MWp	1.03	3.32	2.40
Total hectares	ha	259	830	600
Water				
Cleaning	kL / m ² mirror surface	0.06	0.06	0.06
Dust control	ML / ha	0.03	0.03	0.03
Gas				
Operations	GJ / MWp	0	0	190
Hybrid	GJ / MWh	0	0	0

Source AECOM

Table A.3 Technology matrix (1,000 MW)

	Units	Mono-crystalline	Thin film PV	Solar trough
General				
Mounting frame	N/A	Static	Static	Static
Cooling type	Air / water	Air	Air	Air
Land				
Land size	ha / MWp	1.03	3.32	2.40
Total hectares	ha	1035	3322	2400
Water				
Cleaning	kL / m ² mirror surface	0.06	0.06	0.06
Dust control	ML / ha	0.03	0.03	0.03
Gas				
Operations	GJ / MWp	0	0	190
Hybrid	GJ / MWh	0	0	

Source AECOM

A.2.1 Energy Generation

Due to characteristics such as latitude, longitude, altitude, ambient temperature, and wind speed, the performance of solar systems varies significantly by area. It is therefore necessary to undertake detailed modelling in order to calculate energy generation for each technology at each area. Energy generation for solar tower and hybrid was not modelled at this stage; comparison was based on mono-crystalline PV, thin film PV and solar trough.

A.2.1.1 Mono-crystalline and thin film PV

Electricity generation for mono-crystalline and thin film PV technologies was calculated using the PVsyst software package as discussed in **Section B.3.3**.

The technical characteristics of the specific solar panels and power inverter selected for the feasibility study are described in **Appendix C**. Default values were assumed for energy loss from cables joining the solar panels; the detailed design stage would determine the size of cables required to minimise energy losses.

Weather data required for the model includes global and diffuse solar irradiation, surface albedo, wind speed and temperature. For each item, monthly average values over a 22-year period were sourced from NASA.

The generic layout of the solar arrays (being the arrangement and spacing of panels and mirrors) was determined by a manual iterative process, and the same layout was used to compare each area on a common basis. The model assumed that the study areas are flat and that there is no external shading as a result of trees or buildings.

A.2.1.2 Solar trough

The system performance of solar trough requires very detailed modelling. As such, for the purposes of this initial stage of study a simplified assessment was undertaken. Although the PVsyst tool cannot be used to model solar trough technologies, the software's solar tracking algorithm was used to calculate the effective incident solar irradiation and shading losses on the single axis tracking mirrors. A calculation methodology to estimate energy production from the calculated incident solar irradiation was devised and benchmarked against estimated values that have been published for planned solar trough plants in California and Spain. A more detailed assessment of performance using refined methodologies, including independent sensitivity test modelling using the solar advisor model software, was undertaken for the five shortlisted areas (see **Appendix B**).

A.2.1.3 Solar tower and gas-assisted solar trough hybrid

The evaluation of solar tower and solar trough hybrid was not undertaken for the purposes of short listing the 16 areas and was only undertaken for the five areas selected for more detailed analysis (see **Appendix B**).

A.2.1.4 Assessment

Generation potential was calculated using hourly profiles based on NASA long term average solar resource data and the generic system layouts developed for the study. The system generation was then normalised to units of MWh per MWp per year, where MWp is the equivalent power rating of solar panels under standard test conditions. **Figure A.2** compares annual energy generation potential (MWh per MWp per annum) between each of the 16 areas for the PV technologies. The thin film PV technology is less efficient than mono-crystalline PV on an MWh per m² basis; hence the area of solar panels installed is much greater for a 1MWp thin film system. Also the layout of the individual solar panels to form strings and arrays are different due to the physical dimensions and electrical characteristics; hence they experience different shading losses. On an MWh/MWp/annum basis thin film PV was estimated to be more productive than mono-crystalline PV.

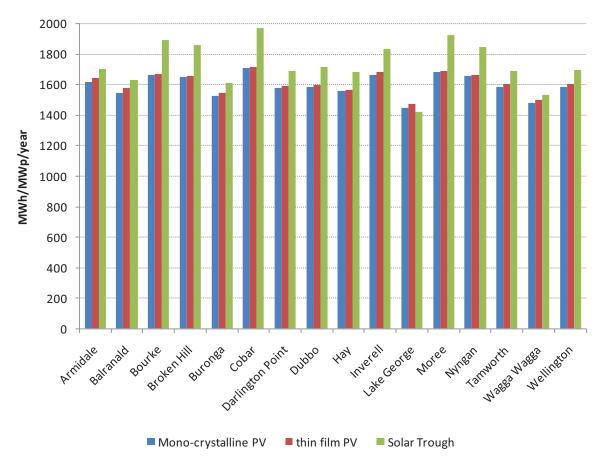


Figure A.2 Energy generation potential [MWh/MWp/annum] by area and by technology

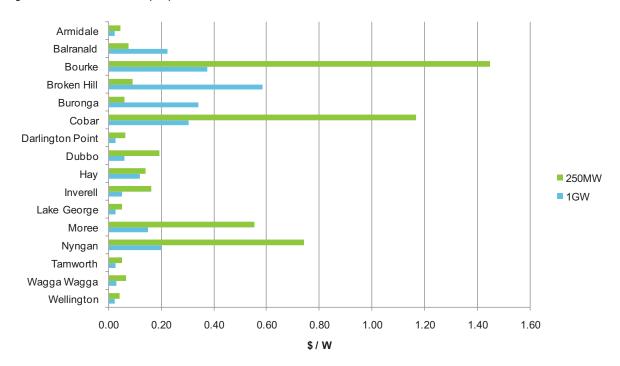
Source AECOM

A.2.2 Transmission cost

The methodology for calculating transmission costs is analogous to that presented in **Section B.4.2** with the exclusion of consideration of construction staging.

Table A.4 and **Table A.5** summarise the analysis undertaken for both a 250 MW plant and a 1,000 MW precinct. The costs vary significantly between areas. **Figure A.3** sets out the cost per MW for each area for a 250 MW plant and a 1,000 MW precinct. The comparison between the 250 MW and 1,000 MW costs shows that there can be significant economies of scale but this is very area specific and depends on the level of existing infrastructure. High costs are estimated at Bourke, Broken Hill, Buronga, Cobar, Moree and Nyngan. The cost per MW drops significantly for some areas such as Bourke, Cobar, and Nyngan. However, for some areas (including Balranald, Darlington Point and Hay) the cost per MW significantly increases from a 250 MW plant to a 1,000 MW precinct. This is because in these areas the current infrastructure is sufficient for a 250 MW plant but would need significant upgrades for a 1,000 MW precinct.

Figure A.3 Transmission cost (\$/W)



Source AECOM

Table A.4 Transmission assumptions for a 250 MW plant

Area	Sol	Connection Type	oe ec		Com	Components		Distances	seou				
	Connectio n Voltage (kV)	Capacity (MW)	Connect to sub, 330, 220 or 132 kV line	Line	Generator connection type	rks	Sub or line connection type	Substation (km)	330 kV Line (km)	Area locality factor	Cost to connect (\$'000)	Cost per watt (\$ / W)	Comment
Armidale	330	250	qns	7.1	1.2	2.1	2.1	4.7	4.6	-	11,257	0.05	330 kV connection to Armidale substation
Balranald	220	250	qns	8.1	3.1	5.1	4.1	15.5	226.5	-	19,115	0.08	220 kV connection to sub at Balranald
Bourke	330	250	330	7.1	1.1	2.1	2.1	0.0	394.8	7.	362,356	1.45	330 kV connection to Wellington substation
Broken	220	250	qns	2.	ы. Т	τ. 1.	1.4	10.0	521.8	1.2	22,640	60.0	220 kV connection to sub at Broken Hill. Local TransGrid plant upgrade required to allow line rating of 400 MVA
Buronga	220	250	qns	1.8	3.1	5.1	1.4	10.4	358.3	7-	15,020	90:0	220 kV connection to sub at Buronga
Cobar	330	250	330	7.1	1.	2.1	2.1	0.0	316.3	-	291,643	1.17	330 kV connection to Wellington substation
Darlington Point	330	250	qns	7.1	1.1	2.1	2.1	9.5	9.5	-	15,588	90.0	330 kV connection to Darlington Point substation
Dubbo	330	250	330	7.1	1.	2.1	2.1	4.0	46.0	-	48,363	0.19	330 kV connection to Wellington
Нау	220	250	220	8.	3.1	5.1	4.2	21.2	110.3	-	34,700	0.14	220 kV connection to line between Balranald and Darlington Point

ರ
$\overline{}$
eci
9
ቧ
ř
×
owe
മ്
_
<u>a</u>
욨
رن
σ
5
÷
중
Stud
\bar{z}
~
≝
=
ᇙ
ğ
ıφ
÷
ģ
n_

	Con	Connection Type	эс		Com	Components		Distances	nces				
Area	Connectio n Voltage (kV)	Capacity (MW)	Connect to sub, 330, 220 or 132 kV line	Line	Generator connection type	Civil works	Sub or line connection type	Substation (km)	330 kV Line (km)	Area locality factor	Cost to connect (\$'000)	Cost per watt (\$ / W)	Comment
Inverell	330	250	330	7.1	7:	2.3	2.2	4.8	29.2	-	40,313	0.16	330 kV connection by building a new 330 kV substation on the 330 kV lines between Armidale and Dumaresq
Lake George	330	250	qns	7.1	7.	2.1	2.1	6.6	3.7	-	12,941	0.05	330 kV connection to nearby 330 kV substation
Moree	330	250	330	7.1	7:	2.3	2.2	0.0	138.1	-	138,268	0.55	330 kV connection by building a new 330 kV substation on the 330 kV lines between Armidale and Dumaresq
Nyngan	330	250	330	7.1	1.1	2.1	2.1	0.0	198.3	-	185,486	0.74	330 kV connection to Wellington substation
Tamworth	330	250	qns	7.1	1.2	2.1	2.1	2.9	4.7	~	12,990	0.05	330 kV connection to Tamworth substation
Wagga Wagga	330	250	qns	7.1	1.2	2.1	2.1	10.5	9:0	-	16,429	0.07	330 kV connection to Wagga Wagga substation
Wellington	330	250	qns	7.1	1.2	2.1	2.1	3.7	3.7	_	10,352	0.04	330 kV connection to Wellington substation

AECOM Source

Table A.5 Transmission assumptions for a 1,000 MW plant

	Con	Connection Type	oc ec		Components	ents		Distances	seo				
Area	Connection Voltage (kV)	Capacity (MW)	Connect to sub, 330, 220 or 132 kV line	Line	Generator connection type	Civil	Sub or line connection type	Substation (km)	330 kV Line (km)	Area locality factor	Cost to connect (\$'000)	Cost per watt (\$ / W)	Comment
Armidale	330	1000	qns	7.2	1.4	2.1	2.3	4.7	4.6	-	23,257	0.02	330 kV connection to Armidale substation
Balranald	330	1000	qns	7.1	1.3	2.1	2.3	226.5		~	222,891	0.22	330 kV connection to Darlington point substation
Bourke	330	1000	330	7.2	1.3	2.1	2.3	394.8		<u></u>	374,356	0.37	330 kV connection to Wellington substation
Broken Hill	330	1000	qns	7.2	1.3	2.1	2.3	521.0		1.2	585,480	0.59	330 kV connection to Darlington Point substation
Buronga	330	1000	330	7.1	1.3	2.1	2.3	358.3		~	341,440	0.34	330 kV connection to Darlington Point substation
Cobar	330	1000	330	7.2	1.3	2.1	2.3	316.3		-	303,643	0:30	330 kV connection to Wellington substation
Darlington Point	330	1000	qns	7.1	1.3	2.1	2.3	9.5		-	27,550	0.03	330 kV connection to Darlington Point substation
Dubbo	330	1000	330	7.2	1.3	2.1	2.3	46.0		-	60,363	90.0	330 kV connection to Wellington substation
Нау	330	1000	330	7.1	1.3	2.1	2.3	110.3	110.3	-	118,256	0.12	330 kV connection to Darlington Point substation

17 December 2010

	Con	Connection Type	90		Components	nents		Distances	ces				
Area	Connection Voltage (kV)	Capacity (MW)	Connect to sub, 330, 220 or 132 kV line	Line	Generator connection type	Civil	Sub or line connection type	Substation (km)	330 kV Line (km)	Area locality factor	Cost to connect (\$'000)	Cost per watt (\$ / W)	Comment
Inverell	330	1000	330	7.2	1.3	2.3	2.4	4.8	29.2	-	52,313	0.05	330 kV connection by building a new 330 kV substation on the 330 kV lines between Armidale and Dumaresq
Lake George	330	1000	qns	7.2	1.3	2.1	2.3	9.9	3.7	~	24,941	0.02	330 kV connection to nearby 330 kV substation
Moree	330	1000	330	7.2	1.3	2.3	2.4	0.0	138.1	-	150,268	0.15	330 kV connection by building a new 330 kV substation on the 330 kV lines between Armidale and Dumaresq
Nyngan	330	1000	330	7.2	1.3	2.1	2.3	198.3		~	197,470	0.20	330 kV connection to Wellington substation
Tamworth	330	1000	qns	7.2	1.4	2.1	2.3	2.9	4.7	~	24,990	0.02	330 kV connection to Tamworth substation
Wagga Wagga	330	1000	qns	7.2	4.1	2.1	2.3	10.5	9.0	~	28,429	0.03	330 kV connection to Wagga Wagga substation
Wellington	330	1000	qns	7.2	1.4	2.1	2.3	3.7	3.7	-	22,352	0.05	330 kV connection to Wellington substation

Source AECOM

A.2.3 Land availability and cost

A.2.3.1 Land availability and gradient

The different solar technologies require varying land area. Another key consideration is the gradient of the land required. Each technology requires flat land to varying degrees, with solar trough having the most stringent gradient criteria. For solar trough, extremely flat land is required to ensure tracking alignment such that the trough focuses sunlight evenly onto the receiver to eliminate hot spots and prevent thermal decomposition of the HTF.

A high level gradient analysis was conducted to determine if there was sufficiently low gradient land in the selected areas.

Figure A.4 shows land with gradient less than 4% and greater than 4%. Most of the 16 areas are predominantly less than 4% gradient. Areas where gradient may be of concern are Inverell, Armidale, Wellington, Wagga Wagga and Lake George. While approximately half of the Tamworth area has gradient greater than 4% this land is concentrated to the east, with the western half of the Tamworth area being predominantly less than 4%.

A.2.3.2 Land cost

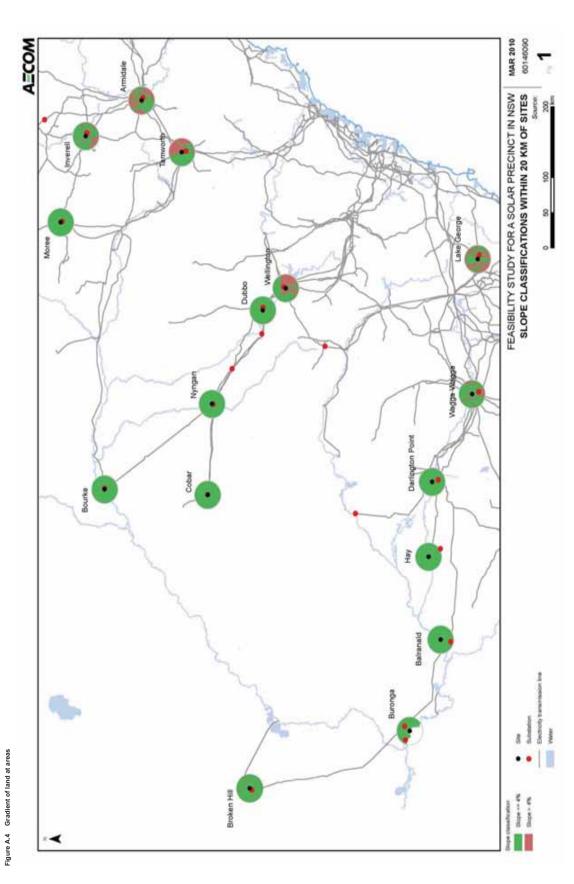
Table A.6 shows the average land value for of the 16 areas broken down into six land parcel sizes. For most areas, land value decreases as the size of the property band increases. In general, this corresponds to larger land holdings further away from population centres and therefore having lower value. As expected, regional centres such as Wagga Wagga, Inverell and Dubbo have land values relatively higher than other areas. More westerly areas such as Cobar and Bourke, which receive less rainfall than their more easterly counterparts, have relatively lower land values.

Table A.6 Average land value per hectare (\$ / ha)

Area	> 10 Ha and <= 50 Ha	> 50 Ha and <= 100 Ha	> 100 Ha and <= 200 Ha	> 200 Ha and <= 500 Ha	> 500 Ha and <= 1000 Ha	> 1000 Ha
Armidale	13,328	6,253	4,181	2,898	2,586	2,179
Balranald	3,376	1,780	1,150	593	582	199
Bourke	1,842	1,037	659	351	212	45
Broken Hill	2,761	1,933	792	1,046	1,046	1,046
Buronga	8,362	3,571	2,158	851	270	80
Cobar	1,767	720	560	182	108	71
Dareton	6,810	2,965	1,741	977	376	62
Darlington Point	3,181	1,736	1,622	1,165	789	339
Dubbo	9,632	3,906	2,267	1,410	1,173	847
Hay	2,786	1,000	587	223	163	117
Inverell	7,779	3,176	2,123	1,582	1,415	1,467
Lake George	20,989	6,456	4,623	3,707	2,433	2,028
Moree	7,142	3,784	3,152	2,774	2,582	2,187
Narromine	5,866	2,661	1,656	930	922	922
Nevertire	3,753	1,169	1,073	692	697	647
Nyngan	3,004	1,505	1,500	595	420	398
Parkes	9,369	1,389	1,254	1,194	1,131	929
Tamworth	10,519	6,431	4,596	3,350	1,920	454
Wagga Wagga	9,527	6,138	4,507	3,462	4,086	2,579
Wellington	5,834	2,902	1,841	1,625	1,360	994

Source LPMA

Pre-Feasibility Study for a Solar Power Precinct



A.2.4 Water availability and cost

Each solar plant will require varying amounts of water for operation and maintenance depending on the technology (PV, solar thermal or gas hybrid) as well as the size of the plant (250 MW and 1,000 MW).

As with other factors, the price of water depends on the quantity and reliability that is required. In principle, water can be transported by pipeline to virtually any selected area. In many inland locations however, the prolonged drought has highlighted the limited water resources available and the high cost of transporting from high security sources. The water for the solar precinct can be drawn from:

- Existing treated town supplies;
- Rivers and storages;
- · Groundwater reserves; or
- Treated wastewater.

It is difficult to undertake a high level analysis of water availability, given the need for detailed assessment including exploration of options to bring the water to the area. The approach adopted for Stage 2 assessed current water sources and quality, current surplus supply capacity, a combination of available supply sources and good local supply and treatment infrastructure. Where water is not available within proximity of the 16 areas, AECOM has identified how water could be transported to the area and the cost of this; this information is summarised in **Table A.7**.

Table A.7 Water availability assessment

Area and local	Major Water	Town Heade(ML)	Supply Source As	Assessment			Potential Supply	Preferred Option for	Cost	
water supplier	Source(s)	2007/08	Townwater Supply	River	Groundwater Availability	Treated Wastewater	Augmentation	guaranteed water supply	Water (\$/ML)	Delivery
Armidale (Shire Council)	River (Malpas Dam)	3140	Secure supply from dam	No	Yes	All supply committed to reuse	25 km pipeline to Malpas dam	Town supply	2740	Minimal if area on town supply
Balranald (Shire Council)	Murrumbidgee River	660	Low supply capacity	Low supply security	Yes	Low supply security	Pump from Murrumbidgee or the Murray	License purchase & pumped	3000 (High supply)	Minimal if aread near river
Bourke (Shire Council)	Darling River & Groundwater	3670	Low supply capacity	Low supply security	Yes		Opt1- buy cotton farm with adequate storage \$25m Opt 2 - 10 x 100 ML bores (\$1.5m each) & 100 km of pipeline	Buy property with storage dam		\$25m
Broken Hill (Country Water)	Menindee Lakes	6730	Low supply security	Low supply security		Low supply security	109 km pipeline to Menindee lakes	Town supply	2360	\$21.8m
Buronga (Wentworth Shire Council)	Murrumbidgee River & Groundwater	290	Low supply capacity	Low supply security	Yes		Pump from Darling or the Murray	License purchase & pumped	3000 (High supply)	Minimal if aread near river
Cobar (Shire Council)	Pipeline (ultimately Burrendong dam)	2180	Low supply capacity	Low supply security		Low supply security	60 km pipeline to Warren (\$40-50m)	60 km pipeline to Warren	3000	\$40-50m
Darlington Point (Murrumbidgee Shire Council)	Murrumbidgee River & Groundwater	670	Low supply capacity	Low supply security	Yes usually blended with riverwater	Low supply security	Opt 1- Surface Water buy high security water at \$3000 per ML Opt 2-GW area has good bores water \$1600per ML	License purchase & pumped	3000	Minimal if aread near river

17 December 2010

	_	
	ပ္	
	등	
	ĕ	
(Ţ	
	ē	
	≷	
C	ĭ	
	≒	
•	∺	
(ĭ	
	α	
	ō	
١	Ξ	
•	Ó	
	₹	
(כת	
	≥	
:	≡	
:		
	<u>s</u>	
	(Ú	
l	ĭ	
	å	
	⋍	

Area and local	Major Water	Town	Supply Source A	Assessment			Potential Supply	Preferred Option for	Cost	
water supplier	Source(s)	2007/08	Townwater Supply	River	Groundwater Availability	Treated Wastewater	Augmentation	guaranteed water supply	Water (\$/ML)	Delivery
Dubbo (City Council)	Macquarie River & Groundwater	7350	Some capacity issues	Low allocations even on High Security license	Yes		80 km pipeline to Burrendong (\$50- 60m)	Town supply	1120	Minimal if area on town supply
Hay (Shire Council)	River & Groundwater	1320	Low supply capacity	Low supply security	Yes	Low supply security	Opt 1- Surface Water buy high security water at \$3000 per ML Opt 2-GW area bores lower yields water \$1600 per ML	High Security license purchase & pumped	3000 (High)	
Inverell (Shire Council)	Copeton Dam	1800	Low supply capacity	No		Developing supply options	20 kms to Copeton Dam	Town supply	1200	
Lake George (Bungendore - Palerang Council)		1	ON.	o _N	Yes		Opt 1 Groundwater supplies Opt 2- 30 km Googong dam	30 km pipeline	3000	\$6m
Moree (Plains Shire Council)	Groundwater	9720	Secure good quality supply from groundwater.	Secure groundwater supply	Yes, good supplies	Supply committed for irrigation & town use	Groundwater readily available	Groundwater supply	1600	Minimal if area near groundwater supply
Nyngan (Shire Council)	Bogan River & Groundwater	520	Low supply capacity	Low supply security		Low supply security	60 km pipeline to Macquarie River (\$40-50m)	60 km pipeline to Macquarie River	3000	\$40-50m
Tamworth (Regional Council)	Chaffey Dam, Rivers, bores	8470	Some existing supply security issues	Yes		Supply committed	Chaffey Dam 44 km from town	44 km pipeline	3000	\$8.8m
Wagga Wagga (Riverina Water)	Murrumbidgee River & Groundwater	14800	Extensive system with some capacity issues	Adequate supply security	Yes	Possibility of supplies	Opt 1- Surface Water buy high security water at \$3000 per ML Opt	Town supply	1170	Minimal if area on town supply

Area and local	Major Water	Town Heade(ML)	Supply Source Assessment	ssessment			Potential Supply	Preferred Option for	Cost	
water supplier	Source(s)	2007/08	Townwater Supply	River	Groundwater Treated Availability Wastew	Treated Wastewater	Augmentation	guaranteed water supply	Water (\$/ML)	Delivery
							2-GW fully			
							embargoed			
							currently but will be			
							tradeable with a			
							plan			
	Macquarie						30 km pipeline to	l icense	3500	Minimal if
Wellington (Shire	Pivor 8.	1120	Low supply	Low supply	>	Low supply	Burrendong (on	Dirchose &	(High	2000 0000
Council)	אַ פֿוּ	071	capacity	security	8	security	pipeline route from	מומוממ מ	1611	. מפש
	Groundwater						Dubbo)	badwind	suppiy)	river

Source AECOM

17 December 2010

A.2.5 Gas availability and cost

The availability and price of gas depend on the volume required and the distance from gas pipeline.

A solar thermal plant requires approximately 190 GJ per MWp per year to prevent heat transfer fluid freezing and to facilitate warm starts. A 250 MW plant would therefore require 47,500 GJ per year (47.5 TJ per year). Such gas would probably be provided under a retail contract rather than wholesale contract. However, rather than seeking quotes from retailers, AECOM has estimated retail gas prices based on NSW retail gas prices for customers up to 1 TJ per year, namely \$9 per GJ (industrial, near Darlington Point)¹ and \$11.75 per GJ (residential price of \$15.75 per GJ less \$4 per GJ residential premium, other areas)².

The minimum gas requirement for a solar thermal plant would be best supplied through a medium pressure gas pipeline, although it could be transported by road if there was no nearby pipeline connection. At an energy density of approx 55 GJ per tonne, 47.5 TJ would be equivalent to approximately 865 tonnes of natural gas. A typical semitrailer can carry approximately 20 tonnes, so trucking would require 43 trucks per year (approximately one per week) plus sufficient storage to hold at least two weeks supply. The cost of trucking gas would be approximately \$0.006 per GJ-km, based on typical transport costs for bulk freight of \$0.20 per tonne-kilometre (\$0.004 per GJ-km out plus \$0.002 per GJ-km back).

Table A.8 illustrates the total delivered cost per GJ for gas at each area, including road transport costs from the pipeline.

Table A.8	Total delivered gas cost for a solar thermal plant (\$ / GJ)
I able A.o	Total delivered gas cost for a solar thermal plant (\$ / GJ)

Area	Gas price to pipeline (\$/GJ)*	Approx distance to gas pipeline (km)	Road transport cost (\$/GJ)	Total delivered cost (\$/GJ)
Armidale	11.75	95	0.57	12.3
Balranald	9	200	1.20	10.2
Bourke	11.75	200	1.20	13.0
Broken Hill	11.75	200	1.20	13.0
Buronga	11.75	110	0.66	12.4
Cobar	11.75	70	0.42	12.2
Darlington Point	9	30	0.18	9.2
Dubbo	11.75	0	0.00	11.8
Hay	9	120	0.72	9.7
Inverell	11.75	150	0.90	12.7
Lake George	9	15	0.09	9.1
Moree	11.75	200	1.20	13.0
Nyngan	11.75	120	0.72	12.5
Tamworth	11.75	0	0.00	11.8
Wagga Wagga	9	0	0.00	9.0
Wellington	11.75	45	0.27	12.0

Source AECOM based on retail gas prices 12

Note Total delivered cost rounded up to nearest 0.1

A gas-assisted solar thermal plant would require a significantly higher volume gas supply to operate and would therefore require a consistent and reliable supply by pipeline. The price for a dedicated gas pipeline is assumed to be \$0.005 per GJ per km (Jemena, 2010). The total gas delivered cost per GJ represented in **Table A.9** is a general approximation. More precise price estimates will depend on the volume of gas required annually and the load profile, which will be calculated in Stage 3.

 $[\]label{lem:http://www.countryenergy.com.au/wps/wcm/connect/3188a68041ca1a438928ef96d29342cf/gas_wagga_09.pdf? $$MOD=AJPERES$$

² http://www.agl.com.au/Downloads/NSW_Gas_RegulatedPrices_Residential.pdf

Table A.9 Total delivered gas cost for a gas-assisted solar thermal plant (\$ / GJ)

Area	Gas price to pipeline (\$/GJ)*	Approx distance to gas pipeline (km)	Piping cost (\$/GJ)	Total delivered cost (\$/GJ)
Armidale	7.42	95	0.5	7.9
Balranald	6.22	200	1.0	7.2
Bourke	7.42	200	1.0	8.4
Broken Hill	6.22	200	1.0	7.2
Buronga	6.22	110	0.6	6.8
Cobar	7.42	70	0.4	7.8
Darlington Point	6.22	30	0.2	6.4
Dubbo	7.42	0	0.0	7.4
Hay	6.22	120	0.6	6.8
Inverell	7.42	150	0.8	8.2
Lake George	7.42	15	0.1	7.5
Moree	7.42	200	1.0	8.4
Nyngan	7.42	120	0.6	8.0
Tamworth	7.42	0	0.0	7.4
Wagga Wagga	6.22	0	0.0	6.2
Wellington	7.42	45	0.2	7.6

Source ACIL Tasman (2009) Open Cycle Gas Turbine delivered gas costs, northern and southern NSW

Note Total delivered cost rounded up to nearest 0.1

A.2.6 Environmental factors

Due to the strategic nature of the study and the broad areas under investigation, AECOM identified environmental features and areas of national, state and regional importance. Features and areas that are recognised on a state and regional level for their high environmental value are often large in size, exhibit unique characteristics and are intrinsically linked to their surrounding environment. For these reasons they are potential constraints to development and it is highly recommended that they are avoided.

This approach of identifying environmental features of State and regional importance has been adopted as it will distinguish between and allow comparison of regional locations much more readily than identifying environmental matters of local importance, which are likely to be more prevalent and exist at most, if not all, of the 16 areas.

State and regionally important environmental features that have been identified as part of Phase 1 include the following:

- World heritage areas
 - The World Heritage List includes 890 properties that form part of the cultural and natural heritage which the World Heritage Committee considers as having outstanding universal value.
- National parks
- Current mining leases
- State Environmental Planning Policy No 14 Coastal Wetlands (SEPP 14) and Ramsar wetlands
 - SEPP 14 is made under the Environmental Planning and Assessment Act 1979. The aim of this policy is to ensure that the coastal wetlands are preserved and protected in the environmental and economic interests of the State. The Ramsar Convention is an intergovernmental treaty that embodies the commitments of its member countries to maintain the ecological character of their Wetlands of International Importance and to plan for the "wise use", or sustainable use, of all of the wetlands in their territories.
- Hydrology
 - Only major water bodies were considered, being rivers and lakes. The availability of water has been assessed in further detail in a separate hydrology assessment.

