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No easy choices: which way to Australia's energy future? Technology Analysis

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This report was written by Tony Wood, Program Director, Tristan Edis, Research Fellow, Helen Morrow, Associate and Daniel Mullerworth, Associate, Grattan Institute. John Daley, CEO made a substantial contribution and James Button assisted in its preparation.

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1. Summary of findings

Australia must substantially and relatively quickly change the nature of its electricity supply. The Commonwealth's goal is to reduce Australia's greenhouse gas emissions to 80% below 2000 levels by 2050. Much of this reduction will need to come from changes in electricity production, while keeping energy secure and affordable for Australians.

How might this happen? This report and its companion main report assess the prospects for seven technologies that generate electricity with near-zero emissions, and which are already developed enough that large-scale deployment by 2050 is plausible. They are wind, solar PV, geothermal, nuclear, Concentrating Solar Power (CSP), Carbon Capture and Storage and bioenergy. Each of these technologies might materially contribute to Australia's future energy mix. All face obstacles to achieving their full potential.

The main report, available on the Grattan Institute website, sets out the findings of the technology assessments and reviews the implications for government policy in terms of developing and deploying low emissions electricity technology. This *Technology Analysis* report assesses each of the seven low-emissions technologies in detail. This includes a review of the barriers that the transmission network can pose to large-scale deployment of low-emissions energy technologies. Transmission is a special case, being monopoly infrastructure and essential to electricity supply.

Table 1.1 summarises our assessment of the seven technologies. The shading in this table indicates the depth of the obstacles to commercially deploying the technology on a scale that would materially contribute to Australia's electricity generation mix.

Table 1.1: Summary of technology assessments

	Scaleability	Current costs and rate of decline	Extent of commercial deployment	Prospects for near term private sector involvement	Government barriers
Wind	Could supply at least 20% of Australia's electricity needs. Given wind variability, other sources also required	Can scale up rapidly at less than key benchmark of $150/MWh, although cost decline has flattened	Significant deployment underway in Australia	Significant investment underway given effective subsidy through 20% renewable energy target Private sector readily involved provided some government support maintained	Grid infrastructure and system integration needs to be improved for remote sites to support multiple, expensive and timely network upgrades. Community resistance to wind farm noise can achieve a high profile: the regulatory framework needs to provide certainty for all stakeholders
Solar PV	Could generate more than30% with grid integration management; significantly more with viable storage	Costs are fair, not yet competitive with wind, but falling rapidly Value depends on local network and timing of peak demand	Already widespread in Australia, but not yet at scale to impact grid	Growing strongly from existing base, but dependent on existent government subsidies	Large-scale deployment constrained by integration with electricity distribution grid, in which Australia lacks skills and knowledge.
Concentrating Solar Power	Resource sufficient to meet all of Australia's electricity needs Thermal storage and gas cogeneration needed to overcome intermittency	Currently uncommercial; costs (particularly mass production of components, better solar field engineering, and more efficient temperature fluids) may decline with development and broad deployment. Towers likely to be cheaper than other CSP technologies in medium term	Some deployment overseas, but limited scale as high cost relative to wind and solar PV	Some involvement already in Australia, but dependent on government subsidies	Grid infrastructure and system integration needs to be improved for remote sites (as per Wind). Government needs to collect and disseminate solar radiation data, given knowledge spillovers.
Geothermal	Abundant resource in Australia could underpin a major contribution	Reliability and costs highly uncertain as still at exploration and development stage, with fundamental engineering challenges in reservoir management	Minimal deployment in Australia, although private companies involved in exploration	May be involved in more accessible shallower Hot Sedimentary Aquifer, which will also develop experience and investor confidence to exploit the more difficult Hot Rocks resource.	Government needs to map, model and disseminate geological resource data, given knowledge spillovers Grid infrastructure and system integration needs to be improved for remote sites (as per Wind). A clear regulatory framework is required to provide certainty for stakeholders.

	Scaleability	Current costs and rate of decline	Extent of commercial deployment	Prospects for near term private sector involvement	Government barriers
Carbon Capture and Storage	Could contribute very significantly and extend life of existing and coal and gas plants	Projected costs competitive, but not proven at scale. Early costs will be high as models are developed to integrate different stages and interests	Only deployed for gas production fields, which are much less complex than CCS for power generation	Absolute size of investment a major barrier for early mover projects Difficult to set up given complexity of many different stages and industries working together	Government needs to map, model and disseminate geological storage resource data, given knowledge spillovers. Clear legal and regulatory frameworks are required to provide certainty for stakeholders.
Nuclear	Could meet a large proportion of Australia's electricity needs	Gen 3+ well developed, but costs uncertain as limited experience in last 25 years with plants meeting increased regulatory requirements Gen 4 may be cheaper and more efficient, but at R&D stage and unproven	Widespread deployment overseas in the past, but limited deployment in last 25 years in developed countries with stringent regulation No deployment in Australia	Public companies better placed in short run given greater ability to manage financial and regulatory risks	Legal and regulatory frameworks are required in Australia so lead time to implementation is 15-20 years. Government could reduce these by 5 years without committing to build Government needs to promote conversation to create social licence to operate
Bioenergy	Significant energy available, although unlikely to be more than 20% of energy demands given competing needs for food. Easy to control short-run output to meet peak daily demand, but some seasonal variation	Not competitive unless supply chain from production to transport improved; likely to take over 10 years. Local customisation required, particularly for nature of demand for electricity and heat and feedstock Commercial viability also may be enhanced through improvements to reduce minimum economic scale to <5MW plants	Employed at significant scale in a number of countries and the combustion technology well-understood. Feedstocks with greatest potential in Australia only deployed in a handful of projects	Several private sector developers already involved in Australia. At current costs, some form of additional government support will be necessary for meaningful levels of project development.	Grid infrastructure and system integration needs to be improved to cater for connection of large number of relatively small power stations in regional areas

2 Wind power

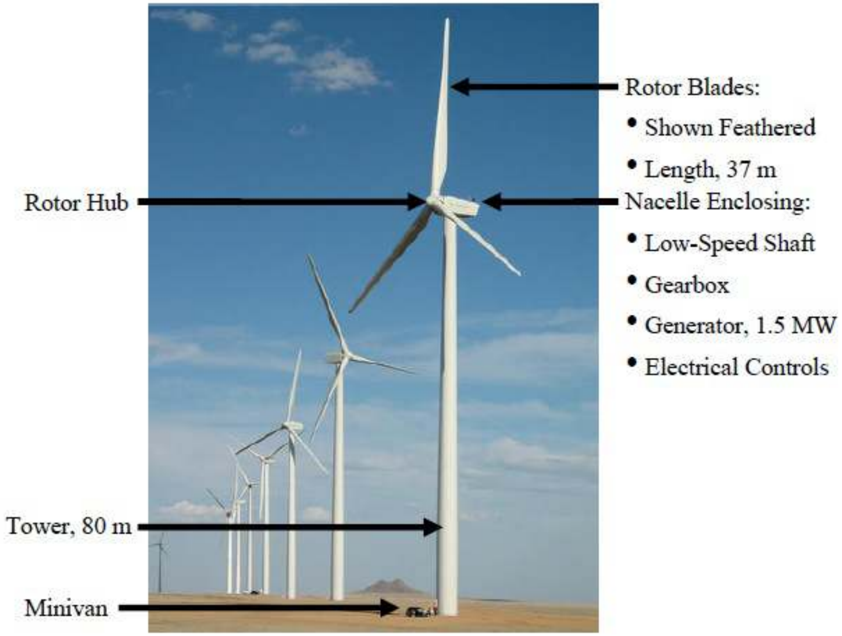
2.1 Synopsis

- Wind power could readily supply at least 20% of Australia's electricity needs without technical difficulty but currently is at just 2%.
- It is the only low emission power technology available to Australia today that could be ready for rapid scale-up within a short period of time at a cost within our key benchmark of $100 to $150 per megawatt-hour.
- The cost of wind power generation may continue to decline with further technology development, although at a lower rate than for other, less mature low emission technologies.
- The low correlation between wind energy and electricity demand means it faces limitations which require Australia to develop system integration capabilities and/or other low carbon electricity options to complement it over the longer term (beyond 2030).
- Transmission infrastructure connection processes and regulatory frameworks are not well-suited to major expansion in locations more remote from the existing grid. This barrier is shared with several other technologies and needs to be addressed by governments.
- Community concerns with wind farm developments have had some impact on projects and regulatory planning and approval processes. It is important that clear, stable regulatory frameworks exist to provide certainty for all stakeholders. some.

2.2 What is wind power?

While there are a range of alternative wind turbine designs, large, horizontal axis turbines with three separate rotor blades overwhelmingly dominate installed capacity (Figure 2.1).

Figure 2.1 Example of a typical wind turbine



Source: US Department of Energy (2008)

The wind acts to turn the blades around the rotor hub which then turns a generator located inside the nacelle at the top of the tower to produce electricity. Modern turbines tend to be placed on top of towers usually around 80 metres or higher above the ground which enables the turbine to access higher wind speeds subject to less turbulence than closer to the ground.

2.3 How scalable is wind power in Australia?

Wind turbine technology has advanced considerably over the past three decades. It is now a mature technology capable of generating large quantities of electricity from available wind resources.

The table below illustrates how wind speed influences the amount of output produced by a wind turbine, in this case a current generation wind turbine that will be employed at the Macarthur Wind Farm in Western Victoria. Other turbine models produce different yield at the same wind speeds but as a general rule higher wind speeds lead to lower generation costs through either greater amounts of output or the same amount of output from a cheaper turbine with shorter blades. Turbine yields have been constantly improving. [1] This means that even as we fully exploit the best available wind sites over time, we can continue to realise good energy yield from lesser quality sites using longer and more efficient blades.

[1] US Dept of Energy (2008), Wiser & Bollinger (2011)

Table 2.1 Relationship between wind speed and turbine capacity

Wind speed (metres / sec)	Capacity yield
5	10.4%
5.5	12.8%
6	16.1%
6.5	23.1%
7	30.6%
7.5	38.2%
8	46.2%
8.5	54.6%
9	67.3%
9.5	75.3%
10	86.1%
11	96.0%
12	99.3%
13	100.0%
25	100.0%

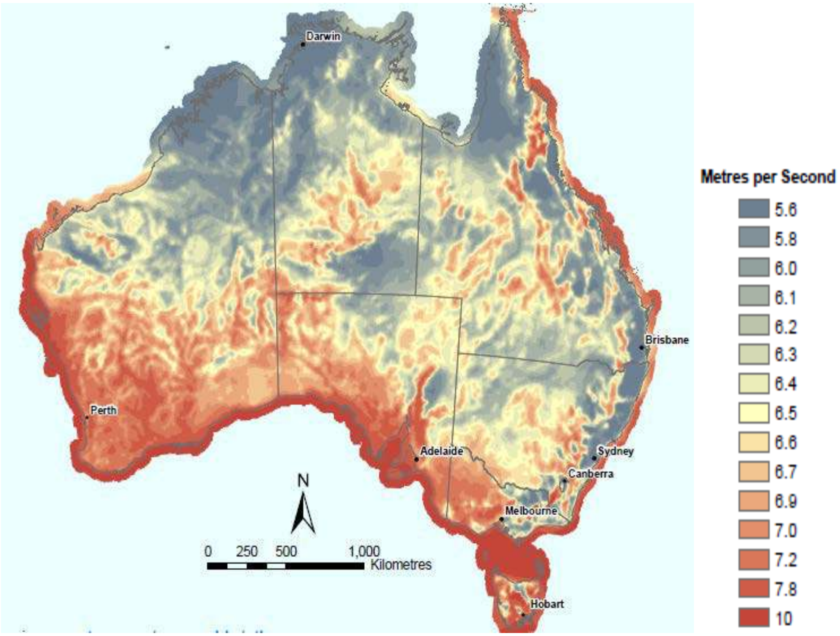
Note: based on Vestas V-112 3MW turbine assuming idealised conditions of 100% availability, 100% park efficiency and air density 1.225kg/m3
Source: Vestas (2011)

ABARE estimates that Australia has around 600,000 km^2 of sparsely populated land with average wind speeds at or above seven metres a second (see Figure 2.2).[2] Turbines (similar to the one in Table 2.1) spaced no more densely than one every 14 square kilometres over this land area could produce more electricity than Australia consumes.

While this would not be entirely practical – the energy produced would not precisely match demand, for example – it shows that wind power is already capable of supplying large quantities of electricity in Australia with existing technology. As well, many of the best sites are in regions around the southern and western coastline and the Great Dividing Range, which are not all that distant from major population centres and large electricity loads relative to options such as geothermal or solar thermal.

[2] ABARE & Geosciences Australia (2010)

Figure 2.2 Australia mean wind speed – 80m hub height



Source: ABARE and Geosciences Australia (2010)

2.3.1 Current generating capacity

Wind is now a well-established technology, employed at large scale by utilities around the globe and in Australia.

Table 2.2 shows that Australia has notable amounts of wind power installed or under construction. It has also established a large pipeline of development sites, detailed in section 2.4.2. Although wind still only represents a small proportion of total electricity supply in Australia (around 2%), there is large room for further growth.

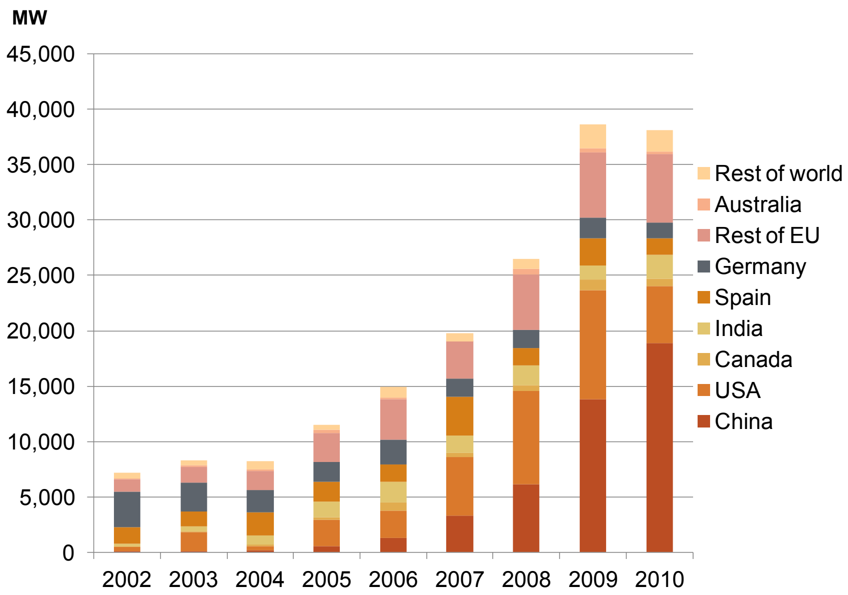
Table 2.2 Australian wind capacity

Development stage	Capacity (MW)
Operating	2,185
Construction	1,005

Source: Grattan Institute (2011), Grattan Institute Power Plant Database

In both 2009 and 2010 the amount installed globally equalled more than half Australia's entire installed electricity generating capacity (Figure 2.3). Global wind turbine manufacturers would have little difficulty supporting a major scale-up of Australian wind power.

Figure 2.3 Global annual wind power capacity installations



Source: Global Wind Energy Council (2011)

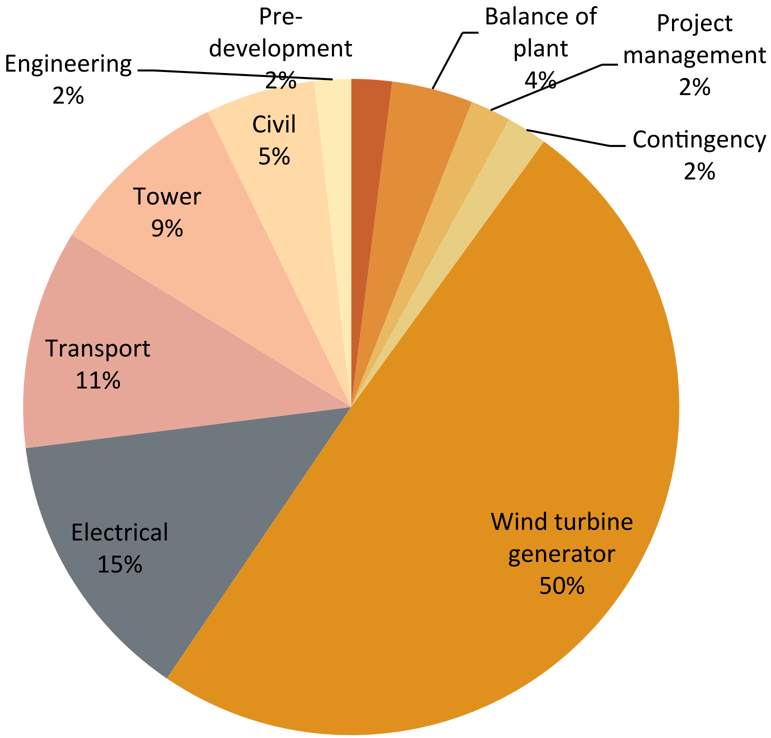
2.3.2 Costs

Wind farms constructed in Australia can today achieve costs within the benchmark of \$100 to \$150 per megawatt-hour that we applied in this study for competitiveness (see Figure 2.3 in the main report that accompanies this publication).

Wind farm economics are driven almost entirely by the capital cost of the plant and the amount of output that the plant can produce (its capacity factor). Operating and maintenance costs are relatively minor at about \$8 to \$10 a megawatt-hour.[3] Figure 2.4 shows that capital cost is largely a function of the cost of the turbine.

[3] Wiser & Bollinger (2011); Pers Comm Peter Cowling (2011)

Figure 2.4 Wind farm capital cost breakdown



Source: Fraser (2010)

Capital costs of Australian wind farms have varied substantially over the past eight years, due to changes in the exchange rate, the dynamics of the turbine supply market, increases in construction costs induced by the mining boom, differences in grid connection costs and fluctuating steel prices. Capital costs have moved from as low as $1.8 million per megawatt fully installed and connected to the grid in around 2004 to as high as $3.5 million per megawatt in 2008 when there were significant supply bottlenecks.[4] Today they are between $1.8 and $2.5 million per megawatt varying according to the reputation of the turbine supplier, the length of blades, hub height, size of the wind farm, grid connection, and site topography.[5]

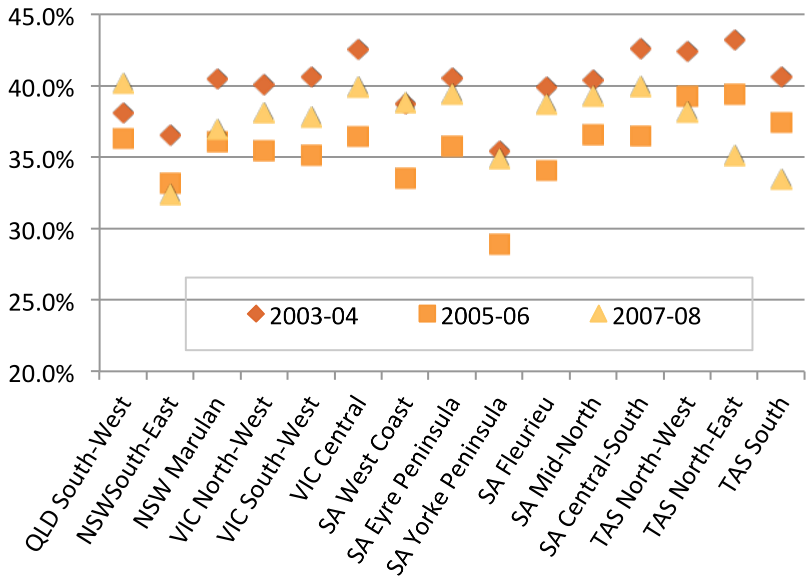
The output that turbines can produce from a given wind speed has increased considerably due to improvements in turbine siting, higher hub heights, larger and lighter blades, better control systems, and more efficient drive-trains. These improvements mean that sites with wind speeds of 7.5 to 7.8 metres per second can achieve capacity factors of 35 to 40% which in the past required wind speeds of 8 to 8.5 metres a second.[6]

According to CSIRO simulations using historical wind data and the latest wind turbine designs, regions currently under active development for wind farms in the National Electricity Market could be expected to achieve capacity factors around 35 to 40% (Figure 2.5).[7] Data on existing and proposed wind farms[8] suggest that WA wind farms would achieve capacity factors above 40%. Based on current capital costs, such wind farms are likely to

[4] EPRI (2009); ABARE (2010); MMA (2006); Edis (2011); Wiser & Bollinger (2011); Pers Comm Barrington, M (2008); Alderson, H. Barber, T. and Yeo, S. (2010)
[5] Pers Comm Cowling, P. (2011)
[6] US Dept of Energy (2008); Wiser & Bollinger (2011); Pers Comm Parris, D. (2011); Pers Comm Cowling, P. (2011)
[7] AEMO (2011a)
[8] Green Energy Markets (2011); ROAM Consulting (2010)

realise generation costs of around $90 to $130 per megawatt-hour.[9]

Figure 2.5 Simulated future wind farm regional capacity factors based on historical wind data[10]



Source: AEMO (2011a)

2.4 What are the obstacles to development of wind power?

Wind Power faces the least obstacles to scale-up in Australia of any of the technologies assessed. Over the past 15 years Australia has steadily built-up many of the assets and capabilities required to support a scale-up of wind to provide a material proportion of Australia's electricity. In addition the underlying power conversion technology can be readily imported. However, transmission grid infrastructure and system integration capabilities still require improvement to support very high amounts of wind.

Investment in wind power in Australia has been underpinned by the Renewable Energy Target. If this support was to be withdrawn or phased out ahead of wind becoming commercially competitive in an emissions constrained market, industry growth would stall and several of these capabilities and assets would be lost. If global wind development and rising emissions prices made wind competitive in the future, rebuilding these capabilities would take some time. Addressing the transmission grid and system integration barriers would be necessary under either scenario.

2.4.1 Power conversion technology

Power conversion technology is not a notable constraint of concern to Australia, although we have a strong interest in ongoing improvement of the technology, given its likely high importance to our future electricity requirements.

As highlighted in section 2.2 of the main report, wind is already one of the cheapest options for producing low emission power

[9] Grattan Institute (2011b); Pers Comm Cowling, P.(2011); Fraser (2010); Infigen Energy (2010); Infigen Energy (2011)
[10] While some existing wind farms have been developed in Australia with capacity factors noticeably below the levels indicated above (usually due to errors in siting resulting in excessive wind turbulence or transmission constraints) interviews with wind experts suggest that developers are extremely unlikely to repeat these same mistakes.

and further significant improvement is expected over coming decades[11].

Denmark, Germany, Spain and the US are well established as leaders in the design of wind turbine technology, with China emerging as a notable challenger.[12] Given its rich wind resources[13], Australia has a strong interest in the improvement of wind technology, but it does not possess notable expertise in this area, and has no need to customise the technology to local conditions. This lack of domestic expertise is not a significant barrier to large scale-up in this country and, aside from towers, we already import all the major turbine components.[14] Also, as indicated in section 2.3.1, global manufacturing capacity would have little difficulty meeting Australia's needs, even if they were to grow substantially. While manufacturing close to market has some advantages, recent history (Australia has manufactured blades and nacelles in the past) indicates this is not critical to success.

Australia is a relatively small market compared to Europe, North America or China. This means that market stability could have a proportionally greater impact on maintaining a competitive number of suppliers. As an example, between 2004 and 2008 project developers complained that they struggled to attract bids from more than one or two turbine suppliers, and several major suppliers withdrew from the country due to a lack of government policy support. In this respect Australia has been lucky that a global downturn in the market for wind turbines occurred just as we have been re-stimulating the local wind market via the expanded Renewable Energy Target.[15]

2.4.2 Resource evaluation and project development

We now have a good understanding of the Australian wind resource. This has been built up over the past decade and half, largely because the Renewable Energy Target created an immediate market for wind power, thereby creating incentives to develop improved, high resolution topographical wind models and establish wind monitoring masts in promising regions. These provide high quality, detailed wind data suitable for reliably projecting wind turbine output which is essential to obtaining debt finance.[16]

As a result, a 19,000 megawatts pipeline of wind farm sites is being developed across a wide range of locations in Australia (Table 2.3). This is in addition to more than 3000 megawatts in operation and construction (Table 2.2). While many of these projects are highly speculative – for example some are distant from required grid infrastructure – many could be viable in the long-term with rising emissions prices).

[11] US Dept of Energy (2008)
[12] Global Wind Energy Council (2011)
[13] Australian wind sites have higher wind speeds than most locations in Europe and North America. Sources: IEA (2011); AGL (2009)
[14] Alderson, H. Barber, T. and Yeo, S. (2010)
[15] Alderson, H. Barber, T. and Yeo, S. (2010); Edis, T (2011); Pers Comm White G. (2010); Pers Comm Cowling, P. (2011)
[16] Pers Comm White, G. (2010)

Table 2.3 Australian wind power capacity in operation and development

	Operating	Construction	Development & Evaluation
NSW	233.56	48.3	7382
QLD	12.46		1235
SA	1150.5	52.5	3380
TAS	153.03	168	772
VIC	432.01	461.8	5341
WA	203.92	274.8	1219.65

Source: Grattan Institute (2011a)

A large proportion of these already have landholder agreements in place which have grouped together enough suitable land to support a large enough number of turbines to provide economic scale (50 megawatts is generally considered a minimum but 100 megawatts or more is preferable to offset connection and development costs).

Already, sites representing more than 5000 megawatts have planning and environmental approvals.[17] To date, obtaining these approvals has not been a notable barrier. Approval times have varied from an average of 6 months in South Australia to around one to two years in Victoria and NSW.[18]

The industry has also demonstrated a reasonably sophisticated capacity to finance wind farms. Financing institutions have been willing to support projects involving a wide variety of firms on a non-recourse basis, and wind farms have been developed on a variety of models. These include vertically integrated businesses, with an electricity retailer as owner and customer (for the power and renewable energy certificates)[19], a specialist wind power project developer with a single electricity retailer as an exclusive customer[20], and even on a merchant basis with the developer taking on some degree of market risk and/or contracting with several retailers for electricity and renewable energy certificates.[21] There are also examples of owners lowering the risk of projects and then on-selling the projectto superannuation funds with lower costs of capital.[22] The industry has also been able to undertake projects on a variety of scales, including some of the largest projects in the world. Financing wind farms has become harder recently[23], but no more so than other capital-intensive projects since the Global Financial Crisis.[24]

While the industry is well positioned to execute a rapid scale-up if required (although with transmission grid connection challenges in

[17] Pers Comm Brazzale, R. (2011)

[18] Edis (2011)
[19] Prime example would be AGL
[20] Pacific Hydro has used this model with Origin Energy as offtaker
[21] Examples of firms employing such a model include Pacific Hydro, Infigen and Acciona
[22] AGL has done this with several wind farms
[23] Alderson, H. Barber, T. and Yeo, S. (2010)
[24] Based on discussions with project finance advisors over 2009 and 2010

the longer-term), this did not happen overnight. Rather, it was steadily built-up through 15 years of dedicated activity. All these development projects are built upon agreements, such as contracts with landholders, planning permits and grid-connection agreements, that tend to be time limited. Therefore, without the prospect of a near-term market these are likely to be left to lapse. They could be revived but not without repeating a process that has taken many years to reach the point the industry is at now.[25]

Grid connection agreements, for example, are predicated on modelling of the capacity of the network to absorb new power generation. This is unlikely to remain static due to changes in electricity demand and the physical condition of the grid.[26] Reaching agreement on grid connection can take as long as two years to finalise (considerably longer in the South West Interconnected System in Western Australia[27]).[28] Yet this has occurred under an environment where the pace of project development has been quite slow. Attempting to revisit grid connection arrangements under an environment of far more rapid scale-up is likely to be considerably more difficult.

The Victorian Government's change to planning approval processes for wind farms – which now need to obtain permission from any household within two kilometres of a turbine – has the potential to complicate and lengthen the process for developing wind farms in the future. Victoria has the second largest wind development pipeline, and while a large proportion already have approvals in place, many will expire before they commence construction, which will trigger the two kilometre household permission requirement. Such regulatory uncertainty is a major barrier to industry development.

2.4.3 Transmission infrastructure and grid connection

Chapter 9, on transmission infrastructure, explains that current regulatory rules need to be reformed to ensure timely and efficient resolution of transmission infrastructure requirements which are particularly important to supporting high levels of wind power within Australian electricity markets.

Obtaining a grid connection agreement is the one major hurdle that many of the wind farms under development are yet to resolve. Discussions with a wide range of project developers and electrical network engineers suggest that transmission company processes have been structured around evaluating connections for infrequent, very large power stations locating close to existing transmission infrastructure. They have difficulty evaluating the possible impacts from a large number of dispersed wind farms. It may also be that, because there was a large overhang of excess generation capacity built in the 1980s, transmission companies have had far less need to evaluate new power plant connections and pulled-back from recruitment and development of the next generation of network engineers. Rebuilding such a capability is expected to take five to ten years.

Experience in this area is valuable. Feedback from developers suggest that the SA transmission company Electranet - which has the greatest experience with connecting wind farms in Australia - is generally better at dealing with wind farm connection

[25] Edis (2011); Pers Comm Upson, J. (2011)
[26] Pers Comm Morton, T. (2010)
[27] AEMC (2008)
[28] Edis (2011)

applications than less experienced transmission companies in other states.[29]

2.4.4 Operations and maintenance

Running and maintaining wind turbines is not particularly different from any other major electro-mechanical equipment such as large mining crushing equipment, and diesel-powered heavy construction machinery. People experienced with such equipment, such as electricians and mechanics with generic vocational training and experience, can usually be trained within 8-12 weeks through turbine company in-house training. This is unlikely to significantly constrain wind power expansion.[30]

2.4.5 System and market integration

Australia is capable of substantially expanding the amount of wind power that is fed into its electricity systems. Yet the fact that wind is subject to uncontrollable (but predictable) short-term weather variation that does not match or only loosely matches demand means that it ultimately faces constraints on how much power it could economically supply without some form of storage. This is not a hard physical constraint (provided the market has been designed well), but rather an economic issue.

Electricity systems are already designed to handle substantial variation in demand and unexpected breakdowns of power plants and transmission lines through the use of power plant capacity that can rapidly increase or decrease output. This enables the incorporation of quite substantial amounts of wind, in spite of its variability, without significant changes to the amount of generating capacity in the electricity system and the cost of maintaining system reliability.

There are now a number of examples of electricity markets and/or regions, including in Australia, which are managing to successfully integrate large amounts of wind into their system (Table 2.4).

Table 2.4 Examples of regions with high wind penetration

	% of installed generating capacity	% of annual energy consumption	Maximum possible instantaneous proportion of electricity demand
Ireland	16.4%	10.0%	81.8%
Iberian peninsula	20.9%	15.0%	99.3%
Western Denmark	35.0%	30.0%	195.7%
ERCOT (Texas)	11.4%	8.0%	27.4%
South Australia	22.1%	20.0%	118.6%
Tasmania	5.1%	5.0%	18.0%
Crete	16.0%	15.1%	57.1%

Source: AEMO (2011c)

[29] Edis (2011)
[30] Pers Comm Cowling, P. (2011)

According to AEMO:

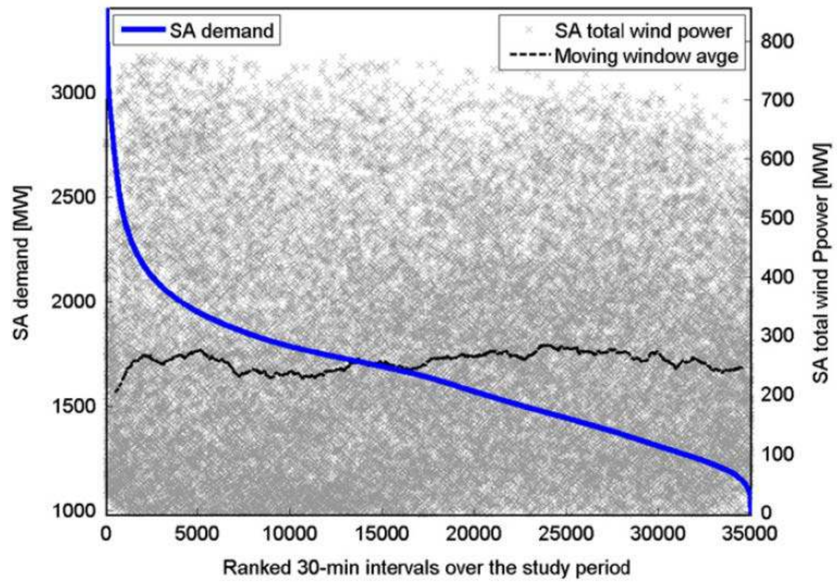
"*Very high wind penetrations are achievable provided the particular characteristics of wind generation are accounted for in planning and operating the grids*"[31]

Nevertheless, the lack of reasonably cheap electrical storage in Australia and the fact that wind is subject to uncontrollable (though predictable) short-term weather variation that is either not correlated or only loosely positively correlated with demand means that it does face constraints to how much power it could economically supply.

Figure 2.6 illustrates this principle for actual combined wind farm output in South Australia. Each grey cross represents the aggregate power output across all wind farms in South Australia for a particular 30 minute interval over the period September 2008 to August 2010. This is plotted in correspondence with the state's electricity demand during this same point in time (illustrated by the blue line). It shows that wind farm power output tends to have wide degree of variation that is not noticeably correlated with electricity demand (note that the scale for wind output is noticeably lower than for demand). While there are circumstances of wind output coinciding with very high electricity demand periods, there are also times when wind power has been very low during high demand periods. This is the case across all points in the demand duration curve.

[31] AEMO (2011c)

Figure 2.6 South Australian demand duration curve and corresponding wind power output, Sept 2008 - Aug 2010[32]



Source: Cutler, Boerema, MacGill and Outhred (2011)

CSIRO weather modelling work undertaken for AEMO suggests similar levels of wide variation in wind output across a range of electricity demand points for other states within NEM, although there is a slight positive correlation between average wind output and demand in NSW.[33] Wind developers familiar with WA

[32] During this period between 675 and 868 megawatts of wind power were operating

[33] AEMO (2011d)

conditions suggest the state also tends to have higher wind speeds during the afternoon when demand is at its peak[34], however a detailed analysis is yet to be published.

As wind penetration reaches high levels of overall system demand this variability in its output is likely to act to increasingly inhibit the economics of further wind capacity. There are two main reasons why:

1. It increases the amount of rapid response generating capacity required to precisely balance supply and demand of electricity.

2. It becomes increasingly likely that wind output will coincide with low prices or exceed demand.

Costs of short-term balancing of supply and demand

Electricity demand and supply need to be closely matched ("balanced") to ensure that system voltage and frequency ("power quality") remain within acceptable tolerances. These tolerances are necessary both for safety and for the effective and efficient functioning of electronic equipment. Over very short time periods (less than five minutes) there will usually be a slight mismatch between what the system operator expects demand and supply to be and what occurs. To prevent this from affecting power quality the system operator automatically alters some generators' output slightly up or down within seconds, without having to notify the generator. This balancing service comes at a cost in terms of redundant capacity and extra fuel use.

As wind output rises to become a significant source of electricity supply, its variability begins to increase the level of short-term imbalances between supply and demand (beyond that simply caused by electricity demand). As a result, the system operator requires more balancing capacity.

Evidence from around the world suggests that managing this variability with large amounts of wind power (10 to 25% share has been studied) is quite feasible. These studies suggest that the additional balancing costs would not materially undermine the cost competitiveness of wind. However, analysis of levels above 30% are limited. Figure 2.7 shows real and modelled balancing cost data from a selection of electricity system regions around the world. At wind penetrations of up to 25 per cent of gross demand, cost increases arising from wind variability and uncertainty were limited to little more than about 4 euros per megawatt-hour.

A range of studies for various US electricity system regions come to similar conclusions indicating wind integration costs of between US $1.50 and $9.40 for wind capacity penetration of between 20% to 30%.[35]

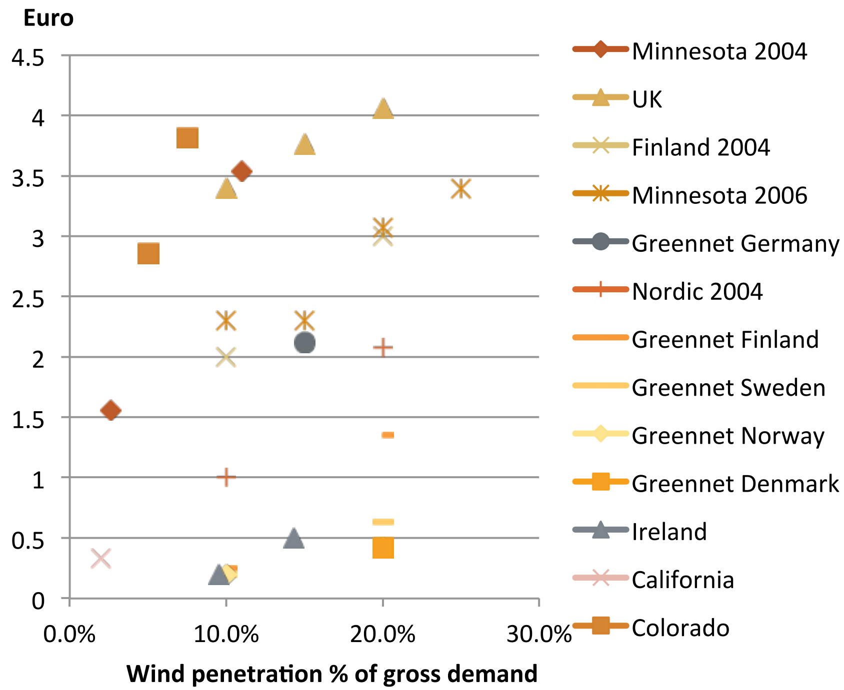
Modelling of these balancing costs in Australia has been inadequate to draw strong conclusions. Wind and demand data over relatively small time scales are needed and the wind data need to cover a large number of locations where wind farms are likely (due to possible smoothing-out of wind variation across wide areas of land). AEMO is building such a modelling capability but current work has focussed on physical effects rather than economic consequences. Nonetheless these results indicate that

[34] Pers Comm Cowling, P. (2011)

[35] Wiser & Bollinger (2011)

geographic dispersion across several states of Australia will help to reduce overall wind output variation. This should help to moderate balancing costs.[36]

Figure 2.7 Increase in balancing cost for wind power



Source: Hannele Holtinnen (2008) Estimating the impacts of wind power on power systems – summary of IEA Wind collaboration, Environmental Research Letters 3, Issue 2 (April-June 2008)

[36] AEMO (2011d)

ROAM Consulting has also analysed the balancing costs from an increased amount of wind in both the NEM and the SWIS.