Figure A.5 below illustrates the distribution of State and regionally important environmental features identified for comparison of the 16 areas. The proximity of State and regionally important environmental features to the 16 areas is outlined in **Table A.10**. The table allows comparison of environmental constraints across the areas.

Table A.10 Potential key environmental constraints for the development of a solar precinct at 16 areas within NSW

	State and regi	onally importan	t environmental	features	
Area	World Heritage Areas	National Parks	Mining Leases	SEPP 14 and Ramsar Wetlands	Hydrology
Armidale	Yes	Yes	Yes	No	No
Balranald	No	Yes	Yes	No	No
Bourke	No	Yes	No	No	No
Broken Hill	No	No	Yes	No	Yes
Buronga	No	Yes	Yes	No	No
Cobar	No	No	Yes	No	Yes
Darlington Point	No	No	No	Yes	No
Dubbo	No	No	No	No	No
Hay	No	Yes	No	No	No
Inverell	No	Yes	Yes	No	No
Lake George	No	Yes	Yes	No	No
Moree	No	No	No	No	Yes
Nyngan	No	No	Yes	No	No
Tamworth	No	No	Yes	No	Yes
Wagga Wagga	No	Yes	No	No	No
Wellington	No	No	No	No	No

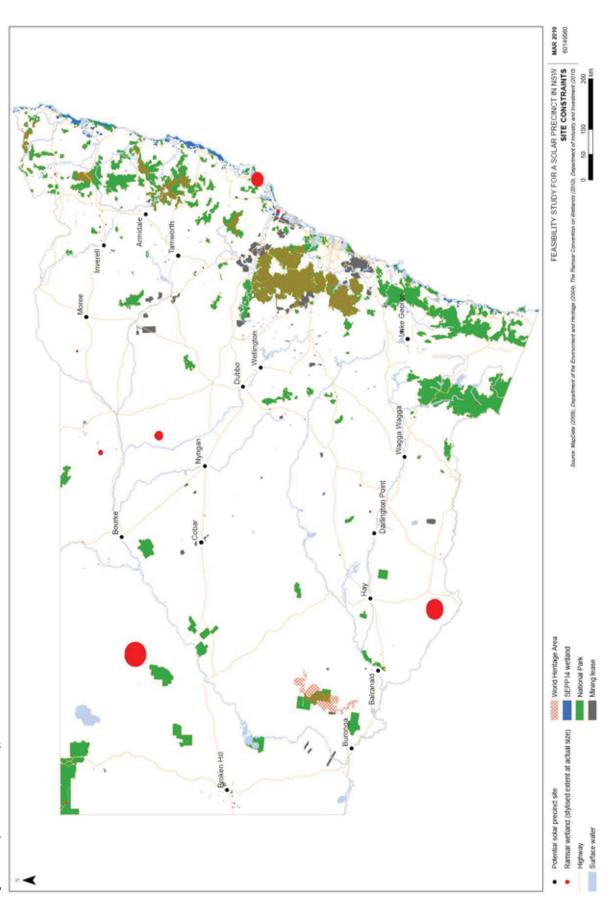
Source AECOM

Dubbo and Wellington represent the areas with potentially the least constraints on the basis of the key issues reviewed for this stage of assessment.

Subject to further investigation, the remaining areas are also likely to be suitable despite having State or regionally important environmental features in the vicinity, although this conclusion will depend on the size and type of plant (and footprint), location of development, and characteristics of environmental feature.

AECOM

Figure A.5 Solar precinct area constraints map, NSW



17 December 2010

A.3 Summary of area selection (Stage 2 analysis)

The information from the technology and area analysis was combined to rank areas on a cost per MWh basis and to qualitatively present environmental, water and land issues. **Table A.11** summarises this information. A workshop was held to discuss these results and finalise the selection of five areas on which to perform more detailed analysis.

Figure A.5 shows that the top five ranked areas are clustered in the north east largely due to better insolation from latitude effects and relatively low transmission costs to connect at 330kV. However, the differences between areas are small in terms of cost per MWh. Indeed, selection based purely on cost per MWh would exclude consideration of factors such as land gradient and water availability.

The selection decision was therefore based on the following criteria in order to capture trade-offs between feasibility factors and conduct more detailed analysis on a variety of scenarios:

- Geographic spread;
- Land gradient;
- Water availability for water cooled solar thermal;
- Gas availability for hybrid plant; and
- Distance to transmission network to illustrate costs of connection.

Due to the land gradient issues potentially ruling out some technologies it was agreed that a precinct is not required to host all solar technologies.

Based on the above criteria the following areas were selected for more detailed assessment:

- Broken Hill;
- Darlington Point;
- Dubbo:
- Moree; and
- One area in the corridor along the 330kV transmission line from the Queensland border south to Tamworth.

Inverell, Armidale and Tamworth each had high rankings, are all clustered in the north east of NSW, and may be constrained by land gradient. It was agreed that one area along the 330kV transmission line corridor from the Queensland border south to Tamworth be considered. This area would be of sufficiently low gradient to install up to 1,000 MW of solar trough, as the gradient at Inverell, Armidale and Tamworth may prevent the installation of such a large trough facility. An area close to the 330kV transmission line would also allow direct connection to the network via a new substation.

Given the comparatively higher gradient in the north eastern NSW areas of Inverell, Armidale and Tamworth, spatial analysis was conducted to identify potential areas along the 330kV transmission line corridor, moving northwards from Tamworth through Armidale and Dumaresq to the NSW-Queensland border. While some land of less than 1% gradient was identified in the far north at the border, this land corresponds to Bebo State Forest. Tamworth was selected as the fifth area because it has more land at 4% gradient than Armidale or Inverell. Inverell has a reasonable amount of 4% land but there are pockets of 11% gradient scattered throughout the 20 km radius. Tamworth also has access to a gas pipeline.

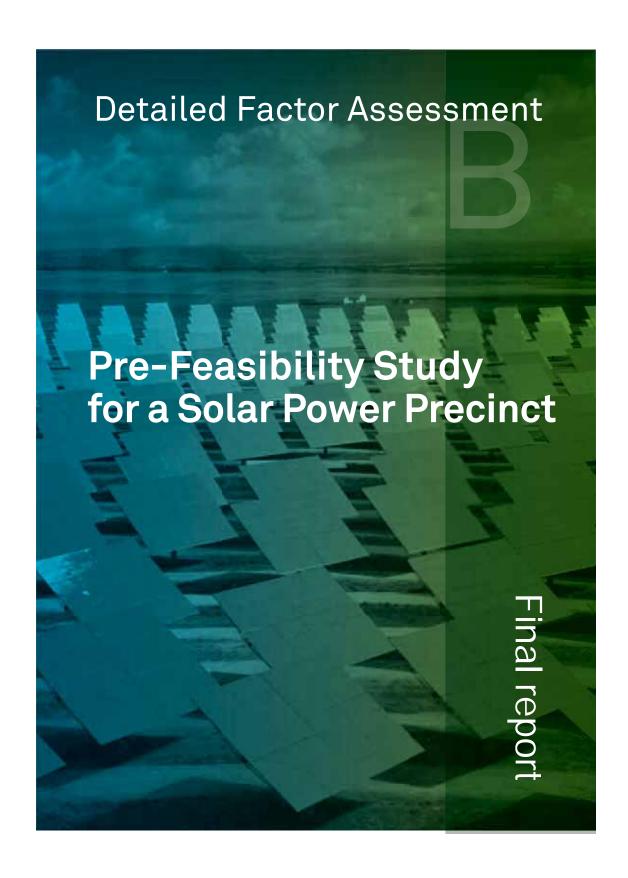
Therefore areas within 20 km of Broken Hill, Darlington Point, Dubbo, Moree and Tamworth were selected for more detailed assessment.

Pre-Feasibility Study for a Solar Power Precinct

AECOM

Table A.11 Stage 2 Summary

Area	œ	Ranking (250 MW)	S	Ra	Ranking (1000 MW)	(w	Water supply issues	Environment	Gradient	Land	Comment
	Mono- crystalline PV	Thin film PV	Solar Thermal - Trough	Mono- crystalline PV	Thin film PV	Solar Thermal - Trough				ownership	
Amidale	2	2	2	7	2	2	Medium Town supply	World heritage areasNational parksMining leases	Unlikely to have sufficient flat land		
Balranald	0	6	7	14	13	14	License purchase & pumped	National parks Mining leases	Flat land in all directions	Crown tenure	250 MW appears more feasible than 1000 MW (220kV line) Water may be constrained
Bourke	16	16	16	13	41	13	Buy property with storage dam	National parks	Flat land in all directions	Crown tenure	
Broken Hill	13	13	13	15	15	15	Town supply	Mining leases	Flat land to south and east	Crown tenure	
Buronga	10	10	10	16	16	16	License purchase & pumped	National parksMining leases	Relatively flat land in all directions	Crown tenure	250 MW appears more feasible than 1000 MW (220kV line) Water may be constrained
Cobar	14	14	14	6	6	10	60 km pipeline to Warren	Mining leases	Flat land in all directions	Crown tenure	1000 MW appears more feasible than 250 MW. Water may be constrained
Darlington Point	Ŋ	Ŋ	Ŋ	ø	9	9	Medium License purchase & pumped	Mining leases	Flat land in all directions		
Dubbo	80	80	6	7	7	7	Good Town supply	No constraints	Flat land to the north west		
Нау	7	7	80	10	10	6	Medium High Security license purchase & pumped	National parks	Flat land in all directions		
Inverell	-	-	-	-	-	-	Medium Town supply	National parks Mining leases	Unlikely to have sufficient flat land		
Lake George	15	15	15	12	12	12	30 km pipeline	National parksMining leases	Very unlikely to have sufficient flat land		
Moree	9	9	9	9	5	5	Good Groundwater supply	No constraints	Flat land in all directions		
Nyngan	11	1-	11	∞	80	∞	60 km pipeline to Macquarie River	Mining leases	Flat land in all directions	Crown tenure	1000 MW appears more feasible than 250 MW. Water may be constrained
Tamworth	4	4	3	4	3	3	44 km pipeline	Mining leases	Potential land to west and south		Depends on land availability and water
Wagga Wagga	12	12	12	1	7	11	Good Town supply	National parks	Potential land to west		Water good Potential water
Wellington	в	е	4	ю	4	4	License purchase & pumped	No constraints	Unlikely to have sufficient flat land. Marginal in the far west		Depends on land availability



Appendix B Detailed Factor Assessment

B.1 Technology

B.1.1 Introduction

There are two principal types of solar technologies:

- Solar photovoltaic (solar PV) technologies that convert sunlight directly into electricity; and
- Solar thermal technologies that focus sunlight to create heat to produce steam that is used indirectly to generate electricity using steam turbines.

This section focuses on technical characteristics of two types of solar PV, namely mono-crystalline and thin film, and two types of solar thermal, namely trough and tower. It also discusses the potential for "hybridising' solar thermal by gas co-firing. These technologies were selected for inclusion in this study because they represent a range of differences in terms of manufacturing processes, costs and efficiencies. These differences in costs and performance of individual technologies clearly affect cost of generation.

B.1.2 Photovoltaic technology

A photovoltaic solar cell is a semiconducting device that produces electricity directly from sunlight. Solar cells are combined to form a solar panel module; multiple modules are then combined to form an array. Modules are essentially a protective package of glass or polymer laminate used to encapsulate the solar cells. In addition to the PV module, other system components include mounting frames and electrical wiring. Grid connected PV also requires inverters to convert the PV generated direct current into an alternating current, transformers to increase the AC voltage, and further electrical equipment and switchgear for the grid connection.

B.1.2.1 Photovoltaic categories

There are four broad categories of PV in the market today: mono-crystalline, poly-crystalline, thin film and concentrating PV (CPV):

- Mono-crystalline and poly-crystalline are fundamentally similar technologies, with poly-crystalline being slightly less efficient than mono-crystalline and having slightly lower costs. Poly-silicon is the primary ingredient used to manufacture crystalline solar cells. Poly-silicon can be cast into ingots and sliced up to form poly-crystalline wafers, then further processed to form poly-crystalline solar cells. Alternatively, through a series of energy intensive processes, poly-silicon can be refined to produce a single crystal ingot which is sliced up into single crystal wafers, and then further processed to form mono-crystalline solar cells. This study selected mono-crystalline as the higher efficiency variant (to compare with thin film), and does not consider poly-crystalline technology further.
- Thin film solar panels are manufactured using a different technique to crystalline technologies. Typically the thin film solar panel starts as a pane of glass and the thin film material layers are applied to the glass substrate using a series of vapour deposition and laser etching, or similar processes. It is common for the panels to be supplied with simple mounting brackets on the back of the panel, rather than with full aluminium frames for a number of reasons such as cost, the encapsulation techniques, typically edge to edge active area and large physical size of thin film technologies.
- Concentrating PV uses a mirror or magnifying lens to concentrate sunlight onto a PV cell to increase the effective sunlight the cell receives and increase electrical output. The mirrors or lenses tend to be lower cost than the solar cells and hence a key benefit of concentrating solar PV is significantly higher energy yield per solar cell. Thus concentrating PV is potentially cheaper and more efficient than other forms of solar PV. There are some technical challenges with CPV, particularly the high accuracy positioning of the solar cells required during encapsulation, the high operating temperature of the solar cells where active or passive cooling may be required, and the cell lifetime with long term temperature cycling. As with solar thermal concentrating technologies CPV only works in direct sunlight, and the majority of CPV technologies need to be mounted on tracking frames in order to achieve solar concentration. CPV is presently in the early stages of commercial development with very different technology types and configurations emerging. Due to the difficulty of identifying a representative CPV technology and limited availability of public domain cost and performance data, CPV has not been considered further in this study.

In summary, this study selected the mono-crystalline and thin film technologies to compare and contrast PV performance between potential precinct areas.

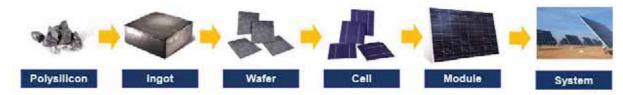
B.1.2.2 Arrays and tracking systems

Solar panel performance improves when panels are oriented to face the sun. Performance can therefore be improved by mounting the panels on a static frame with a fixed tilt to face the sun, and further improved if mounted on frames that track the sun in one or both axes. However yield benefits from tracking arrays must be weighed against land utilisation requirements in addition to increased capital and operating costs to purchase and maintain the additional equipment required for a tracking array. For the purposes of this study static mounting frames have been used to simplify computationally intensive modelling and enable comparison of areas on a common static-mounted basis.

B.1.2.3 Manufacturing processes

Figure B.1 sets out the crystalline PV solar panel manufacturing process.

Figure B.1 Illustration of poly-silicon to crystalline silicon solar panel manufacturing process stages



Source Yingli Solar

There are two types of manufacturing processes used:

- The majority of mono-crystalline solar cells are produced by a few very large capacity factories. These cells (high value, small volume) are then typically shipped out to solar panel factories around the world (closer to market) where the cells are connected together and encapsulated in glass (low value, high volume) to make the final solar panel product. These local factories are called crystalline solar panel encapsulation factories.
- There are also a number of solar cell manufacturers that are vertically integrated and combine the full
 manufacturing process under one roof from processing raw poly-silicon through to producing the final solar
 panel product.

Thin film solar panel factories typically have lower annual manufacturing capacities than crystalline silicon cell factories. Hence (as with crystalline solar panel encapsulation factories) it is more common for the thin film factories to be spread out across the globe to supply local markets. More recently there has been a trend towards establishing thin film production line factories adjacent to large PV projects (e.g. Masdar City).

B.1.3 Solar thermal

Solar thermal refers to technology that uses solar energy to indirectly generate steam to feed a conventional steam turbine generator. Mirrors are used to concentrate the sun's energy onto a receiver, heating the contents of the receiver which then transfers the heat to the power generation system.

There are four main types of solar thermal systems, parabolic trough, dish, tower and Compact Linear Fresnel Reflector (CLFR), with the main difference between systems being the method used to concentrate solar energy onto a receiver:

- **Parabolic trough** systems use parabola-shaped mirrors to focus sunlight onto receiver tubes that contain a heat transfer fluid (HTF). The fluid is pumped through heat exchangers to produce steam to generate electricity using a steam turbine.
- Dish systems use an arrangement of mirrors to form a parabolic dish that focuses sunlight onto a receiver
 at the focal point of the dish. The solar energy is either converted to electricity directly by a Stirling engine
 mounted at the focal point or the receiver uses heat transfer fluid to transfer heat from the focal point to a
 heat exchanger to raise steam to generate electricity.
- Solar towers are conceptually similar to the dish systems but at a much larger scale. A large field of mirrors (heliostats) are used to focus sunlight onto a receiver at the top of a centrally placed tower. The cold HTF is pumped up the tower and circulated through the receiver, the hot HTF is then returned to a ground level heat exchanger used to raise steam to generate electricity. Solar towers can achieve very high HTF temperatures enabling a more efficient steam cycle compared to solar troughs. Figure B.2 shows a simulated view of the Ivanpah Solar Electric Generating System (ISEGS) project upon completion.

Augmenting a solar thermal plant with storage capability is a potential solution to resolve the disparity between solar thermal output and consumer demand. Molten salt thermal storage is one option that enables an improved match between electricity demand and electricity output. Lower temperatures and efficiency losses incurred when transferring heat from the heat transfer fluid to the storage medium make storage less of a compelling issue for solar trough. Molten storage, however, has a high capital cost of approximately \$0.5m per MW (Sargent & Lundy, 2003) and is untested at the scale in this study and is therefore not considered.

• Compact Linear Fresnel Reflectors are similar to parabolic troughs however they use a field of flat mirrors individually tilted to reflect sunlight onto an overhead receiver tube. Compared to parabolic troughs, CLFR allow for a denser array of reflectors, leading to a small land footprint.

The steam cycle associated with solar thermal systems can be either water or air cooled. The selection between wet and dry cooling is primarily driven by water availability and water quality. Evaporative water cooling can increase plant efficiency due to the avoided requirement for high power electric fans. However, this is partly offset by changes to the steam cycle efficiency due to the different operating conditions. Significant efficiency improvements can only be achieved in cases where large water bodies such as lakes or the sea are available for cooling. In most high solar resource locations there are constraints on the available water supply. As such, dry air cooling has become the most commonly adopted process. AECOM has assumed that air cooling for comparative area analysis. Air cooling will increase capital costs for the total plant by approximately 1.25% if potential savings from avoided water infrastructure requirements are ignored.

For the purposes of this study, AECOM has focused on trough and tower solar thermal technologies as both are more commercially advanced than dish or Fresnel reflectors, and therefore have more information available relative to other forms of solar thermal technologies.



Figure B.2 Simulated view of Ivanpah Solar Electric Generating System

Source Ivanpah Solar Electric Generating System Application for Certification.

B.1.4 Gas-assisted solar trough hybrid

The energy generation of a solar plant varies throughout the day and across seasons as it is a function of available sunlight. It is also severely impacted by the presence of clouds. The practical implication for large-scale solar plants is that their energy generation profile may not coincide with peak energy demand. Electrical network issues may also arise with large quantities of capacity moving online and offline.

Augmenting a solar thermal plant with gas-assist is a potential solution to resolve the disparity between solar thermal output and consumer demand.

Hybridising a solar thermal plant with gas is a possible cost-effective option, particularly in the case where legislation allows renewable energy credits to be claimed for the proportion of generation not due to gas. (In some countries renewable credits apply only when all of the system is solar powered and consequently the gas-assist option is often disregarded). The advantage of the gas-assist hybrid is to improve the steam cycle efficiency or to raise steam in a standalone boiler during periods of low solar generation. It is therefore able to better match electrical demand fluctuations and be more attractive to purchases of electricity.

This study has not considered a solar-assisted gas plant where the majority of generation is from gas, as the purpose of this study is to assess the economic feasibility of a solar precinct and not a plant with gas as the primary fuel.

B.1.4.1 Hybridisation

As the purpose of the gas-assist hybrid in this study is to supplement solar generation to meet peak demand, this study assumes a load-following gas-assisted solar trough plant. Electricity is predominantly produced by the solar trough and the gas component only provides the remaining fraction necessary to follow a targeted load profile (see **Figure B.3**). That is, the shape of the total solar and gas output profile is the same as the shape of the target load profile. The maximum output of the overall hybrid system corresponds to the maximum power that the solar trough can deliver.

AECOM assessed solar and gas generation following four load profiles either continuously for 24 hours per day or constrained between morning and evening shoulder (7am to 8pm) periods:

- Base load (continuous generation at full power)
- Local substation load;
- NSW demand profile (scaled to the size of hybrid plant); and
- Country Energy net system load profile (NSLP).

The analysis found that continuous production corresponds to a predominantly gas-fired plant, effectively a solar-assisted gas plant. Therefore, this study assumed the hybrid plant will follow load as defined by the shoulder constrained scaled NSW demand profile; constrained with a 7am to 8pm shoulder period to reduce gas consumption.

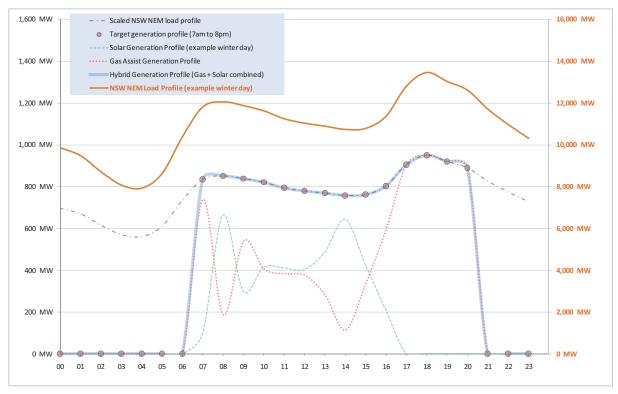


Figure B.3 Tamworth - winter day illustrative example - Hybrid generation and load profiles

A gas-assist hybrid system can be implemented in a number of ways depending on the intended application and capital cost. Potential configuration options for a gas-assist solar thermal plant include:

- Gas-fired steam boiler;
- Gas boiler;
- Combined cycle gas turbine; and
- Steam accumulator.

Table B.1 provides a comparison of the features of each type of gas-assist configuration. **Table B.1** shows that the gas-fired heat transfer fluid boiler and gas-fired steam boiler are both well adapted to a load following application. For the purposes of this study, AECOM has selected the gas-fired heat transfer fluid boiler to assist the solar trough plant; where a boiler is used with a heat transfer fluid and heat exchanger for co-mingling with heat collected from the solar trough field, and the combined heat is used to raise steam for driving the steam turbine. A simplified configuration is shown in **Figure B.4**.

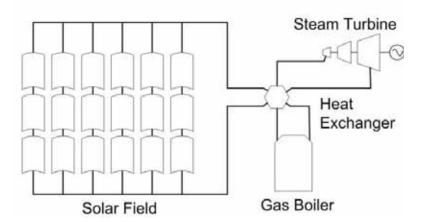
Table B.1 Comparison of gas-assist technologies against potential applications

Feature	Gas-fired HTF boiler	Gas-fired steam boiler	Combined cycle gas turbine	Steam accumulator
Load following	✓	✓	X	X
Optimise steam cycle efficiency	✓	✓	X	X
Recovery support	✓	✓	X	✓
Quick ramp rates	✓	✓	X	✓
Serve base load	Χ	X	✓	Х

Source AECOM

Note: Further details of these configurations are described in Appendix C.

Figure B.4 Simplified illustration of gas assisted solar hybrid configuration



B.2 Technology costs

B.2.1 Introduction

This section discusses the following costs for each technology:

- Capital costs across the different technologies now and how they are expected to change over time;
- Annual operating and maintenance costs;
- Any major periodic maintenance costs; and
- Staging of construction.

System capital costs are the key determinant of overall generation costs as solar power systems generally have no ongoing fuel costs and other cost items such as operating and maintenance expenses are relatively minor by comparison.

B.2.1.1 Background on PV costs

The selection and comparison of solar PV technology typically focuses on the "cost per watt" of a solar panel. However, the cost per watt is often misleading when considered in isolation, due to very significant differences in the efficiency and quality of solar panels. Furthermore, although the cost of the solar panel is the dominant cost component in the overall cost for a solar project, the use of low cost (low efficiency) solar panels is offset by increased costs associated with extra mounting frames, longer cable runs and additional land requirements to achieve a specified installed capacity. For these reasons it is important that comparison of the costs per watt of solar panels are considered in the context of both efficiency and quality. AECOM has therefore selected a utility scale mono-crystalline solar panel and a thin film solar panel on the basis of indicative costs being available and used the characteristics of these panels (efficiencies, land requirements) throughout this study.

Figure B.5 illustrates the variation in the price of solar panels in the past decade. The costs per watt are averaged "retail prices" and do not take into account the huge variation in efficiency and quality of specific solar panels. There have been a significant number of factors that have influenced the price of solar panels over this last decade, including:

- Rising demand for solar panels due to global recognition of climate change and security of supply issues;
- Initial availability of "cheap" waste silicon from the micro-electronics industry followed by a subsequent shortage of raw poly silicon;
- A dramatic and sustained drop in the price of raw poly silicon since 2008;
- The price of raw poly silicon now stabilising;
- Economies of scale volume manufacturing and closure of many smaller facilities;
- Improved solar panel efficiencies;
- Higher capacity solar panels;
- Vertical integration of manufacturing processes; and
- "Boom-bust" price shocks associated with surges in demand resulting from time limited government incentives for solar projects in various countries.

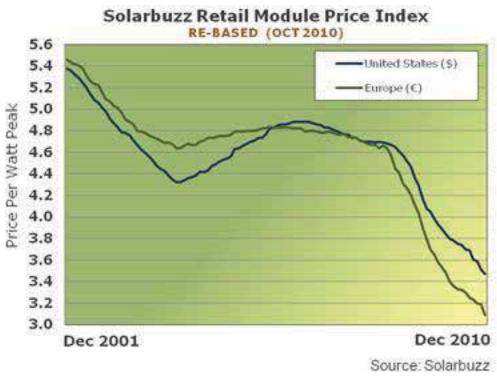


Figure B.5 Module retail price index

Source Solarbuzz

At present, there are very few companies that have sufficient manufacturing capacity to supply solar panels to large scale projects. For the majority of those manufacturers that could supply solar panels for a 250 MW project, the size of the order is of sufficient magnitude that they would have to commit a sizable proportion or all of their manufacturing capacity to the one project. Consequently, companies are unwilling or unable to engage with quoting prices for speculative projects of this scale without potentially firm orders.

AECOM has worked on a number of large scale solar PV projects including one approaching the size of a solar precinct. Discussions with industry and Clinton Climate Initiative have led AECOM to form the view that, whilst there would be economies of scale in moving from 50-100 MW up to 250 MW, there are not anticipated to be large economies of scale between a 250 MW and 1,000 MW plant.

There is a limited PV manufacturing industry in Australia, therefore AECOM has relied on global prices quoted in US dollars and Euros. Prices have been converted using purchasing power parity (PPP) rather than market exchange rates as PPP exchange rates better reflect the different local costs faced in Australia such as labour, higher mark-ups and shipping costs of imported products.

B.2.1.2 Background on solar thermal costs

There is limited public information, particularly about costs, for large scale solar thermal installations. The most comprehensive published solar thermal cost information is a study by Sargent & Lundy (2003) which only considered trough and tower technology. AECOM understands that this study is being updated, but the updated report was not available at the time of writing.

Of the available data for existing and planned solar thermal systems, only limited detail and itemisation of costs is publically available, making it difficult to determine if quoted costs are for generation systems only, or include additional expenses such as land purchase, transmission infrastructure, financing and other cost items which would give a "total project cost". As such, there is considerable uncertainty around solar thermal capital cost assumptions.

AECOM has noted that where available, the cost per MW for both trough and tower solar thermal technologies seem to be lower for systems located in the US compared to those in Europe. Without further cost detail and itemisation, it is difficult to identify the main price differences between locations and which prices are of most relevance to Australia.

B.2.2 Mono-crystalline

B.2.2.1 Current capital cost

As discussed previously, capital costs per watt need to be considered in the context of efficiency and quality of the panel itself due to substantial differences between manufacturers and technologies. For this reason, a specific utility-scale mono-crystalline panel has been selected for the purposes of this study to compare areas on a common cost basis. Details of the technical characteristics of this solar panel can be found in **Appendix C**. Direct comparison of these costs against costs from other mono-crystalline panel suppliers is inappropriate without considering the efficiency and quality of the solar panels.

Table B.2 presents the capital costs of the utility-scale mono-crystalline panel selected for this study. The total installed cost is around \$5 per watt, with 70% of this driven by the panel and frame costs. These capital costs are conservative and towards the top end of the price range, reflecting the relatively high quality and efficiencies of the panels.

These assumptions assume a new cell encapsulating factory is established near the development site. Anecdotal evidence suggests that once a development requires more than 30MW per year it becomes cheaper to establish an onsite production line. This is supported by a recent trend towards establishing thin film production lines factories adjacent to large PV projects (e.g. Masdar City).