It examined a scenario of 8,231 megawatts of installed capacity in the NEM by 2020, equating to just over 10% of electricity generation. It found that NEM balancing costs attributable to wind variation would be about $8 per megawatt-hour.[37] That would be material, but not substantially undermine wind economics compared to other zero-emission technologies. But it seems likely that as wind expands to or beyond 30% of generation, balancing costs will become more significant and make it harder to expand wind power at a competitive cost.

The location of wind capacity makes a difference to system balancing. In a study for the Western Australian Independent Market Operator, ROAM examined a scenario of wind having 1045 megawatts of capacity within the SWIS by 2020 and 1,776 megawatts by 2030, equalling about 15% of generation. The study indicated a potentially wide range of balancing costs depending on the extent of geographic dispersion of the wind capacity. If the wind generation was relatively evenly distributed across the SWIS between areas to the north (Geraldton region) and south (Albany region), the extra balancing requirement would equal just 5% of installed wind capacity. But if wind generation were concentrated in one area the balancing capacity would equal 40% of installed wind capacity. The costs of balancing also varied from as low as $6 to as high as $60 per megawatt-hour, though factors such as fuel prices and the capacity of power plants to provide balancing services also influenced costs.[38] While this wide

[37] Riesz et al. (2011)
[38] ROAM Consulting (2010)

variation makes it hard to form strong conclusions, discussions with the authors suggest that load following costs will become large enough to significantly hinder the economics of wind at around 20 to 30% of generation.

Wind output spilled or coinciding/causing low prices

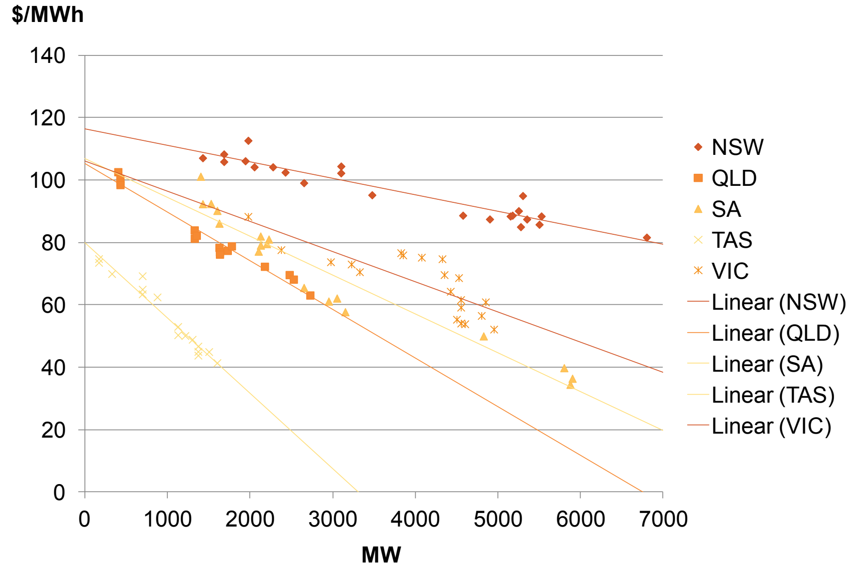
Historical weather data for Australia suggest there are times (usually late at night) when state-wide high wind periods coincide with low electricity demand in that state. As wind capacity reaches a high proportion of state demand, during high wind periods, it becomes likely that wind generation will depress electricity market prices as they displace higher operating cost fossil fuel plant. This can even reach the point where wind farm output has to be spilled because it exceeds both the level of demand for electricity within the state and the capacity of transmission lines to export the excess generation into other states.

In such cases, without upgrades in transmission capacity into other regions, the financial attractiveness of new wind farms is reduced and expansion is automatically constrained.

This is already beginning to occur in South Australia where market prices are noticeably lower in high wind than in low wind periods. There have even been examples of extreme negative prices where high amounts of wind have occurred simultaneously with very low demand periods.[39]

Projections by ROAM Consulting illustrated in Figure 2.8 indicate that as the amount of wind capacity increases in each state it is likely to reduce the wholesale electricity pool prices that these wind farms can obtain.

Figure 2.8 Impact of increasing wind capacity on pool prices



Source: ROAM Consulting (2010b)

Projections by AEMO out to 2030 also suggest that even though available sites within South Australia provide superior wind speeds to other states in the NEM, the amount of output that would need to be spilled due to inadequate local demand and

[39] Cutler, Boerema, MacGill and Outhred (2011)

transmission capacity would materially reduce capacity factors and encourage development in other states.[40]

Discussions with wind industry participants indicate that this is already constraining the development of further wind capacity in SA, and encouraging development in states with lower wind penetration, even though they have lower wind speeds.[41]

These constraints are not absolute. Upgrades to transmission interconnectors would make it economically attractive to develop further wind farms in South Australia and export the power to other states. However there is a trade-off involved between the cost of building new transmission to realise higher wind farm capacity factors against lower output but saving on transmission. As the amount of wind capacity builds up in other states to levels similar to those in SA, the mismatch between wind output and demand is likely to depress the prices these wind farms receive and curtail the addition of further capacity, just as has occurred in SA. This is some way off in Victoria, NSW and Queensland, where wind penetration is below 2% compared to around 20% for SA.[42]

Improving wind system integration capability

While wind's variability constrains how much power could be produced at a cost below $150 per megawatt-hour, a range of factors can help to reduce the costs of managing this variability. Most of these involve ensuring as efficient an electricity market as possible. This requires:

- Precise, fine-grained prices that accurately reflect and allocate, in or as close as possible to real time, the various costs and benefits that generators and customers provide to the system.
- Information that enables participants to have a good understanding of the supply and demand balance in the system and how prices are likely to evolve over time.
- High flexibility in the ability of suppliers and customers to alter their offers in response to prices.
- Many buyers and sellers.

Apart from the way it prices transmission capacity and sends prices to smaller customers, the NEM is reasonably well designed in this respect. It has five-minute interval dispatch processes, a gross pool energy market with a price cap that provides high transparency about generation costs and where prices are determined through an interplay between supply and demand, a separate and open market for balancing services, an advanced wind forecasting system and integration of most wind capacity into the dispatch system via semi-scheduling.

It could be improved, however, by having generators of all fuel types face a clearer price signal relating to use of transmission infrastructure by making them pay a share of the infrastructure.[43] AEMO also needs to build a greater capability to model the interaction of weather with the energy market for the purposes of planning the system, for considering new transmission capacity

[40] AEMO (2011d)
[41] Edis (2011)
[42] AEMO (2011b)

[43] AEMC (2009)

and for aiding analysis of possible policies. It is already working on this task.[44] The Commonwealth Government's requirement that it model scenarios in which renewables comprise up to 100% of power generation[45] will require them to improve its capabilities in these fields.

The SWIS, however, lacks many of these features which means its market is less able to adapt to short-term fluctuations (whether due to wind or other factors), and its capacity to cost-effectively integrate wind is not as a good as the NEM's.

Due to the SWIS' small size and domination of generation supply by a single company (state-owned generator-Verve) the WA government chose a different market structure to control for excessive market power. This involves two separate markets:

- One for instantaneous power capacity acquired usually more than a year in advance (which ensures that sufficient amounts of power plant capacity are built and available to meet brief periods of high demand but may be idle for large periods of the year); and
- Another for energy (based on power plants generating actual electricity, not just being available in case they are needed).

Box 2.1 How South Australia became a test-bed for wind power system integration

In 2001 the national Renewable Energy Target was introduced with the goal of increasing the share of renewable energy by a 2% of total electricity consumption by 2010. However much of the new project activity that the RET stimulated was concentrated in South Australia (Wind is 20% of SA's electricity consumption and it hosts 50% of Australia's operating wind capacity). This concentration of wind power meant that what seemed a relatively minor change in fact represented a major challenge to electricity system operators and regulators. Due to concerns about system reliability the SA regulator froze the granting of generating licences to wind farms in 2005.

This forced system operators and regulators to learn how to integrate high amounts of wind into the electricity system. From 2003, increasingly sophisticated models and studies of how wind might affect system reliability have been developed. In 2005 work began on a wind forecasting system (implemented in 2008). In 2007 a series of reforms were made to the NEM rules providing a means of managing wind farms output, if necessary, based on market bid prices. From 2005, grid connection technical standards have also been steadily revised. This process has taken many years to unfold but the inadvertent lessons from SA mean that the NEM is well positioned to manage a major scale-up of wind in future.

This results in a market where short-term interaction of supply and demand via a wholesale pool market is less significant in co-ordinating the operation and construction of power plants. This hasn't been a major problem so far, but the addition of wind

[44] AEMO (2011d)
[45] Australian Government (2011)

capacity has exposed several of its rigidities. Reforms are underway to address some of these rigidities. They include the development of a separate balancing market open to all generators (not just the state-owned Verve Energy), a wind forecasting system to be integrated within the dispatch process, and removal of the unconstrained model for grid connection, (which ultimately places limitations on its use of a separate market for instantaneous capacity from that for energy (megawatt-hours)).

The reform process to improve these systems' capability to integrate wind is long and has some way to run, particularly in the SWIS. The Renewable Energy Target has driven the deployment of wind ahead of what would have occurred under a pure emissions trading scheme. However, this has meant that market designers, regulators and system operators have been forced to learn how to better manage incorporation of new generation technologies into the system without having the entire electricity market riding on the outcome (see Box 2.1). These lessons will help to ensure electricity markets are more robust and better able to respond to the more widespread changes that an economy-wide carbon constraint will impose.

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3 Solar Photovoltaic power (PV)

3.1 Synopsis

- Solar PV is taking on a larger role in Australia's energy mix, generally as packages of solar cells combined into systems small enough to be mounted on a household rooftop. Falling costs combined with government support have seen PV installations jump dramatically: by 360% in 2008-2009 and a further 500% in the following year.

- Using off-the-shelf technology, PV is already capable of generating enough electricity to exceed Australia's foreseeable needs. PV is modular – meaning it can be rolled out in small units – so it can be located in many places at once, and is easily upgraded with technological improvements.

- PV costs are falling, and are expected to fall further, as a result of cell and system efficiency improvements, lower cost materials, mass production and other factors. The rate at which costs will fall will be influenced by deployment support from governments.

- The value of electricity from PV will be worth more in some contexts than in others, depending on how it affects supply, demand and the local electricity network.

- The variability of PV generation will prevent it from playing a predictable and reliable role in supply on its own, unless it is coupled with storage or 'smart grid' technologies. The cost of such infrastructure remains relatively high, but is likely to fall in the short- to medium-term.

- Large-scale PV deployment could be constrained by problems with integration in the electricity distribution grid. High penetration of PV can affect power system protection, quality of supply, reliability and security. To understand impacts and potential solutions, Australia should build skills and knowledge in grid integration through greater research and experimentation.

- Technical solutions to grid integration issues are available, including different system inverters. Their uptake will require a financial outlay from consumers and network businesses. More critically, it is likely that this will only occur with significant attention to the regulatory issues that arise from widespread deployment of PV.

3.2 What is solar photovoltaic (PV)?

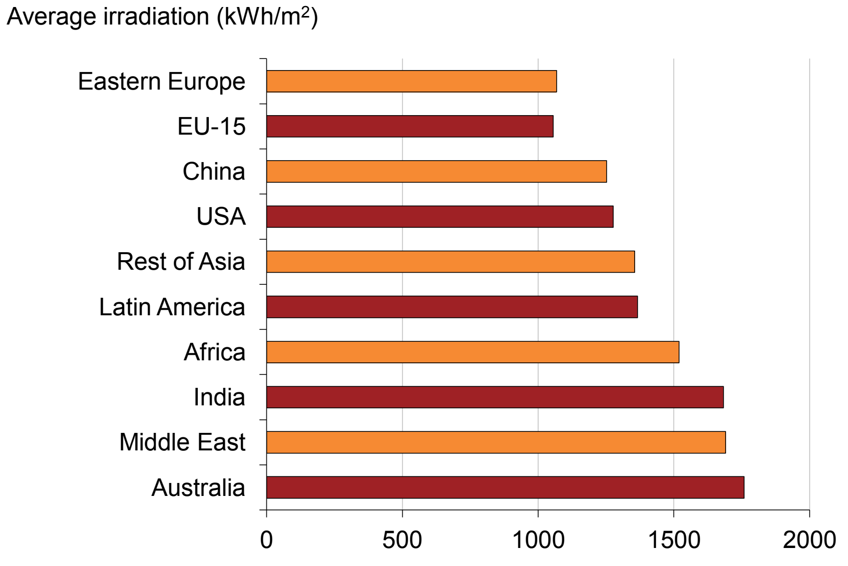
Solar photovoltaic converts light from the sun into electricity using photovoltaic (PV) cells that contain a semi-conductor material. Unlike other types of generation, there is no thermal stage that involves a turbine; the resource (sunlight) is converted directly into electricity. PV cells can be used in conjunction with concentrating mirrors or lenses for large-scale, centralised power. Around 80% of the global PV market is small-scale, that is, cells combined in systems that can fit on the roof of a house or small commercial premises. Most of the capacity installed in recent years is connected to the distribution grid as distributed generation.[1] Small-scale, grid-connected PV is the main focus of this chapter.

There are two main technologies for small-scale systems: crystalline silicon (cSi) and thin-film. Crystalline silicon cells are more mature and widespread. Compared to thin-film these cells convert sunlight more efficiently, but at higher cost.[2] This report considers both technologies.

3.3 How scalable is PV in Australia?

Australia's solar resource is extremely high-quality compared to other countries, including Africa and the Middle East (see Figure 3.1 Average solar irradiation by world regionbelow). It is abundant and well distributed across the country, ranging from about 1500 kilowatt hours per square metre in parts of Tasmania to 2200 kilowatt hours per square metre in central Western Australia.[3]

Figure 3.1 Average solar irradiation by world region



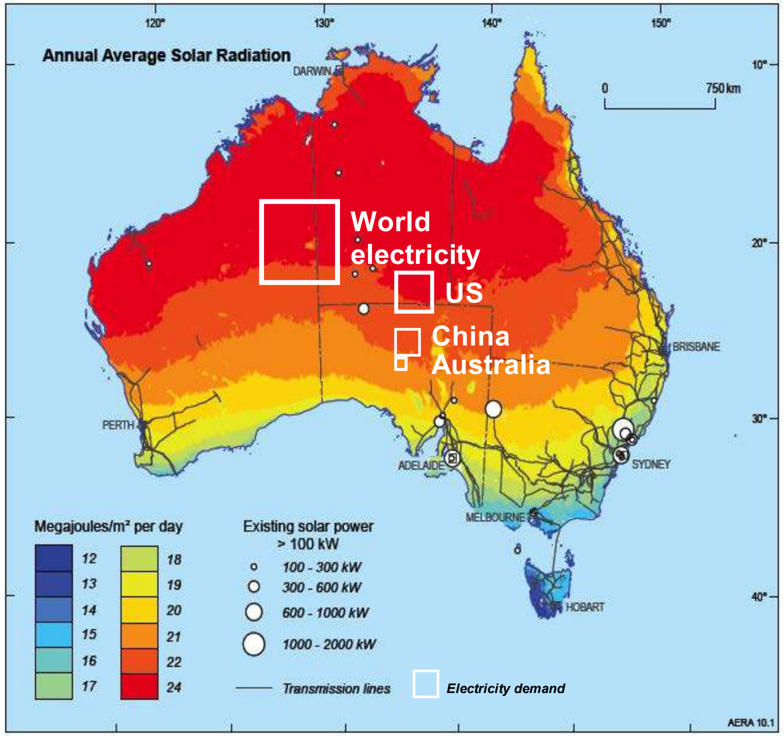
Source: (Business Council for Sustainable Energy, 2004)

Using mass-produced, off-the-shelf technology, PV is already capable of generating a large quantity of electricity from the available resource. Technically possible generation exceeds current electricity demand in Australia and the world (see Figure 3.2).

[1] National Renewable Energy Laboratory (NREL) (2010)
[2] Geoscience Australia and ABARE (2010)

[3] European Photovoltaic Industry Association (EPIA) (2011), Geoscience Australia and ABARE (2010), SKM-MMA (2010)

Figure 3.2 Annual average solar radiation, relative to electricity demand



Source: (Geoscience Australia and ABARE, 2010), Desertec Australia (2010), accessed December 2010 at www.desertec-australia.org

What is more, PV power could produce large amounts of electricity without encountering land or resource constraints, because it is easily fitted into cities – on rooftops, for example. If 5% of Australia's urbanised land were covered in solar panels, it would provide around 6900 megawatts of capacity or annual generation of around 10,350 gigawatt hours.[4] If 3 kilowatt systems were installed on half of Australia's 5.4 million detached houses, this would produce capacity of more than 16,000 megawatts. To put this in perspective, generation from this latter possible capacity of PV would provide around 10% of forecast generation for 2020-21 in the National Electricity Market.[5]

Beyond residential rooftop PV, greater use of commercial roof-top and utility scale PV (near the scale of existing, centralised power plants) would quickly ramp up solar capacity. Commercial roof top PV offers benefits of economies of scale, close correlation to demand and better access to grid infrastructure. Utility-scale PV stretching over 128,000 hectares could provide around 10% of Australia's 2020 generation.[6]

3.4 Status

3.4.1 Installation and production capacity have reached unprecedented peaks globally and in Australia

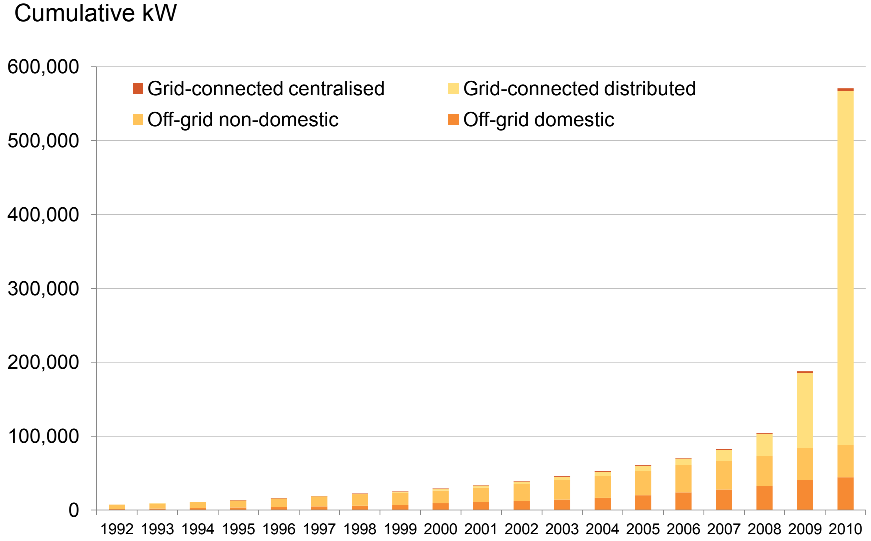
From a low base in the early 1990s, installed PV generation capacity around the world has risen by around 30% a year for 20 years.[7] The past few years have seen unprecedented growth in

[4] Figures on urban land area from Bureau of Land and Rural Services (2001/02) Assumes a 1kW system requires approximately $10m^2$ (Energy Matters (2011)) . Assumes output of 1,500 KWh per kW (Watt and Wyder (2010))
[5] Output from 8,000MW assumed to be 12,000 GWh. Projected NEM energy in 2020-21 under 'medium' scenario is 247,973 GWh (AEMO (2011))
[6] Assuming a land requirement of 8ha/MW (Based on the Moree and Greenough River projects (Moree Solar Farm (2011), Verve Energy (2011)) and a capacity factor range of 11-18%, as presented in SKM-MMA (2010)
[7] SolarBuzz (2011c)

the market in Australia and the world. Globally both solar production and capacity more than doubled between 2009 and 2010. In 2010, annual PV installations reached a record high of 18.2 gigawatts, bringing cumulative global installations to around 39 gigawatts – about 25% less than the total generation capacity installed in Australia's National Electricity Market.[8]

Though much recent growth has been in European markets and in China, Australia's installed capacity rose 360% between 2008 and 2009. There was a further five-fold increase in 2010 (Figure 3.3) with nearly all of it in small, grid-connected installations.[9] Australia has become one of the world's top 10 PV markets, with Australian installations expected to reach 1,200 megawatts by the end of 2011.[10] Despite this rapid growth, PV accounts for only around 2.4% of registered capacity in the National Electricity Market – and only around 0.9% of generation.[11]

Figure 3.3 Cumulative PV installations in Australia, 1992-2010



Source: (Australian PV Association, 2011)

Globally, public policy has driven demand, more than the falling costs of PV systems or the quality of solar irradiation. Incentives – feed-in tariffs, tax credits, rebates, and solar targets – provided by individual country governments have driven growth.[12] Germany is a prime example: despite its relatively poor solar resources it accounts for over 45% of the world's installed PV capacity[13]. In Australia, the Renewable Energy Target Scheme, combined with rebates and feed-in tariffs in many states, has accelerated

[8] (AER (2010), SolarBuzz (2011a)
[9] Parkinson (2011e), Hearps and McConnell (2011), Watt and Wyder (2010)
[10] Ric Brazzale (2011), SolarBuzz (2011a)
[11] Figures on National Electricity Market registered capacity (49,010 MW) and output (206 TWh) from 2009-10 (AER (2010)). Generation figure assumes 1,600 kWh output per kW (Watt and Wyder (2010)).

[12] International Energy Agency (IEA) (2010), Kirkegaard*, et al.* (2010), SolarBuzz (2011c)
[13] Kirkegaard, *et al.* (2010)

deployment of PV and dramatically lowered prices for customers.[14]

Australia's 'soft infrastructure' – skills and logistical capability – has coped well with a rapid roll-out of PV. The solar energy sector now involves 10,000 people.[15] In the years leading up to this period regulatory processes were streamlined and requirements for system connections standardised and clarified, which reduced costs and delays.

Production has actually outpaced PV installation. Worldwide solar cell production in 2010 was 20.5 gigawatts, and total production capacity around 29 gigawatts (just over half the size of total installed capacity in Australia's National Electricity Market).[16] The global economic downturn and the more recent scaling back of PV subsidies have led to an oversupply of materials, cells and modules.[17]

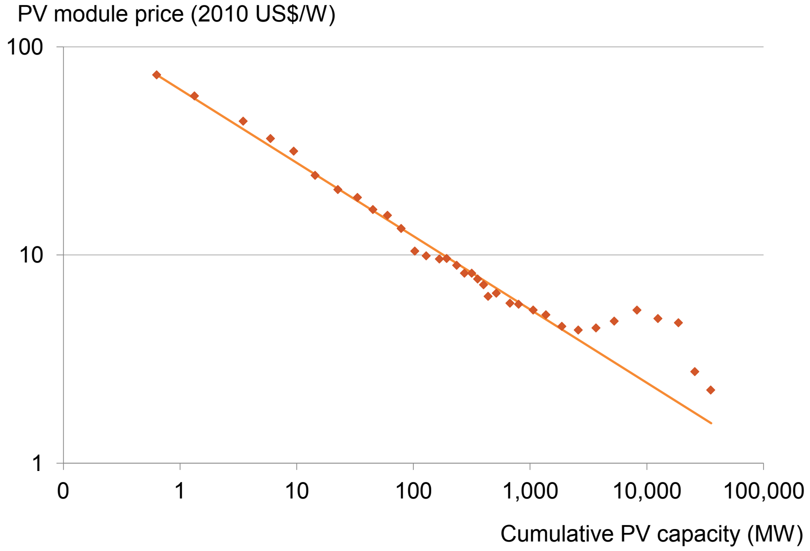
3.4.2 What are the current obstacles to PV's development?

Despite falls, cost of PV technology and electricity costs remain high

PV is still seriously constrained by its costs – both relative and absolute – though they are improving rapidly. The rate of learning (falls in costs relative to a doubling of capacity) for PV modules has been 15 to 22% for the period 1976 to 2003.[18] Costs have fallen more steeply in recent years.[19] Figure 3.4 reflects this trend, though the apparent stalling of the price in later years masks falling costs at times of strong demand, which produced larger profits for suppliers.[20]

[14] Green Energy Markets (2010), Macintosh and Wilkinson (2010)
[15] Twidell (2011)
[16] SolarBuzz (2011a)
[17] UBS (2010)
[18] International Energy Agency (IEA) (2010), European Photovoltaic Industry Association (EPIA) (2011), Hearps and McConnell (2011)
[19] Macalister (2011), Watt and Wyder (2010)
[20] Watt (2010)

Figure 3.4 Historical learning rate (correlation of PV module price and quantity of modules installed)



Source: (ATSE, 2011)

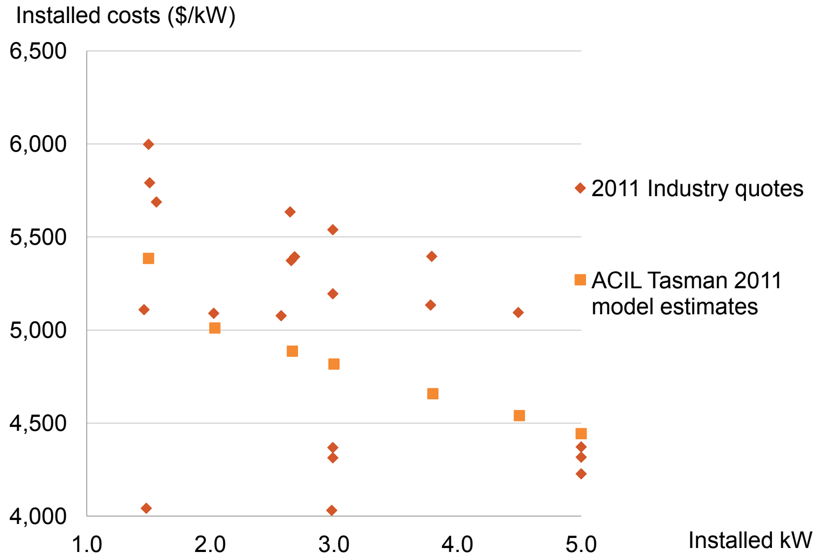
Published costs for typical domestic systems in Australia are around $5 to $6 per watt. Costs for slightly larger, 5 kilowatt systems are as low as $4 per watt, and lower still for utility-scale systems (see Figure 3.5).[21] Yet market prices are very competitive and are falling rapidly. A recent global survey identified 580 solar module prices – about half the survey – below US$3 a watt.[22]

[21] ACIL Tasman (2011), SKM-MMA (2010). The price of a PV system varies depending on the system size, quality of components, exchange rates and competitiveness of suppliers.

[22] SolarBuzz (2011b)

Local sources suggest Australian prices are below international prices (given surplus capacity and inventory and exchange rates) and today are around $3.50 to $4 per watt for installed residential systems.[23]

Figure 3.5 Australian installed PV system costs (inc GST)



Source: (ACIL Tasman, 2011)

Because of PV's relatively low capacity factors – the ratio of a unit's average output to its potential output at peak capacity – the levelised cost of electricity from a PV system remains over $200 per megawatt-hour and as high as twice that amount. These

[23] Pers. comm. Michael Williamson, Sustainability Victoria (November 2011) with reference to SolarBuzz, Solar Hubs and Solar Trade data.

prices are two to three times the level for other currently available large-scale, grid-connected electricity sources.[24] Estimates of the near term costs of PV electricity are shown in Figure 2.3 of the main report accompanying this publication.[25]

The way electricity from PV is valued affects its viability in different contexts

Potentially offsetting PV's high levelised cost of electricity – or LCOE (see glossary) – is the fact that it can be located on or near to customer premises. This not only uses small areas of land (unlike concentrating solar thermal: see glossary) it also offers consumers direct investment alternatives to rising retail electricity prices.

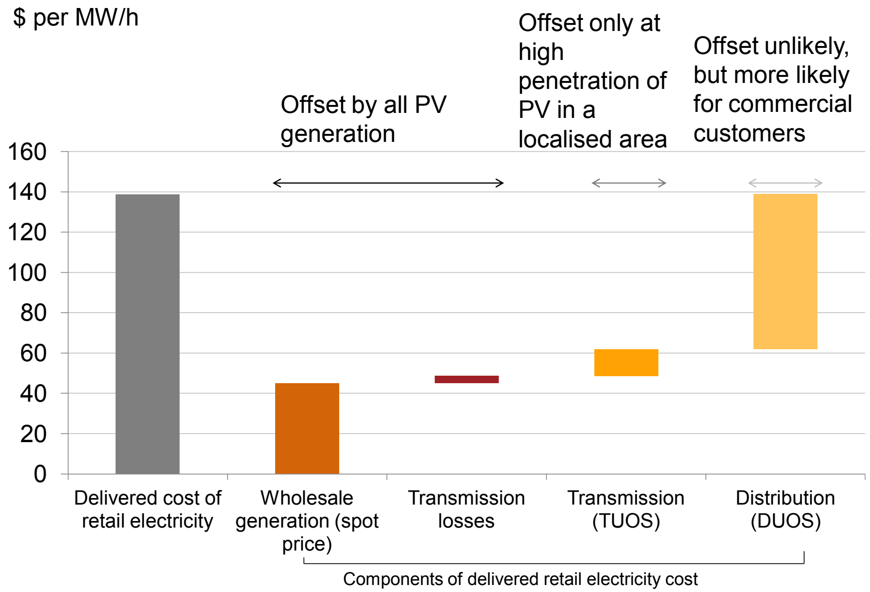
Distributed PV generation avoids at least some of the high costs of transporting or delivering electricity from large, centralised power stations. For residential customers these costs add $90 per megawatt-hour to the delivered costs of large-scale power generation (see Figure 3.6).

When PV generates it displaces another source of generation, so the value of its output should include the spot value of wholesale generation at the time it displaces that generation. Given its proximity to where demand occurs, PV generation avoids the losses of around 8% of electricity incurred when transporting

[24] Kirkegaard, *et al.* (2010)
[25] Estimates of electricity technology experts and modellers vary widely due to assumptions around financing costs, solar irradiance, system size, system costs and installation costs.

centrally generated electricity[26]; thus its value should also include these.

Figure 3.6 Electricity price components



Note: Transportation cost components derived from (Simshauser et al., 2010) and losses from (SKM-MMA, 2011). Generation costs are an approximate average of 2009-10 wholesale spot prices for Queensland and NSW.

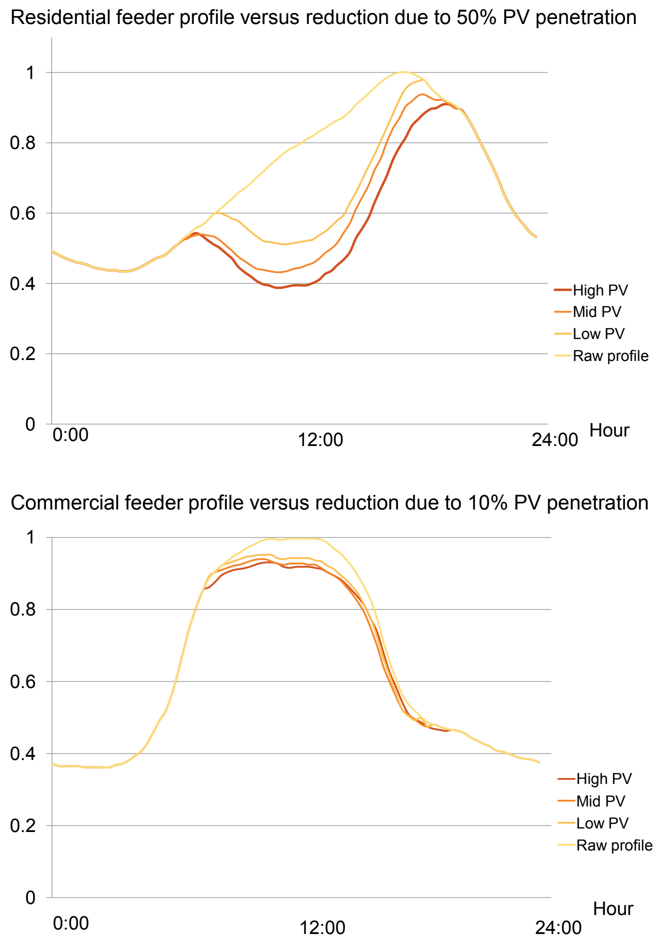
However, it is unclear how much PV offsets transportation network costs by deferring investment in fixed cost assets. It depends on a reliable assessment of the contribution of PV (or PV with other actions) to reduce localised maximum or peak loads,

[26] As assumed by SKM-MMA (2011)

which are the drivers of network economics. [27] Evidence is currently lacking to firmly establish this figure.

As shown in the figure below, output from PV systems – which usually face north – is greatest around the middle of the day.[28] PV generation aligns well with commercial sector and industrial peak demand, but far less so with residential sector demand. That is because output from PV systems tapers off just as residential demand peaks, between four and nine pm. [29] A recent Western Australian study concluded that even if PV were to provide half of the electricity in a given area, it would only reduce residential peak consumption by 5%. In winter, the capacity to reduce peak load was even less.[30] By contrast,10% penetration of PV at a commercial feeder cut peak load by about 4 to 7%.

Figure 3.7 Effect of PV output on residential and commercial demand



Source: (Lark et al., 2011)

[27] Ibid.
[28] AECOM (2010), Elliston, *et al.* (2010), Kamel (2009), Myers, *et al.* (2010), Watt, *et al.* (2007). Note: if PV systems were installed facing west, their generation at the time of residential demand would be higher (though total output would be lower)(Watt, *et al.* (2007)).
[29] AECOM (2010), Boerema, *et al.* (2010), Kamel (2009), Lark, *et al.* (2011), Myers, *et al.* (2010), Watt, *et al.* (2007). Note: Studies suggest during peak periods PV provides anywhere between 30% and 75% of its rated capacity during peak periods.
[30] Lark, *et al.* (2011)

This suggests that PV's value depends significantly on its location, and on the characteristics of the local load and grid. As shown in Figure 3.6 above, the true value of electricity from PV will be at least the value of the electricity that it displaces from the wholesale electricity market[31] plus the value of the losses in transmission. For areas where there is a sufficient concentration of PV systems the capital costs of transmission – the investment in large poles and wires – may also be avoided. However, it is less likely that the value of PV will include the avoided capital costs of distribution – the investment in small poles and wires – especially for residential customers.

Supporters of PV electricity argue that it should be valued at average electricity retail prices —what is called grid parity. However, for the reasons stated above, the calculation overvalues the contribution of PV to the residential sector, though it may be more appropriate in the commercial sector. SKM-MMA (2011) reached a similar conclusion, and suggested that PV output should be valued at 50 to70% of the retail tariff, or around $110 per megawatt-hour.[32] It is important to note, though, that with current pricing structures the value of PV electricity consumed at the site of generation will be worth more because it is a substitute for retail electricity. The current review into solar feed-in tariffs by the New South Wales electricity regulator is continuing the attempt to identify a 'fair and reasonable' way to value PV.[33]

[31] For large-scale solar PV generators this will be the only component of cost offset, and thus the benchmark on which to compare its cost of electricity
[32] SKM-MMA (2011)
[33] See www.ipart.nsw.gov.au/investigation_content.asp?industry=2&sector=3&inquiry=266

3.5 Barriers to be addressed to enable large scale rollout of PV at competitive cost

The cost of generating systems is the most important barrier to PV deployment today.[34] Even over coming years, as a carbon price increases the cost of electricity from fossil fuels, the cost of electricity from PV systems will remain high among existing low-emissions options.

However, PV-generated electricity costs benefit from economies of scale, at least to a point at around 30 megawatts. That makes it likely that larger PV installations for industrial and commercial customers will be economic before small-scale residential systems.[35]

The consultancy AECOM's (2010) analysis of potential large-scale solar precincts in NSW suggested a levelised cost of electricity (LCOE) of between $230 and $270 per megawatt-hour. Bloomberg New Energy Finance suggests that costs will be around US$150 to 230 per megawatt-hour in 2020, while the US Department of Energy's 'Sun Shot' program is seeking costs of US$100 per megawatt-hour (see Figure 3.9).

Many analysts, including the World Resources Institute, the IEA, Ernst & Young, McKinsey and Company, Barclay's Capital, General Electric and the Institute of Electrical and Electronics Engineers, suggest that PV will be able to compete with retail electricity prices by 2020.[36] However, as noted in section 3.4.2,

[34] International Energy Agency (IEA) (2010)
[35] Ibid.
[36] Cass (2011), International Energy Agency (IEA) (2010), Kirkegaard*, et al.* (2010)

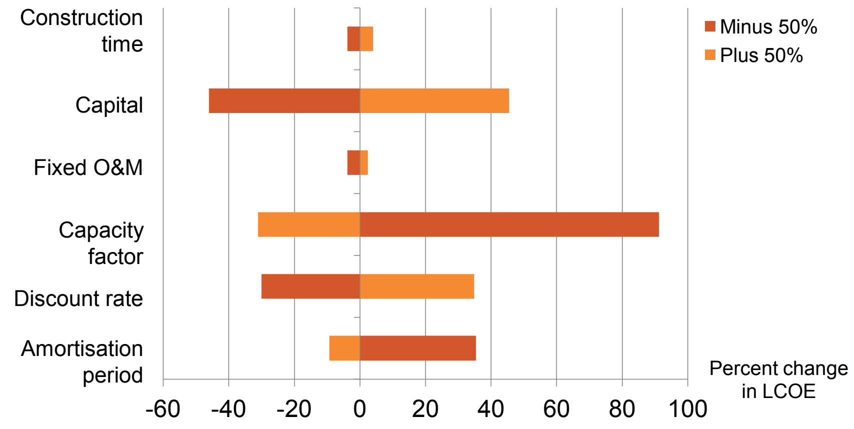
this is not necessarily an appropriate benchmark for cost competitiveness of PV. Competitiveness with wholesale electricity prices is the key measure. That will come later.[37]

3.5.1 Electricity costs must be brought down through lower equipment costs and improved yield

The primary influences on the cost of electricity from PV are capital costs of the system and the capacity factor (see glossary) The figure below suggests an almost linear correlation between a change in the cost of capital and a change in LCOE: a 40% fall in capital reduces LCOE by 39%, while a 24% increase sees LCOE rise by 22%.

[37] Retail prices are not the appropriate benchmark for valuing solar PV exported to the grid, though there is a 'price substitution' value for avoided electricity prices for PV investors themselves.

Figure 3.8 Effect of change in assumptions on forecast LCOE for PV in 2015



Source: (CSIRO, 2011)

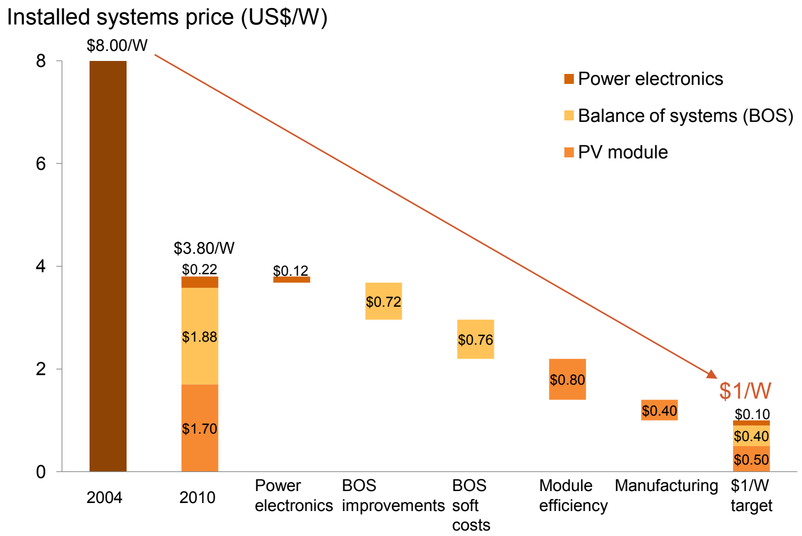
The figure above, and recent analysis from the Australian PV Association, also highlights the influence of exchange rates and the cost of equity (or, for residential systems, interest rates).[38] The cost of finance will be a particularly significant factor for utility-scale projects; some estimates are that lower cost finance may reduce the LCOE of utility-scale PV by 6-7%.[39]

Lower costs of solar panels will drive down system costs

The possible contribution of various factors in these cost reductions are illustrated in Figure 3.9.

[38] Mills, *et al.* (2011b), Mills, *et al.* (2011a)
[39] AECOM (2010)

Figure 3.9 Potential system cost reductions

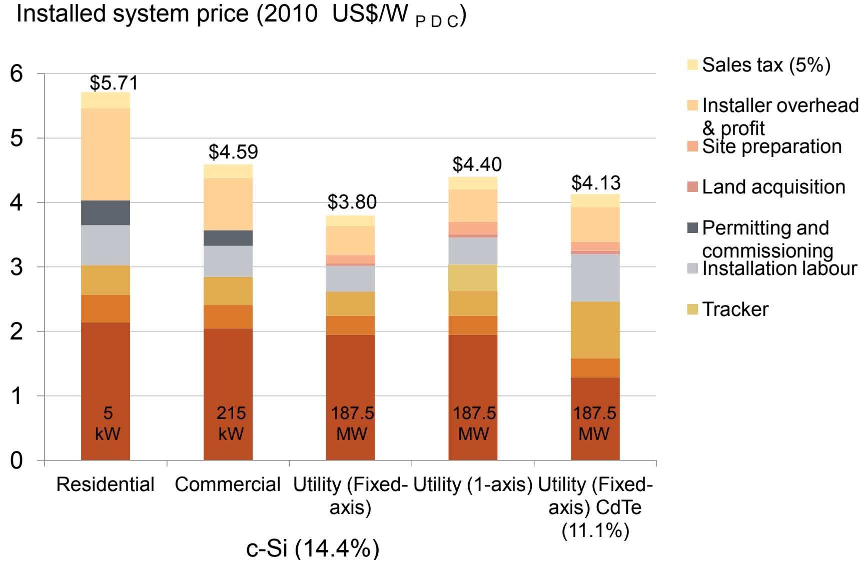


Source: (Twidell, 2011), derived from (US Department of Energy, 2010)

There are a range of avenues for improving PV technology that, if successful, will reduce production and installation costs, and increase electrical output for a given equipment cost.

The main influences on PV system costs (or prices) are module costs, which for most systems account for 40 to 50% of system price (Figure 3.10).

Figure 3.10 Components of PV system price models



Source: (Goodrich et al., 2011)

Note: Results are for Q4 2010. Markup on all materials included in 'Installer Overhead & Profit' Residential $0.89/W$_{DC}$, commercial $0.55/WDC, and utility (fixed-axis) $0.31/W$_{DC}$.

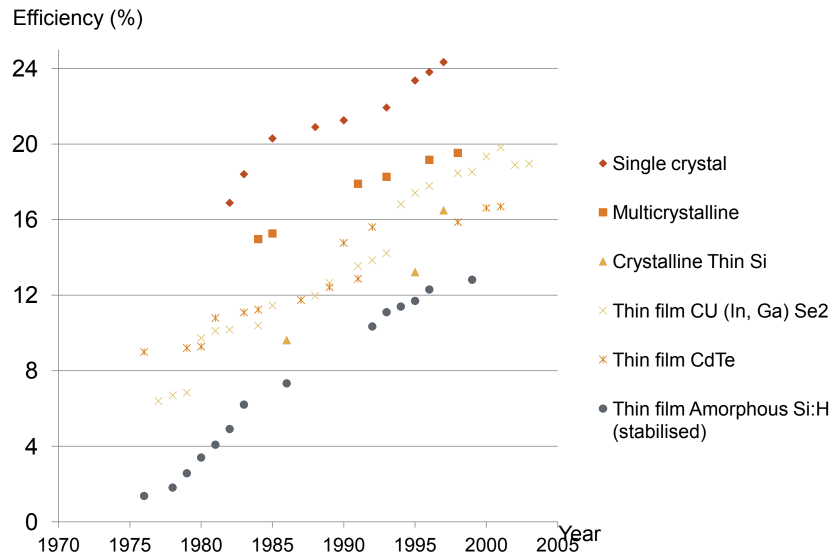
Module costs, in turn are influenced by the costs of materials, in particular silicon[40], the efficiency of cells[41] and efficiencies in manufacturing.[42]

[40] Kirkegaard, *et al.* (2010), National Renewable Energy Laboratory (NREL) (2010)

More efficient cells are critical to reducing costs. They enable reductions in the cost of power for given amounts of material inputs, frames and electrical interconnection costs, installation labour time and area of land or roof space required. A strength of PV is the ease of upgrading to new, more efficient cells as they become available. Technology lock-in is minimal; much of the same infrastructure could remain, with cells simply converted.

Steady improvements in cell efficiencies are illustrated in Figure 3.11. Australia has contributed to these knowledge breakthroughs, including through the research program of the University of New South Wales and the Australian National University.[43] Further improvements in efficiency are predicted, particularly in crystalline silicon (5 to 9% by 2020).

Figure 3.11 Improvements in solar cell efficiency 1976-2004



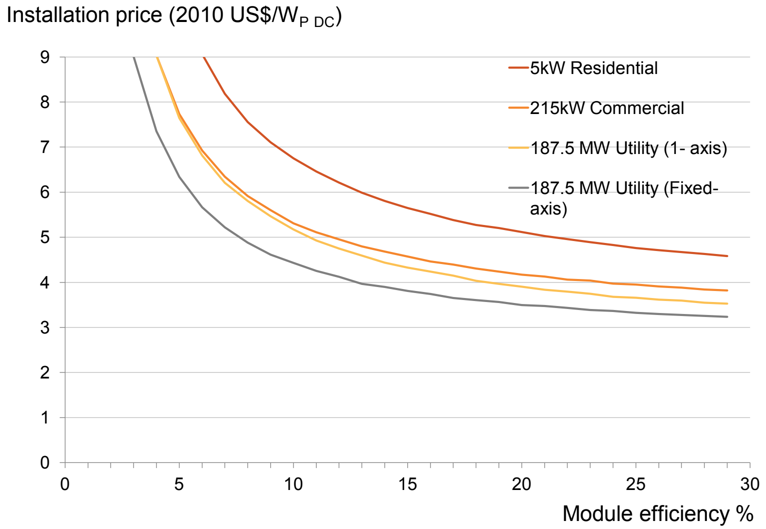
Source: US Department of Energy, 2005, Basic Research Needs for Solar Energy Utilization

Note: Year on year efficiency improvements.

The relationship between system price and module efficiency is illustrated in Figure 3.12. This chart also shows that even when cells reach their maximum theoretical potential efficiency, of around 30%, system prices remain above $3 watt peak. On its own, cell efficiency cannot bring down the LCOE of PV to a level competitive with wholesale prices of other power sources.

[41] Efficiency is a measure of the percentage of sunlight converted to electricity for a given surface area
[42] SolarBuzz (2011c)
[43] School of Photovoltaic and Renewable Energy Engineering (undated)

Figure 3.12 Relationship between system price and module efficiency



Source: (Goodrich et al., 2011)

As module prices plateau[44], improvements in local elements of PV costs – like the balance of systems (see glossary) – will make a difference.[45] These elements include reduction in labour hours for installation, particularly for electricians, improved inverter reliability to reduce the need for repairs, and, for larger projects, streamlining of land preparation and planning approvals.[46]

Greater efficiencies in production have driven down PV system costs and will continue to do so. PV cells are mass produced around the world on larger and larger scales.[47] Chinese and emerging Asian producers have captured market share in recent years; in 2010 their lower costs and support from government and local financiers enabled them to offered 15% (on average) price discounts compared to Japanese and western producers.[48] Such competition has helped to close manufacturers in developed countries, including Australia's only PV manufacturing facility in 2011 and recent bankruptcies in the U.S.[49] Future improvements in manufacturing hold promise. For example, fluidised bed reactor production processes for silicon could produce 20% reductions in module costs by 2030.[50]

A better resource can increase output and lower electricity costs

Beyond module cost, the primary factor with the potential to improve the LCOE of PV is the resource quality (and associated capacity factor).

System output and costs vary dramatically with resource quality. In northern Australia, high capacity factors of around 18% mean that annual output from a 1.5 kilowatt system is around 2500 kilowatt hours. With a lower capacity factor – around 11%, as in Tasmania – annual energy output is closer to 1,700 kilowatt hours.[51] CSIRO (2011) concluded that an increase in capacity factor of 50% could cut the LCOE of PV by 30%; conversely, a

[44] Note: the maximum theoretical potential of c-Si efficiency is around 30% (Source: Department of Energy (2011))
[45] Bony, *et al.* (2010), International Energy Agency (IEA) (2010), M Watt (2010)
[46] Lushetsky (2010)
[47] Kirkegaard, *et al.* (2010)
[48] Ibid., SolarBuzz 2011, 'Global PV Market'
[49] Daily and Steitz (2011), Parkinson (2011d)
[50] Lushetsky (2010)
[51] SKM-MMA (2010)

decrease in capacity factor of 50% could increase LCOE by 91% (see Fig.8 above). Analysis from EPRI suggested that around a 30% change in capacity factor could change electricity costs by up to 40%.

Tracking mechanisms that rotate panels help to maximise exposure to the sun and can lift the PV capacity factor. In circumstances of good sunlight, the higher costs associated with tracking through parasitic load and operation and maintenance costs can be offset to the point where LCOE is lower than for a fixed system.[52]

Trends and expectations suggest that solar costs will continue to fall, but it is uncertain by how much and how quickly. Cost improvements are also likely to require a combination of government funded basic and applied R&D, as well as ongoing technological advancements by the private sector, underpinned by revenue from an ongoing market for PV. PV modules are readily transportable, so although Australia has a strong interest in these improvements, it is not essential that this innovation occurs domestically in order for Australia to benefit. However, if improvements were to occur in Australia, it would receive benefits from licensing the developed technology.

[52] National Renewable Energy Laboratory (NREL) (2010);Parkinson (2011b)

3.5.2 Grid integration issues could constrain rollout and need to be better understood

High penetration of PV can challenge distribution networks and impacts cannot be predicted

As PV generates more electricity,[53] the fact that it is non-dispatchable – meaning it cannot be stored and summoned on demand –
will challenge distribution networks.[54] Greater deployment of PV generation, with its daily variability, can affect power system protection, quality of supply, reliability and safety.[55] Without changes in the physical infrastructure and how it is managed, PV growth will be bound by network constraints.

The problems will not become apparent at a single point, such as a proportion of supply or penetration relative to load. Impacts vary significantly between locations, depending on the size of the generator, its capacity relative to the system capacity, and the existing network infrastructure.[56] These characteristics vary between grids across Australia. Local load (see glossary) will also have an impact: high levels of penetration will be better absorbed in a grid with a load matched to PV generation. In other words, the

[53] There is no clear definition of high penetration, but the following discussion generally relates to rates of penetration of around 20-30% installed capacity ('capacity penetration').
[54] Given the dominant – and fastest growing – type of PV generation is grid-connected and small-scale, the focus of the following discussion is changes that can ease pressures on distributional networks.
[55] Brundlinger, *et al.* (2010), Energy Networks Association (2011), Passey, *et al.* (2011)
[56] Brundlinger, *et al.* (2010), Energy Networks Association (2011), National Renewable Energy Laboratory (NREL) (2010)

demands of commercial and industrial customers, which usually match the hours the sun is shining, make it easier for the grid to absorb generation of PV.

Some Australian experiences are worth considering. Some mass roll-outs of PV in Western Australia suggest that around 20 to 25% penetration is the level at which changes to system or network infrastructure are required.[57] PV penetration has reached similar levels in Townsville's Solar City.[58] In Alice Springs PV penetration levels reached up to 30% of distribution transformer load, with a study concluding that penetration rates were "entirely manageable" and have not "caused any problems of significance to the safe and reliable operation of the...system".[59]

Beyond these case studies the identification of network problems related to PV rollout in Australia has been largely theoretical. More evidence – data collection, including through smart meters, experimentation and modelling – is needed to move towards predicting at what level of penetration and under what circumstances problems might arise in a range of distribution grids.[60] Lessons can be shared at a global level, including through the IEA's Photovoltaic Power Systems Programme.[61]

Technical solutions to grid issues are available, but their relative costs and substitutability are unclear

There are a number of solutions to grid problems, including updated system and grid technologies, more active management of the distribution grid, and a well-integrated grid to move load efficiently.[62] The Energy Networks Association (2011) concludes that "the majority, if not all" issues associated with PV can be overcome through known solutions.[63] The biggest barrier to grid integration will be economic, rather than technical. Customers or network businesses will be reluctant to outlay the necessary expenditure, or consumers will be slow to modify their consumption behaviour. It is also a collective action and regulatory challenge. To maximise PV output without causing problems for networks will require coordination of different stakeholders and options, and a mix of solutions at different points in the electricity supply chain.[64]

Grid solutions will be determined on a case by case basis, depending on the generator specifications, the capacity and load of a particular system, and the existing network infrastructure.[65] Changes will be simpler and cheaper in new-build networks, but most can still be implemented within existing infrastructure.[66]

57 Poyan (2010)
58 Cruishank, 2011, pers comm.
59 Centre for Energy and Environmental Markets (CEEM) (2011)
60 CSIRO 2011, pers. comm.; Business Council for Sustainable Energy (2004), Energy Networks Association (2011)
61 See http://www.iea-pvps.org/index.php?id=58

62 Brundlinger, *et al.* (2010), International Energy Agency (IEA) (2010), Passey, *et al.* (2011)
63 Energy Networks Association (2011)
64 Passey, *et al.* (2011)
65 Butler (2008)
66 Passey, *et al.* (2011)

System inverters, demand response enabling devices and grid technologies can help manage voltage levels

One of the main challenges of high PV penetration is maintaining regulated voltage levels and voltage quality in distribution grids.[67] Problems with voltage beyond what the system is designed for are already apparent in some Australian locations, such as Carnarvon in Western Australia.[68]

The inverter, which acts as the interface between the generator and electricity network, can help to solve these problems. A demand response enabling device (DRED) inside the inverter, or at the connection point, can allow grid operators to communicate with the PV system to increase or decrease its load and voltage.[69] Longer term, the PV inverter or the DRED could become a hub for data acquisition, communication and control for the grid operator, allowing optimal local use of PV electricity and making PV more like a controllable load.[70]

These inverters and DREDs exist, but they are expensive and not all consumers are interested in altering their energy use to modifying peak demand. Currently, the value of inverters and DREDs to the network, system operator or a demand aggregator is not recognised. Therefore these parties rarely invest in these technologies. Also, Australian standards (AS4777.2) do not allow inverters to provide reactive power (see glossary) unless specifically approved by electricity utilities at the point of connection.[71] Regulatory change may be needed to reward the provision of reactive power, for example, in order to make these technology investments more economically attractive.[72]

Technologies can also be applied to the distribution network itself, to allow distribution businesses to more actively manage their network. Network-sensing devices, perhaps contained in smart meters, could provide real-time information on the grid, and identify areas of high and low load, allowing grid managers to raise or lower voltage.[73] However, as with inverters and DREDs, the costs of these grid technologies are a barrier to their rollout and to high levels of PV penetration.[74]

System engineers of distribution businesses will need to be more engaged in grid management, closely monitoring it and remotely adjusting appliance and network settings more regularly.[75] Incentives to reduce or alter the patterns of demand, or to promote the embedded generation that PV provides, should also be better integrated with the investment incentives of distribution businesses. That way, they would be encouraged to identify and implement demand side solutions such as distributed PV when they offer greater benefits than network, supply side solutions.

[67] Brundlinger, *et al.* (2010), Butler (2008)
[68] Aussie Solar (2011), Energy Networks Association (2011)
[69] Brundlinger, *et al.* (2010)
[70] Brundlinger (2011)
[71] Passey, *et al.* (2011)
[72] Parkinson (2011c), Passey, *et al.* (2011)
[73] Energy Networks Association (2011)
[74] Ibid.
[75] CSIRO 2011, pers comm. 13 Sept

Demand management will have a role in smoothing variability and mitigating network issues

Demand management may be important to integrating variable generation – and a major advantage of PV may be its ability to reduce demand on the grid, rather than just provide power. The ability to shift peak demand helps smooth the load profile, reducing the problem of over-voltage from PV and maximising the chance of deferring investment in the distribution network.

For example, Townsville's Solar City project cut peak demand by 2.5% each year, after years of large increases in peak demand.[76] Overall energy consumption dropped by 3% in the year to 2009-10.[77] This was achieved through a combination of PV systems, energy efficiency audits and retrofits, in-house displays, information and financial incentives. More recently, a trial of peak demand reduction tariffs – cost-reflective pricing coupled with rebates to those that reduced electricity consumption by an agreed percentage during the evening peak – has achieved reductions of 23 to 26% in Townsville's peak consumption.[78] Blacktown's Solar City program achieved similar reductions through a trial of dynamic peak pricing.[79]

[76] Australian Government (2010)
[77] Wyld Group (2011)
[78] Cruishank 2011, pers. comm.
[79] Australian Government (2010), Wyld Group (2011)

Longer term, storage technologies can help manage voltage and variability

Storage technologies are another way to manage the variability introduced by high penetration of PV.[80] The IEA (2010) considers that widespread adoption of power storage, along with smart-grid technologies, would enable PV to provide more than 10% of Europe's electricity generation, for example.

A communications device in the inverter or at the connection point can direct output to storage rather than to the grid. This allows storage to absorb solar power during times of excess generation, thereby preventing it from raising voltage on the grid. It can also reduce or shift peak load, as well as provide electricity when the PV system is not generating.[81]

Storage options include on-site or distributed batteries (such as in electric cars), sodium sulphur cells and compressed air storage. Sophisticated storage devices, such as the 10 kilowatt-hour RedFlow units used in Australia's *Smart Grid, Smart City* are costly – around $30,000 each. Simpler inverters, combined with improvements in battery technologies and Balance of System (BOS) costs[82] could halve storage costs in the short- to medium-term.[83] Beyond batteries, other storage-based solutions are generally not commercially viable, and are likely to take time to

[80] Energy Networks Association (2011), Passey*, et al.* (2011)
[81] Passey, *et al.* (2011)
[82] BOS costs generally refer to all costs except the module (and, in some cases, the inverter). It is the components of the system that move and convert energy, including cables, switches and fuses, and can include the labour to install those components.
[83] Estimate from RedFlow, September 2011

emerge.[84] The Energy Networks Association (2011) notes that regulatory endorsement of network storage will help encourage the development and use of these technologies in Australia. With widespread distributed storage, PV could offset residential peak demand, in contrast with what is described in 1.4.2.

3.5.3 Information can help network and market operators manage voltage and variability at a regional level

PV output is variable; it ramps up and down over a 24 hour period. Temporary cloud cover can reduce output from solar panels quickly, and by as much as 60 to 85%.[85]

High quality information -- including satellite monitoring, precise weather forecasts and sunlight forecasting capability -- will help minimise the impacts of this variability on the network by allowing the most suitable network management options to be selected.[86] Combined with information about distribution network capacity and constraints, better information on weather will mean installers can identify the best locations for deployment of PV systems throughout the network, and best positioning of the panels.[87].

Australia's National Electricity Market (NEM) is well equipped to integrate intermittent generation sources on a large scale. With quality forecast information the market can respond in five minutes. Good information will allow market operators to manage PV more like dispatchable generation in balancing supply and demand.[88]

3.5.4 Transmission grid inter-connection could ease network issues

Better investment in and planning of the transmission grid will help ease the pressure on distribution networks by allowing a freer flow of energy between regions. Transmission interconnection – the high-voltage lines that connect parts of the National Electricity Market – will be particularly significant for utility-scale PV because many of the best sites are far from load centres and will require significant investment to transport their energy.[89]

PV's low capacity factor means that there are only short periods during which output is as high as the peak capacity of the plant. Studies suggest it may be more economic to construct a transmission line below the plant's peak capacity and to oversize the solar field relative to available transmission and curtail output during peak output. For a PV plant, even significant transmission constraints have only a modest impact on total generation yield and revenue. (This is not true for generation technologies with high capacity factors, such as CSP with storage, and are therefore generating more consistently).[90]

The transmission network is discussed in chapter 9.

[84] MetaPV (2010)
[85] Energy Networks Association (2011)
[86] Boerema*, et al.* (2010), Elliston and MacGill (2010), Passey*, et al.* (2011)
[87] A west-facing array is better able to reduce the average peak, but over a year it produces about 25% less power than a north-facing array (Watt*, et al.* (2007)
[88] International Energy Agency (IEA) (2010), Energy Networks Association (2011)
[89] Kirkegaard*, et al.* (2010)
[90] Elliston and MacGill (2011)

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4 Concentrating Solar Power (CSP)

4.1 Synopsis

- Concentrating solar power, or CSP, has great potential in Australia. The technology makes use of the component of sunshine that is known as Direct Normal Irradiance, of which Australia has a vast resource, and the flat land needed for CSP. In theory, a solar farm measuring 50 square kilometres could meet all Australia's energy needs.

- CSP can also closely match demand and be reliable and dispatchable when it is integrated with thermal storage or hybridised, meaning that it is combined with another source of heat to drive a power turbine.

- Although CSP has been deployed since the 1980s, government support is helping to produce a resurgence in interest and investment in the technology.

- At present, CSP costs more than many other low-emissions generation technologies. But engineering and new manufacturing capability assisted by deployment and learning-by-doing could significantly reduce costs.

- The greatest cost reductions are likely to come from mass production and engineering improvements that lower the cost of solar fields, as well efficiency improvements from higher temperature fluids. CSP's capital intensity means the cost of finance will have a major effect on project economics. Local engineering capacity will help bring down costs in Australia.

- Government funded collection and dissemination of solar radiation data would address a market failure of positive spillovers and help to accelerate the identification of the best solar sites in the country.

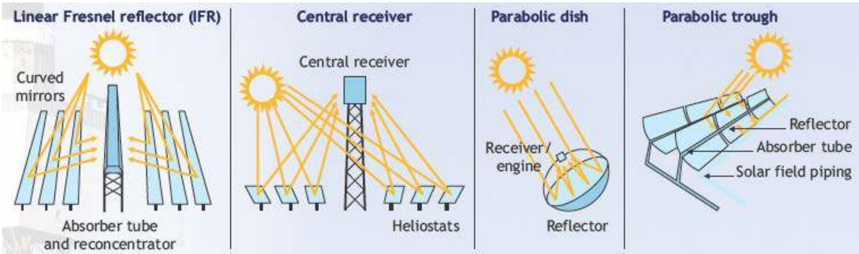
- Existing regulatory frameworks for managing the development of the transmission network are not well suited to the widespread deployment for technologies like CSP. The effective barrier created by these deficiencies need to be addressed.

4.2 What is concentrating solar power?

Concentrating solar power electricity is produced by converting sunlight into heat to drive a generator. Sunlight is concentrated using mirrors and focussed onto a solar receiver, which contains a heat-absorbing working fluid (usually water, oil, gas, salts or air). Heat from the working fluid is then transferred to a conventional steam turbine or a Stirling engine, or stored for later use. Thermal storage is a distinguishing characteristic of CSP, and gives it a competitive edge over other intermittent, generation technologies. The minimum economic scale for CSP plants is 50 megawatts or more.[1]

The four main types of CSP are illustrated below. Each has strengths and weaknesses (see Table 4.1).

Figure 4.1 Linear Fresnel Reflectors, towers, dishes and troughs



Source: UBS (2009)

[1] Geoscience Australia and ABARE (2010), UBS (2009)

Point focussing CSP – described below – seems to offer greatest potential, since its higher capital costs are offset by higher temperatures and greater efficiencies.[2]

Table 4.1 Characteristics of four types of CSP technology

	Line focussing		Point focussing	
Technology type	Parabolic trough	Linear Fresnel reflector	Power tower (central receiver)	Paraboloidal dish
Operating temperature	150-450°C	150-500°C	300-1,200°	300-1,500°C
Capacity factor (indicative maximum)	20%*	12%	30%*	31%
Approx. land required[b] (m^2 per MW)	7,000 – 26,000 m^2	40,000 m^2	10,000 – 12,000 m^2	9,000 – 32,000 m^2

Notes: [a] = the proportion of the calendar year the plant would operate at full load to produce the annual output. * = trough does not include storage; tower includes approx. 3 hours storage. [b] = Figures are for generation without storage. Land requirements change depending on location (and quality of DNI), the efficiency of the technology, and how tightly packed the field is.

Source: (Geoscience Australia and ABARE, 2010); (Hinkley et al., 2011); (IT Power, 2011); (NREL, 2010), (Turchi, 2011), (Transfield, 2011), (Wyld Group and MMA, 2008)

[2] Hinkley, *et al.* (2011), BrightSource Energy (2010), Kolb, *et al.* (2011), Mehos (undated)

4.3 How scalable is CSP in Australia?

Australia's annual solar irradiation amounts to about 16 million terawatt hours. Only a small fraction of this resource – the largest in one country – would meet Australia's energy needs.[3] The ability to realise this potential depends on the locations' solar radiation, the proximity to electricity load centres, and the availability of suitable land for plant construction.

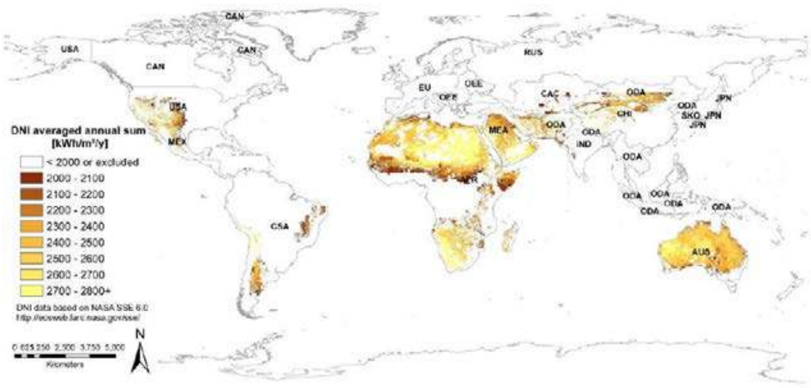
The type and quality of solar radiation is particularly important for CSP technology. Unlike solar PV, CSP needs clear skies and direct sunlight, known as Direct Normal Irradiance, or DNI. This is because CSP can only focus sunlight coming from one direction, using tracking mechanisms to align their collectors with the direction of the sun. CSP also has little tolerance of humidity and dust. The available solar resource for CSP is smaller than that for solar PV technologies, which can generate power from both direct and indirect insolation (a measure of solar radiation that reaches the Earth's surface).

Australia's DNI (the light patches in the figure below) is some of the best in the world[4]. Australia's potential for CSP is particularly good because it has a lot of flat land, which is necessary for a CSP plant. Large-scale solar power plants generally require 20,000 to 40,000 square metres of land per megawatt of power, depending on the solar resource quality and the technology used.[5] Storage increases the land requirement to more than 40,000 square meters per megawatt depending on its size (though it also increases output, so it should not be compared on a megawatt basis).[6] Therefore, one megawatt-hour of output would require at least 2,000 square metres of land a year.[7] If the available flat area of land within 25 kilometres of existing transmission lines (excluding national parks) was used for CSP it would be enough to supply almost 500 times the annual energy consumption of Australia.[8] Theoretically, Australia's entire electricity demand could be met by a solar farm covering 50 square kilometres.[9]

Figure 4.2 points to only a few regions worldwide (most between 15° and 40° parallels[10]) with good DNI and flat land. This suggests that only a limited number of countries are likely to invest in CSP as a large energy source.

[3] Geoscience Australia and ABARE (2010)
[4] Ummel (2010)
[5] EPRI (2010), Geoscience Australia and ABARE (2010), Sandia National Laboratories (2011). Note: land requirements change depending on location (and quality of DNI), the efficiency of the technology, and how tightly packed the field is.
[6] IT Power (2011)
[7] EPRI (2010)
[8] Geoscience Australia and ABARE (2010)
[9] Ibid.
[10] IEA (2009)

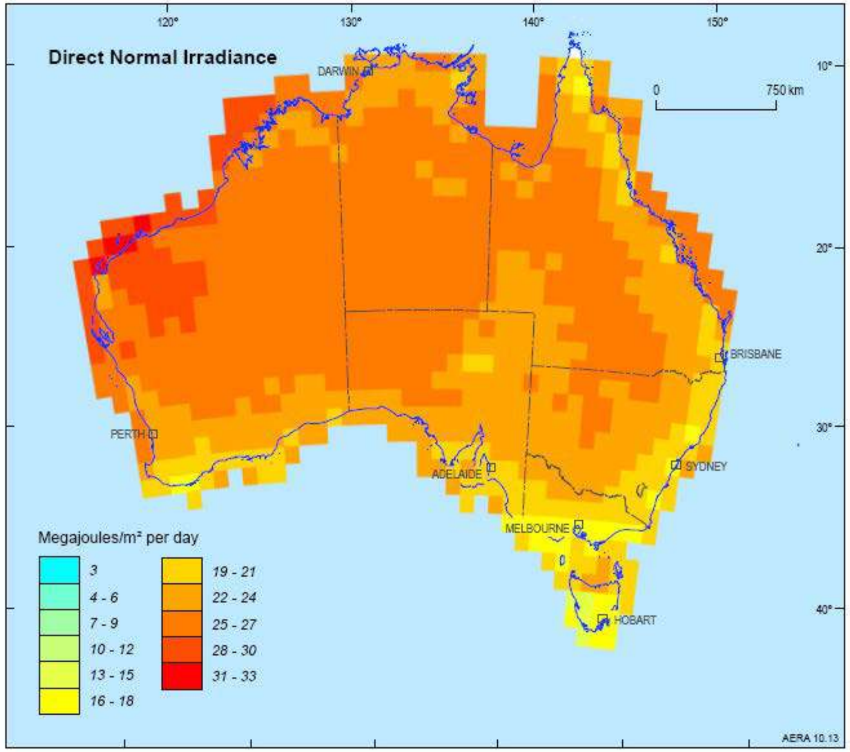
Figure 4.2 Potential CSP regions worldwide



Source: (Trieb et al., 2009)

Australia's DNI is particularly high in inland Australia, as illustrated in Figure 4.3.

Figure 4.3 Average Direct Normal solar irradience across Australia



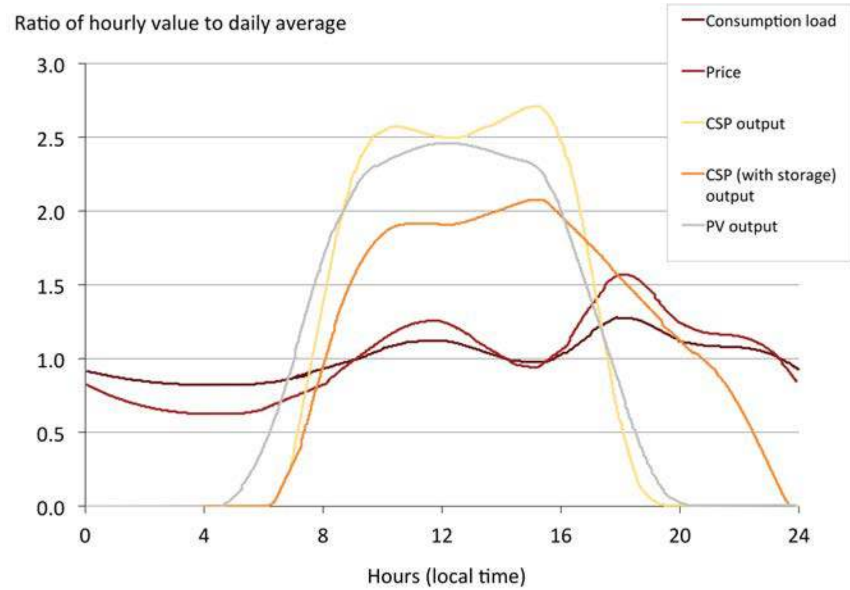
Source: NASA 2009, reproduced in (Geoscience Australia and ABARE, 2010)

Some of the best resources for CSP – Mount Isa, Alice Springs, Tennant Creek and the Pilbara region – are far from the electricity grid.[11] Yet there are high-quality resources closer to the transmissions grid and load, including at Moree, Dubbo, Broken

[11] Wyld Group and MMA (2008)

Hill, Olympic Dam, Geraldton, Longreach and Roma.[12] Development of the solar resource in these regions could complement wind generation in Australia's south. CSP can also come close to matching peak demand when electricity supply is more highly valued (Figure 4.4). Because it only produces by day, when electricity prices are highest, its average revenue per kilowatt hour is eight to 15% higher than a plant with 24-hour output.[13] Its seasonal output also aligns well with seasonal demand.

Figure 4.4 Indicative diurnal trends for price, load and soalr power output with and without storage



Source: (Ummel, 2010)

CSP can be combined with thermal storage, to hold at least 16 hour's worth of power through heat kept in a liquid or solid material, and thereby significantly extending CSP output[14]. Thermal storage is easier and cheaper than electrical storage, giving it advantage over wind and solar PV. CSP can also be hybridised with other thermal generation technologies, both fossil

[12] Wright and Hearps (2010); pers comm. CSP 1
[13] Ummel (2010)
[14] Storage is much less compatible with parabolic dishes

and renewable. That makes it able to dispatch power when it is worth more to the market.[15]

4.4 Status

4.4.1 There is renewed interest and investment in CSP

Three decades after the technology was first deployed, global capacity of CSP is around 1.2 gigawatts, with most capacity installed since 2008.[16] Projects to produce about three times that amount have been committed or are under construction.[17]

After a long period of stagnation, falling production costs and a more favourable political and policy environment are encouraging exploration and development in all four main types of CSP technology. A feed-in tariff in Spain that favours large-scale solar, and the Renewable Energy Portfolio Standards, tax incentives and grants in the U.S are favouring CSP development.[18] Other countries are supporting projects with grants and feed-in tariffs for CSP.[19] These measures help developers secure power purchase agreements, finance and land. By contrast, Australia and Germany are among the countries in which support measures for solar have benefited solar PV – a rival to CSP in some circumstances (see Chapter 3, Solar PV).