Table B.2	Mono-crystalline capital cost assumptions
-----------	---

Parameter	Assumption (250 MW and 1,000 MW)	Description
Panel	€1.53 / watt 2.63 AUD / watt	Assumption based on informal supplier estimate, assuming a new cell encapsulation factory is established near the project area, with solar array construction staged over several years and discussion with Clinton Climate Initiative (See Section B.2.2.5 for more details on planned staging)
Mounting frame	€0.57/watt 0.98 AUD / watt	Indicative price for simple static mounting frame based on previous AECOM projects. This is described as a cost per watt to illustrate capacity of mounting frame for this mono-crystalline technology.
Inverter	€0.27/watt 0.46 AUD / watt	Assumption based on supplier budgetary bulk purchase price for 1 MW utility scale inverters.
Electricals	0.5 AUD / watt	Calculated from fixed costs for switchgear; variable costs for cable and trenching derived from the assumed foot print of the solar array. Note the electrical equipment is for DC circuits and AC collection circuits and does not include switchgear associated with grid connection.
Installation costs	0.45 AUD / watt	Installation costs are calculated as the sum of 5% of panel capital cost and 15% of remaining components, based on previous AECOM experience.
Total	5.0 AUD / watt	

Note Original values in Euros have been converted to Australian dollars using a purchasing power parity (PPP) exchange rate of 1.72 AUD per Euro

B.2.2.2 Forecast capital costs

The majority of a PV panel cost is the price of raw poly silicon, which is stabilising so any reductions in prices will come through improved module efficiency and economies of scale from increased sales. Discussions with Clinton Climate Initiative indicated that industry is generally expecting a 25% shift in the learning curve over the next three to four years. Price forecasts published by Photon Consulting (Solar Annual 2009) suggest that mono-crystalline modules will decline by more than 50% between 2010 and 2013. As a conservative assumption, AECOM has assumed that panel costs will decrease by 50% as per the Photon Consulting forecasts, but that this decline will not occur until 2014 rather than 2013. Beyond 2014, capital costs are assumed to decline by 1% per year by 2025 and are constant thereafter. Other costs as set out in **Table B.2** are not anticipated to change.

B.2.2.3 Annual operating and maintenance costs

Maintenance costs are divided into two categories: replacement of failed panels; and inspection and testing of electrical equipment. It is assumed that 0.1% of mono-crystalline panels and mounting frames require

replacement annually, and therefore the cost of replacing them is 0.1% of the capital cost for panels and frames respectively. Electrical inspection and testing costs are based on three factors:

- Basic electrical inspection cost of \$15,000 per MWp;
- Replacement of failed electrical equipment assumed to be 0.1% of electrical capital costs; and
- Cost to inspect each string of solar panels, assumed to be \$40 per string.

Therefore annual maintenance costs are assumed to be \$31,500 per MWp and \$30,100 per MWp for 250 MW and 1,000 MW respectively. There are small economies achieved by scaling up to 1,000 MW.

B.2.2.4 Major periodic maintenance costs

Major maintenance activities are assumed to occur every 12 years to replace all inverters and half of the electrical equipment at a cost \$882,000 per MWp for 250 MW and \$823,000 per MWp for 1,000 MW plants. This is based on the typical design life of power inverters and electrical equipment. Note that some inverter manufacturers are now offering 20 year extended equipment warranties so these costs may reduce.

B.2.2.5 Construction staging

As a 250 MW PV precinct is a relatively unprecedented development, it is unlikely that 250 MW of PV could be supplied, installed and commissioned in a single year. Instead, construction and commissioning is likely to be staged over a number of years.

First year construction activities include project preparation works for the entire precinct such as levelling land, switchyard construction and installation of the first stage of generation capacity by year end. No electricity generation is assumed during year one.

Additional generation capacity is assumed to come online in each subsequent year until the final precinct capacity of 250 MW or 1,000 MW is reached. Construction activity for a 1,000 MW precinct is assumed to occur in 250 MW blocks for comparison purposes against the standalone 250 MW plant. Generation capacity staging is shown in **Table B.3**.

Table B.3 Mono-crystalline PV precinct capacity staging (total operating MW capacity in each year)

Final Precinct					Year				
Capacity	1	2	3	4	5	6	7	8	9
250 MW	0	125	250						
1,000 MW	0	125	250	375	500	625	750	875	1000

Source AECOM

AECOM has assumed an effective generation life of 25 years for mono-crystalline PV systems, resulting in a gradual reduction in total precinct capacity as each stage is decommissioned at the end of its economic life.

B.2.3 Thin film

B.2.3.1 Current capital costs

Capital cost considerations are analogous to those presented above for mono-crystalline PV. A specific utility-scale thin film panel has been selected for the purposes of this study to compare areas on a common cost basis. Details of the technical characteristics of this solar panel can be found in **Appendix C**.

Table B.4 presents the capital costs of the utility-scale thin film panel selected for this study. The total installed cost is around \$4.6 per watt, with 55% of this driven by the panel and frame costs. These capital costs are conservative and towards the top end of the price range, reflecting the relatively high quality and efficiencies of the panels.

These assumptions assume a thin film production line factory will be established adjacent to the project site. As discussed above for mono-crystalline PV, anecdotal evidence suggests that once a development requires more than 30MW per year it becomes cheaper to establish an onsite production line.

Table B.4 Thin film capital cost assumptions

Parameter	Assumption (250 MW)	Description
Panel	€1 / watt 1.72 AUD / watt	Assumption based on supplier quote; this assumes a dedicated factory to be established near the project area with construction staged over several years.
Mounting frame	€0.47/watt 0.81 AUD / watt	Indicative prices for simple static mounting frames calculated as the ratio of estimated steel mass for mono-crystalline to thin film, multiplied by the price of mono-crystalline mounting frame. This is described as a cost per watt to illustrate capacity of mounting frame for this mono-crystalline technology. No economies of scale have been assumed for 1,000 MW plant.
Inverter	€0.27/watt 0.46 AUD / watt	As above for mono-crystalline.
Electricals	1.16 AUD / watt	As above for mono-crystalline.
Installation costs	0.45 AUD / watt	As above for mono-crystalline.
Total	4.60 AUD / watt	

Note Original values in Euros have been converted to Australian dollars using a PPP exchange rate of 1.72 AUD per Euro

B.2.3.2 Forecasts capital costs

As with mono-crystalline PV, future capital costs are likely to be driven by changes in panel prices. This study assumed a reduction of panel prices of 50% by 2014 based on the forecasts published by Photon Consulting. Beyond 2014, capital costs are assumed to decline by 1% per year by 2025 and are constant thereafter. Other costs as set out in **Table B.4** are not anticipated to change.

B.2.3.3 Annual operating and maintenance costs

As with mono-crystalline PV, maintenance costs arise from replacement of failed panels, and inspection and testing of electrical equipment. Annual maintenance costs are assumed to be \$61,400 per MWp and \$57,100 per MWp for 250 MW and 1,000 MW respectively. There are small economies of scale scaling up to 1,000 MW. Cost parameters are the same as those used for calculating mono-crystalline PV maintenance costs. The total maintenance costs are higher for thin film compared to mono-crystalline as there are physically more panels, frames and equipment to inspect and test.

B.2.3.4 Major periodic maintenance costs

As with mono-crystalline PV, major maintenance activities are assumed to occur every 12 years to replace all inverters and half of the electrical equipment. Major maintenance is assumed to cost \$1,258,000 per MWp for 250 MW and \$1,198,000 for 1,000 MW plants.

B.2.3.5 Construction staging

As for a mono-crystalline PV precinct discussed in **Section B.2.2.5**, thin-film PV precinct construction and commissioning is assumed to be staged over a number of years, with construction lasting three years for a 250 MW precinct and eight years for a 1,000 MW precinct, including first year site preparation works. Operating capacity in each year is shown in **Table B.5**.

Table B.5 Thin-film PV precinct capacity staging (total operating MW capacity in each year)

Final Precinct	Year								
Capacity	1	2	3	4	5	6	7	8	9
250 MW	0	125	250						
1,000 MW	0	125	250	375	500	625	750	875	1000

Source AECOM

As for mono-crystalline, thin-film PV panel prices are assumed to be set at the commencement of construction of each stage and are constant during the construction period of that stage.

An effective generation life of 25 years for thin-film PV systems has been assumed with a gradual reduction in total precinct capacity as each stage is decommissioned at the end of its economic life.

B.2.4 Solar thermal trough

B.2.4.1 Current capital costs

As can be seen in **Table B.5**, there is considerable variation in system costs per MW. Analysis of Sargent & Lundy (2003) combined with a survey of project costs for existing solar trough plants and industry data, revealed a cost range from 3.5 to 7.6 USD per watt, with costs generally decreasing with time. **Figure B.6** shows trough system costs for a number of projects expressed as USD per watt by year of commissioning and cost curves forecast by Sargent & Lundy (2003).

The plants considered vary by size and country. The majority of the projects within the high end of the range (5.5 to 7.5 USD per watt) are for 50 MW plants and are based in Europe. Some plants include storage, but for the purposes of this study, energy storage is considered as a secondary factor and is not included in the capital cost estimate.

AECOM has considered the Sargent & Lundy (2003) data alongside information provided by a developer suggesting trough costs of approximately 3.5 USD per watt. This study assumed a conservative capital cost of 3.9 USD per watt for solar trough system. At PPP exchange rates, this is equivalent to 4.8 AUD per watt, or 4.8 million AUD per MW.

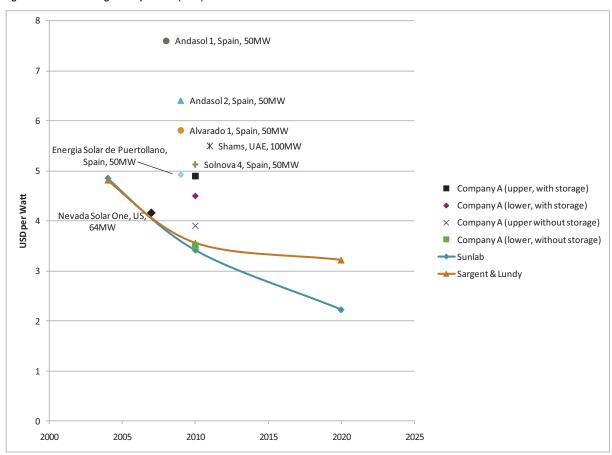


Figure B.6 Solar trough cost per watt (USD)

Source AECOM analysis based on Sargent & Lundy (2003) and project developers

Table B.6 shows the reported proportion of total solar trough capital costs for each system component³. The solar collection field made up of mirrors and collector structure represents the largest proportion of total solar trough capital costs.

³ https://www.htri.net/<u>Public/prodsvcs/HMS_Victoria1.pdf</u>

Table B.6 Solar trough capital cost structure

Component	Percentage of Capital Costs
Mirrors	13%
Absorber Tubes	13%
Collector Structure	18%
Heat Transfer Fluid	8%
Storage	19%
Cycle	12%
Civil Works	3%
Engineering	8%
Others	6%

Source Müller-Steinhagen, H (2008)

B.2.4.2 Forecasts capital costs

There is limited public information available about future capital costs for solar trough (although developers are confident of being able to reduce costs further). As solar trough and solar tower technologies share a number of common processes and similar components, there is the potential for cost reductions by similar means to those discussed in **Section B.2.5.2**. However, as solar trough technology is somewhat more mature and has had already gained from additional development experience than solar tower systems, further cost reductions may be slightly lower than those that could be expected for solar tower systems.

AECOM has assumed that solar trough capital costs will decline by 20% in real terms from 2010 to 2014, resulting in a final cost of \$3.82 per watt in 2014. Beyond 2014, capital costs are assumed to decline by a further 25% by 2025 representing improvements in mirror manufacturing, after which costs are assumed to be constant in real terms.

B.2.4.3 Annual operating and maintenance costs

There is limited publically available information on other operating and maintenance costs for solar trough systems as most operators are reluctant to reveal commercially sensitive information. AECOM has assumed annual maintenance of 35,300 USD per MW based on estimates by Sargent & Lundy (2003), equivalent to 43,200 AUD per MW at PPP exchange rates.

B.2.4.4 Major periodic maintenance costs

Notwithstanding the usual power block major maintenance requirements, no major periodic maintenance is assumed for solar trough.

B.2.4.5 Construction staging

Most large solar trough projects have been developed using a staged approach with construction and commissioning of individual plants occurring sequentially, as is occurring on the Andasol development in Spain.

Construction of each 250 MW stage is assumed to take two years to enable comparison with photovoltaic and solar tower technologies. Construction activity such as project preparation works for the entire precinct is assumed to occur during the first year alongside installation of the first stage of generation capacity by year end. No electricity generation is assumed during year one.

Total operating capacity for both 250 MW and 1,000 MW precincts is shown in Table B.7.

Table B.7 Solar trough precinct capacity staging (total operating MW capacity in each year)

Final Precinct					Year				
Capacity	1	2	3	4	5	6	7	8	9
250 MW	0	125	250						
1,000 MW	0	125	250	375	500	625	750	875	1000

Source AECOM

As for photovoltaic technologies, solar trough prices are assumed to be set at the commencement of construction of each stage and are constant during the construction period of that stage.

As for both PV technologies, generation capacity is assumed to have a 25 year operating life with total precinct capacity being reduced gradually as each stage is decommissioned.

B.2.5 Solar thermal tower

B.2.5.1 Current capital costs

As there are few solar towers that have been constructed to date and existing towers are of significantly smaller scale than those required for a 250 or 1000 MW precinct, only limited cost data is available. **Figure B.7** shows costs expressed as USD per watt for both the solar tower plants in current operation (PS10 and PS20) and available cost estimates for a number of planned solar tower developments. Also shown in **Figure B.7** are cost curves estimated by Sargent & Lundy (2003). Solar tower developers have indicated costs for larger scale systems are broadly in line with those forecast by Sargent & Lundy (2003).

Based on the available data and information provided by a project developer, AECOM has assumed current capital costs are 4 USD per watt, equivalent to 4.9 AUD per watt, or alternatively 4.9 million AUD per MW after adjusting for purchasing power differences.

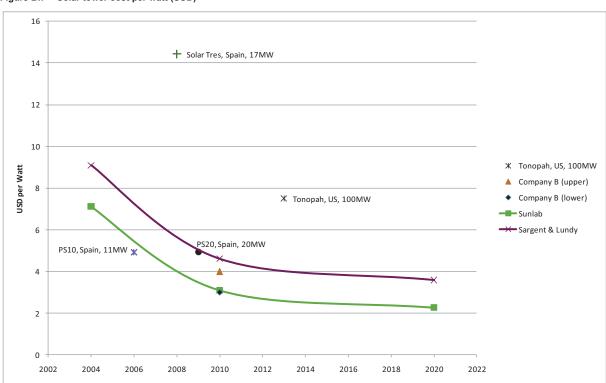


Figure B.7 Solar tower cost per watt (USD)

Source AECOM analysis based on Sargent & Lundy (2003) and project developers

Table B.8 shows the reported proportion of total solar tower capital costs for each system component⁴. The largest single component of solar tower capital costs is the heliostat field.

Table B.8 Solar tower capital cost structure

Component	Percentage of Capital Costs
Heliostats	35%
Receiver	11%
Storage	17%
Cycle	14%
Civil Works	6%
Engineering	6%
Others	11%

Source Müller-Steinhagen, H (2008)

⁴ https://www.htri.net/Public/prodsvcs/HMS Victoria1.pdf

B.2.5.2 Forecasts capital costs

There is limited public information available about future capital costs for solar tower. However, there is considerable research and development effort being undertaken by a variety of companies towards the goal of significant cost reductions.

Google, which has invested in two solar tower technology companies, BrightSource and eSolar as well as undertaking their own independent research, has recently announced that it has developed a prototype mirror using new materials in the reflective surface and mirror substrate that has the potential to halve heliostat costs in the next one to three years⁵. As shown in **Table B.8**, the heliostat field represents a significant proportion of total capital costs and as such, developments in this area have the potential to cause significant reductions in overall capital costs.

Increases in production volumes of components used in solar towers will result in further cost reductions. Bill Gross, eSolar CEO and founder has stated that:

We produced 500 mirrors two years ago, 24,000 last year, and this year we'll produce a million. So we're going to get a quantity break just by going to a million mirrors from 24,000... everything gets more efficient in the supply chains as you get up to those volumes ⁶.

Additional cost reductions are likely to be achieved through:

- The use of larger system sizes providing economies of scale, including power blocks;
- Reductions in component costs due to improved technical design and manufacturing techniques; and
- The use of storage to increase the proportion of full load hours.

Based on the available information and potential for further cost reductions, AECOM has assumed a 25% reduction in tower capital costs by 2014, resulting in a total capital cost \$3.67 per watt in 2014. Beyond 2014, capital costs are assumed to decline by a further 25% by 2025 representing improvements in mirror manufacturing, after which costs are assumed to be constant in real terms.

B.2.5.3 Annual operating and maintenance costs

Annual maintenance is assumed to be 41,500 USD per MW based on Sargent & Lundy (2003), equivalent to 50,700 AUD per MW at PPP exchange rates.

B.2.5.4 Major periodic maintenance costs

No major periodic maintenance in addition to the usual power block maintenance requirements has been assumed for solar tower systems.

B.2.5.5 Construction staging

As for solar trough systems, most large solar tower projects under development make use of sequential construction and commissioning of individual generating units. AECOM has assumed an individual generating system size of 125 MW can be constructed and commissioned each year for a 250 MW precinct and that construction of individual 250 MW systems occurs every two years for a 1,000 MW precinct. The 125 MW individual unit capacity is based on the system assumed for solar electricity generation modelling and comparable with capacity staging for planned tower developments such as the ISEGS project which will use phases of 100 MW and 200 MW to reach a final capacity of 400 MW.

Total operating capacity by year for both 250 MW and 1,000 MW solar tower precincts is shown in Table B.9.

Table B.9 Solar tower precinct capacity staging (total operating MW capacity in each year)

Final Precinct	Year								
Capacity	1	2	3	4	5	6	7	8	9
250 MW	0	125	250						
1,000 MW	0	125	250	375	500	625	750	875	1000

Source AECOM

⁵ http://www.reuters.com/article/idUSTRE61P58V20100226

⁶ http://www.e360.yale.edu/content/feature.msp?id=2248

As for photovoltaic technologies, solar tower prices are assumed to be set at the commencement of construction of each stage and are constant during the construction period of that stage.

As for the other solar technologies considered, generation capacity is assumed to have a 25 year operating life with total precinct capacity being reduced gradually as each stage is decommissioned.

B.2.6 Gas-assisted solar trough hybrid

B.2.6.1 Current capital costs

The capital cost for the gas-assisted hybrid system is divided into three major parts:

- Solar trough. It has previously been estimated at 4.8 million AUD per MW for 250 MW and 4.3 million AUD per MW for a 1000 MW system (see **Section B.2.4.1**).
- Gas boiler. The gas boiler is assumed to have a capital cost of 0.3 million AUD per MW, equivalent to \$0.3 per watt.
- Gas supply. The volume of gas required by a gas assisted solar system is of such a volume that a pipeline is the only viable method of delivery and therefore incurs extra capital costs for the pipe system. Gas costs are included in the gas supply price rather than plant capital cost (see **Section B.7.3.2**).

B.2.6.2 Forecasts capital costs

Capital costs for the solar trough component of the hybrid system are assumed to be the same as for the solar trough-only plant with costs declining to \$3.82 per watt in 2014.

Capital cost for the gas component of the hybrid system is not anticipated to change in real terms.

B.2.6.3 Annual operating and maintenance costs

Annual operating and maintenance costs for the trough component of the hybrid system are assumed to be the same as for a trough-only plant as set out in **Section B.2.4.3**. Additional costs that arise from purchasing gas are discussed in **Section B.7.3**.

AECOM has assumed negligible additional costs for the maintenance of the boiler. The gas supply price also allows for operating and maintenance costs of any gas pipeline.

B.2.6.4 Major periodic maintenance costs

As per the solar only trough system, no major periodic maintenance is assumed for the gas-assisted solar trough hybrid in addition to usual power block maintenance.

B.2.6.5 Construction staging

AECOM has assumed that the additional construction required for a trough-gas hybrid plant compared to a trough only plant will occur in parallel with trough system construction without significantly increasing the total construction time for each stage. As such, the construction and decommissioning of the hybrid plant are analogous to that for the trough-only plant shown in **Table B.7** and capital costs for the trough component are set at the commencement of construction of each stage.

B.3 Electricity generation

B.3.1 Introduction

The electrical output of a solar plant is a function of the available solar resource. **Figure B.8** shows the solar resource available in NSW, and electricity and gas transmission infrastructure. Besides solar resource, area specific characteristics such as latitude, longitude, altitude, ambient temperature and wind speed, also affect the performance of the solar plant. It is therefore necessary to undertake detailed modelling to calculate energy generation for each technology at each area.

This section outlines AECOM's methodology to model electricity generated by each technology at each area.

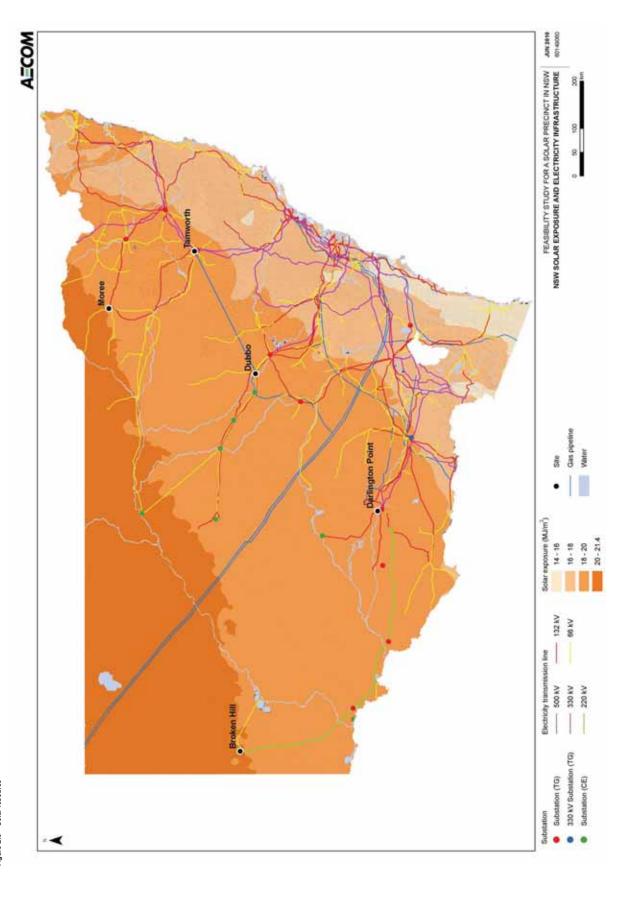
B.3.2 Data

Solar resource data is typically: measured directly using ground based instrumentation; calculated indirectly from satellite data; or by interpolation between ground measurements. To allow comparison of areas on a consistent basis, electricity generation was modelled based on 22 year averaged satellite meteorological data sourced from NASA. The NASA data included long term monthly averages for both global and diffuse solar irradiation, temperature, wind speed and albedo (reflectivity). This long term averaged data was then used to generate synthetic hourly profiles on which to conduct modelling of electricity generation.

Electricity generation was also modelled using the long term averaged BoM satellite derived solar resource data as a comparison against the NASA derived values. The results (see **Section 4.51**, **Table 4.7**) indicated that electricity generation is higher when using BoM data instead of NASA data, however the differences are not consistent between areas or technologies.

B-18

Figure B.8 Solar resource



B.3.3 Mono-crystalline and thin film PV

Electricity generation for mono-crystalline and thin film PV technologies was calculated using the PVsyst software package. PVsyst is an analysis tool developed by the University of Geneva to simulate the real world performance of solar photovoltaic systems. The tool interprets parameters set by the user and undertakes the array of calculations required to estimate energy generation of an installation over the course of a year.

The parameters used in the calculation of energy generation included the following:

- Weather data;
- Longitude and latitude;
- Elevation;
- Physical layout (panel tilt angles, spacing, cross shading, string interconnection);
- Area topography;
- External shading;
- Type and characteristics of solar panels; and
- Type and characteristics of power inverter.

The technical characteristics of the specific solar panels and power inverter selected for this study are described in **Appendix C**. Default values were assumed for energy loss from cables joining the solar panels; detailed design would determine the size of cables required to minimise energy losses.

The optimal layout of the area (the arrangement and spacing of panels and mirrors) was determined by a manual iterative process. The model assumed that the study areas are flat and that there is no external shading as a result of nearby trees or buildings. **Table B.10** presents the electricity generation for mono-crystalline and thin film PV in megawatt-hours per megawatt peak (MWh per MWp).

Table B.10 Mono-crystalline and thin film PV electricity generation (MWh per MWp)

	Broken Hill	Darlington Point	Dubbo	Moree	Tamworth
Mono-crystalline	1652	1578	1585	1684	1589
Thin film	1661	1590	1600	1694	1609

Source AECOM

B.3.4 Solar trough

The solar trough generation potential was modelled by calculating the effective beam energy on the parabolic aperture of a single axis tracking using a calculation algorithm benchmarked against published estimates for generation potential for projects in California. The calculated solar trough generation potentials were sensitivity tested at the shortlisted areas using the Solar Advisor Model (SAM) software (2009 version). Embedded within SAM is software developed by the University of Wisconsin called TRNSYS, which is a validated, time dependent algorithm that uses hourly weather data to simulate the performance of a solar trough.

The parameters used in the calculation of energy generation included the following:

- Distance between solar collector arrays (SCAs) in a row;
- Row spacing;
- Collector tilt;
- Aperture and focal length;
- Mirror reflectivity;
- Incidence angle coefficients;
- Type of heat transfer fluid; and
- Inlet/outlet temperature of the HTF.

 Table B.11 presents the electricity generation for solar trough at each area.

Table B.11 Solar trough electricity generation (MWh per MWp)

	Broken Hill	Darlington Point	Dubbo	Moree	Tamworth
Solar trough estimated generation potential figures as used in the LCoE model base case (benchmarked against					
published Californian					
project estimations)	1858	1693	1716	1927	1692
SAM Model Sensitivity 1	1943	1749	1806	2056	1782
SAM Model Sensitivity 2	777	700	722	822	713
SAM Model Sensitivity 3	2332	2099	2167	2467	2138
SAM Model Sensitivity 4	1554	1399	1445	1645	1426
SAM Model Sensitivity 5	1566	1357	1392	1675	1364
SAM Model Sensitivity 6	1921	1703	1741	2018	1687
SAM Model Sensitivity 7	1743	1530	1567	1846	1525

The model sensitivity testing does not encompass all of the factors that can impact on generation potential but clearly demonstrates the significant variation in generation potential depending on the configuration of the solar trough system and impacts of operational problems resulting in sub-optimal performance. AECOM has assumed that operational problems would be rapidly rectified and hence the low end generation potentials estimates are unlikely to be representative of the long term performance of any solar trough system.

B.3.5 Solar tower

As with solar trough, the solar tower generation potential was modelled by calculating the effective beam energy on the dual axis tracking mirrors using a calculation algorithm benchmarked against published estimates for generation potential for projects in California. The calculated solar trough generation potentials were sensitivity tested using the SAM software to model electricity generation of solar towers at each area. A 250 MW area was modelled in this analysis as two 125 MW central towers, due to a perceived capacity limit per tower of 200 MW. The 200 MW capacity limit per tower is based on construction difficulties that would arise from the tower height required, for example the RSEP 150 MW plant involves a 200m high tower.

The following system components are incorporated within the simulation:

- A field of flat, sun-tracking heliostats that focus solar radiation onto a receiver;
- A cylindrical receiver atop a tower comprised of several panels, which contain vertical heat transfer tubes;
 and
- Steam generation occurs via a heat exchanger within the power block as it drives a steam turbine to produce electricity.

An optimisation algorithm within SAM was used to design the solar field and receiver tower for each area. **Table B.12** lists the heliostat and receiver input parameters entered into SAM and **Table B.13** itemises the optimised tower and receiver parameters. The simulation results, in terms of net electricity generation per year, are presented in **Table B.14**.

Table B.12 Input parameters for 125 MW tower

Heliostat and receiver parameter	Value
Heliostat width	4 m
Heliostat height	3 m
Mirror type	rectangular
Minimum distance from tower	50 m
Maximum distance from tower	900 m
Number of evenly spaced radial zones in heliostat field	12
Mirror reflectivity and soiling	0.91
Heliostat wind stow speed	15 m/s
Heat transfer fluid	Salt (60% NaNO ₃ 40% KNO ₃)

Table B.13 Optimised tower and receiver outputs for 125 MW tower

Output Parameters	Value
Height per tower	164 m
Receiver height	20 m
Receiver diameter	25 m
Number of heliostats	70,600

Source AECOM

Table B.14 Solar tower electricity generation (MWh per MWp)

	Broken Hill	Darlington Point	Dubbo	Moree	Tamworth
Solar tower estimated generation potential figures as used in the LCoE model base case (benchmarked against published Californian project estimations)	2261	2085	2097	2334	2058
SAM Model Sensitivity 1	1720	1533	1550	1837	1582
SAM Model Sensitivity 2			2284	2156	2008
SAM Model Sensitivity 3	1529	1328	1356	1727	1421
SAM Model Sensitivity 4	1820	1628	1646	1945	1678

Source AECOM

The model sensitivity testing does not encompass all of the factors that can impact on generation potential but clearly demonstrates the significant variation in generation potential depending on the configuration of the solar tower system, incorporation of thermal storage and impacts of operational problems resulting in sub-optimal performance.

B.3.6 Gas-assisted solar trough hybrid

As discussed in **Section B.1.4** this study assumed a gas-assisted solar trough hybrid, following the NSW National Electricity Market (NEM) profile constrained between 7am and 8pm. The trough generation is assumed to be the same as for the independent solar trough as shown in **Section B.3.4**, with gas generation producing the remainder of the energy required for load following. **Table B.15** summarises the estimated electricity generation for 250 MW and 1,000 MW plants.