Among CSP technologies, the parabolic trough has by far the greatest market share at present. Since the 1980s, around 350 megawatts of trough plants have operated in California, and several new plants of 50 to 60 megawatts have been built in other U.S. states and many in Spain in recent years. Three solar tower plants operate in Spain, with more under construction in the U.S., including a large (392 megawatt) dry-cooled tower plant in California. A linear Fresnel reflector has been demonstrated successfully in Australia.[20]

Australia's only commercial high temperature CSP plant is the coal-solar hybrid at Liddell Power Station in NSW (built with some Commonwealth support). This configuration uses a limited amount of solar-generated pre-heating to reduce the quantity of coal used in generation. Australia's first large scale CSP plant – a 250 megawatt linear Fresnel at Chinchilla in Queensland – is scheduled to be commissioned by 2015 under the Solar Flagships program.[21]

Improvements in storage technologies are also likely to have re-ignited interest in CSP. Plants developed today are more likely than not to include storage. Some existing CSP plants include storage capacity for up to seven hours of power generation and new designs incorporate up to 16 hours of storage.[22] This is enough to allow 24-hour operation in mid-summer, though more may be required to run constantly throughout winter and other times of extended low direct sunlight.

[15] That refers to the amount of thermal energy required to operate the power block at full capacity for those hours. (Geoscience Australia and ABARE (2010))
[16] Hinkley, *et al.* (2011); Bhavnagri (2011)
[17] Bhavnagri (2011)
[18] UBS (2009), Wyld Group and MMA (2008)
[19] IEA (2009)
[20] Geoscience Australia and ABARE (2010);Hinkley, *et al.* (2011)
[21] DRET (2011)
[22] Geoscience Australia and ABARE (2010), Lovegrove (2009)

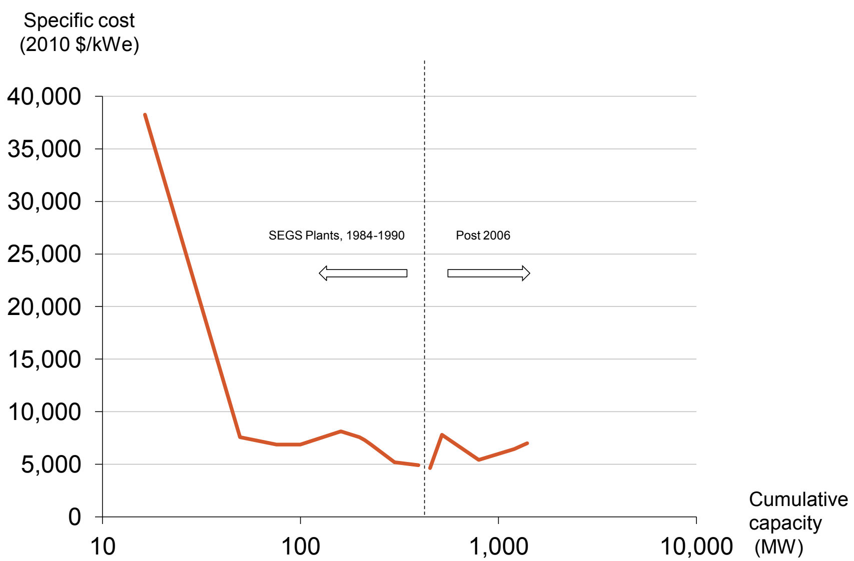
Storage can increase plants' capacity factor (the ratio of actual output to its potential at full capacity) to around 70%.[23] The most developed form of thermal storage is molten salts, which is used in Spain in both trough and tower plants. The Gemasolar power tower plant in Spain has stored 15 hours of thermal power without any solar feed, effectively more than doubling the plant's capacity factor to about 75%.[24] Less developed storage options include latent heat storage in concrete and ceramics, and thermo chemical storage.[25] Solar-enhanced fuels now under development can also be seen as a portable means of storage (see section 4.5.1). While storage is capable of managing fluctuations in DNI that occur during a day and weather patterns, hybridisation may be needed to manage intermittency of the resource over several days or weeks (consecutive cloudy days, for example). In this context, hybridisation means combining CSP with another form of energy that produces heat to supply a common steam turbine.

4.4.2 What are the barriers to development of CSP?

The cost of the technology and its electricity remain high

Costs fell steeply in the early period of CSP deployment, but the fall has slowed (Figure 4.5).

Figure 4.5 CSP cost versus capacity installed



Source: Based on (Hinkley et al., 2011)

Declines in cost have fallen short of some earlier projections. Sargent and Lundy (2003), for example, projected the LCOE of CSP to fall by 40% between the first 50 megawatt plant and the deployment of a mature 200 megawatt plant in 2020. This was based on the assumption that the first plant would be running by 2007 and the first 100 megawatt plant by 2011, neither of which occurred. Their projections also assumed a market size, economies of scale in manufacturing and learning through

[23] Wright and Hearps (2010), Wyld Group and MMA (2008)
[24] Dunn, *et al.* (2011), Torresol Energy (2010)
[25] UBS (2009)

deployment that have yet not materialised.[26] Also, targeted policy support for solar PV has helped produce rapid cost falls in that technology and given it a competitive edge. Consequently, some CSP developers have converted planned CSP projects into solar PV, including the first half of the one gigawatt Blythe plant in California, and two other projects being developed by NRG Energy.[27]

Most estimates of current CSP costs range from between $6.6 to 8.7 million per megawatt (equivalent) for troughs, and $6.5 to 8.1 million for towers (both including six hours storage).[28] However, a recent estimate for CSP tower technology in Australia is considerably lower: $4.2 to 4.9 million per megawatt (equivalent) (with and without storage, respectively).[29]

This means that electricity from CSP is not yet cost competitive with conventional power or with wind, though is within range of solar PV. Estimates of its LCOE in around 2015 are still high, at about $200 to $250 per megawatt-hour, though even in the short term the range of estimates is large.[30] The great advantage of CSP is that its generation aligns with peak demand, and that it is dispatchable with storage. If these features are valued appropriately in electricity prices, or through other policies, the economics of CSP generation become more appealing.

Over time, towers are projected to become cheaper than troughs because they produce steam more efficiently and at a higher temperature, allowing more efficient conversion from thermal to electric energy. Towers use less 'parasitic' energy during operation (because they do not require heat fluid circulation around the solar field) and have a higher capacity factor.[31] The higher temperatures of towers also store energy more efficiently; the cost of storage for a tower plant per kilowatt-hour of thermal heat would be about a third of that for troughs.[32] The greater efficiency of towers also reduces land requirements. Because there is less experience with their deployment, tower projects face higher capital, project management and finance costs, but these are expected to fall with deployment.

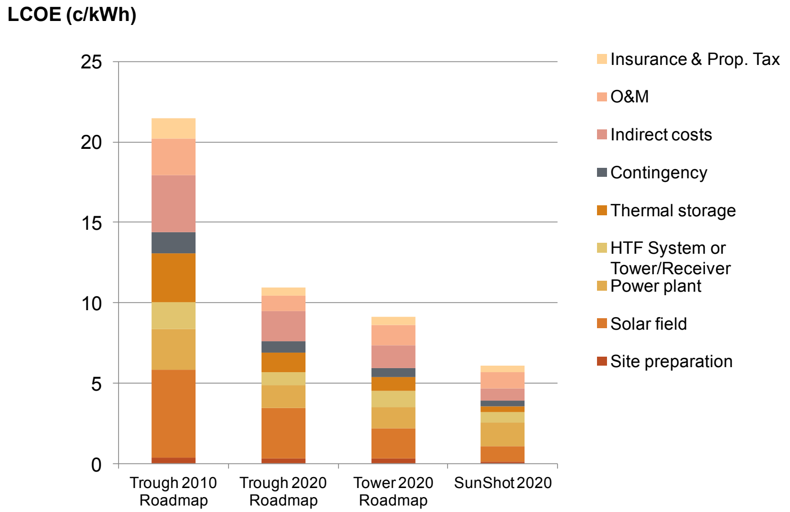
4.5 Barriers to be addressed to enable large scale rollout of CSP at competitive cost

4.5.1 Improve the economics of CSP electricity, by lowering capital costs and achieving higher temperatures

Large reductions in the cost of electricity from CSP are expected as early as 2020. For such reductions in cost to occur, a fall in all cost components, combined with higher plant outputs, will be required. Some possible combinations to reduce costs are shown in Figure 4.6.

26 Melbourne Energy Institute (2011)
27 Kanellos (2011)
28 Hinkley, *et al.* (2011)
29 Ibid.
30 Torpey (2011), UBS (2009)
31 BrightSource Energy (2010), Mehos (undated)
32 Pers. comm. CSP1, CSP2

Figure 4.6 US Department of Energy targets for CSP levelised cost of electricity

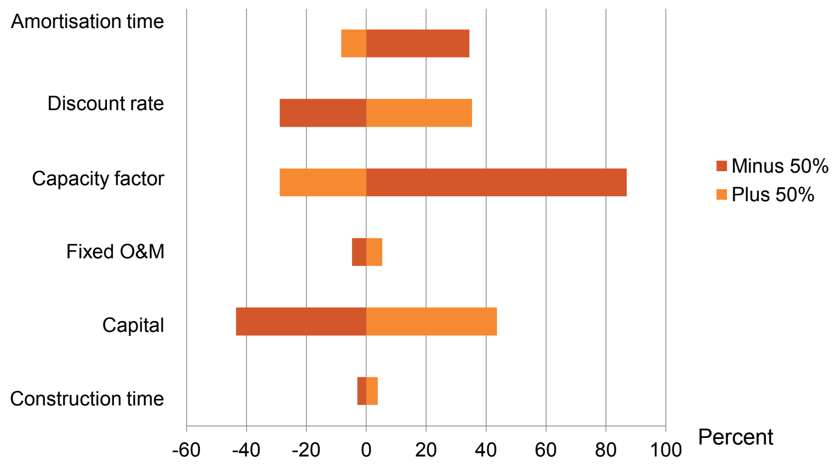


Source: (Australian Solar Institute, 2011)

Capital costs (the solar field, receiver, storage and power plant) account for 80% of CSP project costs, so are a major factor in the LCOE (see Figure 4.7 and Figure 4.8). This capital intensity makes the cost of finance particularly significant for CSP. Capacity factor – the ratio of a plant's actual output to its potential output at full capacity – is the greatest determinant of a plant's LCOE, as shown in Figure 4.7. A 50% increase in capacity factor reduces the LCOE by 29%, while a decline of 50% raises the LCOE by 87%.[33]

The cost of capital is also significant. A certain percentage change in the amount of finance can produce the same change in the LCOE.[34]

Figure 4.7 Effect of change in assumptions on forecast LCOE in 2015, CSP parabolic trough

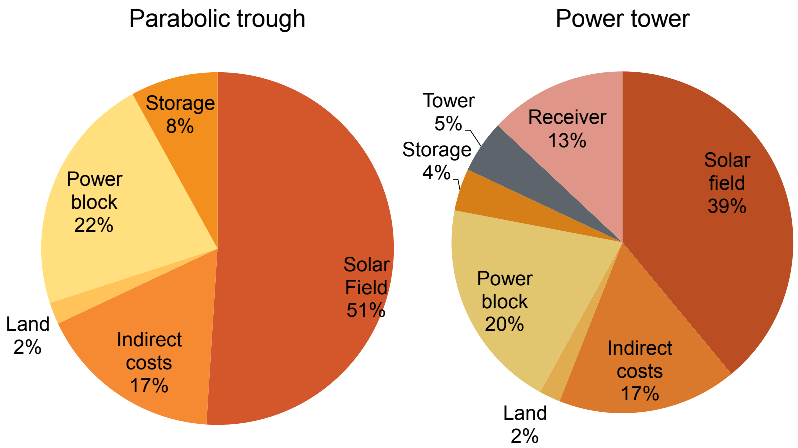


Source: (CSIRO, 2011)

[33] CSIRO (2011)
[34] EPRI (2010), Mehos (undated)

Figure 4.8 shows that the largest component of capital costs – between 40 and 50% – are the mirrors and supporting infrastructure for the solar field.

Figure 4.8 Capital cost breakdown for CSP technologies



Note: Precise cost breakdowns are technology and project specific.

Source: (Hinkley et al., 2011)

Falls in solar field costs of at least 40% are possible.[35] This alone could reduce LCOE by 18-28%.[36] Improvements in engineering and mass manufacturing that come with large-scale deployment will drive down costs in the solar field, which predominantly involves conventional materials such as glass, steel and concrete. Costs may also be reduced by keeping mirrors closer to the ground and reducing steel usage.[37] Mirrors that are wireless and self-powered, with rapid installation and minimal site preparation also offer opportunities for cost reductions.[38]

The International Energy Agency noted the need for system deployment to allow the technology to move down the cost curve.[39] Some of these cost reductions will occur through changes in manufacturing and deployment in other parts of the world, but it will also require some domestic experience to understand and lower the costs through design, delivery and day-to-day operation.[40] The relatively small size of the global market and the limited number of suitable locations for CSP (Figure 4.2) mean that deployment in Australia could have a big effect on global technology costs.

Larger regional deployment exercises, such as the proposed Gujarat solar park in India, or projects like Desertec (see Box 4.1), with shared infrastructure across multiple plants, could support a local manufacturing industry and mass production.

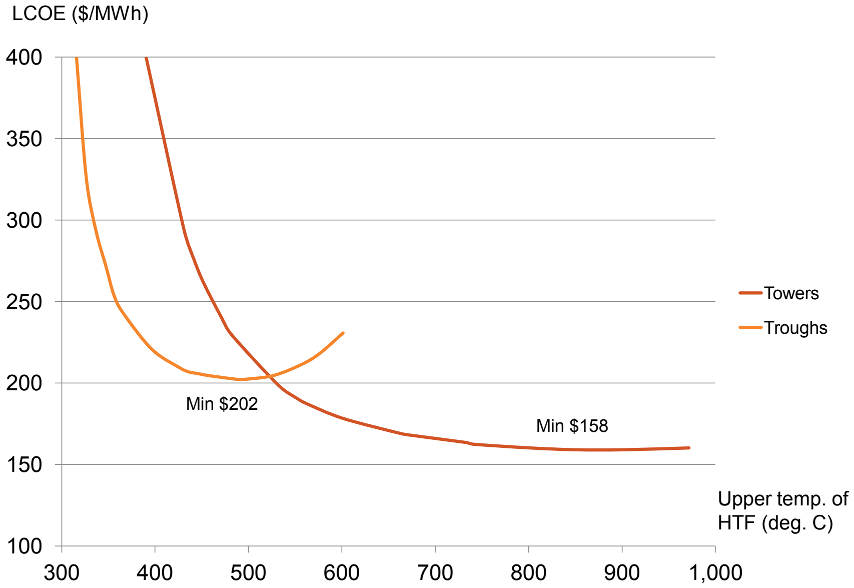
Concentrating the sun's energy can contribute to higher temperatures, which improve efficiency and lower the electricity cost, as illustrated in Figure 4.10. Further, if materials can be

[35] Hinkley, *et al.* (2011)
[36] Assumes solar fields account for 40-50% of capital costs (Fig.XX) and that a 30% change in capital costs change LCOE by up to 28% (Fig.XX).

[37] Ausra (2007)
[38] Stekli (2011)
[39] IEA (2010)
[40] IT Power (2011), Wyld Group and MMA (2008)

found to increase receiver and fluid temperatures beyond around 750°C then further cost reductions of 10 to 15% may be possible.

Figure 4.9 Estimated LCOE for 'current generation' troughs and towers, varying heat transfer (HTF) temperatures



Note: Assumes a constant capacity factor and capital cost

Source: (Hinkley et al., 2011)

4.5.2 Utilise thermal storage to extend operating hours and reduce intermittency

Storage can have a major impact on the success of CSP because it extends output and smooths it over the day. Storage accounts for 4 to 8% of capital costs (Figure 4.8). Development of storage technologies is still at early stages, with potential to reduce costs through higher operating temperatures. Storage is considerably cheaper for towers, compared to troughs, because the temperature difference between the hot and cold tanks is much greater (higher temperatures mean less storage is needed).[41]

The capital cost of storage may have little impact on the cost of produced electricity. The initial higher costs of storage – the extra mirrors, a larger receiver system, and the storage system and medium itself – are offset by extra operating hours, particularly at times of high electricity prices.[42] Just six hours of storage can extend output so that average revenue per kilowatt hour is about 5% higher than PV or CSP without storage.[43] Optimising the size and amount of storage will depend on the relative cost of extra plant, and the revenue generated by more output. Seasonal variation in output complicates this further. Optimisation also depends critically on electricity prices; higher prices will make storage more viable. Thus, optimising a CSP plant design involves more than simply keeping the LCOE low.[44]

In the longer term, CSP-driven solar fuels could offer not only a novel storage option, but also a revenue stream for CSP plants (particularly attractive with rising gas prices) and a means to reduce emissions from the transport sector. Solar fuels – solar driven gas-to-liquids – can be produced in a similar way to CSP electricity generation: a field of mirrors directs sunlight to a tower, which houses a reactor that uses high temperatures, with a

[41] Ibid., Dunn, *et al.* (2011), Kolb, *et al.* (2011)
[42] Hinkley, *et al.* (2011)
[43] Ummel (2010)
[44] Denholm (2011), Hinkley, *et al.* (2011)

catalyst, to perform a chemical reaction between water and natural gas.[45] The result is a gas mix that contains around a quarter more energy than the original natural gas.[46] This product could be stored and burnt later, for example, in a gas-solar hybrid plant, or transported for use elsewhere. This offers a natural opportunity for Australia, already a large gas producer, to create a value-added product for transport energy or for export[47]. Longer term, this link between fossil fuel-based technologies and chemical technologies could lead towards the production of hydrogen[48], which could be a highly efficient long-term option to store and transport energy.[49]

4.5.3 Lower risk and costs through hybridisation

Though storage can smooth the generation profile of CSP over the course of a day, hybridisation can help smooth demand over a longer period. Hybridising CSP plant with a separate source of heat (gas, coal, biomass or geothermal) extends output and increases plant capacity factor over days and weeks.

A major benefit of hybridisation is the potential to retrofit solar thermal systems onto existing fossil fuel power stations without replicating the turbine power blocks. This has been done at Liddell and is planned for Kogan Creek.[50] It can extend the life of existing power stations once a carbon price is in place.

Hybrid plants can also be built and operated more cheaply. Not only is the required solar field smaller, but around 40% of the plant (steam turbine, BOP and ancillary equipment) can be installed as part of the gas plant cost structure, at marginal cost. Turbine start-up and shut-down losses, which are around 7% for a trough plant, are also removed if the plant operates continuously. A recent Queensland study estimated that a gas-CSP hybrid could reduce the LCOE of the solar component by 25 to 35%.[51]

Hybrid plants also potentially reduce the cost of finance by lowering project risk.[52] The ability to vary fuel (gas-solar) ratios is also a way to hedge against the risk of stranded gas plants in the future, as gas and carbon prices rise. A plant that operates predominantly with CSP will be protected against these rising prices. It is theoretically possible to convert a gas-solar hybrid plant to 100% solar over time, provided the DNI entering the plant is high. Plants with such flexibility are being built in the US, Europe, Saudi Arabia and North Africa.[53] Hybrid plants can increase the rate of deployment of CSP and provide a bridge from coal, to gas, to solar.

[45] Wyld Group and MMA (2008)
[46] CSIRO (2010b)
[47] Pers comm. CSP2
[48] Wyld Group and MMA (2008)
[49] Shell International (2007)
[50] DRET (2011)

[51] Range depends on the level of solar-gas integration achieved. Figures apply to trough and towers (Parsons Brinckerhoff (2009))
[52] DRET (2011), Mehos (undated)
[53] This flexibility comes at a cost, because it is not possible to optimise the original design of both a hybrid plant and 100% solar plant; the power station, and potentially the gas infrastructure, will have been over- or under-sized at the outset.

4.5.4 Reduced economic scale will make CSP more deployable

Deployment experience is needed to bring down the costs of CSP, but the large scale of plants constrains this. Plants are generally greater than 50 megawatts[54], excepting dishes, with a minimum efficient scale of at least 10 megawatts to offset turbine and other development costs. This is a major drawback for demonstration and learning by doing, and has contributed to producing a slower learning curve than wind or PV[55].

Large plants further constrain investment, because of the difficulties of finding high-quality DNI, a flat site, building infrastructure, transmission lines, roads and gas pipelines, and bringing in water and labour. These demands are harder to meet as plants get bigger. Big plants require big investment: a minimum scale plant of 10 megawatts requires $45 to 65 million[56], a challenge for an immature Australian industry still negotiating access to finance. A solar park model could improve efficiencies and deliver economies of scale, and help to secure low cost financing.

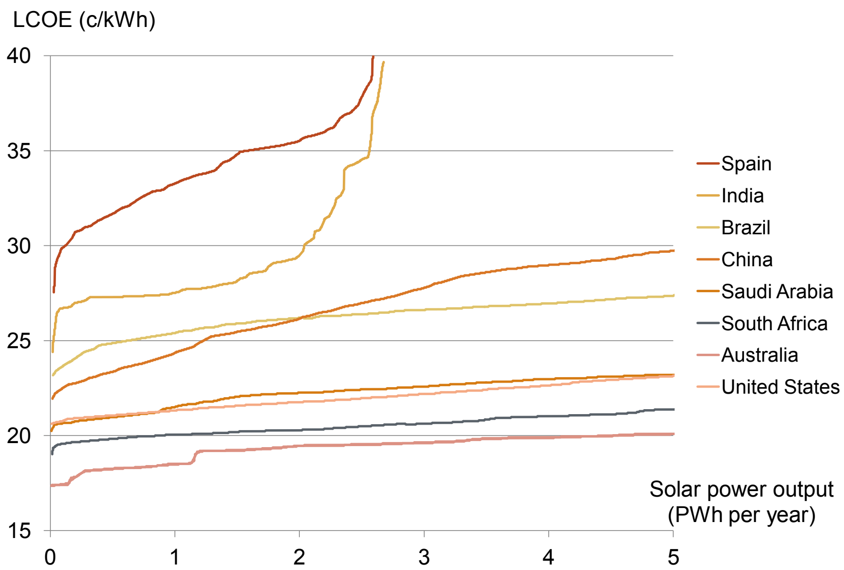
The land requirement is also significant: 30-40 hectares for a minimum scale CSP plant with storage. It can be reduced with more efficient technology or more densely packed fields, though this is more expensive. Higher temperatures will improve efficiencies that will reduce the land and other resources required for CSP plants. And the Paraboloidal dish, so far only deployed with Stirling engine systems and without storage, has the potential over time to be used in modular, or small-unit, form.[57] These improvements can be advanced in several locations around the world.

4.5.5 Better information on the resource will improve location choice and decrease the cost of finance

As Figure 4.7 shows (in terms of capacity factor) the quality of the DNI is one of the greatest determinants of plant efficiency and costs.[58] A Western Australian study also found that "optimal" DNI could reduce LCOE by 14%.[59] The effect of DNI on cost is also reflected in the cost curve for cumulative CSP deployment in various countries, which show that Australia's costs are among the most attractive in the world (Figure 4.9).

[54] Geoscience Australia and ABARE (2010), Hinkley, *et al.* (2011)
[55] Hinkley, *et al.* (2011)
[56] Based on a range of cost estimates presented earlier in chapter, for a 10MW plant.
[57] Geoscience Australia and ABARE (2010), IEA (2009)
[58] Geoscience Australia and ABARE (2010), Hinkley, *et al.* (2011)
[59] Evans and Peck (2011)

Figure 4.10 Estimated cost curve for cumulative CSP capacity (trough) in selected countries



Source: (Ummel, 2010)

Resource quality will significantly affect the costs of Australian solar plants. For instance, low DNI (around 17.5 MJ/m^2/day) in Brisbane or Melbourne could increase solar field by around two thirds, to generate the same output as a plant in areas of high DNI (up to 24.5 MJ/m^2/day) found in inland Queensland or Western Australia (see Figure 10.2 in Chapter 10, appendix on transmission infrastructure).

Accurate information on DNI will also help developers choose the best sites for CSP projects, and to provide greater confidence for investors on likely project performance. To date, the only available information on DNI that covers all Australia are satellite data from the National Aeronautics and Space Administration. These data are relatively coarse grained – at a grid cell size of approximately 100 kilometres (10,000 square kilometres) – and provide only a broad indicator of potential.[60] More detailed mapping of DNI is needed to assess the potential for CSP at a local scale.

To provide greater certainty about the resource, site-specific, long-run data are needed to calibrate satellite measurements.[61] Such precise measurements can only be achieved by on-the-ground monitoring at specific sites, collecting hourly data for at least a year.[62] Information on water and transmission accessibility is also necessary to enable the best site selection.

DNI data will have positive spillovers to others. In other words, those collecting the knowledge and information will not be the only ones to benefit. Others, possibly competitors, will be able to make more informed decisions by observing the actions – and particularly site selection – of those who collect the data. This could discourage private sector investment in collecting the data[63], therefore public support for more accurate DNI measurement may be required. The Victorian and Queensland governments have already developed solar atlases using satellite-based irradiance estimates, calibrated with on ground station measurements from several sites, to provide estimates of

[60] Geoscience Australia and ABARE (2010)
[61] DRET (2011)
[62] Pers. comm. CSP1
[63] Garnaut (2011)

irradiance parameters on a 5 square-kilometre grid. National data is currently being improved through a project led by the Bureau of Meteorology and Geoscience Australia.

4.5.6 To avoid limitations by water requirements dry cooling will be required for large-scale CSP in Australia

Most existing CSP plants need water. A little is used for mirror cleaning but most is for condensing, in 'wet cooling' towers, steam that has passed through the turbines.[64] An 80 megawatt trough plant needs almost 1.2 million m^3 of water per year for cooling the steam cycle.[65] Desalination may meet demand for water for cooling in some locations, but dry or air cooling towers, or wet/dry hybrid systems, which reduce water consumption by around 80 to 95%, would be a better option.[66] Dry cooling is used at Kogan Creek in Queensland, and in Spain, and is becoming the default approach in the U.S. There is a cost in shifting from wet- to dry cooling: the efficiency of the steam cycle reduces by around two to 10%, thereby increasing the cost of electricity.[67]

Parabolic dishes with Stirling engines do not require cooling water, though the technology faces other challenges, including maintenance requirements.[68] Similarly, air turbines use the Brayton Cycle to generate electricity by compressing and heating air to drive a turbine, and do not use any water. However, major challenges remain for the technology, including improving air receivers to withstand higher temperatures.[69]

4.5.7 Transmission connection and costs

Australia has large potential to produce electricity from CSP at low cost. As for technologies such as wind and Solar PV, geographic diversity of plants would help to smooth the total electricity output. These plants would have to be connected to the existing transmission system, either directly or, more likely, via new additional transmission lines. In Chapter 9, we identify a number of issues that arise from the planning, coordination and regulation of transmission connection in Australia, and recommend that resolving these should be a priority for governments.

In Australia, CSP plant location must trade-off solar resource quality with transmission distance (and water availability). As for all types of generation, the costs of transmission connection vary depending on distance, the size of the generator and existing transmission capacity. Estimates for five New South Wales locations are set out in Table 4.2.[70]

[64] Geoscience Australia and ABARE (2010)
[65] IEA (2009)
[66] DOE (2010), Ummel (2010)
[67] DOE (2010), Geoscience Australia and ABARE (2010), EPRI (2010)
[68] UBS (2009)
[69] CSIRO (2010a)
[70] AECOM (2010b);AECOM (2010a). As a rule of thumb, a 250 MW plant can connect to a 220 kV transmission line. A line of at least 330 kV would be needed for a 1,000 MW plant

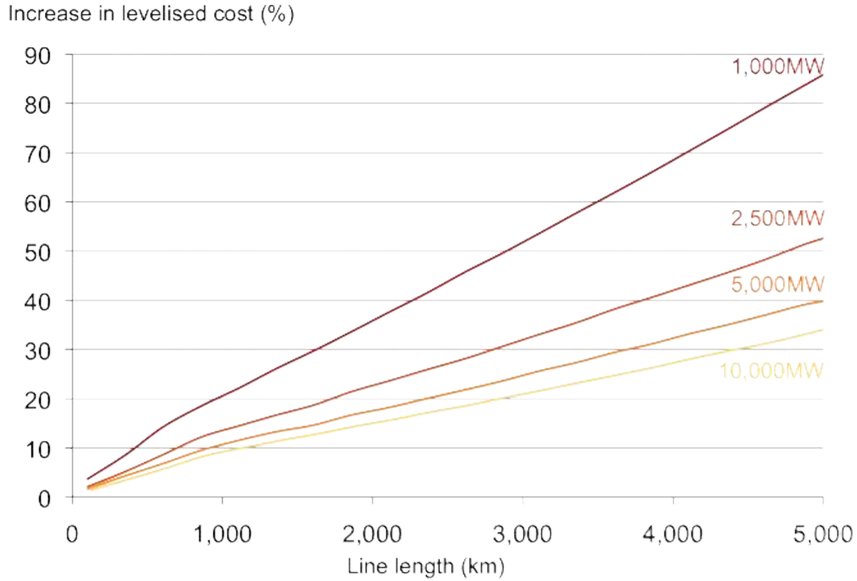
Table 4.2 Transmission connection costs for large-scale solar generation in NSW

Area	Total cost 250 MW	Total cost 1,000 MW	$ per MWh 250 MW	$ per MWh 1,000 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	$13m	$25m	$52,00	$25,000	✔

Source: (AECOM, 2010a)

A study of potential large-scale solar sites in Queensland produced similar results, and concluded that the high costs of transmission and other infrastructure tend to make lower-quality but less remote sites more attractive.[71] Similarly, a recent global study that considered the effect of transmission costs on the cost of electricity produced by CSP (Figure 4.11) concluded that long transmission lines may only be justified if the power to be exported is very large.

Figure 4.11 Illustrative cost of transmission for CSP plant



Note: assumes plant capacity factor of 0.3
Source: (Ummel, 2010)

Nevertheless, the idea of generating large-scale solar energy in remote regions to be transported to demand centres far away is being seriously considered in several parts of the world. In June 2009 the Desertec Foundation proposed exporting power to Europe from large solar farms in Africa and the Middle East (see

[71] Parsons Brinckerhoff (2010)

Box1).[72] The Asia Pacific Sunbelt is considering a similar concept using solar resources from central Australia.[73]

Box 4.1 Desertec: Long-distance CSP

Less than 3% of the Sahara desert covered with CSP plants could meet the electricity demand of the whole world. This has driven companies such as Siemens, Abengoa, Enel, ABB, Deutsche Bank and E.ON to come together on the Desertec Industrial Initiative. They hope that, together with wind power, CSP plants in Northern Africa and the Middle East could provide 15% of Europe's electricity demand by 2050.[74] Construction of the first plant, a 500 megawatt facility in Morocco worth up to 2 billion euros, will start in 2012 and take several years to complete.[75]

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[73] Geoscience Australia and ABARE (2010)
[74] UBS (2009),
[75] Reuters (2011)

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5 Geothermal power

5.1 Synopsis

- Australia has abundant, high-quality geothermal resources several kilometres below the Earth's surface. If commercialised, they could provide reliable, dispatchable energy, with no emissions.

- Yet it is highly uncertain as to whether geothermal energy can be extracted reliably and at reasonable cost. The resource remains at the exploration and development stage, and lacks private sector investment.

- Fundamental engineering challenges remain for the underground operations of geothermal energy, particularly for resources in deep granite (Hot Rocks). The key issues are repeatedly creating effective heat reservoirs, improving drilling practices and equipment and enhancing flow rates.

- It may be worthwhile to focus efforts in the short-term on proving the more accessible, shallower Hot Sedimentary Aquifer resource. This will develop experience and investor confidence to help address the more challenging Hot Rocks resource.

- The data that come from exploration and modelling can provide information to other companies. This may discourage private sector investment if such data collection benefits competitors. Governments should fund the early stage mapping and resource characterisation of the geothermal resource.

- Existing regulatory frameworks for managing the development of the transmission network are not well suited to the widespread deployment for technologies like geothermal. The effective barrier created by these deficiencies need to be addressed.

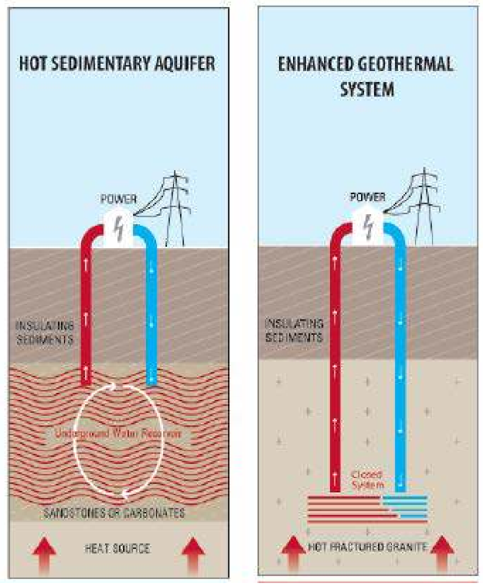
- As the geothermal sector expands, there is the potential for community concern regarding the technologies being applied and any potential environmental impact. This has been the experience with coal seam gas developments in recent years. Active government attention to community concerns and development of appropriate regulatory frameworks are needed to provide certainty for all stakeholders.

5.2 What is Australian geothermal power?

Geothermal energy comes from the heat below the Earth's surface. Two types of geothermal projects have potential in many Australian locations: Hot Sedimentary Aquifer (HSA) and Hot Rocks (HR).[1] The two types are at ends of a spectrum, primarily related to depth and permeability. HR resources are deeper (generally more than 4 kilometres) and are hotter than HSA resources, but are usually in granite, a far less permeable rock.

Geothermal electricity production starts with the drilling of two wells – for injection and production – into rock several kilometres below the Earth's surface. Working fluid, such as saline water, is pumped across rocks that are heated by radioactive decay and/or by flows from lower in the crust. The fluid is then pumped to the surface (Figure 5.1). If the rocks between the wells are not permeable enough, which is the case in the deep, hard granite of HR geothermal resources, and sometimes in HSA, they are fractured ('frac'ed') to allow fluid to circulate between the two wells.

Figure 5.1 Energy production process from HSA and HR



Source: (AGEA, 2010)

When hot water is brought to the surface its thermal energy is transferred to a secondary working fluid in a binary power station. This fluid drives a turbine in a Rankine Cycle (traditional steam cycle) or Organic Rankine Cycle (organic working fluid) power generator.[2]

HSA is sometimes called the "low hanging fruit" of geothermal development because its heat is closer to the surface and its sedimentary basins have better natural flow rates than the HR

[1] HR is also known as Hot Fractured Rock (HFR), Engineered Geothermal Systems (EGS) or enhanced geothermal.

[2] Allen Consulting Group (2011), Petratherm (2011), SKM-MMA (2010)

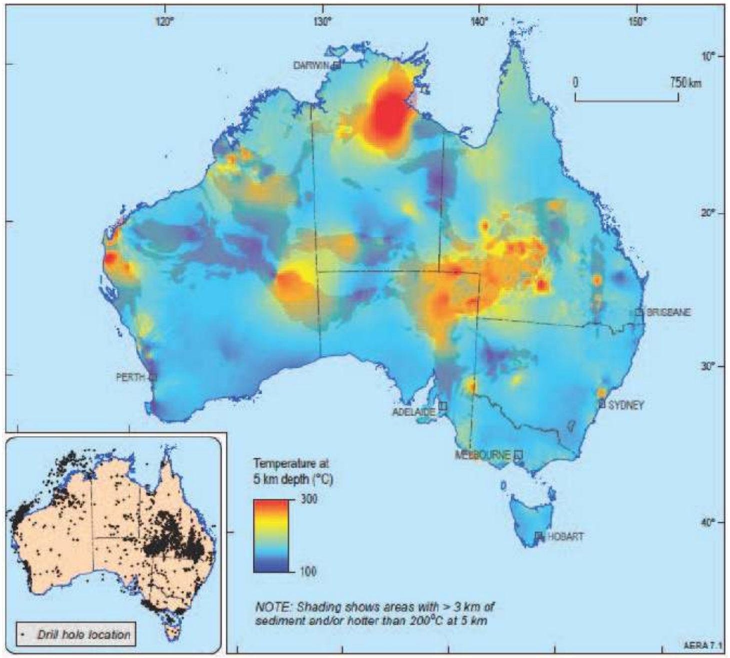
granite.[3] HSA technology is relatively proven, with around 300 megawatts installed worldwide. A small (80 kilowatt) plant has operated for the last 15 years in Birdsville, Queensland, producing 98°C geothermal water and an isopentane working fluid, from a relatively shallow depth.[4] This plant provides the entire town's power in winter and overnight. Australia has yet to demonstrate a deep HSA or HR project.[5]

A third type of geothermal occurs in volcanic regions such as Iceland and New Zealand but not in Australia. Sometimes referred to as hydrothermal or conventional geothermal, it captures naturally forming hot water released at high flow rates from highly permeable rock at relatively shallow depth, and feeds it directly into a steam turbine.[6]

5.3 How scalable is geothermal in Australia?

Geothermal is particularly promising in Australia. Our geology holds a high concentration of the radiogenic particles that create heat as they decay, compared with granites in other parts of the world. Second, the movement of the Australian tectonic plate is causing a horizontal stress orientation in the Australian crust. This favours the creation of sub-horizontal fracture networks, which in turn help to create heat reservoirs. Finally, Australia's enormous land mass offers many sites where the resource exists, though it is difficult to calculate its size and nature, since it is three to five kilometres underground.[7] Current assessments based on temperature estimates from test data from oil and petroleum exploration at drill holes are shown in Figure 5.2.

Figure 5.2 Predicted temperature at 5 km depth



Source: ABARES 2011, reproduced in (AEMO, 2011)

Geoscience Australia (2011) estimates that one per cent of Australia's geothermal energy shallower than five kilometres and hotter than 150°C, could supply Australia's energy requirements for 26,000 years. A more recent and more conservative estimate is that if 2% of Australia's "technically-accessible" HR potential was tapped it would generate capacity of almost 400 gigawatts –

[3] EPRI (2010)
[4] AGEA (2011), Budd (2008)
[5] Allen Consulting Group (2011)
[6] Simshauser (2010)
[7] Geoscience Australia and ABARE (2010)

around nine times the entire registered capacity in Australia's National Electricity Market.[8] This stable and zero-emissions resource is much larger than any fossil fuel resource in Australia.[9] The measured geothermal resource, reported by Geoscience Australia, is less than this estimate but even so, at more than 6,600 terawatt hours per year it is 26 times larger than Australia's projected National Electricity Market (NEM) energy demand in 2020-21.[10]

If it can be commercialised, geothermal could provide a reliable, dispatchable and low-emissions electricity[11] that continues for decades and longer.[12] Geothermal is also renewable after a lag: extracting energy from a resource means that it may take about four times as long as the period in which heat was extracted for the temperature to return[13].

Nevertheless, the scale and timing of geothermal generation remains uncertain. This is reflected in projections of future Australian generation mixes, which see a limited contribution of geothermal until 2020 at the earliest, or even until 2030. ABARE's latest long-term energy projections suggest that geothermal electricity generation will account for just 1.5% of total electricity generation by 2030.[14] Its share is likely to increase after that time, however. Recent projections by ROAM Consulting of the electricity generation mix to 2050 anticipate that geothermal's share of energy generation will rise to provide around 20 terawatt hours, or about 13% of all demand, in 2050 in the core policy scenario, with a carbon price similar to that legislated.[15] More optimistically, SKM-MMA projects several 2050 scenarios in which geothermal provides almost 100 terawatts – almost a quarter of generation in that year.[16]

Finally, there is major potential for 'direct use' of geothermal energy to heat and cool buildings, and to provide heat for agriculture and industry, particularly in Victoria and New South Wales.[17] This direct heat could play a role in co-generation, using its heat as a steam-booster for existing fossil-fuel power plants, and potentially solar power.[18] However, the focus of this report is on the potential for electricity generation from geothermal.

5.4 Status

5.4.1 Industry interest is strong, but finance difficult to obtain

Industry interest has grown quickly since the first geothermal exploration licences were granted in 2001. Applications for licence areas rose from around 110 in 2007 to more than 400 in 2010, covering 475,000 square kilometres.[19] From 2002 to 2009 the sector spent around $454 million on studies, surveys, drilling and tests, and has announced a further $2.9 billion in work plans to

[8] Parkinson (2011a)
[9] Based on 2004-05 figures. Based on a contained heat estimate, using the average temperature of the area between bottom depth of 5km and an upper depth where temperatures are 150C (Geoscience Australia and ABARE (2010))
[10] Ibid., Geoscience Australia (2011)
[11] CSIRO (2011)
[12] Huddlestone-Holmes and Hayward (2011)
[13] Budd (2008)
[14] Geoscience Australia and ABARE (2010)
[15] ROAM Consulting (2011)
[16] SKM-MMA (2011)
[17] Geoscience Australia and ABARE (2010)
[18] ACRE (2011), AGEA (2010)
[19] Goldstein, *et al.* (2010)

2014.[20] Yet it is highly unlikely that all these announced plans will proceed, and some companies have recently applied to defer exploration works due to market conditions and financing concerns.

Most geothermal companies are small, with relatively low market capitalisation, and struggle to secure private sector investment.[21] Only one Australian company, Geodynamics, has market capitalisation above $20 million.[22] Allen Consulting Group concluded that "the larger amounts of capital required for demonstrating the viability of geothermal electricity will remain out of the reach of most [geothermal companies]".[23] Some joint venture arrangements are in place, such as those involving Geodynamics and Origin Energy in Innamincka (see Box 5.1 and Box 5.2) and TruEnergy's and Beach Petroleum's joint venture with Petratherm. These joint ventures are the exception rather than the rule.

Major energy retailers could potentially play a large role in providing finance for geothermal developments because they control power purchase agreements and make some direct investments in generation, but to date these firms have favoured investment in mature renewable energy technologies, and this is likely to continue.[24] Earlier this year, the Geothermal Expert Reference Group reported that the likely short-term rewards of geothermal energy "[do] not justify current private sector risk".[25]

[20] AGEA (2010); Goldstein, *et al.* (2010)
[21] Allen Consulting Group (2011), Batterham (2011)
[22] Elliot (2011)
[23] Allen Consulting Group 2011
[24] Largely to meet obligations under the Mandatory Renewable Energy Target scheme

Box 5.1 Financing case study: Geodynamics

Geodynamics had a market capitalisation of $20 million, and raised $11.5 million when it listed on the ASX in 2002 as a renewable energy developer. The opening share price was 60 cents. In the same year Geodynamics received government funding to develop its Habanero reservoir and to construct a plant in Innaminka. Geodynamics shares rose to their first peak in around February 2005, at about $2.20 a share.[26]

In October 2007 a Binding Heads of Agreement was executed with Origin Energy Limited, with Origin farming-in to 30% of the South Australian Geothermal tenements and 30% of a drilling rig.[27] Six months later Sunsuper Pty Ltd and the Sentient Group became joint cornerstone investors, taking a 10% stake in Geodynamics for $37.5 million, and in 2008 they were joined by the Tata Power Company Limited, which took on a 10% stake in the company for $44.1 million. Having languished as low as 60 cents a share during 2006 and 2007, share prices peaked again around January 2008.

In late 2009 Geodynamics was awarded the largest government award received by any Australian renewable energy project to date: $90 million for a 25 megawatt demonstration plant. However, delays have meant that only $1 million of those funds have been used. A further $7 million was awarded under the

[25] Batterham (2011)
[26] Geodynamics (2011b)
[27] Geodynamics (2011a)

second round of the Australian Government's Geothermal Drilling Program in December. In recent years shares have fallen steadily to their current low of around 20c a share.[28]

Geothermal technology is at an early stage, close to the basic research end of the development spectrum, so public support is important.[29] Yet public funding to date has been thinly spread, with onerous conditions for its uptake. For example, the Renewable Energy Demonstration Program awarded grants to recipients who provided at least two dollars for every one received.[30] Also, a total of $50 million has been allocated on a dollar-for-dollar basis to seven companies through the Geothermal Drilling Program (GDP). However, four of the grants were later terminated "due to difficulties in attracting matching private sector funding to the projects".[31]

Matching private funds are generally not available until the resource is proven – in other words, not until it is drilled. The inability to access private funds has meant that the plans of most geothermal aspirants have been put "on hold", leaving the Government with $35 million of drilling grants that were made but not used, because matching funding could not be obtained.[32]

From mid-2012 the geothermal industry will benefit from the immediate tax deduction of its exploration activities – as explorers of traditional hydrocarbon energy sources already enjoy.[33] The benefit may be limited, however, if companies lack upfront capital for the initial activity.

5.4.2 Technology and electricity costs

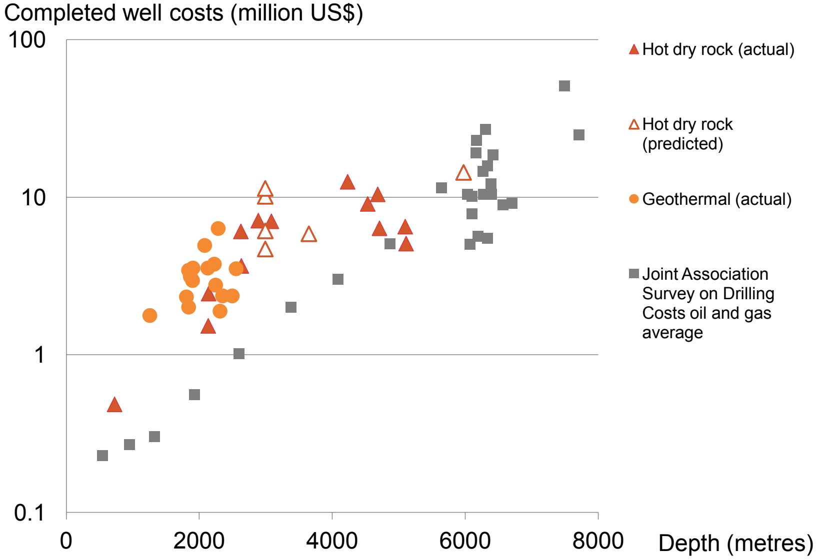
Geothermal capital costs are high...

Geothermal energy is capital intensive, with drilling the greatest component – around 50-80% – of capital costs.[34] In granite, drilling costs $10 to 15 million for a 5 kilometre deep well[35] and up to $40 million per well couplet (around 5 megawatt installed).[36] The cost in sedimentary aquifer, for wells drilled to about 4 kilometres, is slightly less.[37] The greater the depth the more expensive the well, due to the size of the drill rig, the rate of penetration, bit life, casing design, cementing and stimulation activities.[38] Such relativities are illustrated in Figure 5.3.

[28] Geodynamics (2011b)
[29] Geoscience Australia and ABARE (2010)
[30] Allen Consulting Group (2011); Goldstein, *et al.* (2010)
[31] DRET (2011)
[32] Parkinson (2011b)
[33] Talberg (2011)

[34] Huddlestone-Holmes and Hayward (2011)
[35] Geoscience Australia and ABARE (2010)
[36] Allen Consulting Group (2011). Assumes the average cost of MW/installed for HR resources of $8 million. Note: wells do not always have to be drilled in couplets, and may be drilled at a ratio of 1:2 or 4:5 injection to production wells.
[37] G2 pers. comm.
[38] Huddlestone-Holmes and Hayward (2011)

Figure 5.3 Completed well costs as a function of depth



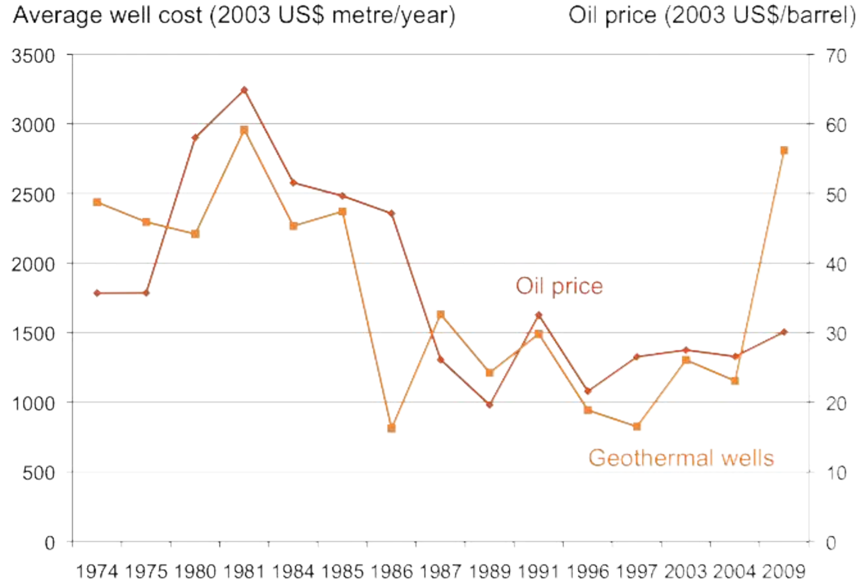
Note: Most data points are from the US.

Source: Augustine, Tester and Anderson 2006 in (Geoscience Australia and ABARE, 2010)

Limited availability of drill rigs in Australia means that they often need to be found overseas and the cost of importing them is prohibitive for most companies. As well as drilling costs, rig mobilisation and demobilisation cost around $5 million and $3 million respectively.[39] Costs increase further when oil costs (and oil production) rise, because drill rigs are in even greater demand (Figure 5.4).

[39] Allen Consulting Group (2011)

Figure 5.4 Geothermal well drilling cost versus oil price



Note: Data were not available for some years

Source: (Huddlestone-Holmes and Hayward, 2011)

...as are operating costs

Operating and maintenance costs are also high – potentially the highest of any power generation technology (excluding fuel costs, which are zero for geothermal energy but are costly for some power sources).

Every installed megawatt of electricity from a HR plant costs between $190,000 to $200,000 a year. A HSA plant costs around $125,000 a year. [40] This is due largely to the pumping required to move working fluid through dense and impermeable rock, which requires power inputs of up to 20%.[41]

The economics of geothermal electricity generation are uncertain

The cost of geothermal can only be estimated because it is at the technology development stage, and because output and costs will vary significantly by location.[42] Key determinants of the cost of geothermal energy include:[43]

- The heat from fluid coming up the production well. Although electricity can be generated using temperatures as low as 100°C[44] a hotter resource allows the turbines in the above-ground plant to operate more efficiently,[45] producing output at lower cost. Deeper wells usually mean higher temperatures, but also higher drilling costs.

- Flow rate from the production well – a more permeable and porous resource means a faster flow rate and higher output. More permeable resources eliminate or reduce the need for frac'ing, which can be expensive, time consuming and risky. Permeability naturally decreases with depth due to confining pressure.

It is unclear whether HR or HSA will be more profitable. The former will always be more expensive to drill and engineer, and more likely to have higher transmission costs because of its distance from load and transmission lines. However, the higher temperatures of the HR resources mean that fewer wells are likely to be needed for the same output. Above-ground plant for HR may also be marginally cheaper than for HSA. This is summarised in Table 5.1 below.

Table 5.1 Comparison of HSA and HR on key parameters

	HR	HSA
Drilling costs	High; uncertain	Med-high
Balance of System (BOS) costs	Med-high	Med-high
Flow rates	Low; uncertain	High; uncertain*
Extractable heat from the production well	High (170-280°C[46]); uncertain	Med (120-170°C[47]); uncertain
Parasitic power requirement	High; uncertain	Med; uncertain

* Depends on geological regimes.

Source: adapted from (Huddlestone-Holmes and Hayward, 2011)

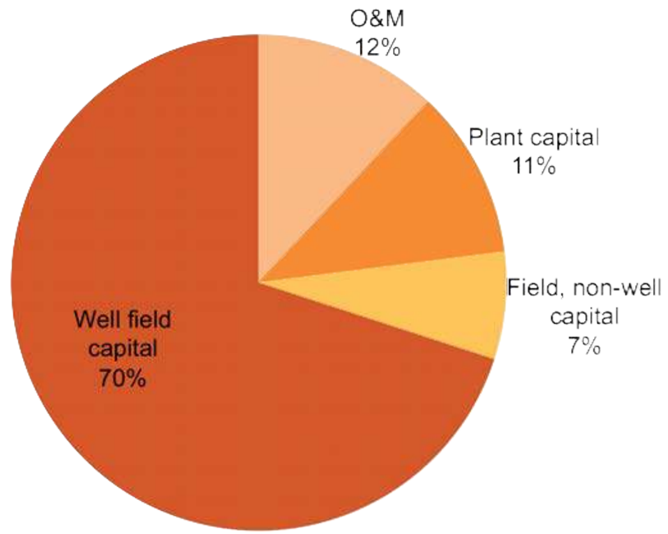
There is a range of estimates for near-term costs. ACIL Tasman (2011) suggest that in 2015 HR geothermal will be $6.9 million per

[40] ROAM Consulting (2011), Simshauser (2010)
[41] Simshauser (2010), SKM-MMA (2010)
[42] Geoscience Australia and ABARE (2010), EPRI (2010)
[43] Huddlestone-Holmes and Hayward (2011)
[44] Geoscience Australia and ABARE (2010)
[45] G2 pers comm., Simshauser (2010)
[46] CSIRO (2009), Elliot (2011)
[47] CSIRO (2009), Elliot (2011)

megawatt installed, and HSA marginally lower at $6.6 million.[48] ROAM's estimates are similar: $6.2 million per megawatt installed of HR, and $5.9 million for HSA.[49] SKM suggests a higher cost for, and greater difference between, the technologies, putting near-term commercial capital costs at around $9 million per megawatt for HR and $7 million per megawatt for HSA.[50]

Electricity production from geothermal energy is likely to be efficient, given a high capacity factor (see glossary) is expected – around 80% to 92% – the same as for fossil-fuel generation and nuclear.[51] This improves the economics of electricity generation compared to solar PV, for example.

Figure 5.5 Components of levelised cost of electricity



Note: O&M includes field maintenance and production pumps

Source: (Gurgenci, 2011b)

In terms of electricity generation costs, SKM suggests that Victorian HSA could produce power for around $130 a megawatt hour.[52] Petratherm's review of its HSA license area in the Victorian Gippsland Basin suggests that it could produce at even lower cost.[53] Estimates for HR geothermal are similar, but with

[48] ACIL Tasman (2010)
[49] 2010 dollars (ROAM Consulting (2011)
[50] G2 pers comm.
[51] EPRI (2010), Huddlestone-Holmes and Hayward (2011), Simshauser (2010)

[52] Assumes 140C resource, 5GW capacity, project lifetime of 30 years (G2 pers comm.)
[53] Petratherm (2008)

higher upper bound estimates. EPRI's report to DRET suggests a range of $120 to$220 a megawatt hour.[54] ATSE (2011) estimates a Levelised Cost of Electricity (a measure of the cost of electricity once all factors of production are considered) in 2015 at $120 a megawatt hour.[55]AGL has published estimates of long run marginal cost of up to $180 a megawatt hour.[56] Other short-run estimates of geothermal electricity costs are presented in Figure 2.3 in the main report that accompanies this publication.

5.5 Barriers to be addressed to enable large scale rollout of geothermal at competitive cost

Several things are needed to demonstrate geothermal technology in Australia and to reduce its costs. Experts suggest that for the capital and LCOE cost projections to be realised, a combination of improvements will be required – primarily in flow rates and in the cost of drilling, but also in conversion efficiency to lower operating costs. Some suggest that these challenges are similar to what the coal seam gas industry faced 15 years ago. It took that industry eight to 10 years to develop commercial tools and achieve commercially viable flow rates.[57]

5.5.1 Engineers must be able to repeatedly achieve – and sustain – good flow rates

The power engineering component of geothermal is technically straightforward and costs are reasonable; a conventional, off-the-shelf power plant (a Rankine Cycle Steam Turbine, for example) sits above the resource, using steam to generate electricity.[58] The surface technical risks – heat exchanges, pumps and power generation – are similar to those of existing and mature technologies so do not warrant focus here.

But the underground operations of geothermal energy pose major challenges. Reservoir engineering is the single biggest issue for enhanced geothermal systems such as HR.[59] The key technical challenge is to create artificial underground heat reservoirs through which large quantities of heat transfer fluid can be circulated continuously and reliably, and brought to the surface at a high enough temperature to generate steam for a turbine. This is yet to be demonstrated at the depths, pressures and temperatures presented by most Australian geothermal resources.

The central challenge is making deep reservoirs sufficiently permeable for high flow rates. Higher flow rates will mean fewer wells and a lower capital cost for the project. Flow rates of 70 to 80 litres per second are needed to produce electricity at a high enough rate to make a plant economic.[60] These rates are an order of magnitude higher than average flows in the US oil industry, and between three to six times greater than fluid circulation rates sustained in engineered geothermal field projects to date.[61] For example, the flow rates of 25 litres per second at a preliminary trial for three months at Innaminka suggest that a 50 megawatt

[54] EPRI (2010)
[55] ATSE (2011)
[56] Simshauser (2010)
[57]Gurgenci (2011b)

[58] G2 pers comm.
[59] Huddlestone-Holmes and Hayward (2011)
[60] Ibid., EPRI (2010), Simshauser (2010)
[61] Huddlestone-Holmes and Hayward (2011)

plant would require 40 production wells, and result in a high long-run marginal cost (LRMC) of about $322 per megawatt-hour.[62]

However, improving flow rates alone will not make geothermal economic. Estimates from Gurgenci (2011), for example, suggest that for a 250°C resource flow rates of 30 litres per second could produce electricity at $270 per megawatt hour, while 60 litres per second would reduce costs to $159 per megawatt hour.

Better reservoir enhancement or fracturing methodologies are needed to increase flow rates. The best process would produce pervasive permeability (so that flows spread through the reservoir, rather than enlarging just a few fractures), be horizontal and stimulate a number of 'zones' individually. This would allow optimum heat extraction through better flows and higher output.[63] Fracturing methodologies could be guided by models for predicting the necessary fracturing surface area, spacing of fractures and likely outcomes in terms of flow impedence. This is the focus of much international research.[64] Finally, improved drilling technologies will allow even hotter rocks to be targeted through deeper wells, and have the potential to increase flows.[65] Opportunities for drilling improvements are discussed in section 5.3.2.

HR typically requires engineering or 'stimulation' to enhance permeability and improve flow rates.[66] This reservoir engineering challenge is much less for HSA systems, which are anticipated to have sufficient natural permeability so that most systems do not need to be enhanced or fractured.[67] It may be sensible to develop and prove the ability to achieve good flow rates and electricity generation from HSA before pursuing the more challenging granites of the 'deeps'. Geodynamics and Origin Energy, for example, are pursuing both 'deeps' and 'shallows'.[68] Prioritising development of shallower, more accessible and simple HSA may help companies overcome the financial difficulties described in section 5.3.3. Even if the resource is less productive than HR resources, it could provide investor confidence and deliver cash flow that would allow companies to pursue riskier, more challenging sites, while providing an opportunity for some learning by doing.[69]

What extent of demonstration is needed to develop and prove this reservoir engineering capability? Industry experts suggest that multiple demonstration plants, in both HR and HSA and across a range of geological types, are needed to show that technology can be reliably replicated and to provide investor confidence.[70] They would need to sustain heat flows and, ideally, electricity generation, for many months and perhaps up to two years.[71] The Geothermal Expert Reference Group suggested a working demonstration in the order of 50 megawatts of power delivered to the grid was required as a first step, to demonstrate the ability to

[62] Ibid., Simshauser (2010)
[63] EPRI (2010), Geoscience Australia and ABARE (2010), Roegiers*, et al.* (2011), O'Leary*, et al.* (2010)
[64] Roegiers*, et al.* (2011)
[65] Huddlestone-Holmes and Hayward (2011)
[66] Simshauser (2010)
[67] Geoscience Australia and ABARE (2010);Huddlestone-Holmes and Hayward (2011),
[68] Origin Energy (2010)
[69] Allen Consulting Group (2011)
[70] Ibid.,Hinchcliffe (undated), Huddlestone-Holmes and Hayward (2011)
[71] Allen Consulting Group (2011)

scale up and deliver an earnings stream.[72] One of the first of those plants might be the one megawatt plant planned by Geodynamics (see Box 5.2 below).

To prove-up this underground heat reservoir concept at around five sites would cost at least $200 million and probably more – assuming geology at each site was successful – with each project taking around seven years to complete.[73]

Box 5.2 Innamincka Project, Geodynamics and Origin Energy

Geodynamics, in a joint venture with Origin Energy, has spent large amounts of money to create and demonstrate a heat reservoir in the Cooper Basin. Their experience has demonstrated how challenging it is and provided useful lessons.

After achieving proof-of-concept of sustained fluid flow between an injector and production well couplet and the surface, at up to 25 litres a second, there was a major setback in April 2009.[74] Pressurised water and steam caused a blowout in one of the wells, primarily as a result of the wrong grade of steel being selected for the barrier casing given the brine chemistry and fluctuating temperatures of the resource.[75] The second well was underbalanced in drilling, which led to loss of the drill string and the well. Different steels were used for liners of subsequent wells, and Geodynamics met with other geothermal companies to "help them understand what went wrong".[76]

Geodynamics still hopes to complete three wells and have a one megawatt pilot plant running in 2012 at Innaminka, with four projects totalling over 500 megawatts to be commissioned between 2015 and 2018.[77]

The slow progress in developing heat reservoir engineering capability through commercial electricity generation projects shows that this challenge will only be overcome through a series of attempts, up to 75 per cent of which will fail, according to

72 ACRE (2011), Batterham (2011)
73 Assumes 25 MW (cumulative) installed, delivered through 7 -10 wells, at a cost of $8 million per installed MW (approximate mid-point of range of HSA and HR estimates, in section 5.2.4). Earlier MW of the project are likely to cost more than later MW of the project. Assumes around a year to prepare for drilling and source the drill rig, around 3 months to drill each well (Allen Consulting Group (2011), G1 pers comm.), and project timing from start to finish is 7 years (John McIlveen (2011))

74 Geoscience Australia and ABARE (2010)
75 Goldstein, *et al.* (2010)
76 Murphy (2010), McDonnell (2010)
77 AEMO (2011), AGEA (2010); Parkinson (2011b)

developers. They also note that oil and petroleum drilling has had even greater failure rates, though much greater payoffs.[78] This is not the kind of risk a start-up company will take. Instead, this initial phase – developing the ability to repeatedly and reliably create heat reservoirs – will need further research and development.[79] The conditions attached to public funds made available to date have meant they have not been used, and not enough progress has been made on this most fundamental barrier to geothermal energy (see 5.2.4).

5.5.2 Very high drilling costs must be brought down

Capital costs must come down for geothermal to succeed. At up to $20 million per well, drilling offers great scope for cost reductions. SKM estimates that reductions of around 30% are possible using already available equipment and changes to practices.[80]

Better drill bits can accelerate the drilling process, reduce breakages and lower costs.[81] Laboratory drilling trials have shown that drill bits using thermally stable diamond composites could have twice the penetration rate and expend half the energy of traditional rock coring bits, as well as much extended lifespans.[82] Such bits should be available for trial in the field within the next few years.[83]

Different drilling practices can also lower time-based costs. Simply by changing the speed and weight at which current technologies are operated, a cost reduction of up to 15% is possible.[84] Drilling techniques, such as the percussion or hammer drilling technique adapted from minerals exploration, may produce faster penetration rates than oil field rigs while using less fuel.[85] There is much international research in this area.[86]

Currently, geothermal drilling is regulated by standards developed for oil and gas. Changes to regulations – for example, to allow different standards for drill hole casings – could also bring costs down.[87]

Costs could also be lowered through program drilling, which delivers economies of scale and learning by doing. When the same rig and crew are used at one site to do multiple wells, a high degree of learning occurs.[88] For an eight-well program, drilling costs can drop by as much as 40%.[89]

5.5.3 Better information can assist resource exploration and increase investor confidence

Exploration and drilling is inherently risky, but good data and modelling can reduce the risk by helping to select suitable exploration sites, and minimising the need for data collection

[78] Allen Consulting Group (2011)
[79] Simshauser (2010)
[80] G2 pers. comm.
[81] O'Leary, *et al.* (2010)
[82] CSIRO (2006), Li, *et al.* (2011)
[83] G1 pers. comm.
[84] G1 pers. comm.
[85] Huddlestone-Holmes and Hayward (2011)
[86] ACRE (2011)
[87] G1, G2 pers. comm.
[88] Huddlestone-Holmes and Hayward (2011)
[89] Simshauser (2010)

using costly drilling equipment.[90] Good data on the reservoir also facilitates the design of the below- and above-ground systems that will be used to extract the resource. Better data and modelling will also help reduce risks for private investment by improving understanding and trust of the technology.[91]

There is currently no comprehensive map of Australia's geothermal resources, and thus no proof-of-resource for many Australian geothermal prospects.[92] Knowledge of the resource is based on a database of temperatures recorded at the bottom of 5,700 deep drill holes, mainly drilled for petroleum exploration. Not only are these data not robust predictors of temperature at depth, but Figure 5.2 above shows that there are many areas of the continent for which no data have been collected.[93] The releases of the nation-wide Heat Flow Interpretations and the OZTemp database by Geoscience Australia in 2010 are a positive development, but are still relatively coarse grained.[94]

Publicly available heat flow measurements and the knowledge of geology characteristics at depth are inadequate for efficient geothermal exploration in Australia.[95] At a minimum, more comprehensive information on the basic characteristics of basins is required, first on the type of rock and temperature, then on its porosity and permeability, including any natural fractures within the target formation.[96] There are localised examples of good quality data collection, including on the HR resource located near to extensive oil and gas exploration in the Cooper Basin.

Several elements of information collection need to be improved, including a better understanding of the most appropriate criteria to assess basins, and methodologies to extrapolate from shallow observations in a range of geological settings.[97] The petroleum and minerals industries may have lessons for developing a system for geothermal systems analysis.[98] Conceptual models also need updating (thermodynamics, chemistry and mechanics) and current models need improvement to better cope with dynamic changes in permeability. The International Partnership for Geothermal Technology (2010) predicts major improvements in models by 2020.[99] Eventually, given variability in the geological resource, to improve the estimate and define the clear potential of a resource, further drilling or geophysical exploration must be undertaken across a site.[100] These real data are also needed to check the accuracy – or otherwise – of models. This is particularly important because there are few real world examples upon which to base exploration models. Finally, effort is also needed in synthesising and disseminating exploration data.[101] Different types of data must be combined to give the most accurate picture of a resource as possible.[102]

[90] Geoscience Australia and ABARE (2010), Huddlestone-Holmes and Hayward (2011), IPGT Exploration Working Group (2011)
[91] Hinchcliffe (undated), Huddlestone-Holmes and Hayward (2011)
[92] Allen Consulting Group (2011)
[93] Geoscience Australia and ABARE (2010)
[94] Ibid., G1 pers comm.
[95] Ibid., EPRI (2010)
[96] IPGT Exploration Working Group (2011), SKM-MMA (2010)
[97] IPGT Exploration Working Group (2011)
[98] Huddlestone-Holmes and Hayward (2011)
[99] Ketilsson and Podgorney (2010)
[100] SKM-MMA (2010)
[101] IPGT Exploration Working Group (2011)
[102] Newman (2010)

Information of this kind is costly to collect, with uncertain returns. More importantly, it involves knowledge spillovers – that is, the benefits of data collection (knowledge or information) will accrue, at least partly, to others not directly involved in the activity (including other geothermal companies, and those with adjacent tenements). Therefore, the private sector will not adequately provide this information (from the perspective of society as a whole). [103]Such data collection is primarily a role for institutions such as Geoscience Australia and similar state bodies, the universities and CSIRO.[104]

5.5.4 Transmission costs may constrain project development

If the technical and economic barriers are overcome, the costs of electricity transmission infrastructure will challenge project developers. The distance from existing transmission lines or load centres could impede the development of some of Australia's geothermal energy resources.[105]

Estimates of the capital costs associated with a transmission line from the Cooper Basin range from $300 million to $2 billion.[106] MMA (2009) estimated that transmission costs for a 400 megawatt plant at Innaminka, South Australia would be $553 million, and for a 250 megawatt plant at Paralana $164 million.[107] Simshauser suggests radial transmission connection costs might add $15 to $20 per megawatt hour to the cost of generation (2009 prices). These costs could make the cost of delivered generation from HR resources more expensive than from HSA.

There will be a trade-off between resource quality, and proximity to the transmission grid. The hotter HR resources are generally far from the transmission grid. Geodynamics' and Petratherm's main operations in South Australia are 200 to 500 kilometres from the main system.[108] Other companies have sought tenements and resources close to the grid because of the cost of transmission.[109] Some existing HSA tenements – Petratherm's Renmark project and Torrens Energy – are within 20 kilometres of the grid.[110]

AEMO's (2010) National Transmission Network Development Plan (NTNDP) identified the need to improve and add to the transmission network if geothermal generation becomes significant. For example, with a medium carbon price in place, geothermal development in South Australia would lead to congestion in export of geothermal generation from South Australia to Victoria, requiring an incremental upgrade of the Heywood interconnector by around 2030.[111] MMA analysed the early development of geothermal power delivery into the NEM through a transmission line from the Cooper Basin (Geodynamics' site) via the Arrowie Basin (Petratherm's site) to the NEM at Olympic Dam. The study assumed LCOE and transmission costs below most estimates, and these optimistic assumptions contributed, in part, to their conclusion that bringing forward transmission investment offered significant benefits to the

[103] Garnaut (2011)
[104] ACRE (2011)
[105] Geoscience Australia and ABARE (2010)
[106] Allen Consulting Group (2011)
[107] MMA (2009)
[108] Simshauser (2010)
[109] Allen Consulting Group (2011)
[110] ENB (2007)
[111] AEMO (2010)

customers in South Australia and the NEM through lower pool prices.[112]

In Chapter 9, we identify a number of issues that arise from the planning, coordination and regulation of transmission connections in Australia, and recommend that resolving these should be a priority for governments.

5.5.5 Manage real and perceived environmental and safety risks

If or when the barriers above – primarily engineering heat reservoirs – have been overcome, and geothermal is widely deployed, there will be some environmental and social considerations.

Depending on the characteristics of the reservoir, HR may require large volumes of water to undertake the fracturing process, and to maintain fluid volumes in the reservoir.[113] 'Wet hot rock' resources contain existing water that can be topped up. However, in other locations where HR resources are under development, water scarcity and competition for supply could present problems.[114] Saline water can be used, but is also generally not found near geothermal resources, so may be costly to supply. Industry and regulators will need to manage this challenge.

The plant also needs water to cool its condensers – around three megatonnes a year for a 50 megawatt geothermal plant.[115] Cost-effective and efficient air cooling technologies will need to be deployed to make geothermal economic in Australia.

Reservoir stimulation causes movement on existing fractures or development of new fractures. Most of these induced seismic events are small – and in 30 years of undertaking them overseas, and in Australia, none has caused damage – but larger events have occurred at several projects, including Geodynamics' Cooper Basin Project (3.2 magnitude).[116] The occurrence of seismic events linked to geothermal developments, primarily during stimulation, has raised concern. Recent negative publicity around hydraulic fracturing in coal seam gas will exacerbate this.[117] Extended community consultation, or regulatory approval delays related to this practice could create another source of financial risk for geothermal projects.[118] Alternatively, active government attention to community concerns ahead of project development and creation of the appropriate regulatory framework would provide greater certainty for all stakeholders.

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[115] Ibid.
[116] Ibid.
[117] Ibid.
[118] Economic Consulting Services (2010), Hinchcliffe (undated)

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6 Carbon Capture and Storage (CCS)

6.1 Synopsis

- Carbon capture and storage (CCS) could contribute significantly to reducing global and Australian emissions. It is the only technology that can address CO_2 emissions from the coal and gas-fired power stations that will be in service over the next 40 years and beyond.

- Projected CCS costs are competitive with other low-emission technologies even without subsidies. Yet the high absolute cost is a disincentive to early mover projects. The combination of technology, operating and market risks is proving beyond the capability of even large energy utilities. Although the core technologies of CCS are well known, they have not been brought together at the necessary scale.

- Integrated, early-mover CCS projects are not advancing at the speed or scale that governments and agencies envisaged. Government support has generally failed to kick-start such projects, with only stripping and re-injection from natural gas extraction deployed at scale to date. The revenue that will come from enhanced oil recovery may make some projects viable, though usually with some level of government subsidy or regulated pass on of costs.

- Integration of capture with transport and storage introduces a high degree of complexity for CCS projects. The commercial business models for such integration have yet to be developed, whilst the sectors involved, ie resources and power have not had a history of needing to work together.

- Lack of information about geological storage options for CO_2 is a significant barrier, both globally and in Australia. CCS cannot be deployed in Australia without greater knowledge of potential storage sites, and the lead times to produce such information will be long. The fact that the information will become public may discourage the private sector from investing in it, so government support[1] for acquiring information to identify and describe potential storage sites may be justified.

- As CCS gains a higher public profile, there is the potential for concern regarding legal liability and physical integrity of CO_2 storage and possible environmental impact. This has been the experience with coal seam gas developments in recent years. Active government attention to such concerns and development of appropriate legal and regulatory frameworks are needed to provide certainty for all stakeholders.

[1] Garnaut (2011)

6.2 What is Carbon Capture and Storage?

CCS encompasses those technologies that capture, transport and permanently store CO_2 to reduce greenhouse gas emissions. They include:

- Capture of CO_2 from coal and gas fuelled power stations, from industrial processes such as cement manufacturing with direct CO_2 emissions and from natural gas production.
- Compression and/or liquefaction of captured CO_2 and transport for storage or sequestration
- Injection of CO_2 into depleted oil and gas reservoirs, deep saline aquifers and unmineable coal seams for permanent storage

CCS now usually includes the use of the injected CO_2 to enhance the recovery of oil or gas remaining in reservoirs when traditional methods have reached their commercial. In these cases it often replaces CO_2 extracted from naturally occurring sources. There are also several potentially interesting but early-stage technologies to chemically transform CO_2 into solid materials such as mineral carbonates. In some quarters, the term CCUS is being applied to include the concept of "Usage" in the CCS family. This chapter focuses on the integration of CCS with fossil fuel power generation, which is potentially its most important role in a low-emission technology future.