Table B.15 Gas-assisted solar hybrid electricity generation

	Broken Hill	Darlington Point	Dubbo	Moree	Tamworth
250 MW					
Solar generation (MWh/MWp)	1858	1693	1716	1927	1692
Gas generation (MWh/MWp)	1652	1817	1794	1583	1818
Total hybrid (MWh/MWp)	3510	3510	3510	3510	3510
Annual gas demand (GJ/MWh)	12.7	12.7	12.7	12.7	12.7
Boiler Efficiency	28.4%	28.4%	28.4%	28.4%	28.4%
Percentage of Solar	53%	48%	49%	55%	48%
1,000 MW					
Solar generation (MWh/MWp)	1858	1693	1716	1927	1692
Gas generation (MWh/MWp)	1652	1817	1794	1583	1818
Total hybrid (MWh/MWp)	3510	3510	3510	3510	3510
Annual gas demand (GJ/MWh)	12.7	12.7	12.7	12.7	12.7
Boiler Efficiency	28.4%	28.4%	28.4%	28.4%	28.4%
Percentage of Solar	53%	48%	49%	55%	48%

B.3.7 Sensitivity

The modelled electrical output of each technology at each area is dependent on three main factors:

- Weather data:
- Modelling technique (software application), and
- System design

A high level sensitivity analysis was conducted on each of the above factors for selected technologies to provide a sense check on the estimated electrical output.

B.3.7.1 Weather data

Given that the electrical output is dependent on the quantity of solar energy available at the area, the modelling for solar generation potential was also calculated using BoM long term averaged global solar resource, temperature and wind data. The results (see **Section 4.51**, **Table 4.7**) illustrate that there are differences between the solar data sets and that these differences are not consistent between areas. The results also illustrate the non-linear sensitivity of the generation potential for the different solar technologies to changes in the solar resource.

B.3.7.2 Modelling technique

The PVsyst software's solar tracking algorithm was used to calculate the effective beam component of the solar resource incident on the solar thermal plants concentrating mirrors. Calculation algorithms benchmarked against published estimates for Californian solar projects were developed to estimate the solar thermal generation potential at the different areas based on the differences in beam solar energy available for concentration. The SAM software was used to sensitivity test how these estimated generation potentials vary with different system configurations and changes to parameters. The modelling tests illustrated that the solar thermal systems' generation potentials are very sensitive to configuration and that performance drops significantly when the plant experiences operational impacts that result in sub-optimal performance (See **Table B.11** and **Table B.14**).

B.3.7.3 System design

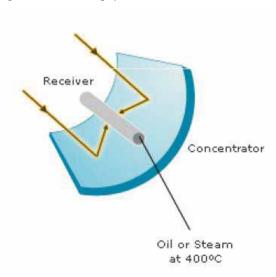
Changes in generation potential associated with Photovoltaic layout tilt angle and row spacing were investigated in order to derive a generic layout suitable for comparing areas on a common basis. The following expanded scale graph illustrates the estimated mono-crystalline PV generation potential for various tilt angles and row spacing's for Moree. As the solar panels are arranged more closely together, distinct step changes in generation potential arise with small changes in tilt angle as a result of string shading where one row of solar panel shades the row behind. The layout chosen has approximately 3% loss in generation potential compared to an ideal system that does not experience any inter-row shading. Other shading influences (such as hills, power lines, buildings and trees) can have a dramatic impact on the performance of solar PV arrays although individual shading sources may be less significant when the impacts are averaged across a large PV array. This study assumed that the PV arrays are installed in flat regions with no external shading factors

Moree - sensitivity of yield to changes in tilt angle and array footprint -infinate (no 1740 shading) 1730 **−**25,077 m2 1720 **−**17,221 m2 1710 **★**13,293 m2 1700 1690 →12,311 m2 1680 **11,329 m2 1670 **−**10,347 m2 1660 ─-8,972 m2 1650 tilt angle 14 19 24 29 34

Figure B.9 Sensitivity of mono-crystalline PV yield to changes in tilt angle at Moree

For the solar trough, the design parameters such as row spacing, mirror reflectivity and heat transfer fluid variables were modified and resulted in percentage changes in energy generation in the order of $\pm 10\%$. The sensitivity testing indicates that solar trough electricity generation can be very sensitive to the incidence angle coefficients of the heat collection element. This is due to the parabolic shape of the trough that makes sun tracking more challenging as illustrated in **Figure B.10** (as opposed to the flat panels used in a solar tower plant). This shows that the system requires detailed design, precise alignment and adjustment for the light to converge properly towards the receiver for effective solar concentration such that the maximum amount of energy is absorbed.





Source Meyer, R. (2009)

Solar tower design parameters that were changed included tower height, heliostat variables, heat transfer fluid variables and mirror reflectivity and soiling. The sensitivity testing indicated that solar tower electricity generation may vary by approximately ±10% depending on which parameter is changed. Tower electricity generation is most

sensitive to changes in mirror reflectivity and soiling, with a reduction of mirror reflectivity from 91% to 70% causing electricity generation to fall by 25%.

In order to validate the design metrics produced from this approach, both of the proposed tower sites in California (RSEP and ISEGS) were first simulated in SAM. The tower height, receiver height and diameter, heliostat footprint and net electricity output for both the RSEP 150 MW site and the ISEGS 200 MW site were compared against the data presented in their respective "Application for Certification' documents; good agreement between the data sets and the SAM modelling was produced.

B.3.8 Summary

Electricity generation was estimated for each technology at each area in units of MWh per MWp per year, where MWp is the power rating of solar panel under standard test conditions. Figure B.11 and Table B.16 compare energy generation (MWh / MWp / year) between each of the five areas and the different technologies. The figure illustrates that of the areas considered, Moree has the highest electricity generation potential, followed by Broken Hill, whilst Darlington Point, Dubbo and Tamworth produce similar levels of electricity per MWp. The areas have different resource characteristics, in particular, differences in the ambient temperature and direct normal irradiation significantly influence the performance of the various technologies between areas. Solar thermal technologies rely on solar concentration to operate and hence their performance significantly improves in areas with high levels of direct irradiation such as Moree and Broken Hill. Although the solar resource is greater at Moree and Broken Hill relative to Darlington Point, Dubbo and Tamworth, the higher ambient and operating temperature affects the efficiency of solar PV panels such that there is only a relatively small improvement in their performance at these areas compared to the performance change with the solar thermal technologies.(see Appendix C)..

Table B.16 Summary of generation (MWh / MWp)

Technology	Broken Hill	Darlington Point	Dubbo	Moree	Tamworth
Mono-crystalline PV	1,652	1,578	1,585	1,684	1,589
Thin film PV	1,661	1,590	1,600	1,694	1,609
Solar trough (air)	1,858	1,693	1,716	1,927	1,692
Solar tower (air)	2,261	2,085	2,097	2,334	2,058
Hybrid					
Solar generation	1,858	1,693	1,716	1,927	1,692
Gas generation (250 MW)	1,652	1,817	1,794	1,583	1,818
Gas generation (1,000 MW)	1,652	1,817	1,794	1,583	1,818

Source AECOM

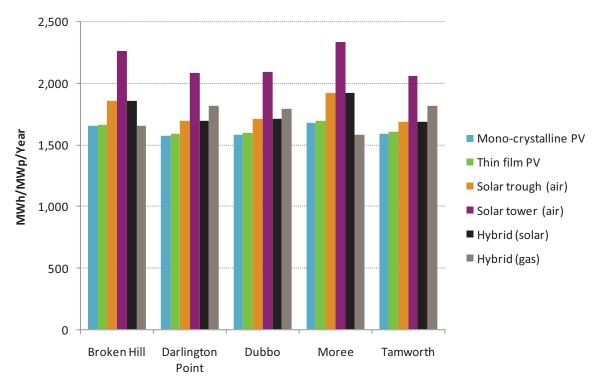


Figure B.11 Energy generation by area and by technology

B.3.8.1 Recommendations

The generation potential of the solar plant is sensitive to the long term solar resource. There are limitations with the solar resource data sets available and there is some discrepancy between the NASA and BoM satellite data sources and further discrepancy between satellite and ground based solar data sets assessed in this study. Hence the magnitude of the global, direct and diffuse components of the solar resource at the areas are subject to some uncertainty. Once a preferred site for a precinct is identified, it is recommended that suitably calibrated instruments for measuring meteorological data and the global, direct, diffuse and albedo optical components of the solar resource be established at the site to facilitate the technology selection and technical design of the plant. Precinct site-specific high quality solar data sets will reduce project development gestation time, facilitate improved investor confidence in the project, and may result in more favourable financing terms and conditions thereby reducing the levelised cost of electricity.

B.4 Connection to the electricity network

B.4.1 Introduction

Connection of a solar precinct of 250 MW or greater capacity is likely to require nearby transmission infrastructure to be upgraded or new infrastructure to be constructed, incurring a cost that depends on:

- Distance from the precinct to the nearest transmission line;
- Voltage rating of the line;
- Construction of a new substation; and
- Connection directly to an existing substation (if possible).

Constructing the solar precinct relatively close to existing high voltage transmission lines or substations would reduce the extent of transmission upgrading required and therefore improve precinct feasibility. **Figure B.8** shows the location and voltage of transmission and distribution lines, and the location of selected substations.

In addition to technical transmission issues, there are also regulatory issues to consider given the size of the precinct.

Note for simplicity in the following discussion the term "substation" will be used interchangeably for both substations that provide supply at lower voltages via transformers and high voltage switching stations that connect circuits at the same voltage without transformers.

B.4.2 Transmission costs at each area

B.4.2.1 Connections

Generally the most cost-effective option for a new connection is to take advantage of existing infrastructure by extending an existing substation. To connect directly from the plant to a transmission line requires a new switching station to be constructed. There are large fixed costs with a substation such as area earthworks, roads, control buildings and telecommunications that need to be established, along with the switchgear bays.

Early analysis revealed that the most efficient connection voltages were 330 kV for up to 1,000 MW or 220 kV (where available) for up to 250 MW only.

Connections at 132 kV were comparable in cost to 220 kV and 330 kV for 250 MW connections over short distances, but would require more substation plant and multiple transmission lines at higher ratings, making it uneconomic. 330 kV is able to deliver power at greater distances with fewer losses compared to 132 kV and 220 kV, making it the preferred technical solution.

In order to test the impact of a precinct, this study has considered construction and connection of transmission infrastructure to cater for 250 MW modules to match the construction build-out identified in **Appendix B.2**, including:

- Standalone 250 MW installation;
- Single stage delivery of transmission infrastructure sufficient for 1,000 MW;
- Planned 1,000 MW precinct with four stage delivery of transmission infrastructure; and
- Incremental expansion of for initial 250 MW plant followed by additional 750 MW delivered over total of 4 stages (not initially planned for total 1,000 MW).

B.4.2.2 Redundancy

The electricity rules do not require network redundancy for connection of solar generation as it is classified as "Intermittent generation". The cost of the transmission connections in this study have therefore been made as low as possible by using single circuits only with no redundancy. This means however, that a single fault or planned maintenance on the transmission line or associated plant would disconnect generation for the duration of the outage. Additional circuits would provide greater security and increased ability to deliver energy to the market, at the cost of increased capital expenditure.

B.4.2.3 Deep System Constraints and Costs

Connecting new generation into the grid will alter power flows and potentially create generation and load constraints, either for the new generator or other generators and consumers in the market. The exact nature and

effect of these constraints can only be predicted by sophisticated load flow modelling and simulation of market behaviour, and is beyond the scope of this report.

In particular, TransGrid have advised that deep system constraints would be expected to occur for 1,000 MW connections to the western extremities of the grid (e.g. Darlington Point) - although the impact would be reduced if the proposed Transgrid SA-NSW "SNI" (Central Route) Interconnector goes ahead. There is also the possibility of deep system constraints for connections elsewhere on the network, although the impact to the 500 kV network is likely to be less severe.

Deep system constraints might typically be ameliorated by transmission line and/or plant upgrades. Under the current electricity market rules the generation proponent would need to pay the costs of deep system upgrades required as a result of its connection.

The connection costs developed in this study only consider the direct costs of connection to the TransGrid network, specifically lines, substation extensions and minor local upgrades. Deep system costs are not included.

B.4.2.4 220 kV connections west of Darlington Point

There is an existing 220 kV transmission line connecting Broken Hill to Darlington Point via Buronga and Balranald. This line is currently rated for 381 MVA from Darlington Point to Buronga and 95 MVA from Buronga to Broken Hill, as limited by existing substation plant ratings. TransGrid have advised that upgrading certain plant would enable the Buronga to Broken Hill section to be rated at 400 MVA.

Installations of 250 MW are therefore able to be connected at 220 kV line directly to Balranald and Buronga, or to Broken Hill with some plant upgrades. This is significantly cheaper than building a 330 kV transmission line for a connection of 250 MW to Darlington Point.

Connections at 220 kV were costed for 250 MW installations to Broken Hill, Balranald and Buronga, a standard connection comprising:

- A step-up transformer and 220 kV circuit breaker at the generator;
- A single circuit 220 kV transmission line from the generator to the nearest Transgrid 220 kV substation; and
- A single bay extension of the existing 220 kV TransGrid substation.

Connections of 500 MW and above would require a new 330 kV transmission line to Darlington Point due to rating limits of the existing 220 kV line.

If building the generation in stages (for an ultimate planned development of up to 1,000 MW) it may be most efficient to build a full capacity 330 kV line for the first stage rather than a connecting at 220 kV and then having to build an additional 330kV connection later.

B.4.2.5 330 kV connections

For all areas not in the vicinity of 220 kV the preferred connection voltage is at 330 kV. Connections would be made either directly into an existing TransGrid substation, or by connecting to an existing 330 kV line by establishing a new 330 kV substation at the point of connection. A standard TransGrid 330 kV single circuit line has a rating of 1280 MVA, and is therefore suitable for connections of up to 1,000 MW.

A standard 250 MW connection to an existing 330 kV substation would comprise:

- A step-up transformer and 330 kV circuit breaker at the generator;
- A single circuit 330 kV transmission line from the generator to the nearest TransGrid 330 kV substation; and
- A single bay extension of the existing 330 kV TransGrid substation.

A standard 250 MW connection to an existing 330 kV line would comprise:

- A step-up transformer and 330 kV circuit breaker at the generator;
- A single circuit 330 kV transmission line from the generator to the nearest TransGrid 330 kV line; and
- Establishment of a new 330 kV switching yard laid out for breaker and a half with two diameters and three 330 kV circuit breakers.

A standard 1,000 MW connection to an existing 330 kV substation would comprise:

- Four step-up transformers and a single 330 kV circuit breaker at the generator;
- A single circuit 330 kV transmission line from the generator to the nearest TransGrid 330 kV substation; and

A single bay extension of the existing 330 kV TransGrid substation.

A standard 1,000 MW connection to an existing 330 kV line would comprise:

- Four step-up transformers and a single 330 kV circuit breaker at the generator;
- A single circuit 330 kV transmission line from the generator to the nearest TransGrid 330 kV substation; and
- Establishment of a new 330 kV switching yard laid out for breaker and a half with two diameters and three 330 kV circuit breakers.

B.4.2.6 Connection pricing

Standardised connection options were developed for connection of both 250 MW and 1000 MW generation to lines and substations at 220 kV and 330 kV. These options were broken into modular components and costed as follows:

- Generator transformers and circuit breakers;
- Transmission lines, per km;
- New substations for connection to existing transmission lines; and
- Extensions to existing substations.

Base component cost assumptions are presented in **Appendix D**. The component assumptions used to develop cost estimates for a 250 MW plant and 1,000 MW precinct under different construction staging scenarios are summarised in **Table B.17**, **Table B.18**, **Table B.19** and **Table B.20**.

An assessment of feasible connection options was made for each area based on published Australian Energy Market Operator (AEMO) line ratings and typical line and substation equipment ratings at 132 kV, 220 kV and 330 kV. For each feasible option a connection estimate was built up using component costs as above.

The following general assumptions were made:

- Power factor of generation is 0.9, so each 250 MW connection requires 280 MVA (rounded up) capacity in lines and transformers;
- TransGrid line from Buronga to Broken Hill has 400 MVA capacity after local substation plant upgrades;
- TransGrid 220 kV lines connecting Buronga, Balranald and Darlington Point has at least 280 MVA capacity;
- Country Energy 132kV networks west of Armidale and Wellington do not have 280 MVA capacity.

A location cost adjustment of an additional 20% was applied to Broken Hill to allow for higher costs of construction in this remote area.

At the 1,000 MW scale, AECOM has considered both single stage and a four-stage construction for the generation component. Only a single stage of major construction was costed for the transmission infrastructure at 330 kV, since the standard single circuit 330 kV transmission line and substation plant can accommodate the full 1,000 MW. Minor protection and control modifications for each stage as the load increases have been allowed for.

This study assumed that the construction of transmission infrastructure for the four-stage 1,000 MW precinct occurs in years 1, 3, 5 and 7.

Figure B.12 presents transmission costs on a per watt basis for a 250 MW plant and a 1,000 MW precinct under different staging scenarios. The comparison shows that there can be significant economies of scale when increasing capacity from 250 MW to 1,000 MW. For example the transmission cost for 250 MW at Moree is \$0.55 per watt; this more than halves to \$0.15 per watt for 1,000 MW. The cost per watt increases for Broken Hill because current infrastructure is sufficient for a 250 MW plant but would require significant upgrades for a 1,000 MW precinct.

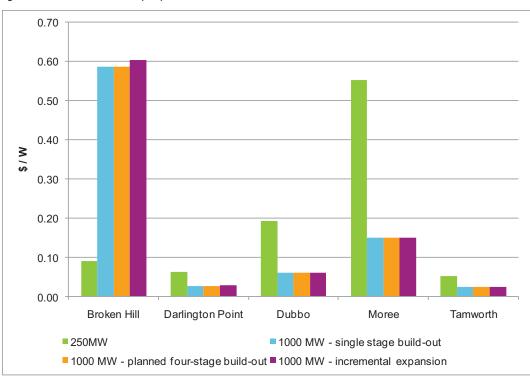


Figure B.12 Transmission cost (\$/W)

Table B.21, **Table B.22**, **Table B.23** and **Table B.24** summarise the cost of connection for a 250 MW plant and 1,000 MW precinct under different construction staging scenarios. Note these costs are to provide an order of magnitude for the purposes of comparing sites and more detailed analysis would be required to determine actual costs.

Transmission costs are categorised as either a cost to TransGrid or the generation proponent. Costs of establishing or upgrading a substation at the plant or precinct are faced by the generation proponent. TransGrid costs are further separated into costs associated with transmission lines, substation civil works, substation plant and equipment, and other local system upgrade costs.

The total connection costs range from \$13m in Tamworth to \$138m in Moree for a 250 MW plant. For a 1,000 MW precinct, the total magnitude of connection costs for the two four-stage construction scenarios are similar to that of the single stage construction scenario.

Under the planned four-stage scenario, the first stage cost for each area is similar to that of the standalone 250 MW plant, except in the case of Broken Hill. This is because the transmission infrastructure at these areas must be upgraded to accommodate the introduction of 250 MW, whether as a standalone plant or the first 250 MW of a 1,000 MW precinct. However for Broken Hill, the existing infrastructure is of sufficient capacity for 250 MW and therefore requires minimal upgrade, but to accommodate a future total of 1,000 MW, significant upgrades in the order of \$570m are required.

The magnitude and timing of costs are similar when comparing the planned and incremental four-stage scenarios, except in the case of Broken Hill. As noted above, the other four areas require infrastructure upgrades to accommodate 250 MW of capacity and therefore costs and timing are similar. For Broken Hill, as the total 1,000 MW is not planned, the connection costs for the first 250 MW are the same as for the standalone 250 MW plant. If additional 250 MW plants are to be connected at Broken Hill, then the substantial \$570m upgrade costs are incurred as the existing capacity has already been used by the first 250 MW plant.

AECOM has assumed the planned four-stage transmission staging scenario as the base case for the 1,000 MW precinct.

Table B.17 Transmission assumptions for a 250 MW plant

		Connection Type	ype		Com	Components		Adjustments	Distances	nces
Aros		Connect to sub,	Connect at		Generator		Sub or line	Location		
7169	Connection	Connection 330, 220 or 132 kV			connection		connection	Cost	Substation	330 kV Line
	Voltage (kV)	line		Line type	type	Civil works	type	Multiplier	(km)	(km)
Broken Hill	220	qns	Broken Hill sub	9.3	1.1	5.1	6.1	1.2	10.0	521.8
Darlington Point	330	qns	Darlington Point sub	9.1	1.1	2.1	3.1	1.0	9.5	9.5
Dubbo	330	330	Wellington sub	9.1	1.1	2.1	3.1	1.0	4.0	46.0
Moree	330	330	Armidale - Dumaresq line	9.1	1.1	2.3	3.3	1.0	0.0	138.1
Tamworth	330	gns	Tamworth sub	9.1	1.1	2.1	3.1	1.0	6.7	4.7

AECOM Source

Table B.18 Transmission assumptions for a 1,000 MW plant – single stage construction

		Connection Type	ype		Con	Components		Adjustments	Distances	nces
Area		Connect to sub,	Connect at		Generator		Sub or line	Location		
2017	Connection	Connection 330, 220 or 132 kV			connection		connection	Cost	Substation	330 kV Line
	Voltage (kV)	line		Line type	type	Civil works	type	Multiplier	(km)	(km)
Broken Hill	330	sub	Darlington Point sub	9.1	1.4	2.1	3.1	1.2	521.0	0.0
Darlington Point	330	sub	Darlington Point sub	9.1	1.4	2.1	3.1	1.0	9.5	0.0
Dubbo	330	sub	Wellington sub	9.1	1.4	2.1	3.1	1.0	46.0	0.0
Moree	330	330	Armidale - Dumaresq line	9.1	1.4	2.3	3.3	1.0	0.0	138.1
Tamworth	330	qns	Tamworth sub	9.1	4.	2.1	3.1	1.0	6.7	4.7

AECOM Source B-30

Table B.19 Transmission assumptions for a 1,000 MW plant - planned four stage construction

		Connection Type	Туре		Components	onents		Adjustments	Distances	ıces
Area / Stage	noitonno O	Connect to sub,	Connect at		Generator		Sub or line	Location		220 IVV 1 inc
	Voltage (kV)	550, 220 of 152 KV line		Line type	type	Civil works	type	Multiplier	Substation (km)	(km)
Broken Hill								•		,
_	330	qns	Darlington Point sub	9.1	1.1	2.1	3.1	1.2	521.0	0.0
2	330	gns	Darlington Point sub	Nil	1.2	ΙΞ	Z	1.2	521.0	0.0
3	330	gns	Darlington Point sub	Nil	1.2	ΙΞ	Z	1.2	521.0	0.0
4	330	qns	Darlington Point sub	Nil	1.2	ΙΪΖ	Nii	1.2	521.0	0.0
Darlington Point										
1	330	qns	Darlington Point sub	9.1	1.1	2.1	3.1	1.0	9.5	0
2	330	qns	Darlington Point sub	Nil	1.2	Nii	Nii	1.0	9.5	0
3	330	qns	Darlington Point sub	Nil	1.2	Nii	Nii	1.0	9.5	0
4	330	qns	Darlington Point sub	Nil	1.2	Nii	Nii	1.0	9.5	0
Dubbo										
1	330	gns	Wellington sub	9.1	1.1	2.1	3.1	1.0	46.0	0.0
2	330	qns	Wellington sub	ΙΞ̈́	1.2	Ē	Ē	1.0	46.0	0.0
3	330	sub	Wellington sub	Nil	1.2	ΙΞ	Z	1.0	46.0	0.0
4	330	gns	Wellington sub	Nil	1.2	Ξ	Z	1.0	46.0	0.0
Moree										
1	330	330	Armidale - Dumaresq line	9.1	1.1	2.3	3.3	1.0	0.0	138.1
2	330	qns	New sub	ΙΞ̈́	1.2	Ē	Ē	1.0	0.0	138.1
3	330	sub	New sub	Nil	1.2	ΙΞ	Z	1.0	0.0	138.1
4	330	sub	New sub	Nil	1.2	ΙΞ	Z	1.0	0.0	138.1
Tamworth										
_	330	qns	Tamworth sub	9.1	1.1	2.1	3.1	1.0	6.7	4.7
2	330	qns	Tamworth sub	ΙΞ̈́	1.2	Ē	Ē	1.0	6.7	4.7
3	330	qns	Tamworth sub	ΙΞ̈́	1.2	Ē	Ē	1.0	6.7	4.7
4	330	qns	Tamworth sub	ΙΞ̈́	1.2	Ē	Ē	1.0	6.7	4.7

17 December 2010

B-31

Pre-Feasibility Study for a Solar Power Precinct

Table B.20 Transmission assumptions for a 1,000 MW plant – four stage construction not initially planned for expansion

AECOM

		Connection Type	ype		Components	nents		Adjustments	Distances	seou
Area / Stage	Connection	330, 220 or 132	Connect at		Generator		Sub or line connection	Location Cost	Substation	330 kV Line
Broken Hill	voitage (KV)	KV IIIIE		Line type	type	CIVII WOLKS	type	munipher	(KIII)	(KIII)
_	220	qns	Broken Hill sub	9.3	1.1	5.1	6.1	1.2	10.0	521.8
2	330	qns	Darlington Point sub	9.1	1.1	2.1	3.1	1.2	521.0	0.0
3	330	qns	Darlington Point sub	Ξ̈	1.2	ij	ΞÏΖ	1.2	521.0	0.0
4	330	qns	Darlington Point sub	Ξ̈	1.2	ij	ΞÏΖ	1.2	521.0	0.0
Darlington										
-	330	qns	Darlington Point sub	9.1	1.	2.1	3.1	1.0	9.5	9.5
2	330	qns	Darlington Point sub	Ē	1.2	Ē	Ξ	1.0	9.5	0.0
8	330	qns	Darlington Point sub	Ξ̈	1.2	Ē	īŽ	1.0	9.5	0.0
4	330	qns	Darlington Point sub	Ξ̈	1.2	Ē	īŽ	1.0	9.5	0.0
Dubbo										
_	330	330	Wellington sub	9.1	1.1	2.1	3.1	1.0	4.0	46.0
2	330	qns	Wellington sub	Ξ̈́Z	1.2	ij	ΞÏΖ	1.0	46.0	0.0
3	330	qns	Wellington sub	Nii	1.2	Nii	Nil	1.0	46.0	0.0
4	330	qns	Wellington sub	Nii	1.2	Nii	Nii	1.0	46.0	0.0
Moree										
_	330	330	Armidale - Dumaresq line	9.1	1.1	2.3	3.3	1.0	0.0	138.1
2	330	qns	New sub	Nii	1.2	Nii	Nii	1.0	0.0	138.1
3	330	qns	New sub	Nii	1.2	Nii	Nii	1.0	0.0	138.1
4	330	qns	New sub	Nii	1.2	Nii	Nii	1.0	0.0	138.1
Tamworth										
1	330	qns	Tamworth sub	9.1	1.1	2.1	3.1	1.0	6.7	4.7
2	330	qns	Tamworth sub	Nii	1.2	Nii	Nii	1.0	6.7	4.7
3	330	qns	Tamworth sub	Ē	1.2	ΙΞ	ΙΞ̈́	1.0	6.7	4.7
4	330	qns	Tamworth sub	Ē	1.2	ΙΞ	ΙΞ̈́	1.0	6.7	4.7
MODEV	MO									

Source AECOM

17 December 2010

Table B.21 Transmission costs for a 250 MW plant

	Description	Substation Cost (\$'000)	TransGrid Line Cost (\$'000)	TransGrid Subs Civil Cost (\$'000)	Subs Plant Cost (\$'000)	Local System Upgrade Costs (\$'000)	(\$,000)
Broken Hill TransG	220 kV connection to sub at Broken Hill. Local TransGrid plant upgrade required to allow line rating	((6
of 400 MVA	MVA	6,000	9,600	480	1,560	2,000	22,640
Darlington Point 330 kV	330 kV connection to Darlington point substation	5,000	8,588	500	1,500	,	15,588
Dubbo 330 kV	330 kV connection to Wellington	5,000	41,363	500	1,500	-	48,363
330 KV	330 kV connection by building a new 330 kV						
Moree substai	substation on the 330 kV lines between Armidale and						
Dumaresq	esq	5,000	124,268	3,000	6,000	-	138,268
Tamworth 330 kV	330 kV connection to Tamworth substation	5,000	5,990	500	1,500	1	12,990

TransGrid local system upgrade costs are an allowance for minor changes to current transformer ratios an associated meter and relay settings. Note

Source AECOM

Table B.22 Transmission costs for a 1,000 MW plant - single stage construction

Area / Stage	Description	Generator Substation Cost (\$'000)	TransGrid Line Cost (\$'000)	TransGrid Subs Civil Cost (\$'000)	TransGrid Subs Plant Cost (\$'000)	TransGrid Local System Upgrade Costs (\$'000)	TOTAL (\$'000)
Broken Hill	330 kV connection to Darlington point substation	20,400	562,680	009	1,800		585,480
Darlington Point	330 kV connection to Darlington point substation	17,000	8,550	200	1,500	-	27,550
Dubbo	330 kV connection to Wellington substation	17,000	41,363	009	1,500		60,363
Moree	330 kV connection by building a new 330 kV substation on the 330 kV lines between Armidale and						
	Dumaresq	17,000	124,268	3,000	6,000	-	150,268
Tamworth	330 kV connection to Tamworth substation	17,000	2,990	009	1,500	•	24,990

TransGrid local system upgrade costs are an allowance for minor changes to current transformer ratios an associated meter and relay settings. Note

Source AECOM

B-33

Pre-Feasibility Study for a Solar Power Precinct

AECOM

Table B.23 Transmission costs for a 1,000 MW plant - planned four stage construction

Area / Stage	Description	Generator Substation Cost (\$'000)	TransGrid Line Cost (\$'000)	TransGrid Subs Civil Cost (\$'000)	TransGrid Subs Plant Cost (\$'000)	TransGrid Local System Upgrade Costs (\$'000)	TOTAL (\$'000)
Broken Hill							
_	330 kV connection to Darlington point substation	6,000	562,680	009	1,800	1	571,080
2	330 kV connection to Darlington point substation	4,800	-	-	-	20	4,820
3	330 kV connection to Darlington point substation	4,800	-	-	-	20	4,820
4	330 kV connection to Darlington point substation	4,800	-	-	-	20	4,820
Darlington Point							
1	330 kV connection to Darlington point substation	5,000	8,550	200	1,500	-	15,550
2	132 kV connection to Darlington point substation	4,000	_	-	-	20	4,020
3	132 kV connection to Darlington point substation	4,000	_	_	-	20	4,020
4	132 kV connection to Darlington point substation	4,000	_	_	-	20	4,020
Dubbo							
1	330 kV connection to Wellington substation	5,000	41,363	500	1,500	-	48,363
2	330 kV connection to Wellington	4,000	_	-	-	20	4,020
3	330 kV connection to Wellington	4,000	_	_	-	20	4,020
4	330 kV connection to Wellington	4,000	_	_	-	20	4,020
Moree							
7	330 kV connection by building a new 330 kV substation on the 330 kV lines						
-	between Armidale and Dumaresq	5,000	124,268	3,000	6,000	-	138,268
2	330 kV connection to new substation from Stage 1on Armidale-Dumaresq line	4,000	_	-	-	20	4,020
3	330 kV connection to new substation from Stage 1on Armidale-Dumaresq line	4,000	_	-	-	20	4,020
4	330 kV connection to new substation from Stage 1on Armidale-Dumaresq line	4,000	_	-	-	20	4,020
Tamworth							
1	330 kV connection to Tamworth substation	5,000	5,990	500	1,500	-	12,990
2	330 kV connection to Tamworth substation	4,000	_	-	-	20	4,020
3	330 kV connection to Tamworth substation	4,000	-	-	-	20	4,020
4	330 kV connection to Tamworth substation	4,000				20	4,020

TransGrid local system upgrade costs are an allowance for minor changes to current transformer ratios an associated meter and relay settings.