Technologies to capture and transport CO_2 and inject it into the ground are well-known and operational. The ammonia and fertiliser industries have stripped CO_2 from gas streams for many decades. For the past 15 years the Sleipner project in Norway has been safely injecting up to a million tonnes of CO_2 a year into a deep saline aquifer. Transport and use of CO_2 for enhanced oil recovery (EOR) has been applied in the USA for nearly 40 years. But deploying CCS for climate change mitigation in the power sector is more challenging. It requires the integration at commercial scale of a range of technologies: power generation, carbon capture, fluid transport and geological storage. Capture and storage technologies will also have to significantly develop to deliver CCS at the scale required and at a cost that will be commercially viable in an emissions-constrained world.

6.2.1 Capture

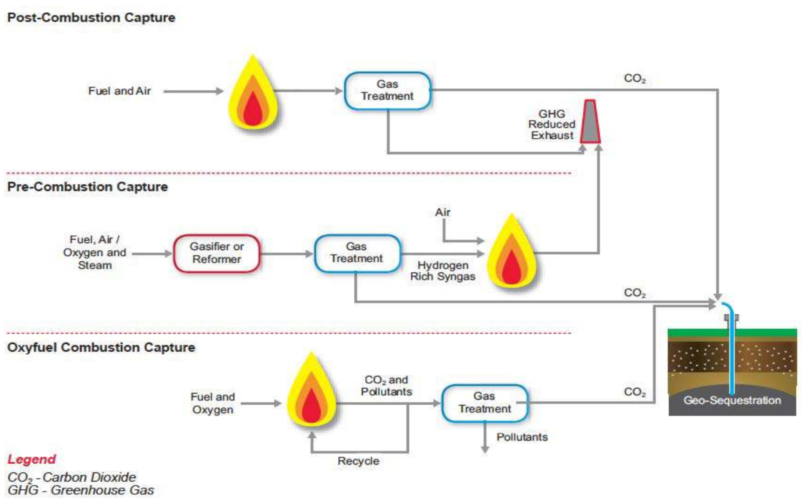
Post-combustion capture involves separating CO_2 from flue gas produced by conventional fossil fuel or biomass combustion. It is today the most compatible and commercially available capture technology for retrofitting CCS capabilities onto existing power plants and industrial facilities such as cement plants.

Pre-combustion capture involves triggering the reaction of a fuel with oxygen and/or air and steam before it is burnt for energy generation. The CO_2 generated in the synthesis of gas from this reaction is more concentrated than CO_2 in a flue gas and can then be separated. The technology can be applied to Integrated Gasification Combined Cycle (IGCC) coal plants.

Oxy-fuel combustion capture combusts fuel with near pure oxygen, resulting in a flue gas that is mainly CO_2 and water vapour (which are easily separated, although gas scrubbing is still required). An advantage is that the flue gas produced is rich in

CO_2 and small in volume, making it ready for storage with limited processing.

Figure 6.1 Carbon capture technologies



Source: Global CCS Institute (2009)

6.2.2 Transport

CO_2 can be transported, in a highly compressed state known as supercritical, via a network of pipelines similar to those used to transport natural gas or crude oil, or by truck, train, or ship. Transport by pipeline and truck has been undertaken for many years, and the issues are well understood.

6.2.3 Storage

Geological CO_2 sequestration options include depleted oil and gas reservoirs, deep saline formations, and unmineable coal seams. Depleted fields have the greatest short-term potential because they are cheapest and carry the least technical challenges. Saline aquifers have the potential to meet long term requirements. Little substantial assessment has yet been done on storage in unmineable coal seams.

The technology for injecting CO_2 into depleted oil or gas reservoirs or aquifers has existed for two decades and has been applied at the Sleipner Field in Norway, in Salah, Algeria and the Otway Basin, Victoria, among other projects. The critical issue for injection and permanent storage is ensuring that the geological structures will safely and permanently trap the CO_2.

Enhanced Oil Recovery injects water, nitrogen or CO_2 into reservoirs to extract oil that traditional methods cannot extract. The introduced material effectively pushes out the oil by flooding the reservoir. The oil industry, especially in the USA, has used this method for many years, although usually without worrying about permanent storage of the injected material. EOR increases the commercial viability of CO_2 storage by generating a revenue stream. For that reason, EOR is attracting attention elsewhere, and led some to rename CCS as CCUS, the U standing for Usage. Yet while the CSIRO has investigated EOR opportunities in Australia,[2] there is little indication of major potential to date.

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[2] CSIRO (2011)

Coal seams that are either too deep or too thin to be economically mined for coal represent another potential storage opportunity. Enhanced coal-bed methane recovery may deliver similar benefits to EOR, but little work has been done in Australia and it is still at the research stage.

Sequestering carbon in the ocean has also been considered. The ocean is by far the largest natural carbon sink on the planet, already containing 40,000 gigatonnes of carbon compared with fewer than 3,000 gigatonnes of carbon in the terrestrial biosphere and atmosphere combined.[3] Yet environmental concerns have restricted serious progress in this direction.[4]

6.3 What is the potential of CCS?

CO_2 capture could be applied not only to existing coal and gas fired power stations, but to those that are forecast to be built in the future.[5] The technologies described above could capture up to 90% of emissions, even more as the technologies improve. A number of countries, including the UK, Canada and Australia, have proposed imposing a requirement that would make future plants "capture ready".

Under International Energy Agency projections for a global energy mix that constrains emissions sufficiently to meet international climate change objectives, CCS has a significant role. But this assumes that approvals for commercial plants incorporating CCS begin in 2015 and that $US16 billion is invested in power generation incorporating CCS over the period 2010-2020 alone.

[3] Herzog, H. et al. (2001)
[4] Stephens 2009
[5] IEA 2011

The IEA analysed a number of global emissions reduction scenarios and concluded that CCS is "the most important single new technology for CO_2 savings" in both power generation and industry.[6] According to the IEA the next decade is a critical period for CCS.[7]

Australian modelling for the Federal Government's Clean Energy Plan indicates that by 2050 power generation with CCS could represent 30% of electricity produced in Australia. Such projections are based on assumptions of future technology costs across a range of low-emission technologies, all of which are at varying stages of development.[8] Allowing for possible inaccuracies in such projections, CCS is generally seen as being competitive with the alternatives.

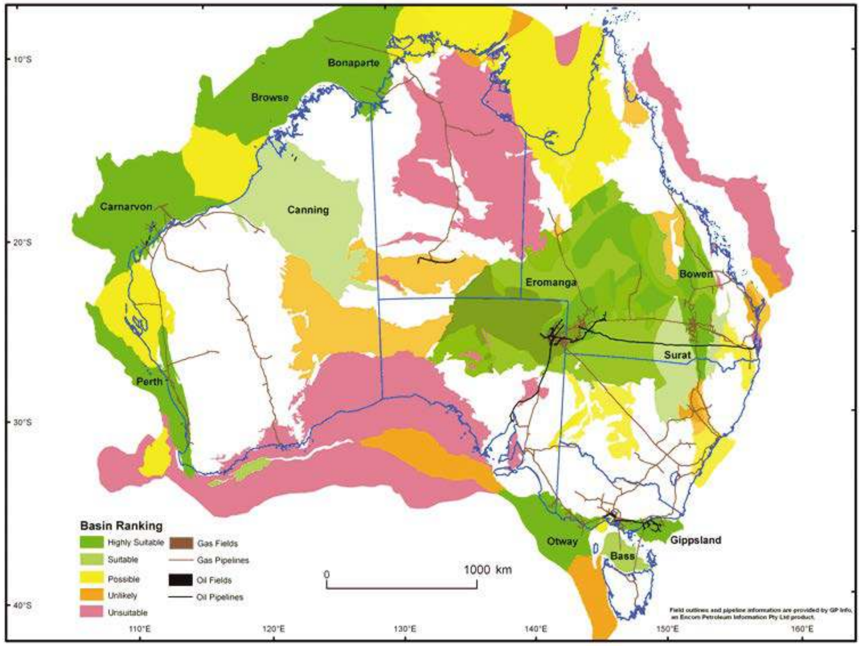
The IEA believes that deep saline aquifers offer the potential to store several hundred years' worth of CO_2 emissions.[9] Detailed evaluation of this potential to the level of confidence required for investment to proceed is required and is being undertaken in a number of countries.

Australia has several basins with potential for geological storage as shown in Figure 6.2. The east of Australia is estimated to have aquifer storage capacity for 70 – 450 years at an injection rate of 200 megatonnes per year. The west of Australia has an estimated capacity for as much as 1000 years at an injection rate of 100 megatonnes a year.[10] Victoria, Queensland and Western

[6] IEA (2008)
[7] IEA (2009)
[8] Treasury (2011)
[9] IEA (2008)
[10] Carbon Storage Taskforce (2009)

Australia have the most promising options to date. Considerable geoscience work is already being undertaken, primarily by government geoscience agencies, to understand the storage and rates of injection potential of these basins. Yet more such work will be required to provide the levels of confidence necessary to embark on major, commercial-scale projects. As an example, greenfield storage assessment is likely to take five to 10 years or more.[11]

Figure 6.2 Australia's basins ranked for CO_2 storage potential



Source: Carbon Storage Taskforce (2009)

[11] Global CCS Institute (2011)

6.4 Current status and trends

6.4.1 Integrated commercial-scale CCS projects

The Global CCS Institute lists 74 large scale integrated CCS projects at various stages of planning and implementation. Eight projects are in operation and a further six are under construction.[12]

Yet even the power projects on the above list have generally struggled to reach a financial commitment. Projects in the United States (Mountaineer) and the UK (Longannet) were recently cancelled. Projects with a component of EOR, such as Saskpower's Boundary Dam Project in Canada, and Southern Company's Kemper County IGCC Project in Mississippi are under construction and may have greater success.

There are currently no integrated CCS projects in Australia, although the Collie Hub project has received funding and two other projects have been listed for potential funding under the Federal Government's CCS Flagship Program. The Gorgon Carbon Dioxide Injection Project is expected to begin operation in 2015, injecting 3 to four megatonnes of CO_2 into a saline formation every year.[13]

In 2010, the US Interagency Task Force on Carbon Capture and Storage concluded: "Whilst there are no insurmountable technological, legal, institutional, regulatory or other barriers that prevent CCS from playing a role in reducing GHG emissions, early CCS projects face economic challenges related to climate

[12] Global CCS Institute (2011)
[13] Global CCS Institute (2011)

policy uncertainty, first-of-a-kind technology risks and the current high cost of CCS relative to other technologies." Further: "CCS technologies will not be widely deployed in the next two decades absent financial incentives that supplement projected carbon prices".[14]

6.4.2 Cost of CCS

Inevitably, capturing, transporting and storing CO_2 will increase the cost of coal and gas power generation. Estimates for early mover projects and for longer term potential vary widely (GCCSI, 2011). Table 6.1 is based on a recent IEA report that shows average costs of power generation for OECD countries based on a review of a range of sources. However, these costs represent wide ranges of accuracy, from -30% to +50%.

Table 6.1 Levelised cost of electricity from alternative technologies

	Coal Post combustion	Coal Oxyfuel	Coal Pre-combustion	Natural Gas Post-combustion
LCOE with capture (US$/MWh)	107	102	107	102
LCOE Increase (US$/MWh)	41	40	29	25
Relative LCOE increase	63%	64%	39%	33%
Cost of CO_2 avoided (US$/t)	58	52	43	80

Source: IEA (2011)

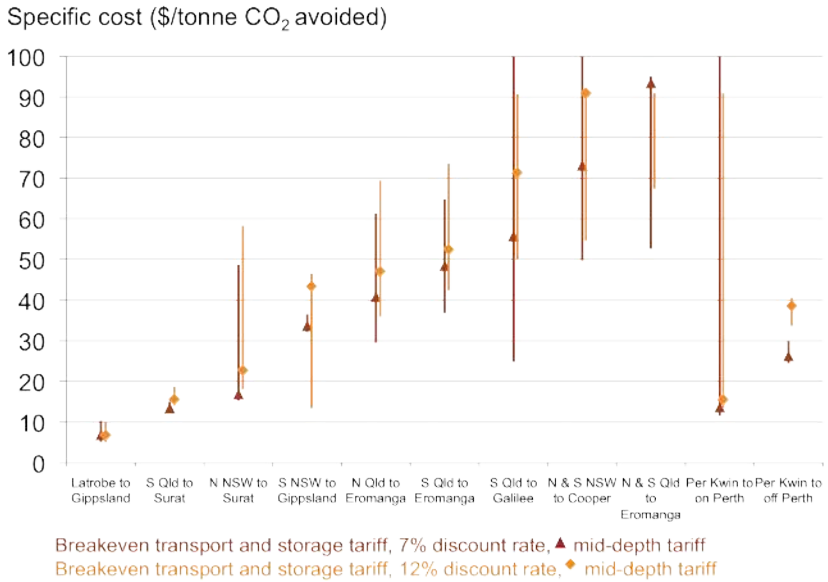
A recent Australian study Feron and Paterson (2011) of post-combustion capture indicated that it would substantially increase costs by about $60 per megawatt-hour.

Yet there is significant potential for lowering costs through learning-by-doing and by technological developments such as new absorption methods. Typically, both learning effects and technology changes could each reduce the levelised cost of electricity by 10 to 20%, IEA (2011) and Global CCS Institute (2009).

[14] US Interagency Task Force on Carbon Capture and Storage (2010)

Site-specific differences (transport distance, terrain, weather, exploration, property costs, reservoir depth and injectivity parameters) can significantly affect transport and storage cost, as illustrated for an Australian study in Figure 6.3.

Figure 6.3 Break-even CO_2 transport and storage tariffs for different locations in Australia



Source: Carbon Storage Taskforce (2009)

This could be a problem for some Australian projects, such as in New South Wales, where distance between likely CO_2 sources and storage sites could lead to material transport costs.

EOR has been adopted for several decades in countries such as the USA using CO_2 and materials such as water or nitrogen. Historically, permanently storing the injected CO_2 has not been an objective. The criteria for success have been the cost of CO_2, the level of remaining oil, the prevailing oil price and the nature of the oil-bearing structures. The potential of a revenue stream, particularly when oil prices above US$100 per barrel are assumed, has focused global attention on CCS. Analysts are seeking to determine the balance of these criteria that would make projects commercially viable.

6.5 What are the obstacles to CCS deployment?

6.5.1 Technical barriers

Several technical issues are yet to be resolved that will differentiate between the capture technologies and determine their future cost.

For post-combustion capture the key challenge is to reduce the parasitic energy load (the extra power required to capture the CO_2) that is associated with chemical absorption and desorption. One calculation puts the parasitic energy load under post-combustion capture as high as 30 to 40% of total power generated. Trials using various amines and chilled ammonia are promising. Depending on plant characteristics, parasitic energy loss may be reduced to around 20%.[15] Yet it may be uneconomic to retrofit post-combustion capture technology to a legacy plant that has low efficiency and limited lifespan. In some cases it may be difficult to find enough space for the capture equipment on site.

[15] CO2CRC, 2008

Pre-combustion capture potentially reduces the parasitic energy penalty by producing a relatively high-concentration CO_2 gas stream. The most prominent approach to pre-combustion capture is known as Integrated Gasification Combined Cycle (IGCC) technology, which is still in the demonstration phase and cannot be retro-fitted to existing plants. In the US, four IGCC plants ranging from 107 to 580 megawatts have been constructed with financial support from the Federal Department of Energy (DOE). Other plants operate in Italy, Spain, Japan and the Netherlands.

Oxy-fuel technology also has the potential to reduce parasitic energy load. It could achieve overall higher levels of efficient CO_2 removal and can be retrofitted to many existing coal-fired plants. But it will affect combustion performance and heat transfer patterns and the production of oxygen is itself energy intensive.[16] Oxy-fuel technology also lags behind other capture technologies in terms of pilot or demonstration projects.

Development is continuing on all the above fronts. Technology suppliers and power companies are undertaking pilot and demonstration projects that will determine the rate of development and cost improvement.[17] Technology developments are more likely to advance at the global level, although research into capture technologies specific to brown coal could be more relevant to Australia. Capture technologies for black coal will also need to be tested on Australian coal and in Australian conditions to support CCS deployment in our export markets and domestically.

With CO_2 storage, the barriers concern storage capacity, injectivity and long-term integrity. Some reservoirs have turned out to be inappropriate for storage on close study: for example, a proposed project by Hydrogen Energy, a joint venture between BP and Rio Tinto near Kwinana in Western Australia.

There is also the possibility of resource conflicts, either with the Great Artesian Basin or active oil and gas operations. These will require both technical and commercial resolution.

6.5.2 Integration of CO2 capture with transport and storage introduces a high degree of complexity for CCS projects.

As indicated in Figure 6.4, CCS demonstration projects are considered high risk because there are multiple uncertainties in operating an integrated system at large scale.

[16] Herzog, Howard and Golomb (2004),
[17] Global CCS Institute (2011)

Figure 6.4 CCS supply chain risks

Risk Category		CAPTURE	TRANSPORT	STORAGE
Price	Price Volatility	× High risk	✓ No risk	✓ No risk
	Technology Obsolescence	× Moderate risk	✓ No risk	✓ No risk
Cost	Operating performance shortfall affecting volume	× High risk	× Low risk	× Low risk
	Cost of construction	× Low risk	× Low risk	× Low risk
Volume / throughput variability	Interparty volume delivery	× High risk	× High risk	× High risk
	Counterparty life	× High risk	× High risk	× High risk
Environmental	Financial loss due to project permitting	× Moderate risk	× Low risk	× Moderate risk
	Operating environmental risk	× Moderate risk	× Low risk	× High risk
	Long-term containment liability	× Low risk	× Low risk	× High risk
Financing	Pricing of debt and equity financing	× High risk	× High risk	× High risk
	Refinancing risk	× High risk	× High risk	× High risk

Source: Clinton Climate Initiative (2009)

The development of commercial models and regulatory structures that reduce and optimally allocate these risks will be essential for integrated projects to be delivered.

6.5.3 Very few commercial players can afford to demonstrate a commercial-scale CCS plant

The minimum scale for commercial-scale CCS infrastructure requires significant capital investment. Depending on the technology type, CO_2 capture creates a premium on pulverised coal or IGCC power plant of around 50 to 70 per cent. At a scale of around 500MW, this creates a cost tag for the power plant of about $US3.3 to 4.6 billion.[18]

In Australia estimated transport and storage costs range from about $10 to 100/tCO2, depending on location.[19] As an indication, this range gives rise to annual transport and storage cost between $60 to 600m/yr for a 1 gigawatt pulverised coal plant.

A 2010 study by the Climate Group surveyed capital providers in Europe to establish on what basis commercial operators could access the necessary capital. The study found the following:

- Only major players could do this by raising capital against their asset base. Figure 6.5 illustrates this by comparing the market value of the asset bases of leading European utilities compared with the funding constraints for a commercial CCS project. By way of comparison, Origin Energy and AGL Energy, the largest, listed integrated energy companies in Australia, have market capitalisations of $15.6 billion and $6.9 billion respectively.

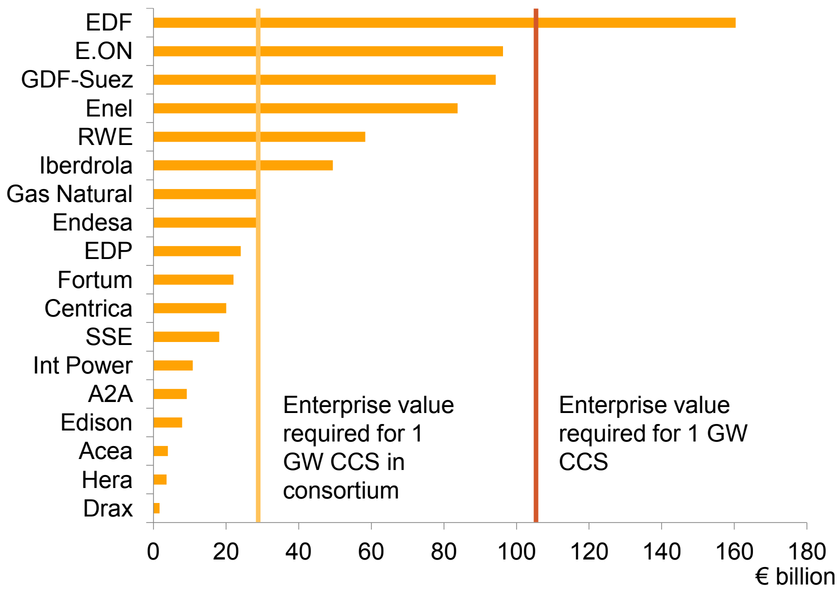
- Specialist equity, such as private equity or infrastructure funds, will not be mobilised to finance demonstration projects

- Pension fund or insurers holding bonds or equity in major corporations would not object to corporations devoting a proportion of their capital budgets to CCS demonstration projects, but only to a limited extent and with conditions

[18] Global CCS Institute (2011)
[19] (Carbon Storage Task Force, 2009)

- sponsors must be major players with track record
- Across Europe, there is likely to be private sector finance for only two demonstration projects, not the eight, let alone twelve that were hoped for.[20]

Figure 6.5 Financing CCS projects in Europe



Source: The Climate Group et al. (2010)

6.5.4 Extensive characterisation of geological storage options is needed to plan for CCS deployment

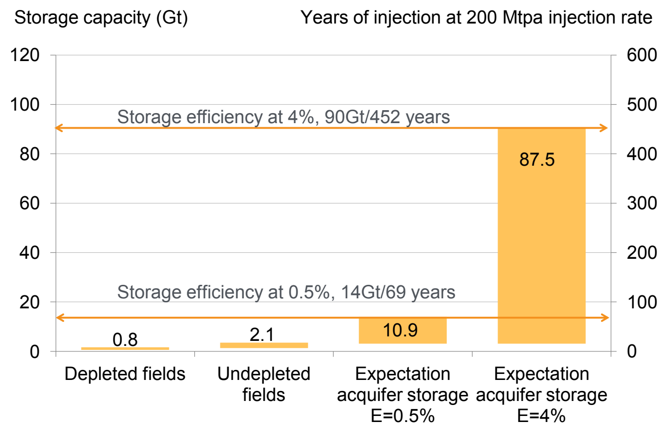
Whilst CO_2 capture represents the major portion of the CCS cost chain, no project will proceed beyond the conceptual stage without a clear and quantified view of the storage options.

This means characterisation of potential geological formations to assess total storage potential, injectivity parameters, likely CO_2 migration patterns (especially in aquifers) and relevant risks.

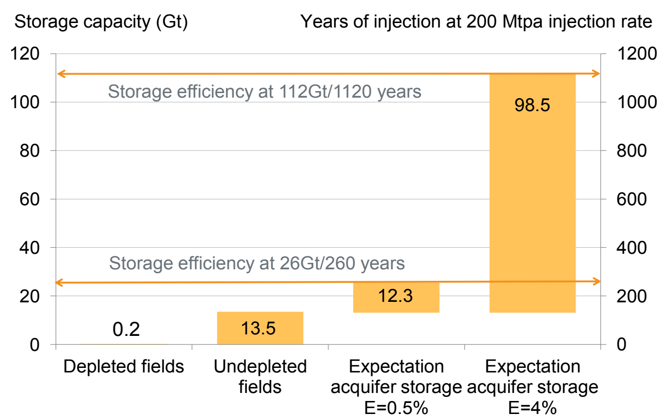
Australia has several basins with potential for geological storage. Victoria, Qld and WA all have promising options. NSW's storage options are less well understood. Ideally, economies of future scale for a CCS network suggest that storage options need to be relatively close to a suitable industrial cluster. There are a limited number of locations that meet these requirements.

[20] The Climate Group et al. (2010)

Figure 6.6 Risked CO_2 storage capacity - Australia Eastern seaboard



Risked CO_2 storage capacity – Australia Western seaboard



Source: Carbon Capture and Storage Taskforce (2009)

Storage characterisation lead times are on the critical path for commercial CCS projects. The work of the Carbon Storage Task Force is being supplemented by further activity funded by the CCS Flagship Program in Western Australia, by the Victorian, Queensland and NSW Governments, and by the industry's Coal 21 Fund and more will be required before projects can proceed.

The private sector is not taking the lead in this work in the short term because:

- Geological characterisation can be a high risk venture, as characterisation can be expensive and there is no certainty that the formation will prove viable; or that even if viable, CCS investment will ultimately occur.
- Unlike oil and gas exploration, the commercial benefit of successful storage characterisation is unlikely to justify the risks involved.
- It is difficult to capture the benefits from characterisation work – CCS projects will probably involve several players in different sectors. There is an incentive to free-ride.

There are four reasons why governments should lead the work to characterise storage options.

No substitute. This work is essential for CCS deployment and the relevant data are local to Australia

Sequencing. Information in this area is needed to help break a deadlock on investment in the sector.

Competition. Making geological data freely available to all players is likely to create more competition in the market and deliver better quality results.

Public interest. Making information about storage options widely available is important for best practice community engagement on proposed projects. Social licence may be a key factor in whether CCS projects can proceed. Equally, a thorough understanding of geology is also important for regulation and long-term liability.

6.5.5 Long term liability for CO2 storage will need to firmly established

A potential barrier to CO_2 storage is the issue of long term liability for the integrity of the storage. Generally, the principle of transfer of this liability to the State some time after the site has been closed for further injection is envisaged. This has been the approach in Europe where the European Commission proposes transferring liability to the public 20 years after site closure, while a proposal for a German CCS law suggests 30 years after long-term safety has been proven. A similar approach has been adopted for the Gorgon project in Western Australia. In an exposure draft for the *Petroleum and Geothermal Legislation Amendment Bill 2011, and in line* with the Commonwealth approach, it is proposed that the State assumes long-term liability post surrender of the injection site by the operator. The decision point for the State to assume liability is at least 15 years after the site closing certificate is issued. The State will also assume long-term liability if the licensee has ceased to exist.

6.5.6 There are potential community concerns with CCS

Many NGOs, and some politicians, are either negative or at least sceptical about CCS, as at best a transitional and partial solution that prolongs the life of fossil fuels. This concern is reflected in, for example, the exclusion of CCS from funding under the Australian Government's recently announced Clean Energy Finance Corporation.

Onshore CO_2 storage acceptability is already an issue in several countries, particularly in Europe. Projects such as that proposed for Barendrecht in the Netherlands illustrate the necessity for effective community consultation and clear regulatory frameworks.

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7 Nuclear power

7.1 Synopsis

- Nuclear power has the technical potential to meet a very large proportion of Australia's electricity needs.

- The economics of nuclear power in Australia are uncertain. New, safer and more efficient reactor designs are on the market. Yet new-build, commercial nuclear power is still subject to economic and technical performance uncertainties. For Australia, the scope to draw on experience from overseas is limited. Over the past 25 years very few nuclear plants have been built in regions with similar economic and regulatory conditions, such Western Europe and North America.

- Nuclear power could be very cost-competitive with other low-emissions technologies. But the private sector may struggle to finance nuclear power plants without government support. The long-run cost estimates for nuclear power broadly match current estimates for several other low-emissions technologies. However, major credit analysts consider that private companies are, at present, unlikely to accept the full risk of building a new nuclear plant. If they do, finance is likely to be high cost.

- Developing nuclear technologies could greatly change the nuclear power sector. Developing reactor designs have the potential to make nuclear power more efficient, produce less high-level waste, and be safer to operate. But these technologies are still in R&D stage. It is unclear when, or if, these technologies will be commercially viable.

- The lead-time to deploy a nuclear power plant in Australia is between 15 and 20 years. This includes a range of technical requirements, such as creating legal and regulatory frameworks and institutions, planning and construction time. An impending global shortage of nuclear sector skills and knowledge could make the lead-time longer.

- Lead-time can be reduced without committing to building a nuclear power plant. Australia can afford to wait to see the results of planned nuclear power deployment in Europe and the US. At the same time, by establishing the institutions and capabilities for a nuclear power sector it could reduce lead-time by around five years. But if this is not done soon, nuclear power may not be feasible if or when Australia would need it.

- Public engagement is essential for nuclear power to be viable. In Australia, nuclear power deployment is not feasible without broad political and public support. At present many Australians do not support nuclear power. A genuine and sustained public decision-making process is needed if nuclear power were to be a credible option. This is likely to add even more lead-time to the 15 to 20 years for technical requirements.

7.2 This chapter is an economic and technical assessment of nuclear power

This chapter reviews the prospects for nuclear power in Australia in terms of economics and related technical factors. It does not include a number of important safety, security and social issues[1] raised by large-scale deployment of nuclear power technology. These would need to be considered in a more complete analysis of nuclear power in Australia and in any decisions on nuclear power policy.

7.3 What is nuclear power?

Commercial nuclear power plants are low-carbon emission thermal generators.[2] That is, they produce electricity from heat in the same way that coal, gas and solar thermal power plants do, but using the energy released when cascades of atomic nuclei are split apart in what is called a nuclear *fission* reaction. Only a few heavy elements are effective as fuel for nuclear fission. Uranium-235, plutonium-239 and uranium-233 are the most common fuels. These nuclides are unstable and comparatively easy to split, because they have a proportionally large number of protons to neutrons. This means they have excess energy, and so are prone to frequent radioactive decay. The spent fuel from most operating reactors is highly radioactive, and some fission products remain so from thousands to millions of years.

A nuclear *fusion* reaction can also be used to generate electricity, but this is a very different process. A fusion reactor would generate heat by fusing together light elements, such as hydrogen-2. It could produce far less waste than a fission reactor, and material of much shorter radioactive life (about 100 years). But while there are large-scale efforts to develop this capability, there is no prospect that power production from nuclear fusion will be commercially viable in the foreseeable future.[3]

There are many reactor designs and types, the features of which are highly technical. We don't propose to discuss these in depth, but it is important to note that different reactor technologies have distinct implications for both the nuclear sector and for society at large. These include electricity costs, nuclear waste management requirements, environment impacts, resource use, safety, security and nuclear material proliferation issues.

One important distinction is between 'fast neutron' and 'slow neutron', or 'thermal' reactors. These are different technologies. Neutron speed refers to the average kinetic energy of neutrons in the reactor core, which influences the type of nuclear reactions that can occur and thereby the type and amounts of waste and other by-products. Around the world practically all operating reactors are thermal reactors.

Related to this, 'fuel cycle' is another factor that distinguishes reactors. Thermal reactors generally operate with a 'once-through' or 'open' fuel cycle, in which fuel is used for a term in the reactor core and then removed for cooling and long term storage. The

[1] eg Uranium mining and land rights

[2] Lifecycle analysis for current nuclear plants suggests that average CO_2-e emissions are about 0.065t/MWh, compared with 0.8-1.2t/MWh for coal-fired electricity in Australia (Lenzen, 2008). Analysis by the UK Government concluded that it is substantially lower that this about 0.007-0.022t/MWh (UK BERR 2008)

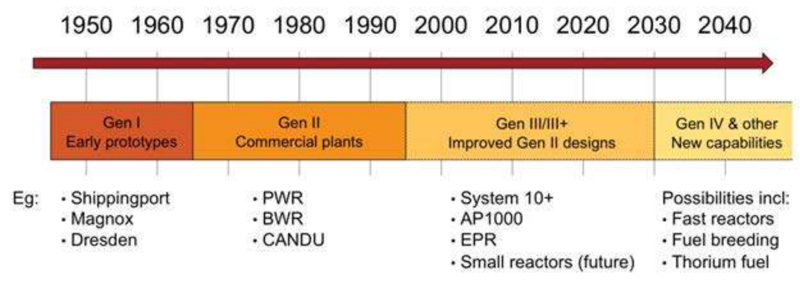
[3] For examples of large-scale nuclear fusion projects see: http://www.iter.org or https://lasers.llnl.gov/

spent fuel from these reactors is the main problem of nuclear waste management.

However, spent fuel also contains a very high proportion of the original uranium, as well as plutonium that has been formed in the core. In some cases the usable nuclear fuel is reprocessed – separated from unusable fission products and packaged for re-use, in a 'semi-closed' fuel cycle. Fast reactors, discussed below, offer the prospect of using fuel more efficiently than thermal reactors or even burning-up' existing nuclear waste, a 'closed' fuel cycle.

Development of nuclear technology for electricity generation began in the late 1940s and deployment of commercial plants became common in the 1960s. To summarise reactor development, nuclear power plants are often loosely grouped into 'generations' of design, following a convention established by the US Department of Energy (Figure 7.1).

Figure 7.1 Past and possible future 'generations' of nuclear power plant



Source: Based on US DOE (2011)

Gen I – early prototypes

Gen I-type reactors are the early power plant prototypes, developed in the 1950s and '60s from military designs and generally retired by the early 1980s. Outside the UK none is operating today.[4]

Gen II – commercial plants

Most reactors in operation around the world belong to the second generation of designs. These plants generally began construction between the late 1960s and mid-1980s, in countries such as Japan, France, the US and the Soviet Union. Cumulatively, there is a significant amount of experience in building and operating reactors of this type. Two reactor types, based on earlier Gen I

[4] World Nuclear Association (2011a)

designs, make up more than 80% of plants in operation today.[5] These are the designs referred to when nuclear power is described as a mature technology.

Second generation reactors were designed for commercial operation. They were built larger, designed for a longer economic lifetime (about 40 yrs) and incorporated efficiency and safety improvements. The global rate of deployment of Gen II reactors slowed abruptly after the mid-1980s, for both economic and political reasons. Competition from fossil-fuel technologies increased, nuclear power economics were worsening, and serious accidents, first at Three Mile Island in 1979 and then Chernobyl in 1986, contributed to widespread public opposition to nuclear power.[6] The Fukushima Daiichi reactors in Japan, the scene of the recent tsunami and safety crisis, are considered Gen II-type designs.[7]

Gen III – improved designs

Current reactor designs are usually described as belonging to Gen III or Gen III+, the most recent designs. These are evolutions of Gen II reactors, sharing fundamental design principles but improving economic performance and incorporating new safety technology. In particular, third generation designs use 'passive safety' designs that rely on physical processes like gravity or convection to avoid accidents, rather than active controls or operational intervention, such as operating pumps or valves. They are designed to operate for longer – in the range of 50-60 years – to have fewer planned outages, and to produce less waste.[8] Any nuclear power deployment in Australia would most likely make use of Gen III+ designs.

Worldwide, only a handful of these reactors have been built. Of the 433 power reactors operating around the world[9], 15 or fewer are considered to be Gen III-types.[10] About a dozen third generation units are under construction and more are planned, but many Gen II-type reactors are still being built, particularly in China.[11]

Gen IV and other developing designs – new capabilities

Several nuclear power technologies are being developed that have potential to make nuclear power significantly more attractive. Potential benefits could include reducing the nuclear waste burden, reducing costs and financial risk, increasing safety and reliability, and increasing the security of nuclear materials. These designs are often cited as holding the future of the nuclear power industry.

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[5] IAEA (2011a). These are the Pressurised Water Reactor (PWR) and the Boiling Water Reactor (BWR). The US submarine program played a significant role in developing reactors of this type (light-water moderated). One likely reason that this technology was selected is that it produces plutonium as a by-product.

[6] The Chernobyl unit at the centre of the 1986 accident was a Russian-designed RMBK-type reactor. It has important differences to Gen II and is not considered to be a Gen II design.

[7] IAEA (2011b)

[8] World Nuclear Association (2011a). Extensions beyond this operating time are not unlikely.

[9] IAEA (2011b)

[10] The 'generation' nomenclature is descriptive and there is disagreement about how to categorise some reactors. For Gen III plants, the US National Energy Institute count begins in 1982 with plants in Canada and South Korea (Garthwaite 2011). The World Nuclear Association (2011a) identifies the first Gen III plant as being built in Japan in 1996.

[11] IAEA (2011b), World Nuclear News (2011b)

The frequently-used term, 'Gen IV', generally refers to six specific reactor designs that were selected for development by the Generation IV International Forum (GIF), an international nuclear technology collaboration.[12] These represent distinct approaches to reactor design and all have their strengths and challenges.

However these designs (and other new reactor technologies) are still in research and development stage. They must still overcome major hurdles and it is generally thought that they will need decades of R&D effort before commercial use might be possible.[13] As such there is no guarantee that any will become viable for widespread commercial deployment, at least in the medium term.

Fast neutron reactors, thorium-fuelled reactors and small reactors are three design directions that are often identified as holding special promise. Given this, we briefly describe these technologies.

Fast reactors would be valuable because they are capable of producing new nuclear fuel (breeding) or 'breaking down' nuclear waste (burning), while also generating electricity.[14] In breeder configuration, a reactor generates more fuel than it consumes – for example, by transmuting ^{238}U into fissile ^{239}Pu. About 96% of current nuclear fuel is ^{238}U, which is not fissioned in conventional reactors. By converting this into usable fuel, a fast breeder reactor can be around 60 times more fuel-efficient than convential Gen II-type thermal reactors.[15] This technology could make long-term use of nuclear power far more plausible.