Source AECOM

17 December 2010

AECOM

Table B.24 Transmission costs for a 1,000 MW plant -incremental four stage construction not initially planned for expansion

Area / Stage	Description	Generator Substation Cost (\$'000)	TransGrid Line Cost (\$'000)	TransGrid Subs Civil Cost (\$'000)	TransGrid Subs Plant Cost(\$'000)	TransGrid Local System Upgrade Costs(\$'000)	TOTAL (\$'000)
Broken Hill							
1	220 kV connection to sub at Broken Hill. Local TransGrid plant upgrade	000	0 600	Uav	1 560	000	22,640
2	330 IV connection to Darlington point substation	6,000	562 680	600	1,800	50,0	571 080
7	SOON V CONTINCATION TO DAILINGTON POINT SUBStation	0,000	302,000		000,	- 8	000,170
m •	330 KV connection to Darlington point substation	4,800				20	4,820
4	330 kV connection to Darlington point substation	4,800			-	20	4,820
Darlington Point							
1	330 kV connection to Darlington point substation	5,000	8,588	200	1,500		15,588
2	132 kV connection to Darlington point substation	4,000	_	-	_	20	4,020
3	132 kV connection to Darlington point substation	4,000	-	-	-	20	4,020
4	132 kV connection to Darlington point substation	4,000		-	-	20	4,020
Dubbo							
1	330 kV connection to Wellington	5,000	41,363	200	1,500	-	48,363
2	330 kV connection to Wellington	4,000	-	-	-	20	4,020
3	330 kV connection to Wellington	4,000	-	-	-	20	4,020
4	330 kV connection to Wellington	4,000	-	-	-	20	4,020
Moree							
.	330 kV connection by building a new 330 kV substation on the 330 kV lines						
_	between Armidale and Dumaresq	5,000	124,268	3,000	6,000		138,268
2	330 kV connection to new substation from Stage 1on Amidale-Dumaresq line	4,000		ı	1	20	4,020
3	330 kV connection to new substation from Stage 1on Armidale-Dumaresq line	4,000	-	-	_	20	4,020
4	330 kV connection to new substation from Stage 1on Amidale-Dumaresq line	4,000	-	•	-	20	4,020
Tamworth							
1	330 kV connection to Tamworth substation	5,000	5,990	200	1,500	-	12,990
2	330 kV connection to Tamworth substation	4,000	-	-	_	20	4,020
3	330 kV connection to Tamworth substation	4,000		ı	1	20	4,020
4	330 kV connection to Tamworth substation	4,000	-	1	-	20	4,020

TransGrid local system upgrade costs are an allowance for minor changes to current transformer ratios an associated meter and relay settings.

Source AECOM

17 December 2010

B.4.3 Regulatory issues

Three challenges dominate the task of integrating large scale renewable energy into the power system:

- Allocation of the cost and risk of grid extensions;
- Accommodation of intermittent renewable generation; and
- Achieving technical compliance under the National Electricity Rules (NER).

Addressing these challenges will assist in the penetration of solar generation into the electricity supply market.

B.4.3.1 Scale Efficient Network Extensions

Under the current National Electricity Rules (Rules), any extension or strengthening of the existing network needed to connect to any new sources of generation (dispatchable or intermittent) must be fully funded by the generation proponent. The cost of this extension or strengthening of the network to connect generation in remote locations, which offer high yield renewable energy sources, may render the generation project unviable.

The proposed Rule change "Scale Efficient Network Extension" (SENE) is intended to address this challenge by sharing the cost of connection between the first and subsequent proponents in a particular region. SENE would help to reduce economic barriers for initial development and connection of large scale solar generation, by providing a mechanism for the regulated customer base to underwrite the cost, and therefore reduce the risk of transmission extensions.

B.4.3.2 Intermittent renewable generation

Renewable energy generation such as solar and wind power stations are presently regarded by the market rules as non-dispatchable because they have limited or no energy storage capability and cannot be relied on individually to contribute to the secure supply of electricity. The energy conversion system used in solar thermal is a conventional generator and therefore technical compliance is not a problem under the Rules.

Currently solar power would normally be designated as intermittent generation by type under the Rules. There are no mechanisms for re-designating solar and other renewable generation as conventional dispatchable generation because the Rules lack a definition of intermittency and designate intermittent generators solely by type.

B.4.3.3 Technical compliance

The accommodation of wind farms into the electricity system may aid the acceptance of the technical characteristics of other types of renewable energy including solar, as the amount of wind capacity increases to meet Large-scale Renewable Energy Target requirements.

B.5 Land

B.5.1 Introduction

Generation at a scale as large as a solar precinct requires significant areas of land to harvest solar energy. Other land factors such as gradient and aspect must also be considered as they influence generation output.

The amount of land required varies between the different solar technologies. Solar PV land area can be as low as 1 hectare per MW for mono-crystalline, rising to 3.5 hectares per MW for thin film PV. Solar thermal plants typically require between 2 to 6 hectares of flat land per MW depending on specific technology type and configuration.

The yield from solar panels improves as land area increases and shading effects are minimised. However the capital cost of the plant then escalates due to the greater land, cabling and trenching requirements. Photovoltaic technologies are less sensitive to gradient and can actually benefit from a north-facing slope. On the other hand, solar trough, for example, has very stringent gradient requirements.

This chapter presents assumptions for land requirements for each technology and discusses gradient issues at each of the five selected areas.

B.5.2 Technology requirements

The following section discusses land requirements for each technology. Land area assumptions are summarised in **Table B.25**.

B.5.2.1 Mono-crystalline PV

This study assumes a land requirement of 1.03 hectares per MWp based on a vehicular access track of 2.5m between rows of solar panels. Narrower access tracks may be achievable however shading effects become increasingly significant and there would be limited space for the doors of standard vehicles to be opened and closed.

Photovoltaic technology is significantly less stringent in its land gradient requirements compared to solar thermal technologies. A variety of mounting frames are available for photovoltaic technology, and mounting frames can be selected to suit the terrain. In some instances a (north facing) slope may be beneficial for a photovoltaic technology, by reducing cross shading between rows of solar panels. Arrays can be terraced or designed to follow the local topography. **Figure B.13** shows a 23 MW facility at Lucainena de las Torres in Spain where the PV arrays follow the topography.

Figure B.13 Lucainena de las Torres, Almeria, Spain



Source PVresource

B.5.2.2 Thin film PV

Land requirements are estimated in the same manner as for mono-crystalline PV. As thin film panels have lower efficiency than mono-crystalline, thin film requires a greater area of land to achieve an equivalent installed capacity. This study assumes a land requirement of 3.32 hectares per MWp based on a vehicular access track of 2.5 metres between rows of solar panels.

Gradient requirements are as above for mono-crystalline PV.

B.5.2.3 Trough

Trough systems require large amounts of land for solar energy collection. A survey of existing trough plants indicates that there is a range of area requirements for trough plants from 2.4 to 4.3 hectares per MW. Most of the variance in land requirements is due to variation in mirror size but fixed access widths between mirrors. Developments with larger mirrors will tend to have smaller land requirements per MW. Information provided by a trough developer indicates that most future projects will have land requirements of approximately 2.4 hectares per MW and AECOM has adopted this value for comparative analysis of areas.

Solar trough requires extremely flat land to ensure tracking alignment such that the trough focuses sunlight evenly onto the receiver to eliminate hot spots and prevent thermal decomposition of the HTF. Extreme cases of trough miss-alignment may result in the support structure melting.

B.5.2.4 Tower

A survey of tower plants reveals that land requirements show some variation between individual projects. Spanish projects PS10 and PS20 have a footprint of 5.5 and 4.5 hectares per MW respectively, whilst larger projects such as the Californian RSEP (150 MWp, 576 ha or 3.8 ha per MW) and ISEGS (400 MWp, 1376 ha or 3.4 ha per MW) have smaller land requirements on a per MW capacity basis. This is partly due to the relatively fixed land requirements for particular plant facilities such as administrative office space and generators regardless of plant size.

However, land requirements per MW are unlikely to decrease significantly for systems beyond this size due to the increase in spacing requirements between mirrors and towers as capacity increases and because larger capacity plants tend to be an aggregation of several smaller individual systems. AECOM has assumed a land requirement of 3.5 ha per MW for both 250 and 1000 MW precinct developments based on available planning documents for

the RSEP and ISEGS projects and information provided by a tower developer. As such, a 250 MW precinct would require 875 ha and a 1000 MW precinct would require 3500 ha.

Solar tower has less onerous land gradient requirements than solar trough, as heliostat mounting frame design can be selected to suit the terrain and mirror alignment software can be used to compensate for small land height variations.

B.5.2.5 Hybrid

It is assumed that equipment required for the gas system does not require additional land. As the gas hybrid is assumed to be a hybridised trough system, the land requirements for the hybrid are assumed to be the same as for solar trough at 2.4 hectares per MW.

B.5.2.6 Summary

Table B.25 sets out the total area requirements for each technology.

Table B.25 Land area assumptions

Technology	Area per MW (ha / MW)	Total Area (ha)		
		250 MW	1,000 MW	
Mono-crystalline PV	1.03	260	1035	
Thin film PV	3.32	830	3322	
Solar trough	2.4	600	2400	
Solar tower	3.5	875	3500	
Hybrid	2.4	600	2400	

Source AECOM

B.5.3 Area gradient

As discussed above, the gradient of the available land is an important factor for feasibility, particularly when considering solar trough. Clearly, starting with land that has the smallest gradient reduces costs to move large volumes of earth. For example, a uniform gradient of 1% over one hectare would require 1250 cubic metres of earth to be moved to flatten the land. At an estimated cut to fill rate of \$10 per cubic metre, the cost for levelling would be \$12,500 per hectare. For a 250 MW mono-crystalline photovoltaic requiring approximately 260 hectares, total cost may be \$3.25 million. Earthworks cost for the 1,000 MW solar tower requiring 3500 hectares with 1% gradient may total \$44 million.

Spatial analysis conducted by this study identified land segments of less than 1% gradient within the 20 km locality radius. Overlaid onto the maps were grids of 260, 600 and 1800 hectares representing indicative land requirements for different solar technologies and capacities. **Figure B.14** to **Figure B.18** show grids at 600 hectares.

B.5.3.1 Broken Hill

The land around Broken Hill is typically flat, particularly to the south. There are areas in all directions with gradient less than 1%. **Figure B.14** shows that it is likely that there is sufficient land for all technologies of both 250 MW and 1,000 MW capacities, given earthworks to level the land.

B.5.3.2 Darlington Point

The land around Darlington Point is predominantly 1% gradient in all directions with some small pockets of gradient less than 0.01%. **Figure B.15** shows that it is likely that there is sufficient land for all technologies of both 250 MW and 1,000 MW capacities, given earthworks to level the land.

B.5.3.3 Dubbo

Figure B.16 shows that land of less than 1% gradient is generally concentrated to the northwest of Dubbo at the edge of the 20 km radius. It is likely that solar plants would be located in this northwest area given earthworks to level the land. Depending on the cost of earthworks a 1,000 MW solar trough plant may be marginal. It is likely that there is sufficient land for all other technologies of both 250 MW and 1,000 MW capacities, given earthworks to level the land.

B.5.3.4 Moree

Like Darlington Point, the land around Moree is predominantly 1% gradient in all directions with some small pockets of gradient less than 0.01%. **Figure B.17** shows that it is likely that there is sufficient land for all technologies of both 250 MW and 1,000 MW capacities, given earthworks to level the land.

B.5.3.5 Tamworth

Figure B.18 shows that western half of the Tamworth area is predominantly less than 1% gradient. It is likely that there is sufficient land for all technologies of both 250 MW and 1,000 MW capacities, given earthworks to level the land

B.5.4 Cost of land

Table B.26 shows the average land value for the five areas broken down into six land parcel sizes. For all areas, land value decreases as the size of the property band increases. This corresponds to larger land holdings further away from population centres and therefore having lower value. As expected, regional centres such as Dubbo and Tamworth have land values relatively higher than other areas. The westernmost area of Broken Hill which receives less rainfall than the other more easterly areas has relatively lower land values.

Table B.26 Average land value per hectare (\$ / ha)

Area	> 10 Ha and <= 50 Ha	> 50 Ha and <= 100 Ha	> 100 Ha and <= 200 Ha	> 200 Ha and <= 500 Ha	> 500 Ha and <= 1000 Ha	> 1000 Ha
Broken Hill	2,761	1,933	792	1,046	1,046	1,046
Darlington Point	3,181	1,736	1,622	1,165	789	339
Dubbo	9,632	3,906	2,267	1,410	1,173	847
Moree	7,142	3,784	3,152	2,774	2,582	2,187
Tamworth	10.519	6.431	4.596	3.350	1.920	1.920

Source LPMA

Table B.27 sets out the total land costs for each technology at each area. Whilst the land costs do vary by technology and area the total costs are not significant in terms of total project capital costs. It is anticipated that developers will investigate a number of land purchase arrangements in order to reduce acquisition costs; however these costs are likely to remain in the same order of magnitude as those presented in **Table B.27**.

Table B.27 Total land costs for each technology (\$m)

	Broken Hill	Darlington Point	Dubbo	Moree	Tamworth
Land cost (250 MW)					
Mono-crystalline PV	0.3	0.3	0.4	0.7	0.9
Thin film PV	0.9	0.7	1.0	2.1	1.6
Solar trough (air)	0.6	0.5	0.7	1.6	1.2
Solar tower (air)	0.9	0.7	1.0	2.3	1.7
Hybrid (air)	0.6	0.5	0.7	1.6	1.2
Land cost (1,000 MW)					
Mono-crystalline PV	1.1	0.4	0.9	2.3	2.0
Thin film PV	3.5	1.1	2.8	7.3	6.4
Solar trough (air)	2.5	0.8	2.0	5.3	4.6
Solar tower (air)	3.7	1.2	3.0	7.7	6.7
Hybrid (air)	2.5	0.8	2.0	5.3	4.6

Source AECOM

B.5.5 Summary

While the area of land required for each technology is substantial, given the proposed scale of capacity, it is likely that there is enough land of sufficiently low gradient to accommodate the different technologies at each area. Furthermore, as the cost of purchasing land is in the range of \$0.3-\$7.7m depending on area, capacity and technology, it is unlikely that land costs will significantly affect feasibility compared to technology capital costs.

Figure B.14 Broken Hill area less than 1% gradient with 600 hectare grid

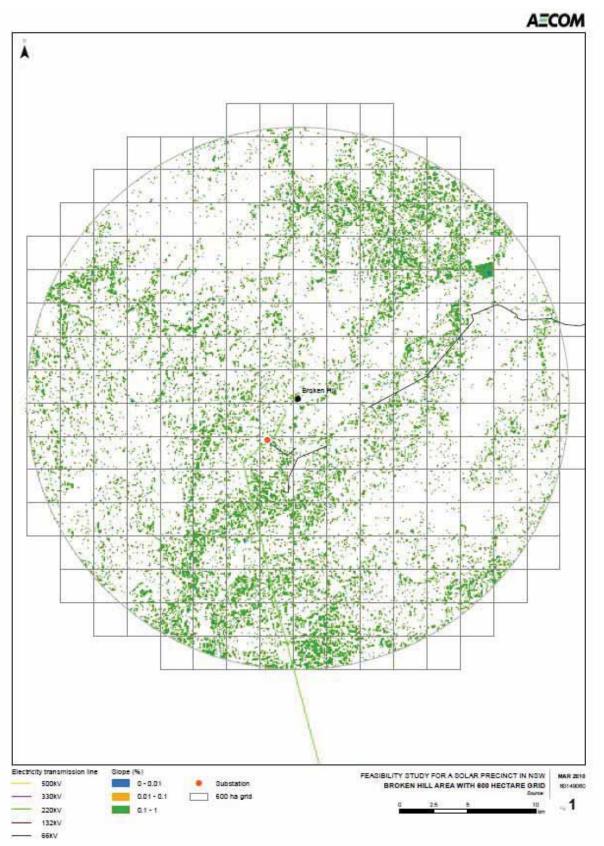


Figure B.15 Darlington Point area less than 1% gradient with 600 hectare grid

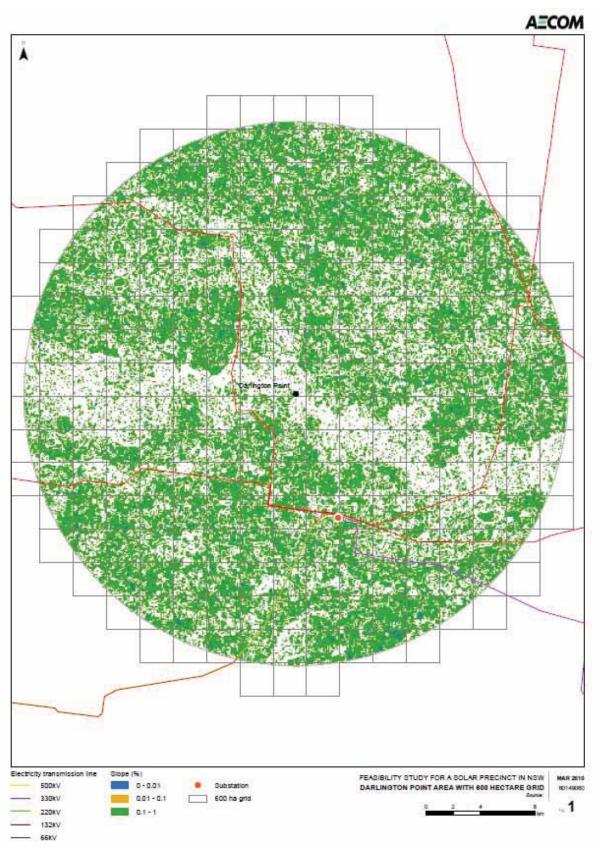


Figure B.16 Dubbo area less than 1% gradient with 600 hectare grid

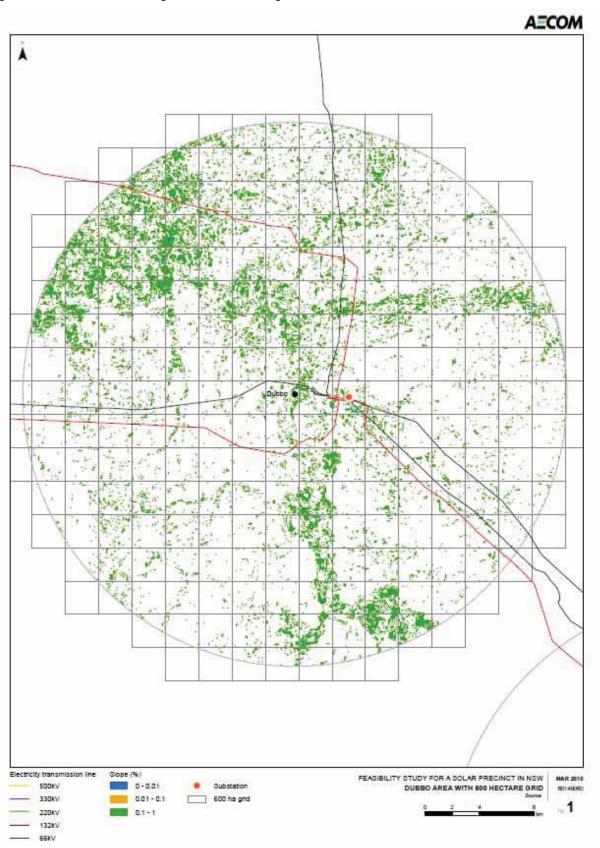


Figure B.17 Moree area less than 1% gradient with 600 hectare grid

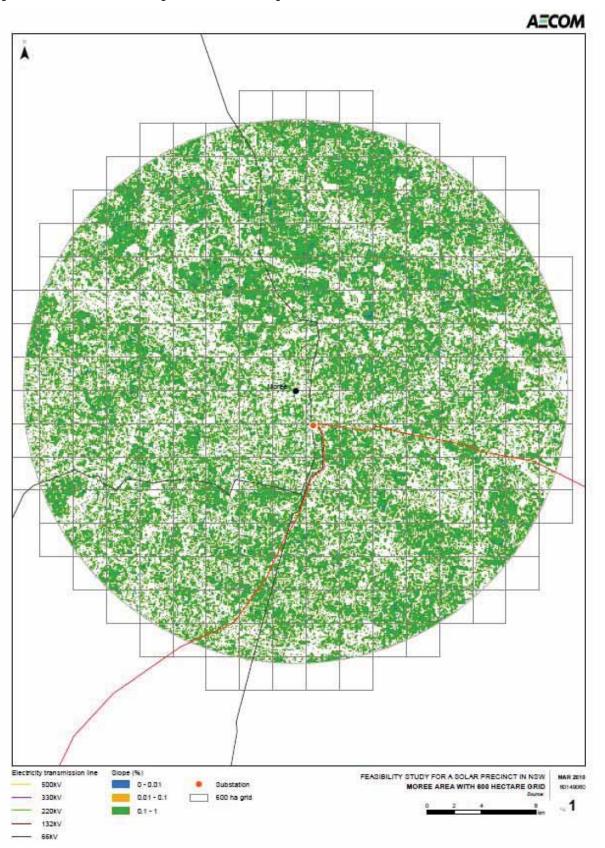
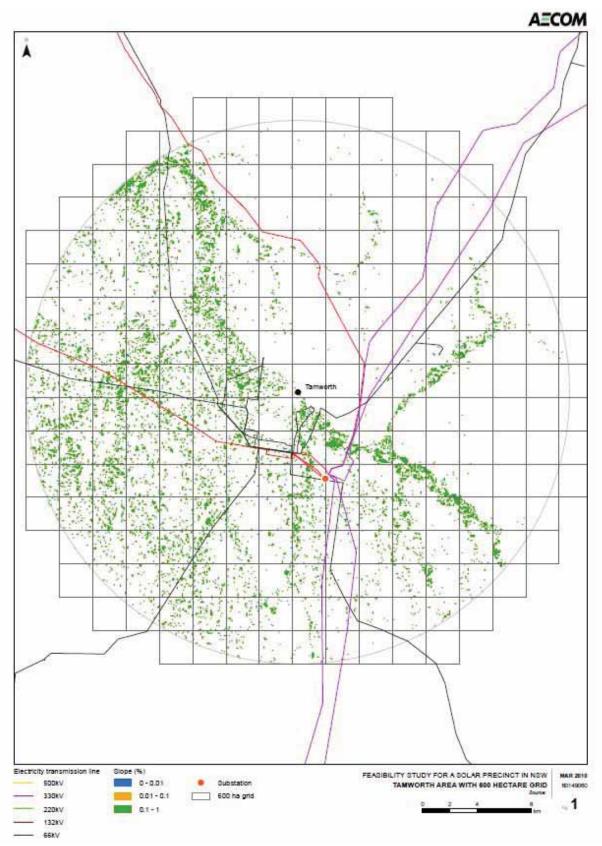


Figure B.18 Tamworth area less than 1% gradient with 600 hectare grid



B.6 Water

B.6.1 Introduction

A solar power plant requires water for a number of purposes, such as cleaning and dust control. Solar thermal plants also require water for the steam cycle and additionally have the option of using water cooling to aid efficiency. The combination of these functions necessitates access to a reliable supply of water. Over and above the prolonged drought conditions experienced by much of New South Wales, areas of high insolation are typically further inland in desert regions. As a result, securing reliable water supply is likely to be difficult, which effectively rules out the water cooled option for the scale of plant considered by this study.

This chapter discusses water requirements for each technology, identifies preferred options to supply each area with water and discusses the water licensing and approval process.

B.6.2 Technology requirements

B.6.2.1 Mono-crystalline PV

Water is required for cleaning solar panels. Without periodic cleaning, bird droppings, dust, dirt and other material that can obscure the panel will build up and shade the panel, reducing yield. Water will also be required for land dust control.

Solar panel performance is less sensitive to "soiling" than mirror-based solar thermal technologies, hence during periods of water shortage it is quite reasonable to delay cleaning activities. It is noted that build up of dust and other materials can be reduced depending on the tilt angle of the panel. However this effect is limited as the static arrays assumed in this study are fixed at a relatively flat 22 degrees to account for NSW latitudes and to reduce shading effects.

The total demand for water will further depend on area-specific conditions and there is some variability in estimates of demand between sources. For example Sargent & Lundy (2003) estimate an annual usage of 0.022 kL per m² of panel surface; using this figure would estimate annual water requirement at 0.140 ML per MWp.

To enable areas and technologies to be compared on a common basis, AECOM estimated water requirements based on Solar Millennium data. **Table B.28** summarises the water requirements. Annual water usage per unit of solar panel surface area and land area are respectively multiplied by estimated panel surface area and land per MWp to derive estimates for annual required water per MWp.

Table B.28 Mono-crystalline PV water requirements

Purpose	Water usage per unit area	Panel / land area	Annual water required (ML / MWp)
Panel cleaning	0.064 kL / m ²	5166 m ² / MWp	0.331
Dust control	0.026 ML / ha	1.03 ha / MWp	0.027
Total			0.357

Source AECOM based on Solar Millennium data.

B.6.2.2 Thin film PV

As with mono-crystalline PV, performance is less sensitive to "soiling" than mirror-based solar thermal technologies; hence during periods of water shortage it is quite reasonable to delay cleaning activities. Most thin film panels are supplied without a full mounting frame around the edges, which facilitates cleaning by enabling dust to roll off the panel, however this effect is limited due to the 22 degree fixed tilt assumed in this study.

The total demand for water will further depend on area-specific conditions and there is some variability in estimates of demand between sources. For example Sargent & Lundy (2003) estimate an annual usage of 0.022 kL per m² of panel surface; using this figure would estimate annual water requirement at 0.435 ML per MWp.

Water requirements are estimated in the same manner as for mono-crystalline PV. **Table B.29** summarises the water requirements for thin film PV.

Table B.29 Thin film PV water requirements

Purpose	Water usage per unit area	Panel / land area	Annual water required (ML / MWp)
Panel cleaning	0.064 kL / m ²	15,879 m ² / MWp	1.016
Dust control	0.026 ML / ha	3.32 ha / MWp	0.085
Total			1.102

Source AECOM based on Solar Millennium data.

B.6.2.3 Trough

Electrical output is directly related to the amount of solar energy reflected from mirror surfaces onto the receiver. As such, regular cleaning with demineralised water is needed to ensure the reflectivity of the mirror surface and maintain efficiency. Water consumption for cleaning purposes is therefore effectively a function of capacity (mirror surface area).

AECOM has calculated that 0.064 kL of water per square metre of mirror surface is required per year for washing purposes based upon water requirements published by Solar Millennium as part of their planning application documentation. Solar Millennium data indicates total annual water consumption of 0.74 ML per MWp used as follows:

- 38% solar mirror washing;
- 8% dust control:
- 26% feed-water makeup;
- 27% ancillary equipment heat rejection; and
- 2% domestic.

Based on this usage, AECOM has calculated annual water requirements as shown in Table B.30.

Table B.30 Solar trough water requirements

Purpose	Quantity	Units
Mirror cleaning	0.064	kL / m ² mirror surface
Feed water	0.1924	ML / MWp
Dust control	0.026	ML / ha
Ancillary equipment	0.1998	ML / MWp
Domestic	0.0222	ML / MWp
Total	0.76	ML / MWp / year
		(250 MW and 1,000 MW)

Source AECOM analysis based on Solar Millennium data

In addition, the steam cycle associated with solar trough systems can be either water or air cooled. The selection between wet and dry cooling is primarily driven by the availability and quality of water. Evaporative water cooling can increase plant efficiency due to the avoided requirement for high power electric fans. However, this is partly offset by changes to the steam cycle efficiency due to the different operating conditions.

Significant efficiency improvements can only be achieved in cases where large water bodies such as a lake or the sea are available for cooling. In most high solar resource locations there are constraints on the available water supply. As such, air cooling has become the most commonly adopted process. Air cooling will increase capital costs for the total plant by approximately 1.25% if potential savings from avoided water infrastructure requirements are ignored.

As discussed in **Section B.6.3**, the supply of sufficient quantities of water for water-cooled solar thermal is unlikely, particularly at the 1,000 MW scale and was therefore not considered by this study.

B.6.2.4 Tower

Solar towers require water for similar operating purposes as solar troughs, such as mirror cleaning and steam generation. AECOM has assumed the same unit rates of water consumption for solar towers as for solar trough systems shown in **Table B.30**. However, different system configurations in terms of mirror surface area, land requirements and system capacity will result in different water consumption between individual systems. AECOM has assumed air cooling for analysis on a common basis.