In burner configuration, fast reactors can transmute long-lived radioactive material into other forms that are still radioactive but have much shorter half-life. Conceivably, burner reactors could use existing high-level nuclear waste as fuel, radically reducing its radioactive lifetime, to hundreds of years, and decreasing the total volume of waste that needs to be stored. But achieving this would require multiple passes through the reactor, and reprocessing the fuel each time. This means that long periods of reactor operation would be needed (perhaps 200 years) before most of the radioactive materials from one fuel load is burned.[16, 17] Although fast reactor technology has been in existence for many years, these designs also face technical and economic challenges, have low potential for passive safety and, depending on the reactor/fuel configuration, could create major risks of plutonium proliferation.[18]

[12] Formed in 2000, initial members included: The USA, Argentina, Brazil, Canada, China, France, Japan, Russia, South Korea, South Africa, Switzerland, the UK and the EU (Euratom). The Forum aims to develop new reactor designs by 2030. 'Gen IV' is sometime used to describe future reactors in a general way.

[13] eg Lenzen (2009), a literature review on energy technology development

[14] Breeder technology is also possible with thermal-spectrum reactors, but is more efficient in fast neutron reactors. Three of the six Gen IV designs are fast reactors.

[15] World Nuclear Association (2011c)

[16] Committee on Separations Technology and Transmutation Systems - National Research Council (1996). This would not avoid having to dispose high-level nuclear waste in entirely. Some high-level waste would be separated out during reprocessing and the final core from the fast reactor would also need to be disposed.

[17] For comparison, one reactor fuel load is about 80te (tonnes-equivalent), depending on the design. The world's current inventory of spent fuel is about 270,000te. A single unit Gen-II commercial reactor discharges about 27te of spent fuel per year. World Nuclear Association (2011k).

[18] The earliest fast reactor dates from 1946. The US, Russia, Kazakhstan, France, Germany, Japan, India and the UK all have operated fast reactors, but none were commercial power plants. Worldwide two fast breeder reactors are in operation (in Russia and China) and two are under construction (in Russia and India), IAEA (2011b).

Thorium-fuelled designs have potential for much greater fuel efficiency, much less high-level waste and greater resource availability, as thorium is naturally more abundant than uranium. There may also be advantages in terms of safety and proliferation.[19] But here too are technical challenges. The most abundantly occuring form of thorium (^{232}Th) is not fissile. The nuclear fuel is in fact ^{233}U, 'bred' from thorium in the same way that ^{238}U is transmuted to ^{239}Pu. As such, some form of breeder technology and fuel reprocessing is needed to produce the final fuel. There are also problems related to fuel-handling and developing sufficiently robust reactor core materials.

A different direction is to reduce reactor size, from gigawatt scale down to units of 300 or even 25 megawatts. Theoretically this can be done with existing technologies, and several of the Gen IV designs. Small modular reactors (SMRs) have potential to reduce several cost, safety and security uncertainties, by permitting units to be factory-built and sealed for security purposes. This simplifies many of the issues with fuel handling and transport, as well as concerns about proliferation of nuclear materials. Small reactors could be especially appealing for Australia because they could be more easily integrated into existing electricity markets. Several designs are in development, but so far there are no commercial prototypes.[20]

7.4 What is the potential of nuclear power?

Nuclear power has the potential for very large-scale use in Australia. However, at present the construction or operation of a nuclear power plant is illegal.[21] The only reactor permitted and operating, for research purposes, is the Australian Nuclear Science and Technology Organisation's unit at Lucas Heights. This prohibition means there is limited analysis of how and when nuclear power plants could be integrated into Australian electricity markets. A study by the CSIRO (2011) is one exception.

On a purely technical basis nuclear power plants could probably operate in Australia in much the same way that coal and combined-cycle gas-fired plants do, using the same transmission and market infrastructure. In particular, many Australian fossil-fuelled power plants are gigawatt-scale generators, as any nuclear power plants would be, using current reactor technology. In order to be economic, nuclear power projects need to achieve an average capacity factor (see glossary) of around 80%.[22] Capacity factors for operating coal and gas plants in the National Electricity Market (NEM) are close to this.[23] About 75% of Australia's electricity is coal-fired. For comparison, France generates around 75% of its electricity from nuclear power, Sweden 38% and the US 20%.[24]

Australia has an ample supply of land and is geologically and politically stable. It also has the world's largest reasonably assured resources of uranium and identified recoverable thorium resources.[25] Fuel costs could be low and fuel supply secure, particularly if Australia were to develop its own enrichment and fuel fabrication facilities.

[19] World Nuclear Association (2011d), Hargraves and Moir (2010)
[20] For an introduction to SMRs see Irwin (2011)
[21] *Australian Radiation Protection and Nuclear Safety Act 1998*
[22] EPRI (2010)
[23] CSIRO (2011)
[24] World Nuclear Association (2011j)
[25] Geoscience Australia and ABARE (2010)

Yet there are limitations to how much nuclear power generators might meet Australia's total electricity demand. Firstly, nuclear power may not be flexible enough to follow the peaks and troughs of electricity demand. Nuclear plants have a degree of load-following capacity, especially where there are multiple units.[26] But doing this may not be economically attractive and requires more sophisticated (and error-prone) reactor operations. Peak demand is usually met by other generators, such as open-cycle gas-fired plants.

Secondly, Australian electricity markets are relatively small compared to very large size of current reactor designs. To illustrate, the minimum demand load in Victoria and NSW is about 4,000 and 6,000 megawatts respectively. In Western Australia, the South West Interconnected System minimum load is around 1,400 megawatts. [27] In contrast, current-technology nuclear power units are typically 1,000 to 1,600 megawatts in size – compared with 750 megawatts for the largest generator units in the NEM.[28] Given that there is sometimes vigorous competition in electricity generation, and that nuclear power plants need to consistently sell 80% or more of their total generating capacity, it may not be viable to build many plants of this size in Australian electricity markets.

In addition, power stations of this scale this would probably increase the amount of reserve capacity needed to safeguard electricity supply, should for instance the nuclear power plants be taken off-line. For very large amounts of nuclear power, the additional reserve capacity would also be very large, may be rarely used and therefore uneconomic.[29]

[26] World Nuclear Association (2011h)
[27] AEMO (2010), Western Power (2011)
[28] There are coal plants in Australia with total capacity of more than 2,000 MW, but these comprise several smaller units which can follow load individually

This constraint could change, if in the future small modular reactor technology develops and becomes economically viable. This type of reactor, with units of less than 300 megawatts, could avoid many of the problems of integrating nuclear power into smaller electricity markets.

7.5 Current status and trends

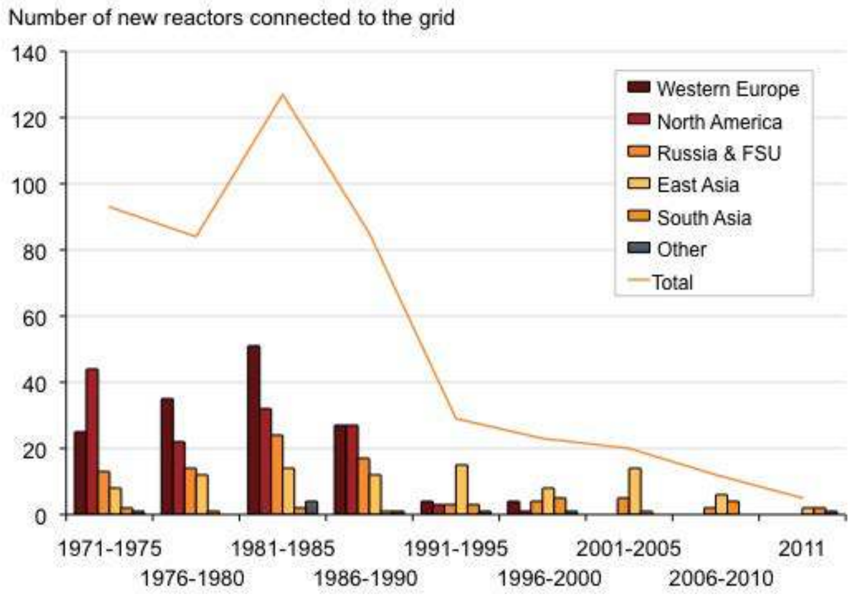
7.5.1 The nuclear power sector declined sharply after the mid-1980s

Nuclear power's status as an established technology refers in effect to Gen II nuclear plants built in the late 1960s, '70s or early '80s. These continue to operate in many countries, including France, the US, the UK and Japan.

As Figure 7.2 illustrates, the global nuclear power industry declined sharply from the mid-1980s. Rising plant costs and public opposition combined to halt nuclear power programs in many countries, and many governments returned to fossil fuels as the mainstay of their power sectors. Public opposition continues to be a major factor for the future of nuclear power.

[29] Commonwealth of Australia (2006)

Figure 7.2 New reactors connected to the grid by world region



Source: IAEA (2011a, b), IAEA (2006)

7.5.2 Concerns about energy security and climate change have helped to renew interest in nuclear power

More recently, several countries have shown renewed interest in nuclear power. For instance, the UK Government has indicated its intention to support deployment of nuclear power within the next decade (at least 8 reactors), citing concerns about energy security and carbon emissions as primary motivations.[30]

In the US, the 2002 US Nuclear Power 2010 program and supporting measures in the *Energy Policy Act 2005* were developed as a means to kickstart the US nuclear power sector and help address an expected need for new power plants. The initial goal was to bring two new power reactors online by 2010, the first completed units in the US since 1996. The goal was not achieved, but there has been significant uprating of existing plants. Since 1996 these (mostly small) increases have provided a total growth in capacity of about 4,500 megawatts, equivalent to three or four new plants.[31]

Elsewhere, Finland, France and the United Arab Emirates have recently begun projects to expand their nuclear fleets and Poland is developing a nuclear power program, due to concerns about its energy mix and emissions. Several other countries have announced plans to increase their installed capacity of nuclear power, such as China, South Korea, Russia, India, Bulgaria, Lithuania and the Czech Republic. A number of other countries, such as Hungary, Slovakia, Spain and Canada, have plans to extend the lifetime of operating nuclear units.[32]

Yet lack of recent experience creates uncertainty about the economics of new nuclear plants. Practical experience deploying

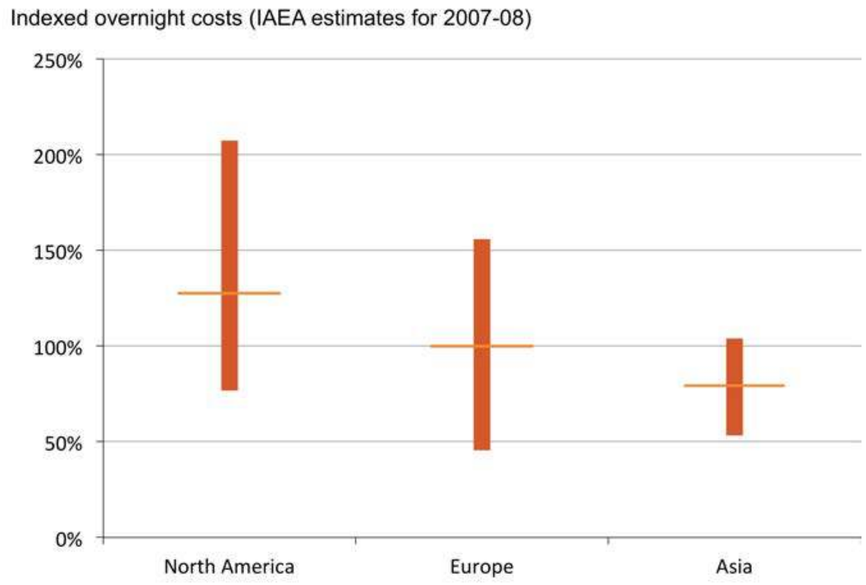
[30] UK BERR (2008). The November 2010 House of Commons vote on deployment of new nuclear power in the UK passed with significant cross-party support, with 520 votes in favour to 47 against.
[31] US NRC (2012). This figure is the total of National Regulatory Commission approved uprates since 1996
[32] World Nuclear Association (2011b)

nuclear power plants is essential to be able to accurately predict what a nuclear power sector is likely to deliver in a given country. This is because the local conditions for any given project strongly influence the plant's overall economic performance.

Developing a nuclear power plant is a very large and complex engineering operation. Each project is unique, being exposed to local factors, such as political and planning processes, environmental conditions, project management, local labour and regulatory requirements. The closest analogy may be a coal power-plant with CCS capability. But the construction time for a CCS plant is likely to be lower, and safety/quality regulations less stringent, which substantially reduces the project's financial exposure.

Such conditions can vary significantly between countries with different political systems or standards for labour and environmental protection. In fact, the estimated costs of nuclear power vary significantly by location, as IAEA figures show (Figure 7.3). The UK Government's published cost-benefit analysis on new-build nuclear power noted: 'Examples from Eastern Europe are not relevant to the UK context given differences in labour market conditions, possible exchange rate distortions, and different accounting standards used in formulating cost estimates.'[33]

Figure 7.3 Regional variation in nuclear plant capital cost



Source: International Atomic Energy Agency data, adapted from von Hippel (2010)

Recent experience building nuclear power plants is particularly limited in North American and European countries, where the economic and regulatory conditions for nuclear power projects are closest to what they might be in Australia (see Figure 7.2). In these regions, deployment has slowed almost to a halt since the early 1990s. Experience with contemporary Gen III-type designs is limited to just two projects, one in Finland and one in France, both of which are currently under construction. Australia has only one operating research reactor, completed in 2007, and two

[33] UK BERR (2007)

research reactors that have been shut down. It has no power reactors.[34]

It is true that deployment of nuclear power plants has continued elsewhere, notably in Japan, South Korea, Russia and China. The experience of these countries is not irrelevant to Australia – more experience with a given design means greater certainty. But to date these programs have not come anything close to the new nuclear build rate of the 1970s and early 80s. Compared with coal or gas-fired power, or even wind or solar, practical experience with new nuclear power plants is spare.

In practice, this means that while strong claims are made about what new nuclear power stations can achieve in Europe, the US or Australia, the costs, repeatability and operating record of new nuclear designs remain uncertain.

7.6 What are the obstacles to the large-scale roll-out of nuclear power in Australia?

7.6.1 The economics of nuclear power are uncertain

In the absence of recent project experience, estimates for the cost of nuclear power rely on assumptions about a range of project factors. As these vary significantly, published cost estimates do also. Uncertainty is set to continue until there is a weight of practical project experience deploying current reactor designs, in countries with similar economic and regulatory conditions to those in Australia.

However, the range of cost estimates for nuclear power broadly matches cost ranges of other low-emissions technologies. At the low end, nuclear power could be very cost-competitive, around $100 per megawatt-hour – potentially cheaper than many alternatives, including gas-fired generation, depending on how gas and carbon prices change in the future. At the high end, at around $200 to 250 per megawatt-hour, it is still not certain that alternatives like solar power, geothermal power or CCS will be significantly cheaper than nuclear power.

Nuclear power cost estimates

Current nuclear power technology requires very large plants in order to achieve sufficient economies of scale and be commercially viable. Commercial plants are typically sized 1,000 megawatts or greater.

As a result these plants must be engineered on site, are highly capital intensive and need to operate for many years before they provide returns on investment. The need for scale, along with stringent quality requirements, makes construction the major driver of the cost of nuclear power, about 70 to 80% of total cost.[35] As such, projects are highly sensitive to construction risk. Any delays during construction increase interest and overall cost rapidly – financing adds around 30% to the project's bottom line. Without real project experience to draw on, estimates for the cost of nuclear power rely on assumptions about these factors.

Comparing cost estimates can be difficult, because they may include only a subset of the site-specific costs that a given project

[34] See www.ansto.gov.au

[35] Keystone Centre (2007), MIT (2011)

may incur. Capital cost is most often quoted for nuclear power plants, but frequently refers to the nuclear island only, not the entire plant. Owner's costs take in factors like the cost of land, site works, cooling towers, fuel loading, transmission connection and the cost of interest during construction, all of which vary significantly from project to project. In addition, there is a question as to whether cost figures are in current year currency value or in those of the year in which spending will occur. This can create material differences where a construction takes place over several years.

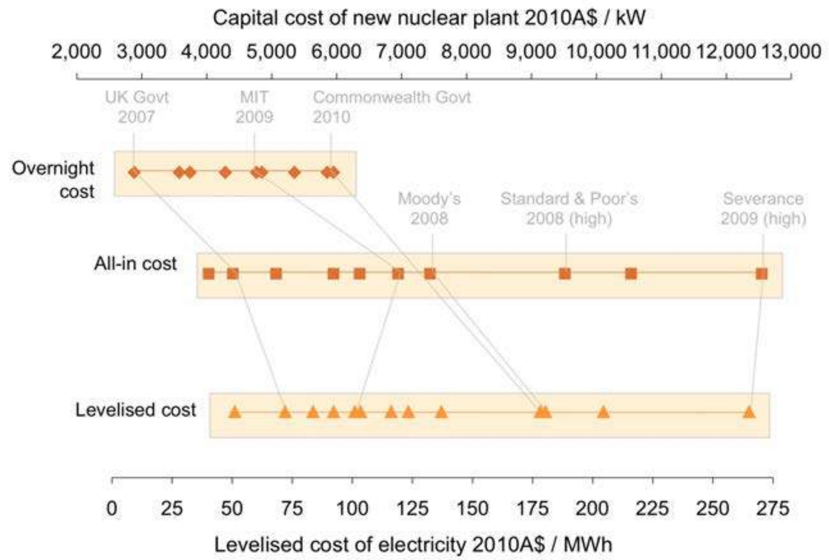
Comparisons are also made using levelised cost calculations. These illustrate the average cost of generating electricity over the economic life of the plant, based on the factors above plus operation and maintenance costs over the plant's lifetime (including fuel), with provision for decommissioning and waste disposal.

Published cost estimates for nuclear power do not always make clear which factors are included in their assessment.

Figure 7.4 shows a wide range of cost estimates published by reputable sources. Two types of capital cost estimate are included. 'Overnight cost' does not include the cost of interest during construction (as if the plant were built overnight) and may not include some owner's costs – for example, transmission cost is often excluded. 'All-in' costs are intended to reflect plant total capital expenditure and are therefore more variable. Figure 7.4 also illustrates to some degree how capital costs correspond to probable levelised cost of electricity.[36]

As Figure 7.4 suggests, whether new reactor costs will be high or low is a subject of debate.

Figure 7.4 A range of estimated costs for new-build nuclear power in the UK, the US and Australia



Source: Citigroup Global Markets (2009), CSIRO (2011), DRET and EPRI (2010), Keystone Centre (2007), MIT (2009), Moody's Investor Services (2008),

[36] This is variable. To illustrate, the high estimate by Severance (2009) uses a mid-range overnight cost, but assumes a long construction period (11 years) and a very high average cost of capital (14.5%).

Severance (2009), Standard & Poor's Rating Services (2008), UK BERR (2007) and UK BERR (2008)

Why the cost of nuclear power could be low

One view of future costs is that they will be very competitive. This is based on project parameters that the nuclear industry believes it can achieve, such as rapid build time and low costs of capital, labour and basic materials like steel and cement.

In 2007 the UK government gave the following reasons for anticipating that nuclear power will be very cost-competitive with other low-carbon technologies: First, project management techniques have improved over the last fifteen years, and projects would be delivered by private consortia that are subject to global competition pressures – and therefore likely to better manage costs and risks. Second, the cost of building new reactor designs is likely to fall after the first plant has been constructed, especially as new units will use standardised designs, evolutions of earlier models with which there is ample experience. Also, while new reactors are larger and achieve greater economies of scale, they also have a smaller footprint, requiring less piping, steel and concrete. Third, improved regulatory standards and certification before construction are likely to shorten build time and help avoid costly design changes.

Other analysts also suggest that there may be cost savings in operations and maintenance both through fewer moving parts (like pumps and valves) and smaller plant staffing levels[37] and through improvement in construction practices, such as computer-controlled manufacturing of components and computer simulation of construction sequences, adpated from the ship-building industry.[38] Vendors claim that construction time (for the nuclear island) can be shortened dramatically, to as little as three years.[39]

Under these assumptions levelised cost estimates are at the low end of Figure 7.4. Even if capital cost is higher than might have been expected, a high average capacity factor over the plant's lifetime can still bring the levelised cost down to $100 to $150 per megawatt range broadly covered by the technologies assessed in this report.

Since the early 2000s there has been renewed optimism that developments like these have addressed the problems underlying the cost-overruns of the 1970s (described in the following section). This seems plausible – in Japan and South Korea, a number of plants have been completed at very competitive cost, employing some of these construction techniques (Table 7.1).

[37] Keystone Centre (2007)

[38] Koomey and Hultman (2007)

[39] eg Westinghouse (2012)

Table 7.1 Nuclear power plant capital costs, Japan and South Korea 1997-2004

Country	Plant name	Type	Year of commercial operation	All-in cost (2002)US $/kW
Japan	Kashiwazaki-Kariwa-7	ABWR	1997	1,790
	Genkai-4	PWR	1997	2,288
	Onagawa-3	BWR	2002	2,409
	Hamaoka-5	ABWR	2004	1,820
South Korea	Yonggwang-5&6	PWR	2001-02	2,300
	Ulchin-5	OPR	2004	2,830

Source: Du and Parsons (2009), Keystone Centre (2007)

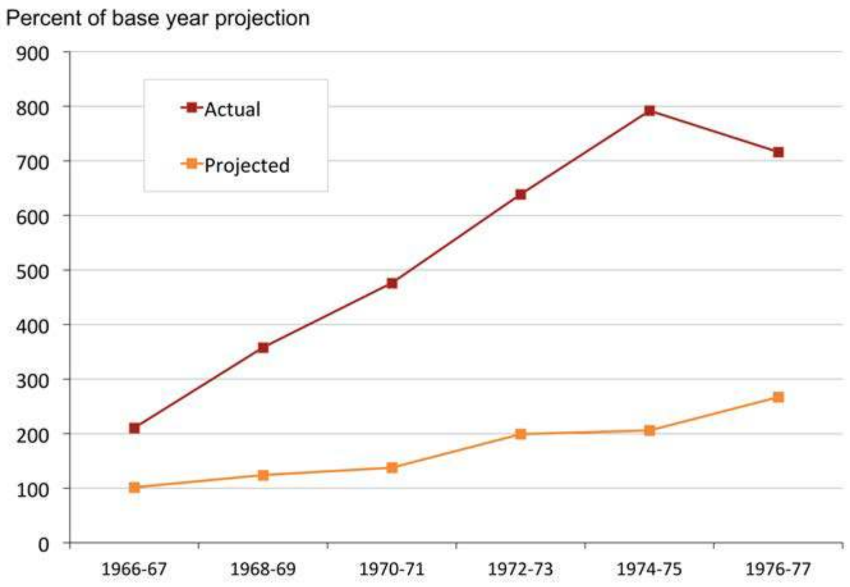
Why nuclear power could be expensive

1. History suggests that reactor costs will be higher than expected and will increase over time

Figure 7.5, overleaf, shows that over the decade from the late 1960s to the late 1970s, average real US reactor construction costs consistently surpassed projected costs - for the most part by a large and increasing amount.

These data suggest two things: one, the US nuclear industry has a history of underestimating its costs, based on optimistic beliefs about what nuclear technology will achieve in future. Two, the cost of building nuclear plants in the US has increased over time (Figure 7.5 and Figure 7.6). This is contrary to the common expectation, articulated by the UK Government, that industries reduce costs as they gain experience.

Figure 7.5 Projected and actual average capital costs, by year construction commenced, as percent of 1966-67 project cost. US reactors completed prior to 1 January 1986



Source: Cooper (2009)

There are a number of reasons why US nuclear power plant costs increased. Some of these relate to the financial environment. At the time the US increased its build rate, it also experienced high interest rates, inflation and a slowing rate of growth in electricity demand. These worked against financing new, large projects.

Some utilities also experienced problems with construction quality control and cash-flow.[40]

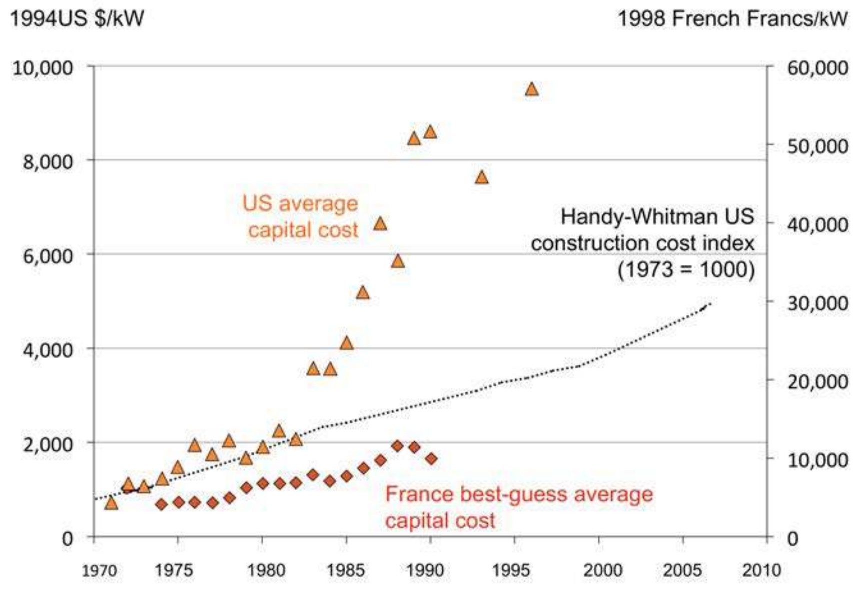
However, several analysts argue that costs escalated because of rapidly changing and more complex reactor designs. These changes were required by tightening regulations, including changes to safety standards triggered by accidents such as the fire at Browns Ferry in 1975 and the core melt-down at Three-Mile Island in 1979.[41]

The US is not the only country to experience nuclear power cost escalation. France has as well, shown in Figure 7.6.[42] However, the increase in French reactor costs was much less dramatic, much closer to the rate of inflation in construction costs, largely because France's nuclear power program has been centrally planned and benefitted from firm regulation from the outset. Starting in the mid-1970s, France deployed nuclear power with a largely state-owned system, commissioning highly standardised nuclear plants through Electricité de France (EDF). Just three reactors designs dominate French units and all of the same basic type (pressurised light-water reactors). They were all developed by the then state-owned nuclear agency Framatome (now Areva) and were based on an established Westinghouse design.[43] EDF maintained its own complement of experienced engineers that

[40] Keystone Centre (2007), Koomey and Hultman (2007)
[41] eg Komanoff (1981)
[42] Grubler (2010). France has the highest penetration of nuclear power in the world, generating over 75% of its electricity from nuclear plants.
[43] World Nuclear Association (2011g)

engineered plant architecture and managed project sites.[44] Nevertheless, French reactor costs also increased over time.

Figure 7.6 US and France average construction costs, by year of completion



Source: von Hippel (2010), adapted from Grubler (2010)

By contrast, the US approach relied on the market to choose from a range of approved reactor designs and to engineer the plants. While inflation and changing market conditions have no doubt been influential in increasing plant costs, some argue that this approach – limited experience with any one design – is the primary cause of the volatility and steepness seen in the US cost curve.[45] Varying conditions of deployment led to some plants coming in cheap and others very expensive.

This experience suggests that, because nuclear plants have been few, large and costly, it is difficult to achieve the scale and experience necessary to internalise learning and reduce costs in a consistent way – even when production is centrally controlled. This challenges the conventional logic that competitive markets will always drive costs down. Where there is little experience, high capital risk and changing technical requirements, costs in the nuclear sector have tended to do the opposite.

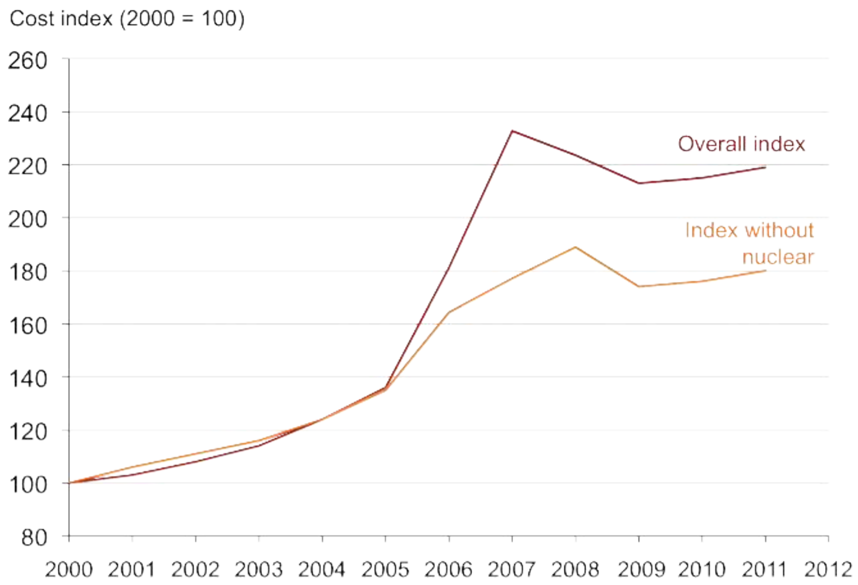
2. Recent experience has added to doubts that nuclear power plants can be constructed at low cost

Since the late 2000s several analysts have grown more sceptical about the nuclear power industry's capacity to deliver on earlier cost estimates. This is largely due to dramatic increases in power plant construction of all types, together with more specific issues related to nuclear power plant components and labour costs. Two high-profile project management failures in nuclear power plant construction in Europe have also affected the outlook.

[44] Thomas (2010)

[45] Grubler (2010)

Figure 7.7 PCCI Capital cost index for North America power plants



Source: IHS CERA (2012)

Figure 7.7 illustrates that power plant costs have risen sharply since about 2005, and that nuclear power plants have pushed the average up significantly. In its (2008) analysis on nuclear power, Standard and Poor's suggested an all-in capital cost of (2008)US $5,000 to $8,000 per kilowatt as being realistic, noting that the cost of building new power plants had more than doubled since the year 2000. Similarly, in 2009 MIT doubled its 2003 capital cost estimate[46] and the US Energy Information Administration (2010) increased its 2009 estimate by 37%. This was despite the impact of the Global Financial Crisis, which depressed the cost of power project construction.

Nuclear power plant component and labour costs are commonly identified as special issues contributing to this trend. The Keystone Centre (2007) noted that the number of licensed nuclear technology suppliers and sub-suppliers in the US had dropped from about 1,300 to 280 over the previous two decades. That meant that in 2007 the procurement or manufacture of some plant components took about six years. Standard & Poor's (2008) analysis identified pressure vessels, circulating water pumps and turbine forgings as being particularly problematic, but not the only components that were difficult to find or make. Global capacity to supply the ultra-heavy pressure vessels needed for large reactors has recently increased, but while there is no longer a monopoly in this sector, production is still limited to three or four companies.[47] Skills shortages are also known to be a major constraint that cannot be quickly overcome.[48]

The recent experience of constructing new Gen III+ reactors in Finland and France has increased scepticism about the ability of contractors to manage the costs of new-build nuclear. Finland was the first European country to order a current generation reactor, the Olkiluoto-3 unit. The project, which began in early 2005, was reported in 2010 as running at around 1.7 billion euros over budget (at 2010 prices) and up to four years late.[49] According to the Finnish regulator, STUK, the causes include inadequate

[46] MIT (2003), MIT (2009)

[47] Keystone Centre (2007), World Nuclear Association (2011e)
[48] Standard & Poor's Rating Services (2008)
[49] Westall (2010), Thomas (2010)

design work, some of which was being done in parallel with construction, insufficient readiness in regulation, poor project management and lack of craft labour experience. The last led to construction quality problems in nuclear plant-grade concreting and welding.[50]

In France, EDF's 1,650 megawatt Flamanville-3 project began in 2007 and was planned to cost about 3.55 billion euros (at 2008 prices), or 2,152 euros per kilowatt produced, to be completed in 2012. Since then the completion date has slipped to 2016 and the capital cost has been revised up three times. It is now expected to cost about six billion euros (2008 prices). According to EDF, the project has suffered problems in coordinating the project's nine different sub-contractors.[51]

Together these factors raise the business risk of undertaking a nuclear power project and are likely to increase the cost of commercial finance for nuclear power. As a result, some financial analysts consider that nuclear power plants will be too risky for the private sector unless they have substantial government backing.[52] This issue is discussed in section 7.7.

Could China change the game?

There is a prospect that China could shift the costs of deploying nuclear power around the world.

In contrast to Europe and the US, deployment has been gaining pace in Asia, and especially in China, which is building nuclear plants an order of magnitude faster than the rest of the world. China has plans to increase its nuclear generating capacity to 70 to 80 gigawatts or more by 2020. Since 2002 China has completed and commenced operation of 12 plants, with 27 more are under construction.[53] These include four Gen III+ units and a demonstration Gen IV high-temperature gas-cooled reactor. A series of 51 further units are planned, with construction due to start within three years. Most reactors under construction will be indigenous models, derived from French or US designs.[54]

One expectation is that China will effectively mass-produce plants, dramatically forcing down unit cost and construction time. It will then be able to export its own low-cost designs.[55] Learning from this program, combined with experience from other projects, such as in South Korea, France, the UK and the Middle East, could lead to nuclear power costs falling over the next decade or so.

On the other hand, China is not Australia and the conditions of deployment matter when engineering nuclear power plants. In some areas, such as commodities and construction sector supply chain, it is doubtful whether projects in Australia could benefit from the same economies of scale. In fact, Asian demand for raw materials has to date had the opposite effect, helping to push up the costs of large-scale construction projects, as shown above.

[50] Koskinen (2010)
[51] World Nuclear Association (2011g)
[52] eg Citigroup Global Markets (2009)
[53] IAEA (2011b)
[54] World Nuclear Association (2011i)
[55] eg Switkowski (2010). For an example of public comment by a Chinese State-owned utility see World Nuclear News (2010a). Recently South Korea began exporting its nuclear technology, with the Korea Electric Power Corporation winning the contracts to supply the United Arab Emirates with an initial four 1,400 megawatt reactor units.

In other areas Australia and China are plainly different. The cost of finance for Chinese state-owned utilities may be significantly lower than the commercial rates that merchant plants in Australia would have to pay. Other areas of difference are the processes for decision-making, the cost of labour, standards for labour and environmental impact management, and standards and regulations for locating nuclear plants. As a result Australian deployment may incur greater time and economic costs.

7.6.2 Nuclear waste disposal needs to addressed

Long-term waste disposal is an ongoing problem for the nuclear industry. It must be adequately addressed by any country with a nuclear power programme, including low, intermediate and high-level radioactive waste.

Nuclear waste is not a physical barrier to nuclear power deployment, in the sense that it does not prevent the construction and operation of a plant. Nuclear facilities are capable of holding the high-level waste they produce for long periods of time, often the lifetime of the nuclear power plant. A typical 1,000 megwatt commercial reactor will generate about 20 m^3 (27 te) of high-level waste per year, in the form of spent fuel, as well as 200 to 350 m^3 of low- and intermediate-level waste.[56]

However, waste disposal can be a long-term risk for governments and may be an acute issue for community support of nuclear power. The UK's approach been to require nuclear power plant operators to accumulate sufficient funds to pay the full cost of plant decommissioning and a share of waste management costs during the plant's lifetime. The 2008 White Paper on nuclear power also includes a 'Page 99' test, requiring the Government to be satisfied that 'there is or will be' a solution to nuclear waste disposal before issuing final consent to build new reactors.[57]

High-level waste requires the most sophisticated response. Many governments consider deep geological storage as the best means to dispose of this type of waste. This was also the conclusion of the 2006 UK government-sponsored enquiry into waste disposal, which now forms the basis of UK government policy.[58] Yet presently high-level waste is generally held on-site, near to the reactor that produced it. While there are a number of deep geological storage test sites around the world, there is only one final waste facility in operation, the Waste Isolation Pilot Plant in the US. Both Finland and Sweden are presently constructing deep repositories, and these are expected to receive waste after about 2020. There are also efforts to create shared storage, for smaller nuclear power users.[59] In contrast, funding for a large-scale storage facility at Yucca Mountain in the US was withdrawn in 2009 and currently it is unclear what alternative will be.[60]

Should Australia choose to store nuclear waste, it has areas with geology that may be favourable. In the late 1990s proposals were developed for an international nuclear waste repository in

[56] World Nuclear Association (2011k)

[57] UK BERR (2008). In the White Paper's assessment, the additional cost towards each plant's decommissioning fund (£636-950 m) and waste disposal fund (£276-320 m) is negliable, about £1 per megawatt-hour.

[58] Committee on Radioactive Waste Management (2006), UK DEFRA et al. (2008)

[59] eg ERDO http://www.erdo-wg.eu/Home.html, and ARIUS http://www.arius-world.org/

[60] US Office of Management and Budget (2009)

locations in Western Australia and South Australia, based on suitable geological conditions and remoteness from population centres.[61] The proposals were met with significant opposition in the public in state and federal parliaments and did not proceed.

The alternative to long-term geological storage rests on developing future nuclear technologies, such as the fast-reactor technology discussed earlier, which can shorten the radioactive lifetime of many nuclear wastes. Although it has a number of difficulties, this approach has received interest from a number of governments. China, for instance, sees this type of technology as a possible solution to treat its nuclear waste.[62]

7.6.3 The lead time for nuclear power in Australia is between 15 and 20 years

A nuclear power sector requires highly specialised physical, regulatory and human infrastructure. These all need a long time to develop before the key can be turned on a new plant.

The groundwork includes establishing specialised physical and regulatory infrastructure, such as appropriate legal and regulatory frameworks, institutions and the plant itself; and important processes, such as for consultation and licensing.