B.6.2.5 Hybrid

This study assumes that the gas-hybrid option is hybridised with solar trough technology. In comparison with the solar trough, the additional water requirements are relatively insignificant and are not considered in this study. Therefore water requirements for this option is equivalent to that assumed for solar trough as presented in **Table B**.30.

B.6.3 Water availability, quality and cost

It is difficult to undertake a high level analysis of water availability, given the need for detailed assessment including exploration of options to bring water to an area. Potential water sources are:

- Existing treated town supplies;
- Rivers and storages;
- Groundwater reserves; and
- Treated wastewater.

Water quality is an important factor as clean (possibly demineralised) water is needed for washing and demineralised water is needed for steam cycles. Drawing water from existing treated town supplies represents the best opportunity for consistency in quality. The quality of water drawn from rivers and dams will vary depending on the location and may vary widely in quality at the location itself as flows and levels fluctuate. The lowest quality (and lowest price) water is likely to be sourced from wastewater treatment plants. If relatively consistent quality specifications could be maintained by the wastewater operators, the efficiency of additional treatment required before use in the power generation plant could be improved and treatment costs reduced.

As with other factors, the price of water depends on the quantity and reliability that is required. In principle, water can be transported by pipeline to virtually any selected area. In many inland locations however, the prolonged drought has highlighted the limited water resources available and the high cost of transporting from high security sources.

AECOM assessed current water sources and quality, available supply sources and capacity, local supply and treatment infrastructure, town usage and climate impacts. Where water is not available in proximity to the five areas, this study has identified how water could be transported to the area and the cost of transport.

Table B.31 shows that Dubbo and Tamworth have the highest daily town water supply capacity as expected, given their status as major regional centres. Conversely, Darlington Point and Moree have the lowest daily town water supply capacity. The western areas of Broken Hill and Darlington Point have experienced severe rainfall deficiency and Darlington Point currently has Level 1 water restrictions in force. Tamworth has permanent water restrictions in place while Broken Hill, Dubbo and Moree have no restrictions at present. Water quality is good to excellent in all areas, with Tamworth the worst performing due to some chemical non-compliance in the five years to 2009.

The availability of water from town supply, surface water, groundwater and treated wastewater is summarised in **Table B.32**.

Table B.31 Water supply, climate and water quality

			Town w	Town water supply assessment	ssessment		Climate		Water quality compliance
		Town usage	Town water supply	Treated supply			Water	Water	
Area and local water supplier	Major water supply source(s)	(ML/d avg) 2007/08	capacity (ML/d)	capacity (per WTP)	Issues with town water supply	Climate impacts	restrictions (2005-08)	restrictions - current	
Broken Hill (Country Water)	Menindee Lakes	18.44	37	36/1		Severe rainfall deficiency	97% of the time	None	Excellent - 100% compliance
Darlington Point (Murrumbidgee Shire Council)	Murrumbidgee River and groundwater	1.84	10	5	Low volume of treated water available.	Severe rainfall deficiency	None	Level 1	Very good - nearly 100% compliance - some microbiological issues
Dubbo (City Council)	Macquarie River and groundwater	20.14	80	80		Recent below average rainfall	33% of the time	None	Very good - nearly 100% compliance
Moree (Plains Shire Council)	Groundwater	26.63	30	0.4	Very small amount of treated water available. Groundwater would need to be softened prior to use.	Recent average rainfall	None	None	Very good - nearly 100% compliance - some microbiological issues
Tamworth (Regional Council)	Chaffey Dam, rivers, bores, and Peel River	23.21	92	80/5/4/1		Recent close to average rainfall	None	Permanent	Good - some chemical non-compliance in the past 5 years
001									

Source AECOM

17 December 201049

B-49

Table B.32 Availability of supply sources

			Groundwater	
Area	Town water supply	Surface water (river or dam)	availability	Treated wastewater
Broken Hill	May be feasible for dry cooling or water cooling for 250 MW	Unregulated		Low available volume
Darlington Point Unfeasible	Unfeasible	General security regulated river licensed users restricted to 50% of entitlement High Security restricted to 95% of entitlement	May be available	Very low available volume
Dubbo	Some capacity issues	General security regulated river licensed users restricted to 21% of entitlement	May be available	Committed to irrigation effluent reuse
Moree	Not likely to be feasible - would also need additional treatment	Unregulated	Yes, good supplies	Supply committed for irrigation and town use
Tamworth	May be feasible for dry cooling or water cooling for 250 MW	Unregulated - may be available from Chaffey Dam		Supply committed

AECOM

Source

B-50

B.6.3.1 Water supply options

Based on the analysis of water supply and availability, AECOM developed potential supply augmentation options and preferred options for each of the five areas which are presented in **Table B.33**. The analysis also included consideration of water cooled systems to identify whether sufficient water is available for water cooling. It is unlikely that water cooling is feasible for a 1,000 MW plant at any area; Tamworth and Dubbo may be able to support a 250 MW plant with water cooling. Construction of the pipeline would not be staged as the pipeline for both 250 MW and 1,000 MW is a 150mm pipeline and it would be uneconomical to attempt to stage construction.

It should also be noted that prices for town water supply are based on consumer bills and in practice industrial customers are likely to pay a lower price.

For the purposes of this study, for each area, AECOM has selected the first potential supply augmentation as the preferred option.

Table B.33 Preferred water supply options

Area		Price for Options			Preferred option
	augmentation	Water	Delivery (\$m)	Treatment	
		(\$ / ML)	Delivery (\$111)	(\$m/ML)	
Broken Hill	1. Town treated water	1500	1	0	Air cooled
	supply 2. Extraction from Menindee Lakes if high security water	150	80	1	Town supply (may not be feasible for 1,000 MW precinct) Water cooled
	licence is available, plus 110 km pipeline and water treatment plant.				Not feasible
Darlington Point	Extraction from the Murrimbidgee River if high security licence is available construct pipeline and water treatment plant. Purchase groundwater,	150	2	1	Air cooled Purchase river extraction licence, treat and pump. May not be feasible due to severe impact of drought. If river extraction not feasible, groundwater extraction may be.
	construct water treatment plant.	150	2	1	Water cooled Not feasible
Dubbo	Extraction from the Lachlan River if high security licence is available; construct pipeline and water treatment plant.	300	1	1	Air cooled River extraction, pipeline and treatment plant Water cooled 80 km pipeline from Burrendong
	Town treated water supply	1500	1	0	Dam and treatment plant
	3. High security licence and 80 km pipeline to Burrendong Dam and construct pipeline and water treatment plant.	300	50	1	
Moree	Ground water extraction licence and water treatment plant.	100	1	1	Air cooled Groundwater supply, pipeline and treatment plant
	Extraction from the Mehi River if high security licence is	300	1	1	Water cooled Not feasible

Area	Potential supply augmentation	Price for O	Price for Options		Preferred option
		Water (\$ / ML)	Delivery (\$m)	Treatment (\$m/ML)	
	available, water treatment				
Tamworth	1. Extraction from Peel River if a high security licence is available and construct pipeline and treatment plant	300	1	1	Air cooled River Extraction, pipeline and treatment plant Water cooled River extraction if volume is
	2. Purchase groundwater, construct pipeline and treatment plant	100	1	1	available, otherwise 44 km pipeline from Chaffey Dam
	3. Extraction from Chaffey Dam id high security licence is available, construct 50 km pipeline to town and water treatment plant	300	30	1	

Source AECOM

B.6.4 Water Licensing

To extract water from rivers or aquifers for commercial purposes, a water licence or approval needs to be issued by the NSW Office of Water. Within NSW, two pieces of legislation govern water licences and water trading (the buying and selling of water licences or annual allocation water):

- The Water Management Act 2000 (WMA 2000), which controls the issue of new water licences and the trade of water licences and allocations for those water sources (rivers, lakes and groundwater) in NSW where water sharing plans have commenced.
- The Water Act 1912, which covers issues of water licensing in all other areas.

B.6.4.1 Licenses

When applying for a new access licence, two different application procedures are used depending on the Act under which the water extraction falls.

Generally under the WMA 2000, new water access licences for commercial purposes (irrigation, industry, and mining) that have a share of the available water are no longer being granted, although an established online application process is available for use. The application will be assessed by the NSW Office of Water against the water sharing plan rules applicable to the relevant water source and provisions of the *Water Management Act* 2000 and Regulations 2004. In the event that the application is unsuccessful, an existing licence would need to be purchased on the water market if a permanent share of water needs is required. However for most water sources it is still possible to apply for:

- Specific purpose licences (such as domestic and stock, Aboriginal cultural, or local water utility access licences) depending on the rules in the water sharing plan. Granting of the licence is not automatic and will need to be assessed by the NSW Office of Water.
- Zero share licences. Although this will not provide the licence holder with an allocated share component, it allows the licence holder to have a water account and to buy allocation water on an annual basis or share component from another licence holder.

Water access licences may also become available under a controlled allocation order. Under this order the Government may make licences available in a specific water source through a tender or auction process.

In some water sources covered by the *Water Act 1912*, new water licences may still be granted. However, in other areas there is an embargo in place, particularly on water licences for irrigation and industry. In these areas licences from DECCW can only be obtained for specific exempt purposes such as town water, stock and domestic

supply, domestic hydro-electric schemes, hydro-static testing of pipelines, and drought relief. To obtain an irrigation or industrial licence in an embargoed water source, licensed entitlement must be purchased from an existing licence holder. For surface water or groundwater licences in a water source that is not embargoed or for a non-embargoed purpose an application form must be completed and submitted for assessment by the NSW Office of Water.

B.6.4.2 Water dealings and trade

There are two types of water access licence dealings:

- General water dealings
- Water allocation assignment dealings

General water dealings under the *Water Management Act 2000* include the trading of water access licences, as well as any change to water access licences on the WAL Register. Water access licences are maintained on the Water Access Licence Register (WAL Register) by LPMA. The details of each water access licence on the WAL Register are publicly available. General water dealings only take effect when registered by LPI on the WAL Register. Some general water dealings, including assignment of share component and change of nominated work, require consent by the NSW Office of Water, before registration with LPI.

Figure B.19 Process for general water dealings



Water allocation assignment dealings refers to a volume of water (in megalitres) credited to a water access licence water allocation account, where all or part of the water allocation can be traded.

Water allocation assignment dealings under the *Water Management Act 2000* in regulated and major inland groundwater systems must be lodged with State Water.

Water allocation assignment dealings in unregulated rivers and groundwater systems not managed by State Water are available in very limited circumstances where extraction is metered. The NSW Office of Water is the consent and registration authority for these dealings.

Figure B.20 Process for water allocation dealings

Process for water allocation assignments dealings		
Water allocation assignment dealings on regulated rivers and major inland groundwater systems	Requires consent and registration	State Water
Water allocation assignment dealings on unregulated rivers and other groundwater systems	Requires consent and registration	NSW Office of Water

B.6.4.3 Approvals

There are three main categories of approvals that can be granted.

Water supply works approvals

A water supply work approval authorises its holder to construct and use a specified water supply work at a specified location. Approvals cannot be traded to another property or location. Approvals may be granted by the NSW Office of Water to construct and operate water supply works such as pumps, bores, spearpoints or wells and to use water for a particular purpose, such as irrigation. Approvals that replace the former *Water Act 1912* licences will reflect the water supply works that were authorised by those licences.

Each approval includes conditions to minimise adverse impacts.

Water use approvals

This approval simply allows for extraction and use of water from a water supply source. Approvals that replace the former *Water Act 1912* licences will reflect the water use/s that were authorised by those licences. Activities subject to approvals under the *Environmental Planning and Assessment Act 1979* do not require water use approval from the Office. Each approval includes conditions to minimise adverse impacts.

Activity approvals - controlled activity approvals

Under the WMA, a controlled activity means:

- The erection of a building or the carrying out of a work (within the meaning of the Environmental Planning and Assessment Act 1979);
- The removal of material (whether or not extractive material) or vegetation from land, whether by way of excavation or otherwise;
- The deposition of material (whether or not extractive material) on land, whether by way of landfill operations
 or otherwise; or
- The carrying out of any other activity that affects the quantity or flow of water in a water source.

Before a controlled activity is undertaken, an application form must be submitted to the NSW Office of Water.

Activity approvals - aquifer interference approvals

Groundwater is a complex and often very fragile resource which plays an important role in natural ecosystems. Groundwater sources (aquifers) are often connected to surface water flows and it is important that they are managed sustainably and that their quality is protected.

Landholders considering accessing groundwater in New South Wales must obtain the relevant approval or licence from the NSW Office of Water before any drilling or bore construction takes place.

In an area covered by a water sharing plan for a groundwater source, the Water Management Act 2000 requires:

- Water supply works approval to construct a bore, well or spear point: and
- Water access licence to access the water.

In all other areas, that is, those still covered by the Water Act 1912, users must obtain a Groundwater licence.

B.6.4.4 Application Process

In each of these cases, a separate application form needs to be completed and submitted to the NSW Office of Water for assessment.

B.6.5 Summary

Table B.34 summarises the annual water requirements for each technology.

Table B.34 Annual water requirements (ML)

Size of plant	Mono-crystalline PV	Thin film PV	Solar trough, tower and Hybrid (air cooled)
250 MW	89.25	275.5	190
1,000 MW	357	1102	760

Source AECOM

The preferred supply augmentation option for each area was selected to ensure the secure supply of water for the solar precinct. The supply of sufficient quantities of water for water-cooled solar thermal is unlikely, particularly at the 1,000 MW scale and was therefore not considered by this study.

Having identified the necessity for a reliable and sustainable water source for the operation of the proposed solar precinct, the next stage requires the procurement of water access licences or approvals from the NSW Office of Water to extract and use the water in the proposed areas. The overall application process is relatively straight forward and uniform in NSW whereby an application form is completed and submitted for assessment. Having reviewed the application with other relevant agencies and authorities, the NSW Office of Water will either grant a WAL or decline to do so. Since the supply and demand of water and environmental constraints vary across NSW, the depth, detail and requirements of each application for the specific area will vary accordingly.

B.7 Gas

B.7.1 Introduction

Solar thermal technology requires small quantities of gas for freeze protection of the heat transfer fluid and standby ancillary operations. Another option for solar thermal generation is the use of gas for hybridisation to either improve the steam cycle efficiency or for the use in a standalone boiler for raising steam during periods of low solar generation. Gas is not required for mono-crystalline and thin film PV technologies.

The availability and price of gas depends on the volume required, supply profile and the distance from the nearest gas pipeline; proximity to a gas pipeline is therefore advantageous for feasibility. This section discusses gas requirements for solar thermal, and availability and cost of supplying each area.

B.7.2 Technology requirements

B.7.2.1 Thermal operations

To enable the reliable operation of the thermal plant, a small amount of gas is required for services such as freeze protection and quick start in the morning depending on the specific technology in use. AECOM has estimated annual gas consumption for both trough and tower at 190 GJ per MWp based on figures published in various planning application documents for large scale trough systems. **Table B.35** shows the quantities of gas required.

Gas is not required for mono-crystalline PV or thin film PV.

B.7.2.2 Hybrid generation

Large quantities of gas are required for the hybrid plant to generate energy. As shown in **Table B.15**, a hybrid plant is approximately 29% efficient in use of gas for boilers, so would consume specified amounts of gas per MWh depending on plant size and area; **Table B.35** shows the quantities of gas required.

For more detailed discussion of hybrid see Sections B.1.4 and B.3.6.

Table B.35 Gas requirements for thermal operations and hybrid generation

	Broken Hill	Darlington	Dubbo	Moree	Tamworth
		Point			
Thermal operations (GJ / MWp)					
All capacities	190	190	190	190	190
Hybrid generation (GJ / MWh)					
250 MW	12.7	12.7	12.7	12.7	12.7
1000 MW	12.7	12.7	12.7	12.7	12.7

Source AECOM calculations and developer application documents.

B.7.3 Gas availability and cost

B.7.3.1 Thermal operations

As discussed in **Section B.7.2**, a solar thermal plant has an annual requirement of approximately 190 GJ per MWp to prevent heat transfer fluid freezing and to facilitate warm starts. A 250 MW plant would therefore require 47,500 GJ per year (47.5 TJ per year). Such gas would probably be provided under a retail contract rather than a wholesale contract. AECOM has estimated retail gas prices based on NSW retail gas prices for customers up to 1 TJ per year, namely \$9 per GJ (industrial, near Darlington Point)⁷ and \$11.75 per GJ (residential price of \$15.75 per GJ less \$4 per GJ residential premium, other areas)⁸.

The minimum operational gas requirement for a solar thermal plant would be best supplied through a gas pipeline, although road transport is an alternative option if there was no nearby pipeline connection. At an energy density of approximately 55 GJ per tonne, 47.5 TJ would be equivalent to approximately 865 tonnes of natural gas. A typical semitrailer can carry approximately 20 tonnes, so trucking would require 43 trucks per year (approximately one per week) plus sufficient storage to hold at least two weeks supply. The cost of trucking gas would be

17 December 201056 B-56

-

 $[\]label{lem:http://www.countryenergy.com.au/wps/wcm/connect/3188a68041ca1a438928ef96d29342cf/gas_wagga_09.pdf? MOD=AJPERES. \\$

 $^{^8}$ http://www.agl.com.au/Downloads/NSW_Gas_RegulatedPrices_Residential.pdf

approximately \$0.006 per GJ-km, based on typical transport costs for bulk freight of \$0.20 per tonne-kilometre (\$0.004 per GJ-km out plus \$0.002 per GJ-km back).

Table B.36 illustrates the total delivered cost per GJ for gas at each area, including road transport costs from the pipeline.

B.7.3.2 Hybrid generation

A gas-assisted solar thermal plant would require a significantly higher volume gas supply to operate and would therefore require a consistent and reliable supply by pipeline. The gas volume required will depend on mode of operation, but could be 500-5,000 TJ per year. This volume is comparable with a large open cycle gas turbine or small combined cycle gas turbine.

AECOM has conservatively estimated gas prices based on open cycle gas turbines (OCGT) referring to *Fuel resource, new entry and generation costs in the NEM* (ACIL Tasman, 2009), namely \$6.20 for Darlington Point and Wagga Wagga, and \$7.40 for Dubbo, Moree and Tamworth.

Gas for hybrid generation must be delivered by pipeline, which would have to be built for precincts not located near existing pipelines. The price for a dedicated gas pipeline is assumed to be \$0.005 per GJ per km based on Eastern Pipeline Gas reference tariffs, taking into account long term pipeline capital and operating costs (Jemena, 2010). A general approximation of the total gas delivered cost per GJ is presented in **Table B.36**.

B.7.4 Summary

Gas will have a cheaper unit price if required in large volumes for hybrid generation, although gas pipelines would need to be constructed for precincts not located close to existing pipelines. **Table B.36** shows delivered gas prices for solar thermal plants .

Table B.36 Total delivered gas cost for a solar thermal plant (\$ / GJ)

	Broken Hill	Darlington Point	Dubbo	Moree	Tamworth
Approximate distance to gas					
pipeline (km)	200	30	0	200	0
Operations cost (\$/GJ)					
Retail gas price at pipeline*	11.75	9.0	11.75	11.75	11.75
Road transport	1.2	0.2	0	1.2	0
Total	13.0	9.2	11.8	13.0	11.8
Hybrid generation cost (\$/GJ)					
OCGT Gas price at pipeline*	6.2	6.2	7.4	7.4	7.4
Additional pipeline cost	1.0	0.15	0	1.0	0
Total	7.2	6.4	7.4	8.4	7.4

Source ACIL Tasman (2009)

Note Costs are rounded up to nearest \$0.1.As there is no published OCGT gas price for Darlington Point, the gas price is assumed to be the same as for Wagga Wagga.

There is likely to be development of a liquefied natural gas (LNG) terminal in eastern Australia within the next 4-5 years. Santos and PETRONAS are making final investment decisions for an LNG plant at Gladstone by mid 2010 which would enable the plant to be operational by 2014. There are a number of other plants currently in the planning stage (Global LNG Info, 2010). An LNG plant would increase domestic gas prices to international parity. The current spot price for LNG is around \$6.65 per GJ⁹. The estimated delivered gas costs for new entry and generation costs in the NEM in Yarwun (closest place to Gladstone) is \$3.57 per GJ suggesting an LNG premium of around \$3 per GJ (ACIL Tasman, 2009). AECOM has not modelled the effect of the introduction of an LNG plant.

⁹ Using a conversion factor of 1 MMBtu = 1.054615 GJ and an exchange rate of US\$1=A\$0.9

B.8 Planning

Planning approval in NSW is governed by the *Environmental Planning and Approvals Act* 1979 (EP&A Act). Under the EP&A Act, approval/consent can be achieved via three pathways, outlined under Part 3A, Part 4 and Part 5 of the Act. Given the nature and scale of the proposed solar precinct, it is likely that it would be eligible for assessment as "major development' under Part 3A of the EP&A Act. Part 3A provides for a consolidated approvals process in which the Minister for Planning is the approval authority.

Development of a solar precinct may also require approval at a Commonwealth level. Commonwealth environmental approval is issued under the *Environment Protection and Biodiversity Conservation Act 1999* (EPBC Act). The Commonwealth approvals process is separate and in addition to the State approvals process, however there is provision for these processes to be undertaken concurrently through a single approvals process through Commonwealth accreditation of the State process via a bilateral agreement or a one-off accreditation.

A solar precinct is consistent with the strategic objectives for NSW as set out in the *State Plan: Investing a Better Future*, which emphasises the need for increased use of renewable sources of energy. Accordingly, there is strong strategic planning justification for the establishment of a solar precinct in NSW.

B.8.1 Introduction

This section examines the planning framework applicable to the proposed solar precinct and provides a review of:

- The approvals process and approval authority;
- Assessment requirements for the project;
- Indicative consultation requirements (key stakeholders, community and government agencies); and
- Indicative timeframes for approval.

Planning approval in NSW is governed by the *Environmental Planning and Approvals Act* 1979 (EP&A Act). Under the EP&A Act, approval/consent can be achieved via three pathways, outlined under Part 3A, Part 4 and Part 5 of the Act. Given the nature and scale of the proposed solar precinct, it is likely that it would be eligible for assessment as "major development' under Part 3A of the EP&A Act. Part 3A provides for a consolidated approvals process in which the Minister for Planning is the approval authority.

Development of a solar precinct may also require approval at a Commonwealth level. Commonwealth environmental approval is issued under the *Environment Protection and Biodiversity Conservation Act 1999* (EPBC Act). The Commonwealth approvals process is separate and in addition to the State approvals process, however there is provision for these processes to be undertaken concurrently through a single approvals process through Commonwealth accreditation of the State process via a bilateral agreement or a one-off accreditation.

A solar precinct is consistent with the strategic objectives for NSW as set out in the *State Plan: Investing a Better Future*, which emphasises the need for increased use of renewable sources of energy. Accordingly, there is strong strategic planning justification for the establishment of a solar precinct in NSW. The NSW Government has taken a proactive approach to supporting delivery of renewable energy projects and has introduced measures to streamline the application process. These measures include:

- A commitment to assess major project applications for renewable energy projects within 4 months (from exhibition period and excluding the time taken for the proponent to prepare a submissions report or preferred project report in response to issues raised during the consultation period);
- The introduction of a Project Delivery Unit to assist the proponents of renewable energy schemes with negotiating the major project assessment process;
- The declaration of renewable energy projects with a peak generating capacity of 30 megawatts or more to be Critical Infrastructure; and
- Critical Infrastructure fees under Section 245H of the *Environmental Planning and Assessment Regulation* 2000 are being waived for renewable energy projects classified as critical infrastructure from August 2009 to 30 June 2011.

B.8.2 Commonwealth Approval

If a project is likely to have significant impacts on a matter of National Environmental Significance (NES), the project may require Commonwealth approval in addition to State approval. Matters of NES include:

- World Heritage sites,
- National Heritage listed properties;
- Wetlands of National Importance;
- Commonwealth listed Migratory species;
- Commonwealth listed Threatened species;
- Nuclear action;
- Commonwealth marine area; and
- Commonwealth land.

Where it is considered that a project may have a significant impact upon matters of NES, a referral is submitted to the Commonwealth Department of Environment, Water, Heritage and the Arts (DEWHA) and is subject to a determination period of 20 working days (which includes a 10 day exhibition period). This process results in a determination by the Commonwealth Minister as to whether the project is a "controlled action", requiring approval under the EPBC Act.

If it is determined that the project is a "controlled action' a process of environmental assessment is required. There are five different levels of assessment, depending on the significance of the project and how much information is existing. Controlled actions may be assessed using one of the following assessment approaches:

- Accredited assessment (e.g. bilateral agreements with the relevant State, allowing assessment to be undertaken via the State process);
- Assessment on referral information (assessment undertaken solely on the information provided in the referral form);
- Assessment on preliminary documentation (referral form and any other relevant material identified by the Minister as being necessary to adequately assess a proposed action);
- Assessment by Environmental Impact Statement (EIS) or Public Environment Report (PER); or
- Assessment by public inquiry.

The process and timing requirements differ for each type of assessment under the EPBC Act. In order to streamline the assessment and approvals process, it is recommended that the process of accredited assessment be pursued to allow for one set of approvals documentation and one assessment process. Should an appropriate bilateral agreement not be in place for NSW at the time of the application, provision is made in the EPBC Act for the one-off accreditation of a State process subject to consultation with DEWHA.

B.8.3 State Approvals

B.8.3.1 NSW Approvals Process

The principal environmental and planning legislation in NSW is the EP&A Act. Under the EP&A Act consent or approval can be achieved via three pathways:

- Part 3A: Major development of State or regional planning significance; identified under *State Environmental Planning Policy (Major Development)* 2005 (Major Development SEPP);
- Part 4: Local development and designated development; and
- Part 5: Development which does not require consent under Part 4 or approval under Part 3A; often
 development carried out by or on behalf of public authority.

Given the intended scale of a solar precinct it is assumed that the capital investment value for the project would exceed \$30m and as such the project would be eligible for assessment under Part 3A of the EP&A Act, subject to declaration by the Minister. Part 3A provides for a consolidated approvals process in which the Minister for Planning is the approval authority.

B.8.3.2 Part 3A

Part 3A projects are generally developments that, in the opinion of the Minister for Planning are of State or regional environmental planning significance. The Major Development SEPP identifies categories of "major

development'. It is anticipated that the solar precinct project would fall within Schedule 1, Group 8 - Transport, Communications, Energy and Water Infrastructure – Generation of Electricity or Heat or Co-generation being:

"Development for the purpose of a facility for the generation of electricity or heat or their co-generation (using any energy source including gas, coal, bio-fuel, distillate and waste and hydro, wave, solar or wind power), being development that:

- a) has a capital investment value of more than \$30 million; or
- has a capital investment value of more than \$5 million and is located in an environmentally sensitive area of State significance.

B.8.3.3 Critical Infrastructure

If a project has been declared as a project to which Part 3A applies, the Minister may make an additional declaration that the project is also a Critical Infrastructure project, if the Minister is of the opinion that the project is essential to the State for economic, environmental or social reasons. In November 2009, the Minister for Planning declared renewable energy projects with a peak generating capacity of 30 megawatts (MW) or more to be "Critical Infrastructure". This declaration was published in the NSW Government Gazette on 27 November 2009. As such the proposed solar precinct project is likely to be deemed Critical Infrastructure.

The declaration of a project as Critical Infrastructure is intended to:

- Ensure the timely and efficient delivery of essential infrastructure projects;
- Allow the NSW Government and the planning system to rapidly and readily respond to the changing needs
 of the State;
- Provide certainty in the delivery of these projects;
- Provide for scrutiny to ensure environmental outcomes are appropriate; and
- Focus on delivering outcomes essential to the NSW community.

The key differences between the assessment of Critical Infrastructure projects and other major developments are:

- An application for a Critical Infrastructure project can be lodged without the consent of landowners.
- There are no merit-based appeal rights in relation to a decision regarding a Critical Infrastructure project and
 no opportunity for judicial review proceedings in the Land and Environment Court (LEC) to challenge the
 declaration or to remedy or restrain a breach of the EP&A Act in relation to the way the decision was made
 (unless the proceedings are brought or approved by the Planning Minister).
- Exemption from other environmental laws. Critical Infrastructure projects are exempt from administrative orders which may be used by public authorities to enforce environmental laws such as interim protection orders, stop work orders, or environment protection notices.

B.8.3.4 Concept Approval and Project Approval

Within the Part 3A approvals process there are two types of approval that can be pursued:

- 1) Concept Approval; and
- 2) Project Approval.

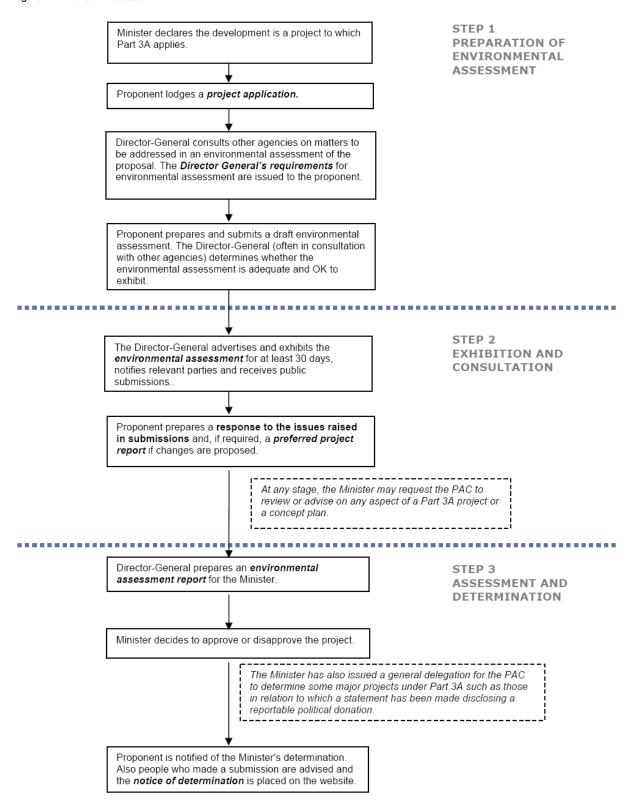
The Minister for Planning can allow, or in some cases, require a proponent to submit a concept plan before lodging a project application for a Part 3A project. The purpose of the concept plan is to give a broad overview of the project by outlining what the project would entail, and whether it would be built in stages. Unlike a project application, a detailed description of the project is not required. A proponent can lodge a combined concept plan and a project application to carry out part of a project at the same time. This is advantageous where the detailed design of a scheme has not been developed.

The main advantages to the proponent of lodging a concept plan are that the full detailed design of the scheme is not required at the time of the initial application, thereby allowing for in-principle approval of a scheme with the detailed design left to a later stage. In addition, the Minister for Planning can either approve the development outright or alternatively can refine the rest of the assessment process to more closely suit the project.

Once a concept plan is lodged the usual Part 3A process is followed, as described in **Figure B.21** (projects deemed to be Critical Infrastructure follow the same approvals process).

Further approvals may be required at the discretion of the Minister for Planning. In deciding whether or not to approve a concept plan, the Minister for Planning can require the proponent to do further work, such as requiring further environmental assessment. Alternatively, the Minister for Planning may require the proponent to obtain further approvals under Part 3A, Part 4 or Part 5 of the EPA Act.

Figure B.21 Part 3A Process



Source NSW Planning Fact Sheet October 2009

B.8.3.5 Environmental Assessment

The environmental assessment requirements (EARs) for major developments and critical infrastructure projects are discretionary. The Director-General for Planning determines the form of environmental assessment that is required for a Part 3A project and the issues that the assessment must cover through the issue of EARs for the project.

B.8.3.6 Consultation

The environmental assessment report must be made publically available for at least 30 days. During that period any person can make a written submission to the Director-General about the project. In response to the issues raised in the public submissions, the Director-General can require the proponent to submit:

- A response to any of the issues;
- A report outlining any proposed changes to the project to address those issues; or
- A revised statement of commitments.

B.8.3.7 Permissibility

In deciding whether to approve a Part 3A project, the Minister is not bound by the provisions of any Local Environmental Plan (LEP) however, the Minister may choose to take them into account in deciding whether to approve a project. Where an LEP prohibits the type of development being applied for under Part 3A the Minister for Planning can only approve the development if the project application is also accompanied by a concept plan. Notwithstanding this, the Minister cannot approve a Part 3A project, which is located within an environmentally sensitive area of State Significance or a sensitive coastal location if the development would have been prohibited under the relevant LEP.

B.8.3.8 Process and Indicative Timeframes

Following a declaration from the Minister that Part 3A of the EP&A Act applies to the project, a preliminary environmental assessment (PEA) is required to be undertaken. The PEA informs the EARs, which are issued by DoP to guide the content of the environmental assessment.

An environmental assessment is subsequently prepared and lodged with DoP. The environmental assessment is publicly exhibited (for a minimum of 30 days), to provide an opportunity for stakeholder and public comment, which may require a response in the form of a submissions report and/or preferred project report dependent upon the issues raised.

In determining the timeframe for the project the key variable would be the preparation time for the environmental assessment, which would be heavily dependent on the nature and type of studies required. The DoP has undertaken to assess major project applications for renewable energy projects within 4 months, from exhibition period and excluding the time taken for the proponent to prepare a preferred project report/submissions report in response to issues raised during the consultation period.

Table B.37 outlines the key stages of the Part 3A approvals process and indicative timeframes for each stage.

Table B.37 Part 3A application

Part 3A Application to the Minister			
Action	Timeframe		
Request for Minister's opinion	1 – 3 months		
Submit project application and preliminary environmental			
assessment which would include:			
Project description;			
Project justification;			
Site context;			
Consideration and evaluation of alternatives;			
Consideration of other approvals required;			
Details of consultation to be undertaken; and			
Assessment methodologies.			
Director General's Requirements (DGRs) issued	3 months		
Prepare and lodge Environmental Assessment (EA)			
Pre-exhibition review/ Adequacy review – DoP may seek advice	1 month		
from relevant Government agencies to ensure consistency with			
DGRs and that the EA is adequate for exhibition.			
EA placed on exhibition (minimum 30 days)	Less than 4 months		
Respond to issues and modify the concept design and/or	(NSW Government is committed to		
Statement of Commitments.	assessing Part 3A applications for		
Issue Preferred Project Report (PPR) including the revised	renewable energy projects within 4		
Statement of Commitments if necessary.	months, taken from the exhibition		
Note: the PPR will be exhibited for a 30 day period.	period and excluding the tie taken to		
DoP undertake an assessment and prepare a draft assessment	prepare a preferred project		
report for the Director General (DG).	report/submissions report in response		
DG will consult with Government agencies before finalising the	to comments/issues raised during the		
assessment report, including reference to the Statement of	exhibition stage).		
Commitments.			
Assessment Report submitted to Minister for determination.			
Total time (estimated)	8 – 11 months		

Source AECOM

B.8.3.9 Key Stakeholders

Consultation is required with relevant State and Commonwealth Government agencies and utility providers. It is anticipated that the following agencies would be consulted during the assessment and approvals process (the list of consultees would be confirmed in the EARs for the project):

- NSW Department of Planning;
- NSW Department of Environment, Climate Change and Water;
- NSW Department of Industry and Investment;
- Local Aboriginal Land Council(s) and Traditional Owners;
- NSW Heritage Branch;
- NSW Roads and Traffic Authority;
- NSW Rural Fire Service;
- Catchment Management Authorities; and
- TransGrid.

Regional and Local

- Regional Organisation of Councils;
- Relevant local government authority; and
- Local community including general public and local interest groups.

Electricity Market

- National Electricity Market;
- Network Operators; and
- Electricity Retailers.

B.9 Environment

B.9.1 Introduction

This appendix considers environmental issues associated with the five selected areas and builds on the preliminary analysis employed to shortlist down from sixteen to five areas (see **Appendix A**). More detailed analysis of each area has identified important environmental features on a local and regional scale that are potential constraints to a solar precinct. As such, a radius of 20 km around each regional centre has been used for analysis. This approach allows for comparison of the five areas and assists with assessing feasibility. Environmental features include:

- Ecology:
 - Threatened flora and fauna;
 - Endangered ecological communities (EECs);
 - Critical habitat: and
 - Ramsar wetlands.
- Aboriginal and European heritage database searches;
- Discussion of significance of native title and aboriginal land claims;
- Identification of urban areas; and
- Identification of other potential constraints.

An outline of the likely planning approval framework for a new solar development has not been included within this report. However, depending on the preferred location of the solar precinct, it is likely that the proposal will trigger key environmental legislation and reference to these has been included where relevant.

The analysis reveals that environmental constraints are present in each of the areas. However these constraints do not necessarily preclude any area from hosting a solar precinct. Further investigation is required to ascertain the potential impacts of a solar precinct on these constraints.

B.9.2 Environmental constraints maps

The following environmental constraints maps (**Figure B.22**, **Figure B.23**, **Figure B.24**, **Figure B.25** and **Figure B.26**) provide an orientation and summary of the key issues that are discussed in the following sections.

Figure B.22 Environmental constraints within a 20 km radius of Broken Hill

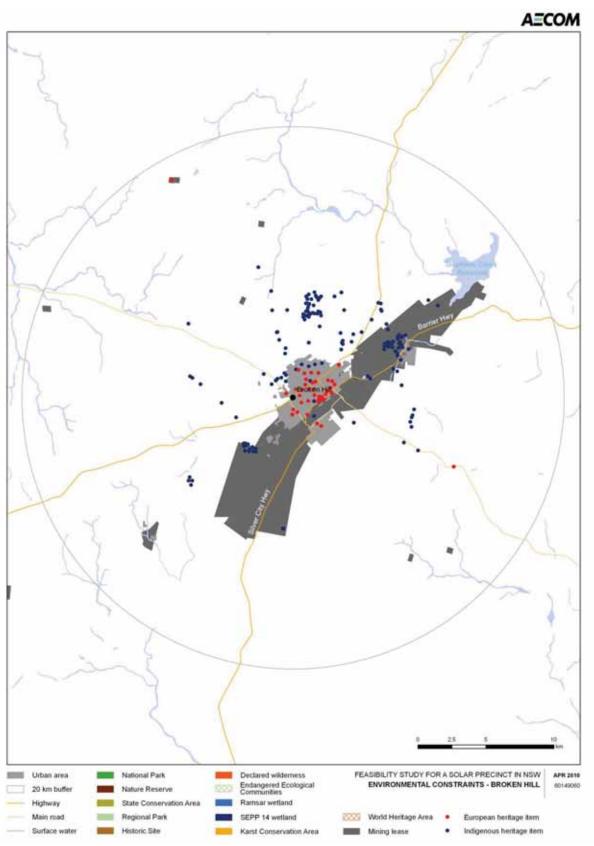


Figure B.23 Environmental constraints within a 20 km radius of Darlington Point

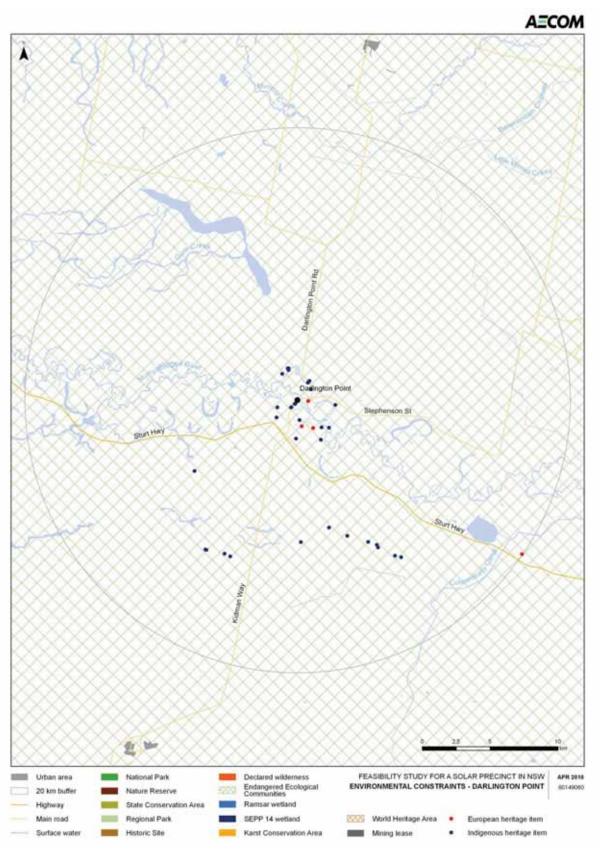


Figure B.24 Environmental constraints within a 20 km radius of Dubbo

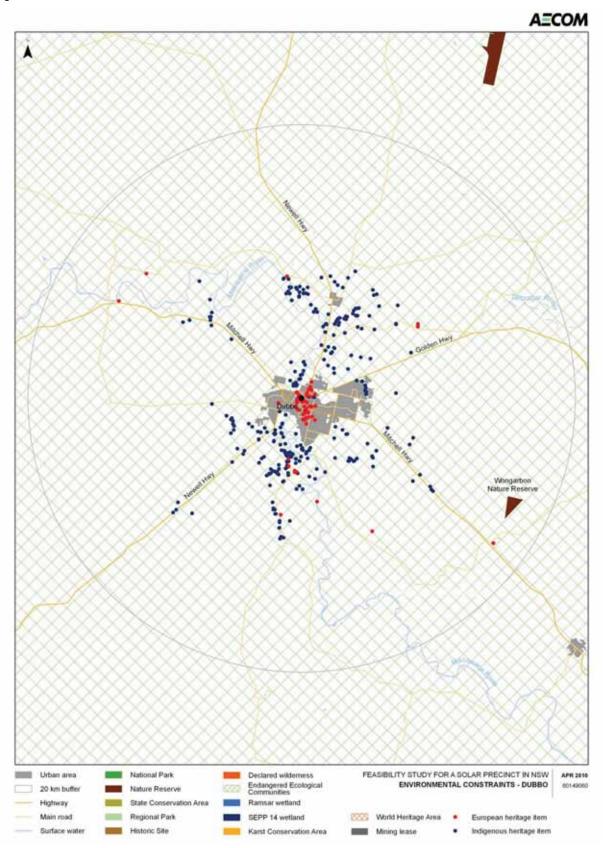


Figure B.25 Environmental constraints within a 20 km radius of Moree

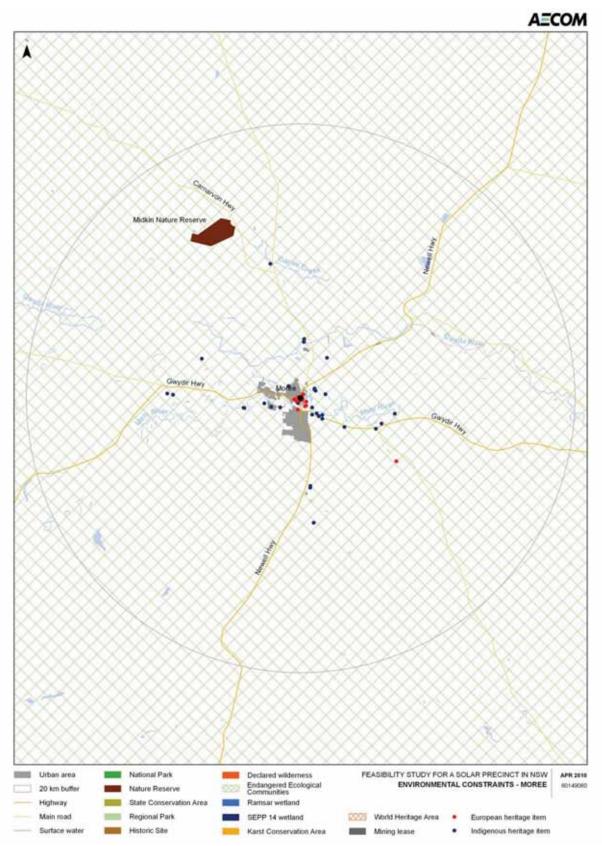
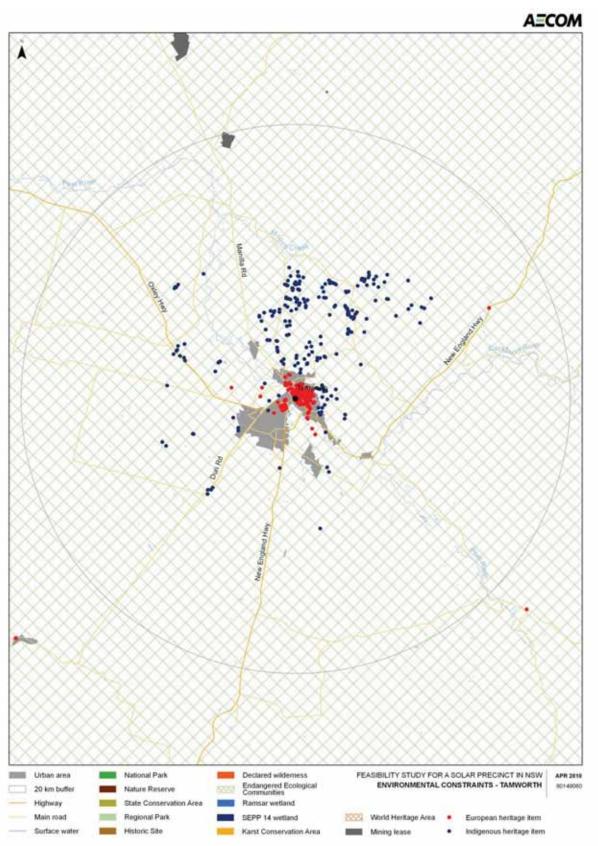


Figure B.26 Environmental constraints within a 20 km radius of Tamworth



B.9.3 Ecology

B.9.3.1 Database searches

Preliminary database searches of the National Parks and Wildlife Service (NPWS) Atlas of NSW Wildlife and Commonwealth EPBC Act Protected Matters Search Tool identified the potential occurrence within the five areas of the following:

- Threatened flora and fauna species;
- EECs recorded or predicted to occur;
- Critical habitat: and
- Ramsar wetlands.

These searches provide species and EECs that are listed and protected under the *Threatened Species Conservation Act 1995* (TSC Act) and/or the EPBC Act. The results are presented in **Table B.38** and **Table B.39**¹⁰.

The five areas each have a relatively similar number of threatened species within each class as shown in **Table B.38**. As such, the presence of threatened species cannot be used as a means of distinguishing between areas.

The Commonwealth EPBC Act Protected Matters Search Tool lists several Ramsar wetlands as occurring within the areas. However, examination of the wetland boundaries on the Department of Environment, Water, Heritage and the Arts (2010) Australian Wetlands Database revealed that these wetlands are not located within the areas. Consequently, protected wetlands are unlikely to be impacted, and as such the presence of Ramsar wetlands is not a factor that may be used to differentiate between areas.

In all areas except for Broken Hill, the EECs listed in **Table B.39** cover the majority of the area whereas Broken Hill does not contain any listed EECs, as can be seen in figures in **Section B.9.2**. Based on the legislation outlined below, using this criterion it would be advisable to locate a proposed solar precinct in an area that does not contain EECs. Although Broken Hill is the only area that does not contain any EECs, this mapping is only a broad, indicative representation of the EEC distribution, and therefore it does not necessarily preclude the other areas from development. Ground truthing of the chosen area will determine what locations exist without EECs within Darlington Point, Dubbo, Moree and Tamworth.

No critical habitat was identified as occurring in any of the areas.

Table B.38 Number of threatened flora and fauna species

Area	Number of threatened species potentially occurring within area				
	Birds	Amphibians	Mammals	Reptiles	Plants
Broken Hill	20	24	37	20	27
Darlington Point	0	2	0	0	1
Dubbo	3	2	8	5	8
Moree	3	0	0	2	2
Tamworth	2	5	7	8	9

Source NPWS Atlas of NSW Wildlife and Commonwealth EPBC Act Protected Matters Search Tool

17 December 201072 B-72

-

¹⁰ Detailed database results are available upon request

Table B.39 Ramsar wetlands and endangered ecological communities

Area	Ramsar wetlands	Endangered Ecological Communities
Broken Hill	Lake Pinaroo	None
Darlington Point	Fivebough and Tuckerbil Swamps	Buloke Woodlands of the Riverina and Murray-Darling Depression Bioregions
		Weeping Myall Woodlands
		White Box-Yellow Box-Blakely's Red Gum Grassy Woodland and Derived Native Grassland
Dubbo	Macquarie Marshes Nature Reserve	Natural grasslands on basalt and fine-textured alluvial plains of northern New South Wales and southern Queensland
		Weeping Myall Woodlands
		White Box-Yellow Box-Blakely's Red Gum Grassy Woodland and Derived Native Grassland
Moree	Gwydir Wetlands	Natural grasslands on basalt and fine-textured alluvial plains of northern New South Wales and southern Queensland
		Weeping Myall Woodlands
		White Box-Yellow Box-Blakely's Red Gum Grassy Woodland and Derived Native Grassland
Tamworth	-	Natural grasslands on basalt and fine-textured alluvial plains of northern New South Wales and southern Queensland
		Weeping Myall Woodlands
		White Box-Yellow Box-Blakely's Red Gum Grassy Woodland and Derived Native Grassland

Source Commonwealth EPBC Act Protected Matters Search Tool

B.9.3.2 Statutory requirements

Threatened Species Conservation Act 1995

The NSW *Threatened Species Conservation Act 1995* (TSC Act) provides for the protection of threatened species, populations and ecological communities, their habitats and critical habitat. Where approval under Part 5 of the EP&A Act is required, a determining authority must not carry out an activity or grant approval in relation to an activity that is "likely" to have "a significant effect" on any threatened "species, populations, ecological communities or their habitats" or critical habitat listed under the TSC Act.

Threatened species, populations, ecological communities or their habitats listed under the TSC Act are all located in the vicinity of the five areas (see **Table B.38** and **Table B.39**). Depending on their proximity to the proposed works, and in turn the project's impact on these items, the project or activity may need formal assessment and approval under the TSC Act. This may involve Seven Part Test(s) to assist in deciding whether there is likely to be a significant effect on any threatened biota, and potentially a Species Impact Statement to further assess the significance of the impact if there is reasonable doubt regarding the likely impacts, or where detailed information is unavailable.

Environment Protection and Biodiversity Conservation Act 1999

The Commonwealth *Environment Protection and Biodiversity Conservation Act 1999* (EPBC Act) regulates actions that may have a significant impact on matters of National Environmental Significance (NES), which include:

- Nationally threatened species and ecological communities;
- Australia's World Heritage properties;
- Ramsar wetlands of international importance;
- Migratory species listed under the EPBC Act (species protected under international agreements);
- Commonwealth marine areas;
- Nuclear actions, including uranium mining; and
- National heritage.

Actions likely to impact on matters of NES require approval from the Commonwealth Minister for the Environment, Heritage and the Arts under Part 6 of the EPBC Act.

The EPBC Act requires separate approvals to be obtained in cases where any NES matters may be affected.

Nationally threatened species and ecological communities, and migratory species listed under the EPBC Act are all located in the vicinity of the five most suitable regional areas. As such, depending on the proximity and in turn the impact on these items, a referral of the proposed action may need to be made to the Commonwealth Minister for Environment, Heritage and the Arts to determine whether the action will need formal assessment and approval under the EPBC Act.

No world heritage properties, Ramsar wetlands, Commonwealth marine areas, nuclear actions or national heritage approvals are anticipated as being necessary, as these NES matters are unlikely to be affected by a solar precinct.

B.9.3.3 National Parks and Wildlife Act 1974

The NSW *National Parks and Wildlife Act 1974* (NPW Act) aims to protect native flora and fauna. Under the NPW Act, protected species and biota cannot be harmed, picked, removed or disturbed without a licence, permit or other authority from the DECCW.

B.9.4 Aboriginal and European heritage

B.9.4.1 Database searches

Items listed by the Heritage Council under the *Heritage Act 1977* (Heritage Act) that are located within the five areas were identified from the State Heritage Register and Inventory. This includes listings on the State Heritage Register, an Interim Heritage Order or protected under section 136 of the *Heritage Act 1977*. It also contains items listed by local councils and shires and state government agencies. Known archaeological sites the five areas were identified from the DECCW Aboriginal Heritage Information Management System (AHIMS).

The results of these searches are illustrated in **Section B.9.2**; **Table B.40**¹¹ presents the number of listed heritage items in each area. The presence of heritage items does not necessarily preclude the development of a solar precinct in any of the areas; however areas containing these heritage items should be avoided to circumvent relevant environmental legislation being triggered.

Table B.40 Heritage items listed to occur within each area

Area	Indigenous	Non-Indigenous	Total
Broken Hill	182	365	547
Darlington Point	35	5	40
Dubbo	290	206	496
Moree	32	28	60
Tamworth	242	301	543

Source Heritage Council and DECCW

B.9.4.2 Statutory requirements

Heritage Act 1977

The *Heritage Act* 1997 (Heritage Act) aims to promote understanding and encourage conservation of NSW's state heritage. Section 139 identifies those circumstances where a permit is required to excavate or disturb land, namely where there is existing knowledge or where there is reasonable cause to suspect that such work will, or is likely to, result in a relic being discovered, exposed, moved, damaged or destroyed.

Accordingly, if the preferred area will impact upon a listed heritage site, further assessment will likely be required and a Section 139 permit obtained.

National Parks and Wildlife Act 1974

The NSW National Parks and Wildlife Act 1974 (NPW Act) aims to protect the integrity of any Aboriginal heritage items. Under the NPW Act, any Aboriginal artefacts or sites cannot be harmed, removed or disturbed without a license, permit or other authority from DECCW.

¹¹ Detailed database results are available upon request

B.9.5 Aboriginal Land Claims and Native Title

B.9.5.1 Aboriginal Land Claims

There are several thousand parcels of land subject to Aboriginal Land Claim under the NSW *Aboriginal Land Rights Act 1983* (ALR Act). The Minister for Aboriginal Affairs administers the ALR Act, however any claims for land made pursuant to this Act and lodged in respect of "claimable Crown lands" as defined in section 36, are determined by the Minister for Lands.

If the land proposed for a solar precinct is already subject to an Aboriginal Land Claim, the proposed solar precinct would not be able to proceed until the Minister has determined the claim not to be claimable Crown lands. Courts have held that "determined" means when all the appeal provisions under the ALR Act have been exhausted. The date of the determination is at the date of the claim.

The definition of claimable Crown lands under section 36 of the ALR Act includes lands that are not lawfully used or occupied or are lands that are not needed, or likely to be needed, for an essential public purpose, or in the opinion of the Minister for Lands, are needed or likely to be needed as residential lands. Therefore it follows that land which is required for a solar plant could be argued to be not claimable Crown land in the event a land claim is made.

If land required for a solar precinct has the effect of attracting an Aboriginal Land Claim, all work has to stop until the Minister has determined the claim.

B.9.5.2 Native Title

Native title needs to be addressed under the Commonwealth *Native Title Act 1993* (NTA) prior to any dealings or development of land. The existing title of land to be used for a solar precinct has relevance to Native Title Claims.

Grants of freehold land extinguish Native Title and, in addition, Schedule 1 of the NTA under the heading "Scheduled Interests" sets out specific interests in land that extinguish Native Title. Included are certain types of leases; for example, a special lease under section 75 or 75B of the *Crown Lands Consolidation Act 1913* that permits the lessee to use the land solely or primarily for (for example) agriculture. This particular lease would extinguish Native Title. The majority of crown land in the Western Division of the State is subject to a lease.

As a general proposition, the reservation of Crown land for a particular purpose does not, by that event alone, extinguish Native Title. Native Title issues and particularly the history of the tenure of the land that is proposed to be developed must be examined in detail.

If it is established that Native Title has not been extinguished, there are a number of avenues which can be explored to enable the proposal to proceed.

The Minister for Lands is nominated under the NTA as the State Minister administering the Native Title process for the State of New South Wales. The LPMA has the administrative carriage of Native Title claimant applications for the Minister which are commenced in NSW on behalf of Native Title Claim groups. (Personal communication, Pieta Laing, Land and Property Management Authority May 2010).

B.9.6 Urban and rural development

Urban development within the five selected areas is illustrated in **Section B.9.2**. These areas are likely to contain sensitive receivers such as residential and commercial properties, including churches, hospitals, nursing homes and child care centres that may be subject to noise, dust and traffic during construction of a solar precinct, and/or those that may be impacted by a change in the surrounding visual setting and/or landscape character.

Outside the urban centre of each of the regional areas, scattered rural residential properties occur on lots of variable size. Rural properties are likely to be more sensitive to an increase in noise, relative to urban receivers, given the relatively quiet ambient noise.

B.9.7 Other potential constraints

Other environmental features that may represent a potential constraint to the development of a solar precinct include:

- Historic Sites:
- Nature Reserves;
- State Recreation Areas;

17 December 201075 B-75

- Regional Parks;
- Designated Wilderness;
- Karst Conservation Sites; and
- State Game Reserves.

Wongarbon Nature Reserve is located approximately 16 km southeast from the Dubbo central business district (**Figure B.24**) and Midkin Nature Reserve is located approximately 14 km northwest from the Moree CBD (**Figure B.25**). No Historic Sites, State Recreation Areas, Regional Parks, Designated Wilderness, Karst Conservation Sites or State Game Reserves exist within the other areas.

The above Nature Reserves do not preclude the selection of Dubbo or Moree for the proposed development. However the Reserves should be avoided when selecting an area in order to avoid triggering the *National Parks and Wildlife Act 1974*, which provides for the protection of Nature Reserves.

B.9.8 Summary

Based on the findings of this data collation task, there are environmental constraints in each of the regional areas. These restrictions do not necessarily preclude any one area from development, but highlight the need to undertake further investigation to ascertain the potential impacts on these constraints. **Table B.41** summarises the number of constraints by category.

The maps produced as part of this environment analysis illustrates the locations within the five areas that are potentially unsuitable for development from an environmental perspective. If these locations are avoided, subject to further environmental investigation, any of the five areas may still be suitable for the development of a solar precinct.

Table B.41 Environmental constraints summary

Regional Area	Threatened Flora and Fauna	EECs	Critical Habitat	Heritage Sites	Matters of NES	Protected Areas*	Mining Leases
Broken Hill	28	0	0	547	566	0	Present
Darlington Point	33	3	0	40	78	0	0
Dubbo	52	3	0	556	613	1	0
Moree	35	3	0	60	99	1	0
Tamworth	47	3	0	243	293	0	Present

Source Heritage Council, DECCW and DEWHA

*Historic Sites, Nature Reserves, State Recreation Areas, Regional Parks, Designated Wilderness, Karst Conservation Sites and State

B.9.8.1 Recommendations

Once a preferred area has been selected, it is recommended that further field studies are undertaken to confirm the reliability of the desktop information gathered during this study for that area, including but not limited to:

- Ground truthing to confirm desktop information and improve understanding of local topography;
- Confirmation of the classification of agricultural land within and adjacent to the preferred area; and
- Environmental Impact Assessment involving:
 - Review of statutory framework;
 - Stakeholder consultation;
 - Flora and fauna site survey;
 - Acoustic assessment;
 - Heritage impact assessment report;
 - Impact assessment of any relevant Aboriginal Land Claims or Native Title holders;
 - Traffic impact assessment; and
 - Assessment of alternatives.

17 December 201076 B-76

B.10 Embedded load

AECOM considered two types of embedded load – firstly, load within the local region and secondly, potential load within the precinct itself. Any embedded load reduces the size and therefore cost of network connections from the transmission network to the edge of the precinct and within the precinct itself, respectively.

B.10.1 Local load

TransGrid has advises the following maximum loads at its substations in 2009 as set out in **Table B.42**. Wellington and Tamworth have the greatest local loads, which reduce the cost of transmission.

Table B.42 Monthly load profile for 2009 (MW)

Month	Broken Hill	Darlington	Dubbo (Wellington)	Moree	Tamworth
January	20	15	169	24	105
February	19	16	172	25	114
March	18	13	142	22	91
April	18	14	122	29	75
May	19	11	131	30	80
June	21	13	141	34	94
July	20	12	148	29	92
August	19	13	148	20	89
September	20	11	140	18	80
October	19	12	134	19	77
November	19	14	176	26	112
December	18	14	174	27	109

Source TransGrid

B.10.2 Potential embedded loads within precincts

Preliminary research and communication with local councils has not identified any significant loads that might be co-located in precincts. Darlington Point and Moree are agricultural regions where the main electricity consumption is from food processing. There are mining activities around Broken Hill, but these are not compatible with solar precincts.

Dubbo Council (Wellington) expects organic growth in electricity demand. However, there is potential for manufacturing due to good water and transport access. The Council has held discussions with a manufacturer interested in developing a facility that could employ up to 300 staff, although no development applications has yet been lodged.

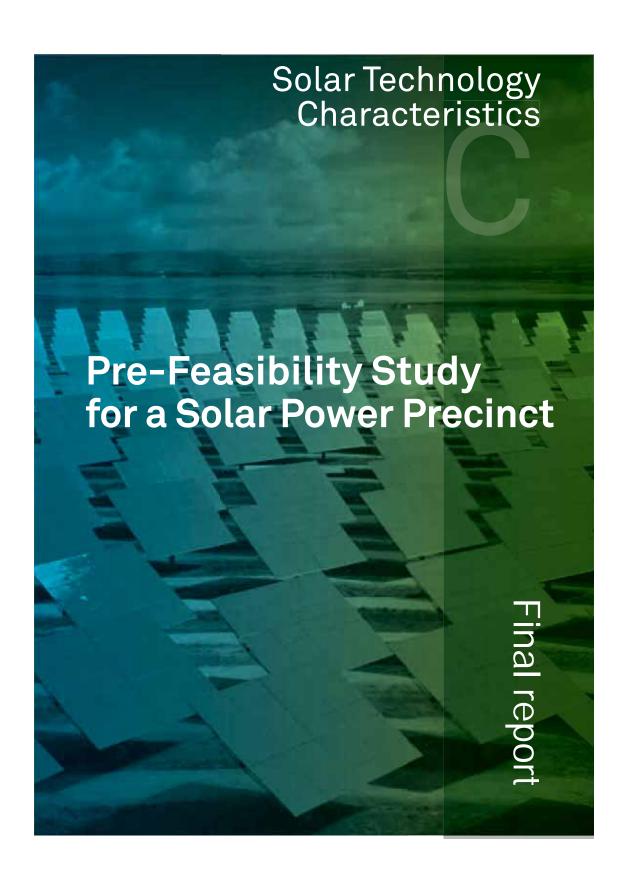
Tamworth has not identified any growth beyond business as usual trends.

Notwithstanding the above, components for solar generations, such as PV panels, could be manufactured at plants co-located within solar precincts. There are many benefits of co-locating manufacturing, including:

- Local load reduces the need for transmission connection;
- Local manufacturing reduces transport costs and damage to delicate components; and
- Development of industry in regional areas where employment costs are lower.

Benefits of local manufacturing have not been included because the scope depends on particular technology chosen.

17 December 201077 B-77



Appendix C Solar technology characteristics

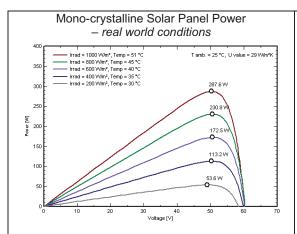
C.1 Mono-crystalline

A 315 watt mono-crystalline solar panel with the following technical characteristics at standard test conditions (standard test conditions: irradiance of 1000W/m², air mass 1.5, and cell temperature 25° C) has been selected for the comparative analysis of areas in this study.

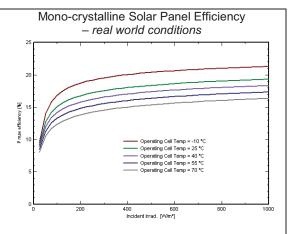
Table C.1 Mono-crystalline panel technical characteristics

Technology	Nominal power rating (Wp)	Vmpp (V)	Impp (A)	Voc (V)	Isc (A)	Module Area (m²)
Si-mono	315	54.7	5.76	64.7	6.14	1.631

The following graphs illustrate how this mono-crystalline solar panel's effective power and efficiency is expected to vary under a range of "real world" operating conditions.



The effective solar panel power is proportional to the incident irradiation (the sunnier the day; the more power available). The solar panel warms up during operation and gets hotter with higher levels of incident irradiation as illustrated on the graph legend. Due to temperature impacts on efficiency (see right) the effective power of the solar panel with an incident irradiation of 1000W/m2 under "real world" conditions is significantly lower than the 315 watt power plate rating quoted under the idealised low temperature "standard test conditions".



At very low irradiation levels (dawn/dusk) there are a number of factors (such as internal resistances and internal diode losses) that manifest as a sudden drop in efficiency as illustrated at the left end of the graph.

At "significant" (day time) levels of irradiation where useful power is available from the sun, the efficiency of mono-crystalline solar panels is very sensitive to temperature; the hotter the solar panel the lower the efficiency.

High altitude sites tend to have lower ambient temperatures than low lying sites, which enables the panels to run cooler improving efficiency. Windy sites assist with cooling the solar panels and improving efficiency.

For the purposes of this study, the following configuration of mono-crystalline panels was assumed:

- Each string consists of 12 solar panels;
- There are 8 strings (96 solar panels) per row width; and
- There are 3 solar panels in row height.

17 December 20101 C-1



17 December 20102 C-2

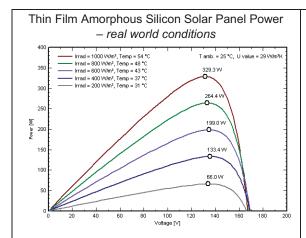
C.2 Thin film

A 360 watt amorphous silicon thin film solar panel with the following technical characteristics at standard test conditions (standard test conditions: irradiance of 1000W/m², air mass 1.5, and cell temperature 25° C) has been selected for the comparative analysis of areas in this study.

Table C.2 Thin film panel technical characteristics

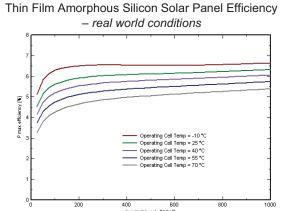
Technology	Nominal power rating (Wp)	Vmpp (V)	Impp (A)	Voc (V)	Isc (A)	Module Area (m²)
a-Si	360	146.4	2.46	187.6	3.00	5.72

The following graphs illustrate how this thin film solar panel's effective power and efficiency is expected to vary under a range of "real world" operating conditions.



The thin film solar panel also has a lower effective power rating under real world conditions compared to the 360 watt plate rating under the ideal (cool) standard test conditions.

The thin film panel is expected to run slightly hotter than the mono-crystalline solar panel (less incident energy is converted to electricity) as illustrated in the graph legend.



The efficiency of thin film amorphous silicon technology drops as the solar panel gets hotter.

Thin film efficiency is slightly less sensitive to temperature effects than the mono-crystalline technology.

Thin film technology is more resilient to long term operation at high temperatures compared to monocrystalline technology.

For the purposes of this study, the following configuration of thin-film panels was assumed:

- Each string consists of 4 solar panels;
- There are 24 strings (96 solar panels) per row width; and
- There are 1 solar panel in row height.

17 December 20103 C-3

C.3 Hybrid

Gas-fired heat transfer fluid boiler

The efficiency (~29%) of a typical solar thermal steam cycle is limited by the temperature of the heat transfer fluid (~400°C). Typically, the flow rate of the heat transfer fluid is reduced during periods of limited solar radiation in order to maintain temperature. An alternative to flow rate control is to add thermal energy to the heat transfer fluid using a gas boiler and heat exchanger.

Gas-fired steam boiler

Gas is used in a standard boiler to convert water into high pressure, high temperature steam. This steam is combined with steam created via the solar thermal plant and fed into the steam turbine. In this configuration, the maximum total efficiency of converting gas into electricity is expected to be ~29%. Steam cycle efficiency gains could be achieved by raising the cycle temperature and pressure via strategic use of gas firing, in conjunction with possible energy storage in steam accumulators.

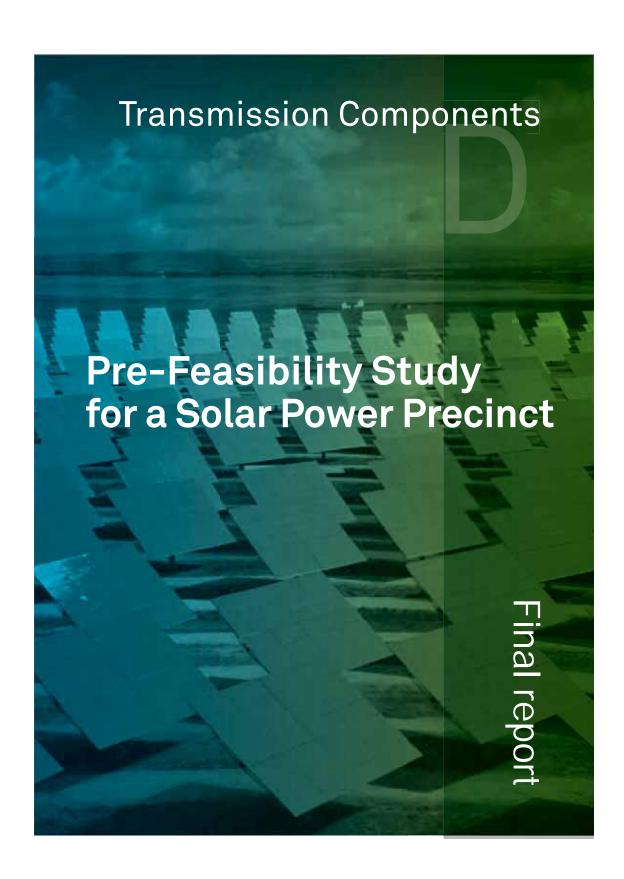
Combined cycle gas turbine

A combined cycle gas turbine (CCGT) is a fundamentally different system to a gas boiler. The gas to electricity conversion efficiencies are higher for a CCGT (40%), compared to a standard steam cycle (35%), but the capital costs are significantly higher (\$1m per MWp) compared with a gas boiler (\$50,000 per MWp). For this reason, it is not cost effective to consider CCGT for gas-assist. A CCGT could be better used as a base load generation plant in a solar-assisted gas configuration.

Steam accumulator

A variable-pressure steam accumulator, is an option for smaller, short term, shoulder storage. Steam accumulators store sensible heat in pressurised saturated liquid water, profiting from the high volumetric storage capacity of liquid water; they are capable of providing saturated steam in the 100-300°C temperature range at pressures of up to 100 bar. Hot pressurised water comprises between 50-90% of the volume of a variable-pressure accumulator, which relies on changes in pressure within the storage vessel to flash the water to steam. The large volume of water allows for greater storage capacities than could be achieved with a direct steam accumulator. High discharge rates and rapid deployment of the storage system are possible since water is used both as a storage medium and a working medium, making the steam accumulator an ideal candidate for a buffer or short-term storage system.

17 December 20104 C-4



Appendix D Transmission components

Table D.1 Transmission component costs

ID	Voltage (kV)	Gen Rating (MW)	Plant Rating (MVA)	Description	Cost (\$'000)		
1.1	330	250	280	Generator connection with HV breaker, comprising 1 x LV CB, 1 x 320 MVA transformer and 1 x HV CB to suit 330 kV	5,000		
1.2	330	250	280	Generator connection without HV breaker comprising 1 x LV CB and 1 x 320 MVA transformer	4,000		
1.3	330	1000	1280	Generator connection with HV breaker, comprising 4 x LV CBs, 4 x 320 MVA transformers and 4 x HV CBs to suit 330 kV	20,000		
1.4	330	1000	1280	Generator connection without one HV breaker, comprising 4 x LV CBs and 4 x 320 MVA transformers and 1 x HV CB	17,000		
2.1	330	250	280	Civil works and earth grid for one new 330 kV bay	500		
2.2	330	250	280	Civil works and earth grid for one new 330 kV diameter	1,400		
2.3	330	250	280	Civil works and earth grid for a new 330 KV switching station laid out for breaker and a half with 2 diameters and 3 x 330 kV CBs. Minimal treatment only.	3,000		
2.4	330	1000	1280	Civil works and earth grid for four new 330 kV bays	2,000		
2.5	330	1000	1280	Civil works and earth grid for a new 330 KV switching station laid out for breaker and a half with 4 diameters and 12 x 330 kV CBs. Full establishment for ultimate 1,000 MW development.	5,000		
3.1	330	250	280	1 x connection to existing 330 kV substation, comprising 1 x 330 kV bay and 1 x 330 kV CB (does not include civil works).	1,500		
3.2	330	250	280	1 x connection to existing 330 kV transmission substation, comprising 1 x 330kV diameter and 3 x 330 kV CBs (does not include civil works)			
3.3	330	250	280	1 x connection to existing 330 kV transmission line, comprising establishment of a new 330 KV switching station laid out for breaker and a half with 2 diameters and 3 x 330 kV CBs. Civil works not included.	6,000		
3.4	330	1000	1280	4 x Connections to existing 330 kV substation, comprising 4 x 330 kV bays and 4 x 330 kV CBs. Civil Works not included.	6,000		
3.5	330	1000	1280	1 x Connection to existing 330 kV transmission line, comprising establishment of a new 330 KV switching station laid out for breaker and a half with 4 diameters and 12 x 330 kV CBs.	25,000		
4.1	220	250	280	Generator connection with HV breaker, comprising 1 x LV CB, 1 x 320 MVA transformer and 1 x HV CB to suit 220 kV	4,500		
4.2	220	250	280	Generator connection without HV breaker comprising 1 x LV CB and 1 x 320 MVA transformer	3,700		
4.3	220	1000	1280	Generator connection with HV breaker, comprising 4 x LV CBs, 4 x 320 MVA transformers and 4 x HV CBs to suit 220 V			
4.4	220	1000	1280	Generator connection without HV breaker, comprising 4 x LV CBs and 4 x 320 MVA transformers	14,800		
5.1	330	250	280	Civil works and earth grid for one new 220 kV bay	400		
5.2	330	250	280	Civil works and earth grid for one new 220 kV diameter	1,200		
5.3	330	250	280	Civil works and earth grid for a new 220 KV switching station laid out for breaker and a half with 2 diameters and 3 x 220 kV CBs. Minimal treatment only.	2,400		

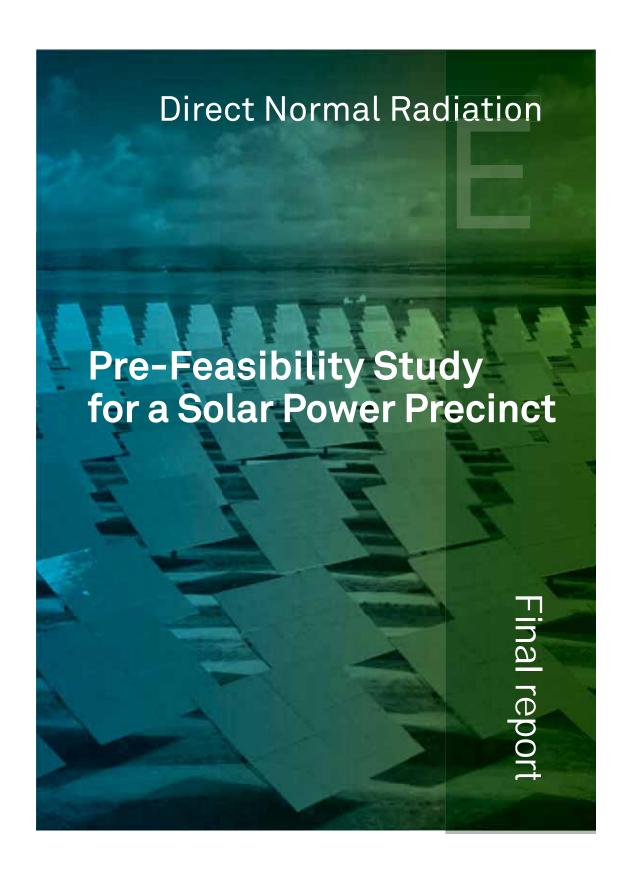
17 December 20101 D-1

ID	Voltage (kV)	Gen Rating (MW)	Plant Rating (MVA)	Description	Cost (\$'000)
5.4	330	1000	1280	Civil works and earth grid for four new 220 kV bays	1,600
5.5	330	1000	1280	Civil works and earth grid for a new 220 KV switching station laid out for breaker and a half with 4 diameters and 12 x 220 kV CBs. Full establishment for ultimate 1,000 MW development.	4,500
6.1	220	250	280	1 x connection to existing 220 kV substation, comprising 1 x 220 kV bay and 1 x 220 kV CB	1,300
6.2	220	250	280	1 x connection to existing 200 kV transmission substation, comprising 1 x 220kV diameter and 3 x 220 kV CBs (does not include civil works)	4,500
6.3	220	250	280	1 x Connection to existing 220 kV transmission line, comprising establishment of a new 220 KV switching station laid out for breaker and a half with 2 diameters and 3 x 220 kV CBs.	5,600
6.4	220	1000	1280	4 x Connections to existing 220 kV substation, comprising 4 x 220 kV bays and 4 x CBs	5,200
6.5	220	1000	1280	1 x Connection to existing 220 kV transmission line, comprising establishment of a new 220 KV switching station laid out for breaker and a half with 4 diameters and 12 x 220 kV CBs.	24,500
7.1	132	250	280	Generator connection with HV breaker, comprising 2 x LV CBs, 2 x 160 MVA transformers and 2 x HV CBs to suit132 kV	
7.2	132	250	280	Generator connection without HV breaker comprising 2 x LV CBs and 2 x 160 MVA transformers	5,000
7.3	132	1000	1280	Generator connection with HV breaker, comprising 8 x LV CBs, 8 x 160 MVA transformers and 8 x HV CBs to suit 132 V	24,000
7.4	132	1000	1280	Generator connection without HV breaker, comprising 8 x LV CBs and 8 x 320 MVA transformers	20,000
8.1	132	250	280	1 x Connection to existing 132 kV substation, comprising 2 x 132kV bays and 2 x 132 kV CBs	2,000
8.2	132	250	280	1 x Connection to existing 132 kV transmission line, comprising establishment of a new 132 kV switching station laid out for folded bus with 2 incomers, 4 feeders and 1 bus coupler for a total of 7 bays and 7 x 132 kV CBs	8,000
8.3	132	1000	1280	4 x Connections to existing 132 kV substation, comprising 8 x 132 kV bays and 8 x CBs	8,000
8.4	132	1000	1280	N/A	N/A
9.1	330	250	1280	1 x Single circuit 330 kV transmission line, steel towers	900
9.2	330	1000	2240	1 x Double circuit 330 kV transmission line steel towers	1,100
9.3	220	250	280	1 x Single circuit transmission line, steel towers	800 per km
9.4	220	1000	1280	2 x Double circuit transmission line, steel towers	
9.5	132	250	280	1 x Double circuit transmission line, steel towers	700 per km
9.6	132	1000	1280	4 x Double circuit transmission line, steel towers	2,800 per km

Note Diameter refers to the plant along a cross section between busbars, especially when referring to breaker and a half configurations. In this case a complete diameter would include three circuit breakers and all disconnectors, CTs, VTs etc.

Source AECOM

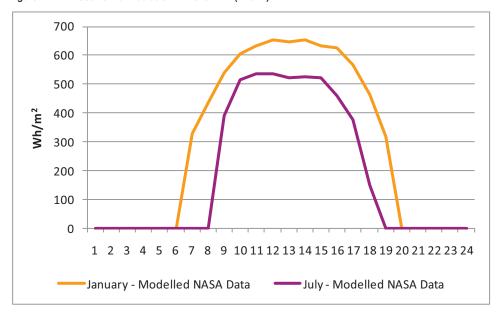
17 December 20102 D-2



Appendix E Direct Normal Radiation

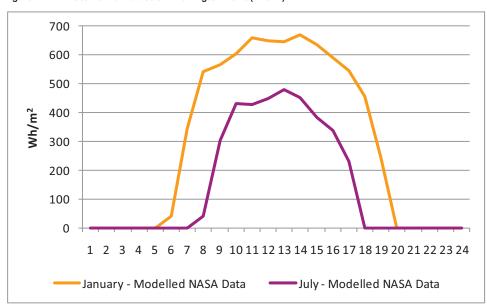
he figures below illustrate the average January and July Direct Normal Radiation at each area.

Figure E.1 Direct Normal Radiation – Broken Hill (Wh/m²)



Source AECOM based on NASA data

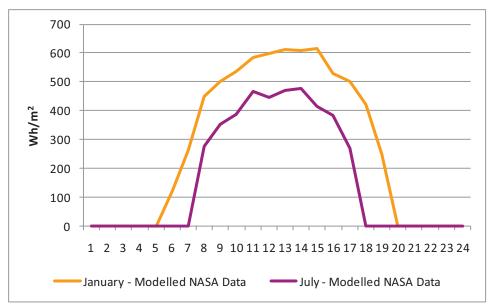
Figure E2 Direct Normal Radiation –Darlington Point (Wh/m²)



Source AECOM based on NASA data

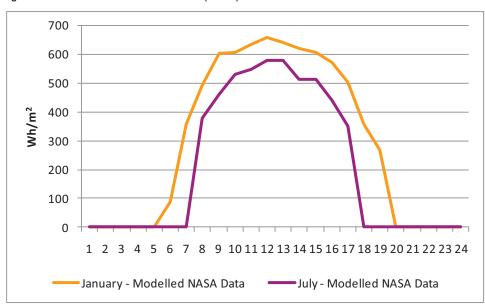
17 December 20101 E-1

Figure E.3 Direct Normal Radiation – Dubbo (Wh/m²)



Source AECOM based on NASA data

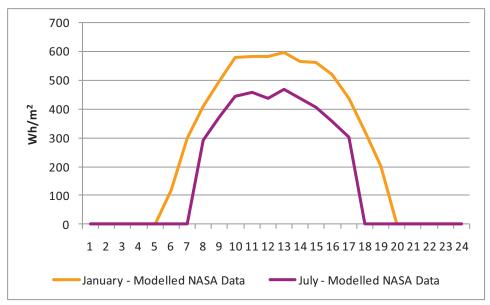
Figure E.4 Direct Normal Radiation -Moree (Wh/m²)



Source AECOM based on NASA data

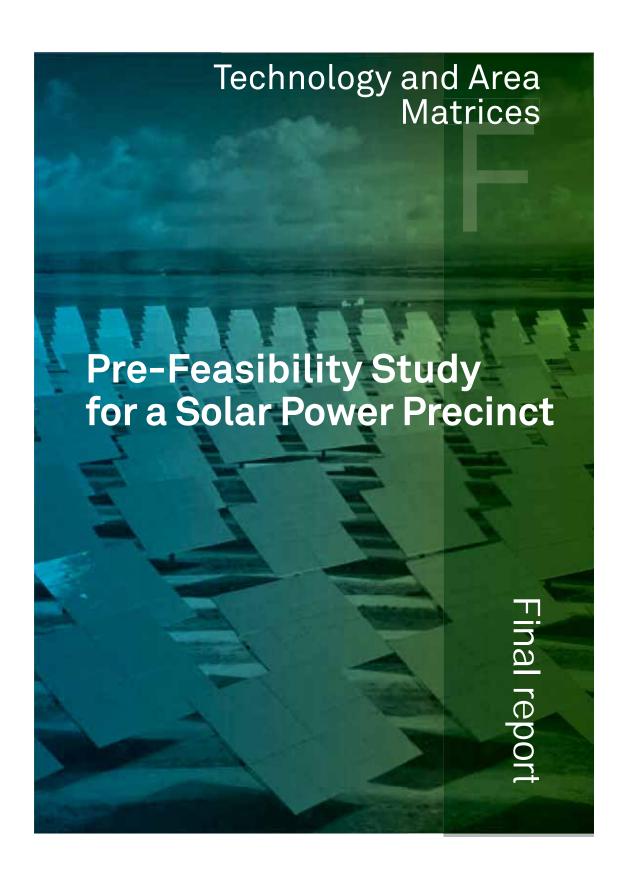
17 December 20102 E-2

Figure E.5 Direct Normal Radiation –Tamworth (Wh/m²)



Source AECOM based on NASA data

17 December 20103 E-3



Appendix F Technology and Area Matrices

Figure F.1 Technology matrix

Characteristic	Units	PV		Thermal	Thermal	
		Mono- crystalline PV	Thin film	Solar trough (air)	Solar tower (air)	Hybrid (air)
General						
Mounting frame	N/A	Static	Static	Static	Static	Static
Cooling type	Air / water	Air	Air	Air	Air	Air
Land requirements						
Land size (ha / MW)	ha / MWp	1.0	3.3	2.4	3.5	2.4
Total hectares (250 MW)	ha	259	830	601	875	601
Total hectares (1000 MW)	ha	1035	3322	2404	3500	2404
Water requirements						
Operations	ML / MWp	0.4	1.1	0.6	0.7	0.6
Feed water	ML / MWp / year	0	0	0.2	0.2	0.2
Gas requirements						
Operations	GJ / MWp	0	0	190	190	190
Technology cost (in 2014)						
Total Technology cost	\$ / Wp	4.31	4.24	3.82	3.67	4.12
Annual maintenance costs						
Total annual maintenance	\$ / MWp	28,500	52,200	43,200	50,800	56,200
Major periodic maintenance						
Frequency	Years	12	12			

Source AECOM

Figure F.2 Area matrix

Characteristic	Units	Broken Hill	Darlington Point	Dubbo	Moree	Tamworth
Coordinates						
Longitude	Digital degrees	141.44	146.00	148.60	149.84	150.93
Latitude	Digital degrees	-31.96	-34.57	-32.25	-29.46	-31.09
Weather						
NASA derived average daily insolation	MJ / m ² .day	19.22	18.18	18.40	19.73	18.47
Generation						
Mono-crystalline PV	MWh/ MWp / year	1,652	1,578	1,585	1,684	1,589
Thin film PV	MWh/ MWp / year	1,661	1,590	1,600	1,694	1,609
Solar trough (air)	MWh/ MWp / year	1,858	1,693	1,716	1,927	1,692
Solar tower (air)	MWh/ MWp / year	2,261	2,085	2,097	2,334	2,058
Hybrid (air) - solar	MWh/ MWp / year	1,858	1,693	1,716	1,927	1,692

17 December 20101 F-1

Characteristic	Units	Broken Hill	Darlington Point	Dubbo	Moree	Tamworth
	MWh/ MWp	1,652	1,817	1,794	1,583	1,818
Hybrid (air) – gas (250 MW)	/ year					
	MWh/ MWp	1,652	1,817	1,794	1,583	1,818
Hybrid (air) – gas (1,000 MW)	/ year					
Capacity factor						
Mono-crystalline PV	%	18.9%	18.0%	18.1%	19.2%	18.1%
Thin film PV	%	19.0%	18.2%	18.3%	19.3%	18.4%
Solar trough (air)	%	21.2%	19.3%	19.6%	22.0%	19.3%
Solar tower (air)	%	25.8%	23.8%	23.9%	26.6%	23.5%
Hybrid (air)	%	21.2%	19.3%	19.6%	22.0%	19.3%
Transmission (250 MW)						
Distance to substation	km	10.0	9.5	4.0	0.0	6.7
Distance to 330 kV line	km	521.8	9.5	46.0	138.1	4.7
Total	\$m	22.6	15.6	48.4	138.3	13.0
Cost per watt	\$ / W	0.09	0.06	0.19	0.55	0.05
Transmission (planned 1000 MW)						
Distance to substation	km	521.0	9.5	46.0	0.0	6.7
Distance to 330 kV line	km				138.1	4.7
Total	\$m	585.5	27.6	60.4	150.3	25.0
Cost per watt	\$ / W	0.59	0.03	0.06	0.15	0.03
Land cost (250 MW)						
Mono-crystalline PV	\$m	0.3	0.3	0.4	0.7	0.9
Thin film PV	\$m	0.9	0.7	1.0	2.1	1.6
Solar trough (air)	\$m	0.6	0.5	0.7	1.6	1.2
Solar tower (air)	\$m	0.9	0.7	1.0	2.3	1.7
Hybrid (air)	\$m	0.6	0.5	0.7	1.6	1.2
Land cost (1000 MW)						
Mono-crystalline PV	\$m	1.1	0.4	0.9	2.3	0.5
Thin film PV	\$m	3.5	1.1	2.8	7.3	1.5
Solar trough (air)	\$m	2.5	0.8	2.0	5.3	1.1
Solar tower (air)	\$m	3.7	1.2	3.0	7.7	1.6
Hybrid (air)	\$m	2.5	0.8	2.0	5.3	1.1
Water						
Water fixed cost	\$m	1	2	1	1	1
Variable water cost	\$m / ML	1500	150	300	100	300
Gas delivered prices						
Distance to pipeline	km	200	30	0	200	0
Hybrid requirement (250 MW)	GJ / MWh	12.7	12.7	12.7	12.7	12.7
Hybrid requirement (1000 MW)	GJ / MWh	12.7	12.7	12.7	12.7	12.7
Delivered price - truck	\$ / GJ	13.00	9.20	11.80	13.00	11.80
Delivered price - pipe (Hybrid)	\$ / GJ	7.20	6.40	7.40	8.40	7.40
Environmental	7					
Heritage sites		547	40	556	60	243
Mining leases		Present	0	0	0	Present
Wetlands		Present	Present	Present	Present	0

Source AECOM

17 December 20102 F-2



AECOM is a global provider of professional technical and management support services to a broad range of markets, including transportation, facilities, environmental, energy, water and government. With approximately 51,000 employees around the world, AECOM is a leader in all of the key markets that it serves. AECOM provides a blend of global reach, local knowledge, innovation, and technical excellence in delivering solutions that enhance and sustain the world's built, natural, and social environments. A Fortune 500 company, AECOM serves clients in more than 100 countries and had revenue of \$6.3 billion during the 12-month period ended June 30, 2010. More information on AECOM and its services can be found at www.aecom.com.