For nuclear power to be a credible option for low-emissions electricity in Australia, planning and sector development need to begin well in advance of deployment. This means that the lead-time to develop a nuclear power sector is potentially a major barrier to large-scale deployment.

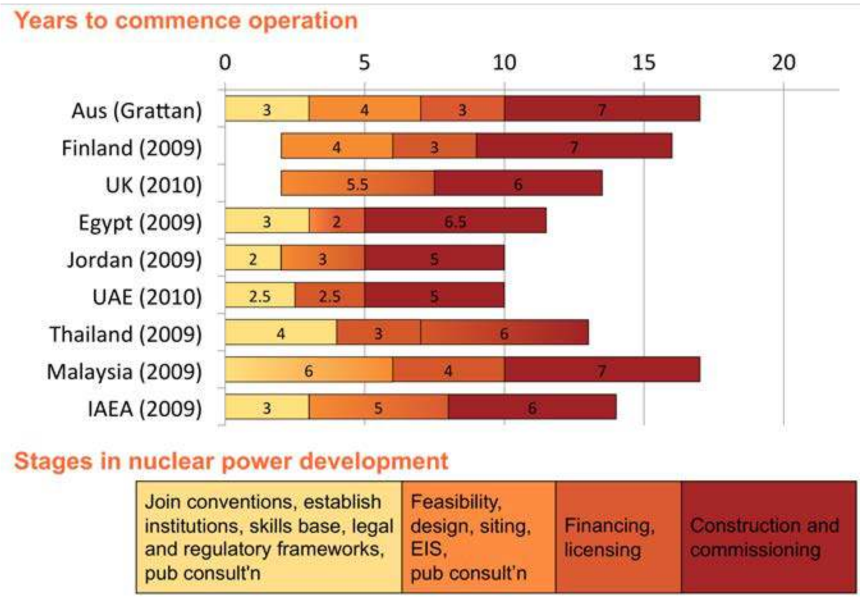
[61] World Nuclear Association (2011f)
[62] World Nuclear News (2010b)

Estimating nuclear power sector lead time in Australia

Figure 7.8 shows various governments' estimates for the time required to establish a new nuclear plant in their countries.[63] To aid comparison, where possible we fit the countries' programs to four generic development stages - though no two countries' project management are identical.[64] Finland and the UK show no first stage, as both have an established nuclear power sector. To aid comparison, an nominal offset of two years is included for each. Grattan Institute developed the estimate for Australia.

[63] Finland's estimate is informed in part by actual experience at its Olkiluoto-3 project, currently under construction. The first two stages shown reflect completed stages; the last an revised estimate for total construction time.
[64] The timelines shown do not account for any political process to obtain public consent for a nuclear program. They also assume that a long-term high-level waste site would be established prior to operation. Nuclear plants usually store high-level waste on site for long periods, most often until the end of their operational life.

Figure 7.8 Estimates for time to deploy nuclear power



Sources: Araj (2009), Awaise (2009), Chongkum (2009), Emirates Nuclear Energy Corporation (2010), IAEA (2007), Koskinen (2010), Muslim (2010), Mazour and Molloy (2009), UK DECC (2010),

Our central estimate for time to deploy the first plant in Australia is 17 years. But given all the factors at play, this number sits in the middle of a wide range. At the low end, lead-time could conceivably be reduced to about 12 years, assuming that all stages are compressed and to some extent run in parallel. At the high end, if there were major political and legal delays, lead time could blow out to around 25 years.

We arrived at the estimate by factoring in differences between Australia and the other countries shown. For instance, while Australia might well achieve Stage 1 as quickly as the middle eastern nations, it seems likely that Australian community expectations would lead to appreciably longer periods for Stage 2, which comprises several decision-making processes, such as siting and environmental impact assessment. These are all quite uncertain, particularly for a first plant.

Construction time, Stage 4, is also subject to uncertainty. On one hand, nuclear industry vendors suggest that nuclear island construction time will be as short as three to four years, based on improved construction techniques and standardised reactor design. On the other, construction time, like cost, has a history of going up. For example, Figure 7.9 shows that French plant construction time has consistently grown with time. The Flamanville-3 project is not shown as it is under construction, but it is expected to take about seven years, about four years behind the original schedule.

It seems plausible that construction in Australia might take longer than in the UK, where there is considerably more nuclear sector experience. Given this we estimated seven years for construction of the first plant in Australia.

It is tempting to argue that development timelines can be compressed if needs be. No doubt more rapid nuclear deployment is possible. However, experience shows that rushing large projects can easily result in mistakes, delays and higher costs, as the projects at Flamanville and Olkiluoto have illustrated. Given the complexity and sensitivity of nuclear power deployment, this should be approached with care.

Figure 7.9 France average nuclear plant construction time

Source: adapted from Grubler (2010)

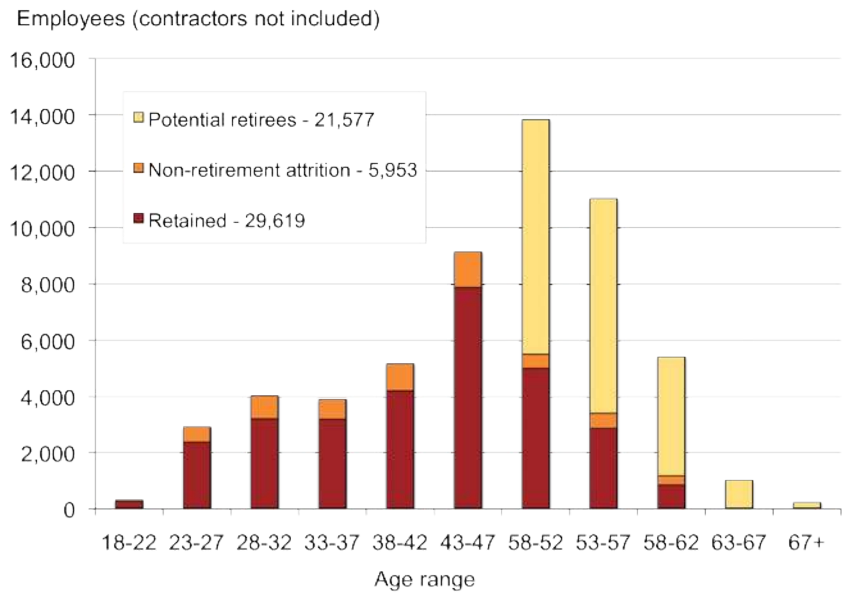
A global nuclear skills shortage could increase lead time

A nuclear power industry requires a substantial workforce with specialised skills and knowledge, in areas ranging from supply chain and construction to regulation to operation of power plants. The UK has 11,500 megawatts of installed nuclear capacity and an estimated nuclear sector workforce of about 44,000 employees. Almost 24,000 of these people are directly employed by nuclear operating companies, the remainder being contractors in the supply chain.[65]

Around the world many experienced workers are nearing retirement age, since workforce replacement has been at best slow since the global nuclear slow down of the late 1980s. Retirement of old nuclear plants works to reduce the workforce further and the experience of younger workers is limited to operating existing plants, not new designs. As Figure 7.10 shows, in the US almost half of the generation workforce is considered to be at risk of attrition (including non-retirement losses).

[65] Cogent Sector Skills Council (2008)

Figure 7.10 US nuclear power generation sector age profile (2009)



Source: 2009 NEI Pipeline survey results, in Berrigan (2010)

In other words, there is a growing skills bottleneck. A lack of skilled people could make it harder, longer or more expensive to establish a nuclear power sector in Australia, for the following reasons. Firstly, there are clear advantages in being an 'intelligent customer'. Senior, experienced personnel would be needed to lead an Australian nuclear industry. But there is likely to be tough international competition for these individuals if nuclear power turns out to be inexpensive and worldwide deployment increases rapidly. Poland, which is currently developing a nuclear power sector, has reported skills-shortage problems.[66]

Secondly, the lead time to establish the other elements of a nuclear power sector may not be enough to guarantee a sufficiently large and well-trained workforce. Many roles in a nuclear sector require several years of education and training.[67] But attracting individuals to specialise requires certainty. Given that a single unit gigawatt-scale reactor currently requires an operating workforce of more than 900 people, it is uncertain that enough of them would commit to specialist training without certainty that nuclear plants will actually be built in Australia.[68]

Lastly, in Australia there is no dedicated school of nuclear science or engineering, although some courses deal with aspects of nuclear physics. While some training can be obtained through institutions overseas, there would be a need to establish and develop local training programmes before they can produce high-quality graduates.

[66] Wasilewski (2010)

[67] Overseas experience suggests that specialist engineers and personnel with Master degrees usually require five or six years of training. Doctorate-level training may require up to eight years, although this is not required to operate a nuclear power plant. For technical functions, Radiation Protection has the shortest lead time of about three years, and clerical and administration roles may still require several months' training in nuclear safety protocols. Recruitment would also draw on trained engineers and other professionals, who could adapt their skills for work in a nuclear sector. They may require only 1-2 years' of additional training. Guet (2010), Goodnight Consulting (2009)

[68] The US the reactor workforce requirement is estimated at an average 0.94 FTE per megawatt for single unit reactors and 0.58FTE per megawatt for dual units, including contractors. Goodnight Consulting (2009)

Several countries have been acting to address the nuclear sector skills problem.[69] The uncertainties related to skills can be expected to reduce as international experience with new nuclear power deployment and associated training increases.

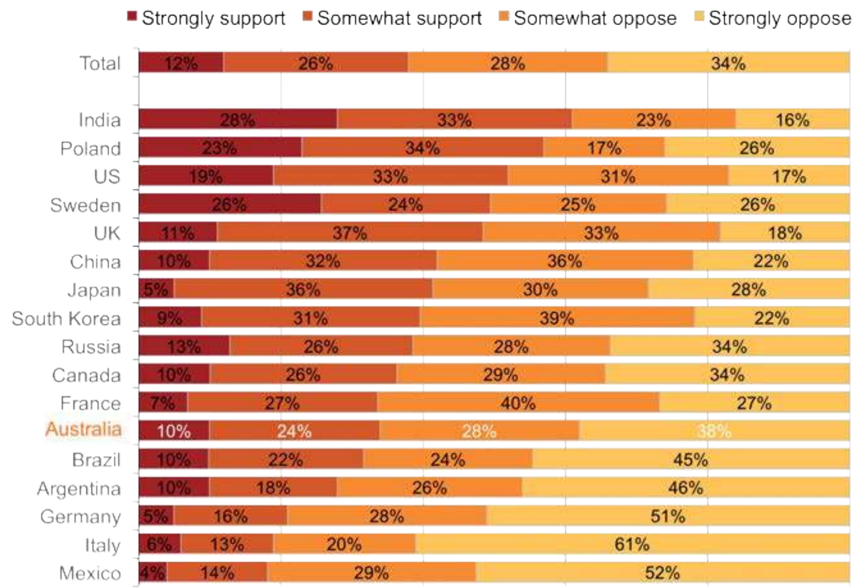
7.6.4 Public opposition is a major barrier for nuclear power

Around the world, public opposition to nuclear technologies has been and continues to be a major factor in the future of the nuclear power sector. For many people, the major accident at Fukushima, Japan in March 2011 underlined the dangers of operating nuclear power plants and the failure of institutions to properly ensure safety. Immediately subsequent to this, the German government has put on hold plans to extend the life of its operating fleet, reportedly for political reasons.[70] In June 2011 an Italian referendum resoundingly rejected a proposition to restart that country's nuclear power program, with 94% of participants voting against the nuclear power question.[71]

In Australia, broad political and public support for nuclear power is essential for the sector to develop. It is very unlikely that large private sector investment would proceed if it were exposed to significant political risk or highly vulnerable to public opposition.

Recent survey evidence suggests that in Australia many people strongly support renewable energy technologies over nuclear power. A 2009 Newspoll (before the Fukushima accident) taken for the Clean Energy Council found that about 49% of respondents approved of federal government support for development of nuclear power, compared with about 93% for renewable energy technologies. When asked to make a choice, only 15% felt that priority should be given to nuclear power.[72] Following the Fukushima accident, a global survey suggested that support for nuclear power in Australia is about 35%, with 65% against. This is comparable to results in several other surveyed countries (Figure 7.11).

Figure 7.11 Global survey on support for nuclear power



Total respondents 18,787, with 1,000 respondents in most countries, minimum of 500 in any country

Source: Ipsos (2011)

69 Commonwealth of Australia (2006)
70 Deutche Welle (2011), The Economist (2011)
71 World Nuclear News (2011a)
72 Newspoll (2009)

7.7 Implications for Australia

Australia should wait and watch the economics of new-build nuclear power in other countries

As outlined above, the most plausible means to gauge the cost of nuclear power in Australia is to look to experience in similar economies, primarily in the UK, Europe and the US. In these countries deployment would involve similar political and regulatory requirements, international vendors, a standard design, reasonably high cost of capital and probably local, high-cost labour with limited prior nuclear construction experience. Deployment under these conditions will almost certainly be more expensive and take longer than projects in Asia or the Middle East.

Uncertainty about the probable cost of nuclear power in Australia will continue until there is a weight of practical experience in deploying current reactor designs in countries with similar economic and regulatory conditions. But unlike the UK, Australia can afford to wait for this to happen, having multiple options to ensure its overall energy security.[73] Given this, Australia should wait to see the economics of new nuclear deployment in other countries before considering any commitment to build nuclear power plants.

In the near future nuclear power is unlikely to be demonstrated in Australia unless government takes on most of the material risks

Yet even if practical experience does bring more certainty to the global nuclear power sector, nuclear plants may not be built unless governments agree to take on a proportion of the project risk, at least for the initial plants. This is the conclusion drawn in investment analysis by Citigroup (2009) and to some extent by Moody’s (2008).

Citigroup’s report on new build nuclear in European markets found that the investment risks are ‘… so large and variable that individually they could each bring even the largest utility company to its knees financially. […] We see little if any prospect that new nuclear stations will be built in the UK by the private sector unless developers can lay off substantial elements of the three major risks. Financing guarantees, minimum power prices, and / or government-backed power off-take agreements may all be needed if stations are to be built.’

Similarly, Moody’s noted that nuclear plants are ‘bet the farm’ projects for most utilities in the US, whose balance sheets are generally smaller those in Europe. As well as being capital intensive, the long duration and fixed design of nuclear projects can expose the plant owner to material changes in the political, regulatory, and commodity price environments.

Given this, nuclear power plants are often operated under highly regulated or monopoly conditions, where there is a low risk on the operator’s rate of return. But Australia has a competitive energy market, in which nuclear projects would be exposed to

[73] UK BERR (2008)

competitive pressure from a range of technologies with quite different risk profiles.

All of the above represent major sources of risk for the nuclear industry. Taken together they look like a formidable challenge to private investment.

To be clear, this is not the only view. It may prove that with good management and some positive experience nuclear power can be deployed by the private sector without government support. Equally, changes in nuclear power technology could make large-scale deployment far easier and lower risk. However, in some quarters the need for public support is unequivocal. For instance, the website of the proposed Bellbend nuclear power plant in the US states that: *'[w]ithout federal loan guarantees or other acceptable financing structures, companies like PPL will not be able to secure financing for advanced-design nuclear power plants to meet future energy needs without adding to carbon dioxide emissions.'*[74]

Lead time can be reduced without committing to build any nuclear power plants

It will fall to governments undertake much of the preparatory work for a nuclear sector. This includes establishing actions, such as developing a regulatory framework and institutions, feasibility and siting studies and the critical processes for public engagement. However, none of these actions requires a commitment to build nuclear power plants.

[74] PPL Corporation (2008)

Lead time is a major source of risk and uncertainty for the nuclear sector. Undertaking this work ahead of a final decision could reduce lead time by around five years. Exactly which tasks this includes and how much time might be saved depends on how Australia would structure any nuclear programme.

As noted above, arguably Australia can afford to wait and see the results of new nuclear deployment in Europe and North America. However, Australia also needs to meet its carbon emissions reduction targets by 2050. If nuclear power turns out to be the best choice overall, but preparatory work is not done in advance, Australia may not have a realistic nuclear power option by around 2030 or 2040, when it would be needed. If this were the case, Australia could be forced into making other, less attractive energy technology choices.

Developing regulatory and training institutions to support a future nuclear power sector in Australia is likely to create an advocacy base for nuclear power. Accepting this likelihood is part of the trade-off in reducing the barriers to nuclear power development and increasing Australia's overall flexibility in energy policy.

Sustained public engagement is essential for developing a nuclear power option

Early, genuine and sustained public engagement would be essential before any commitment to nuclear power plants is made. Nuclear power raises a broad range of issues and concerns that would need to be worked through.

In 2007 the UK undertook a White Paper process to examine options and engage British communities on new-build nuclear power. This experience may be a useful reference point for thinking about how Australia could hold a conversation about nuclear power. Inevitably, this would add to the lead time for a nuclear power sector.

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8 Bioenergy

8.1 Synopsis

- The available energy from biomass globally and within Australia is large and the technology to exploit it for electricity is available and well understood. Bioenergy is similar to fossil fuels in that the energy supply and output can be readily controlled with less susceptibility to diurnal weather variation (although seasonal variation can be a potential issue).

- For biomass to represent a significant source of electricity supply (10% or greater) will require usage of agricultural residues and dedicated Bioenergy crops (that do not substantially compete with food and fibre production) for which there is little experience in Australia. These sources could enable Bioenergy to provide more than 10%, but probably less than 20%, of Australia's electricity supply.

- To achieve this scale-up at a competitive cost would require major improvements in two areas: management of the biomass resource supply chain to reduce costs and improve reliability of supply; and/or fuel conversion and power generation technology that would enable the use of small power-plants of 5 megawatts or lower without an increase in capital cost.

- In addition to R&D, these improvements are likely to require more than a decade of field experience. Both are needed to get costs and reliability to levels where large-scale roll-out would become feasible. In relation to development of biomass fuel supply chains, this will involve a large local component that cannot be resolved through importing overseas expertise and equipment. Improvements in fuel conversion and power generation technology are likely overseas, although innovation is also taking place within Australia. In addition there is a degree of customisation required to cater for the different characteristics of feedstock between Australia and other countries

- A second-order barrier is the difficulty of the grid connection process. Current network connection practices and expertise are not conducive to a scenario of connecting a large number of relatively small power stations to the grid in regional areas. This barrier is shared with several of the other low-emission technologies assessed in this report.

8.2 What is Bioenergy?

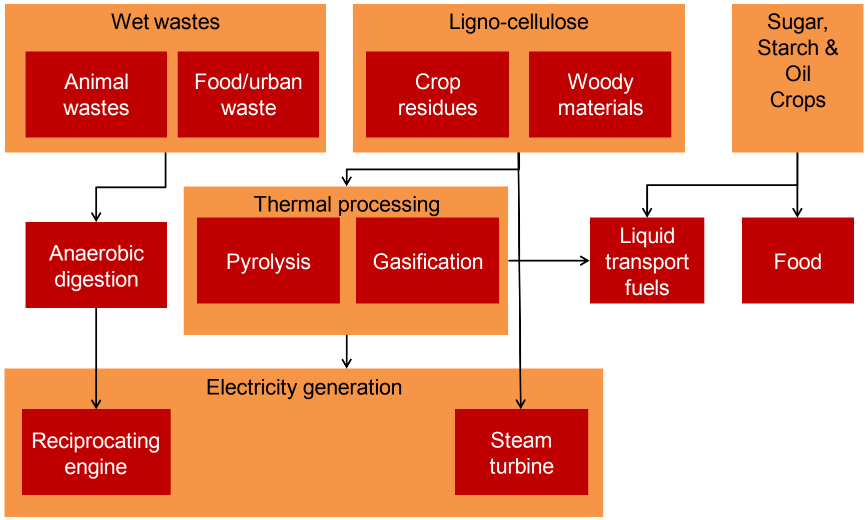
Bioenergy describes the usage of any biological material, "biomass", such as wood, straw, grains, food waste or even sewerage, to produce electricity, heat, gaseous fuels or liquid transport fuels.

There is a very large amount of energy available from biomass, around the world and within Australia. The technology to exploit it is available and well understood.

There are several different streams through which these biological feedstocks are best processed which then determines their potential end energy product. This is illustrated in Figure 8.1. This report only considers their capacity to produce electricity, but there is competition between alternative uses for some biomass fuels that need to be considered when making conclusions about Bioenergy's potential to provide low-carbon electricity.

For a number of the processing routes in Figure 8.1 the technology is quite mature and well understood. Straight combustion through the use of a steam turbine has been employed for many decades and is very similar to a conventional coal-fired power station. This is well suited to semi-dry cellulose materials such as the stems of food crops and wood. Anaerobic digestion, where microbes break biomass down into gaseous methane that can be used in a conventional gas reciprocating engine, is also quite mature. The use of purpose-built[1] anaerobic digestors is not yet widespread, and the technology has potential improve as experience increases. It is well-suited to processing animal and urban wastes with high moisture content.[2]

Figure 8.1 Bioenergy feedstocks and processing streams



Source: Adapted from Stucley et al (2004) and IEA Bioenergy (2009)

Pyrolysis and gasification, however, are only at the demonstration and early commercial stage of development. Both require substantial further improvement before they become attractive commercial options for energy production. With further improvement these technologies have the potential to provide

[1] As opposed to waste landfills which inadvertently create methane

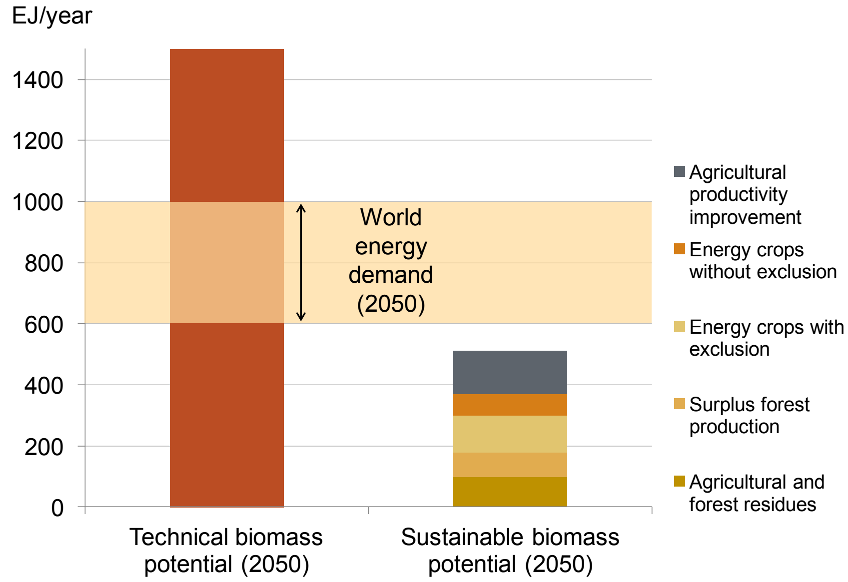
[2] IEA Bioenergy (2009)

greater flexibility in scale, improved fuel efficiency, and valuable by-products in addition to electricity.[3]

8.3 How scalable is Bioenergy in Australia?

Globally, the International Energy Agency believes the potential energy available from biomass is vast and could from a technical basis comprise a sizeable proportion of total expected primary energy demand (including not just electricity but all sources of energy including heat and transport). Figure 8.1 illustrates the IEA's estimate of what is considered the range of the sustainable biomass yield, meaning it would not adversely affect food production or come at the expense of existing forests. This represents between a fifth to a half of total energy demand.

Figure 8.2 Biomass primary energy supply - Technical potential and sustainable yield



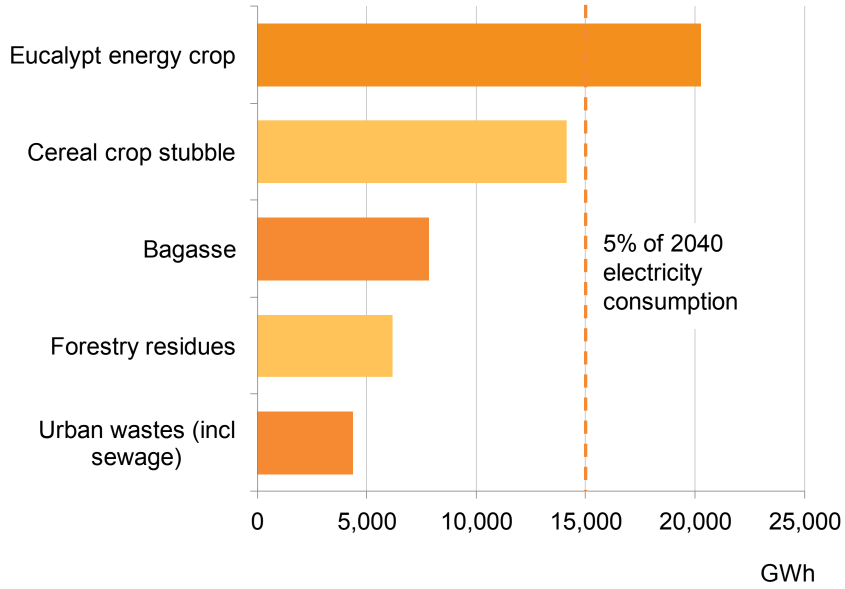
Source: IEA Bioenergy (2009)

Australia's large agricultural sector and amount of land per head gives it plentiful Bioenergy fuel sources.

[3] IEA Bioenergy (2009)

Figure 8.3, based on research by the CSIRO and the Clean Energy Council illustrates that Australia could meet around 15% of its electricity consumption in 2040 from a range of Bioenergy feedstocks considered to be available on a sustainable basis with very low emissions intensity.

Figure 8.3 Potential for bioenergy electricity production in Australia



Note: Excludes the use of pulp logs which were considered to have higher value use than energy.

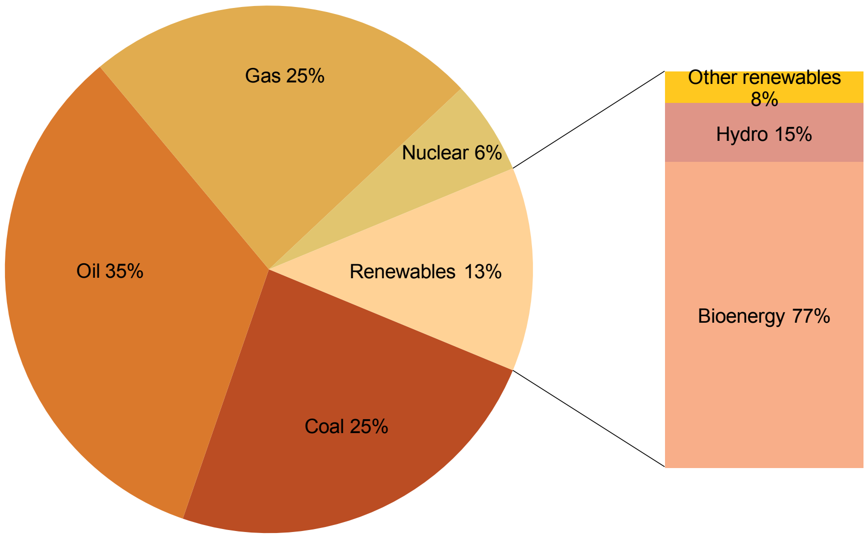
Source: For energy crops, cereal crop residue and forestry residue: Farine et al (2011); For bagasse and urban wastes: Clean Energy Council (2008)

The estimates are reached on the basis that that the production of the fuel did not lead to clearing of native vegetation, and allowed for retention of some agricultural and forestry residues to protect soil fertility. The greenhouse reduction benefit of Bioenergy is contingent on it not reducing overall photosynthetic CO_2 storage out of the atmosphere that would otherwise occur. For example there is little CO_2 benefit from using wood for electricity if it comes from an existing forest that would have otherwise locked up that CO_2 in trees for a long time, even if it avoids release of CO_2 from fossil fuels. Also, use of agricultural residues for energy will only produce a benefit to the extent that those residues would otherwise have decomposed into CO_2 and methane and not been retained within the soil as solid carbon.[4]

8.3.1 Current generating capacity

Globally, Bioenergy represents a very large source of primary energy but much of it is used in an inefficient and unsustainable manner to provide heat rather than electricity in developing nations (Figure 8.4).[5]

Figure 8.4 Bioenergy share of global primary energy use



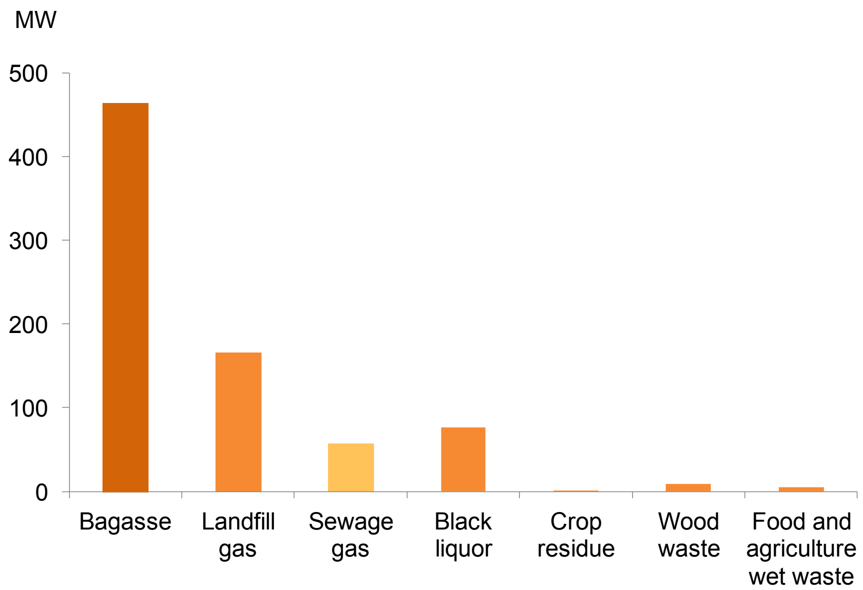
Source: IEA Bioenergy (2009)

In terms of electricity, Bioenergy is much smaller. Global installed capacity is close to 50 gigawatts and in 2008 generated over 250,000 gigawatt-hours, representing 1.3% of global power production. This compares reasonably well with wind and solar but Bioenergy does not have the rapid growth rates of these newer technologies.[6]

[4] European Environment Agency Scientific Committee (2011)
[5] IEA Bioenergy (2009)
[6] IEA (2011)

In Australia Bioenergy generated over 2000 gigawatt hours of electricity, or nearly 1% of total Australian consumption, in 2009-10.[7] The total generating capacity is 867 megawatts, of which the vast proportion is concentrated in use of sugar cane residues (Bagasse) and urban landfill and sewage waste. There is very little capacity tapping the far larger potential resources of non-sugar cane crop residues and dedicated forestry energy crops (Figure 8.5).

Figure 8.5 Current bioenergy electricity generation capacity in Australia



Source: Grattan Institute (2011a)

Additions of new capacity over the past decade have been infrequent and average annual growth has been slow. The significant project development in landfill and sewage gas in the 1980's and 90's has largely stalled as the best resources have been captured. Also, many of the sugar cane bagasse plants were installed several decades ago and the industry has focussed on making more efficient use of the existing bagasse resource through more modern and energy-efficient boilers and turbines rather than large-scale expansion.[8]

The project development pipeline is also relatively thin: just 420 megawatts of projects are in construction or development, according to the Australian Electricity Market Operator and the WA Office of Energy.[9]

8.3.2 Costs

Costs for Bioenergy power projects vary widely depending on the kind of Bioenergy feedstock (e.g. woodchips, straw, urban waste), the size of power plant employed and the type of power conversion technology used. Some feedstocks available in Australia can support generation costs within the range of \$100 to \$150 per megawatt-hour. But to generate 10% or more of total power would require use of more costly feedstocks.

[7] Schultz and Petchey (2011)

[8] Edis (2011)

[9] AEMO (2011); Office of Energy (2010)

Capital costs for Bioenergy projects are around $3 to $6 million per megawatt[10]. Capital costs per megawatt are lower when larger steam turbine plants -- above 20 megawatts -- are used[11] or when the feedstock has already been broken down into methane (such as in landfills and sewage treatment plants) and small reciprocating engines (just like a motor car engine) can be employed.[12] Capital costs are usually higher at smaller scale plants or when additional fuel treatment equipment, such as gasifiers or anaerobic digestors needs to be used. Although Bioenergy plants tend to have higher capital costs than wind farms, higher capacity factors are possible. Bioenergy plants are technically capable of achieving capacity factors similar to those of coal plants of 90%[13], and some Australian projects with access to year-round fuel achieve capacity factors at this level[14]. However most existing plants' capacity factors are lower,[15] due to seasonal fuel supply, and feedstock storage constraints.[16]

Where Bioenergy feedstocks are delivered to a centralised location as a byproduct of another process such as food production or waste disposal, Bioenergy power projects can already achieve costs competitive with wind and nuclear power in the realm of $100-$150MWh.[17] Sugar cane bagasse and urban waste disposal are the two low hanging fruit in this regard which are not surprisingly also the feedstocks which have the highest installed generating capacity in Australia.

Yet these opportunities are relatively limited. For Bioenergy to represent a material (greater than 10%) source of Australia's electricity supply it needs to make greater use of forestry and cereal crop residues as well as dedicated energy crops, that do not substantively compete with food and fibre production (Because food and fibre are high value products, energy crops utilising the same resources would involve a prohibitive cost).[18] The precise costs for such projects are not well understood due to limited project development in Australia, but they would have difficulty achieving costs below $150 per megawatt-hour unless they can establish a stable and efficient supply of feedstock that could support capacity factors of at least 70%, as well as effective net delivered fuel costs around $5 per gigajoule.[19] Such high capacity factors are essential because these projects are unlikely to achieve capital costs lower than projects that use bagasse[20],yet have a more complex and costly fuel supply.

[10] US EIA (2010) IEA Bioenergy (2009); Simhauser (2010); Sucrogen (2010)
[11] Pers Comm Stucley (2011)
[12] Pers Comm Helps (2011)
[13] Pers Comm Stucley (2011)
[14] Based on data from www.rec-registry.gov.au
[15] Based on data from www.rec-registry.gov.au
[16] Edis (2011)
[17] Simhauser (2010), Sucrogen (2010)

[18] Oil mallee's are grown at large scale in belts with wheat production and while they might compete with wheat production in the short-run, their effect in lowering the water table and reducing agricultural yield losses from salinity means that they probably don't compete with wheat production over the long-run
[19] Grattan Institute (2011b)
[20] The capital cost for such feedstocks could be substantially reduced by co-firing them in existing coal-fired power stations, however this will not deliver desired emissions intensity levels of below 0.3tCO_2 unless CCS has also been fitted to the power station, as increasing the ratio of biomass to coal above 60% would require very major plant modifications involving substantial capital expenditure.

8.4 What are the barriers to Bioenergy's development?

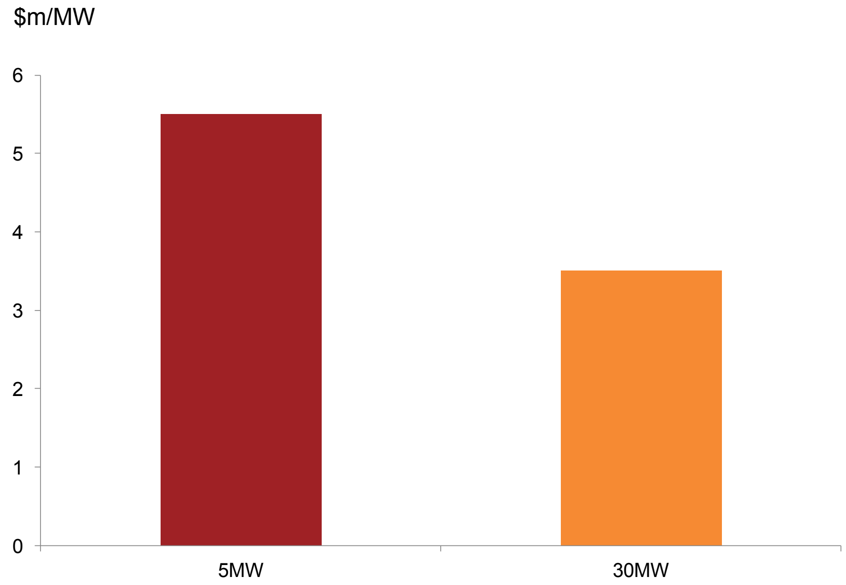
For Bioenergy to provide 10% or more of Australia's electricity needs it will have to use the large amounts of energy embodied within cereal crop residues and the potential energy from crops that can be grown in areas unsuitable for conventional food crops or that mitigate salinity in agricultural areas.

At present there is little experience within Australia of generating electricity from these feedstocks. Substantial innovation and learning is required for this to be possible at large scale at a cost below $150 per megawatt-hour.

The main problem with these fuel types is that they have relatively low energy density relative to conventional fossil fuels, leading to higher delivered cost per unit of energy when fed into a power plant.

Conventional combustion steam turbine power plants currently represent the most technologically mature, low cost option for generating electricity from biomass feedstocks like crop stubble and prospective energy crops such as mallee eucalypts. However, steam turbine power plants are characterised by economies of scale as shown in Figure 8.6, and ideally need to be a minimum of 20 to 30 megawatts in size, to keep capital costs to reasonable levels (between $3.5 to $4million per megawatt).

Figure 8.6 Difference in capital cost due to plant scale

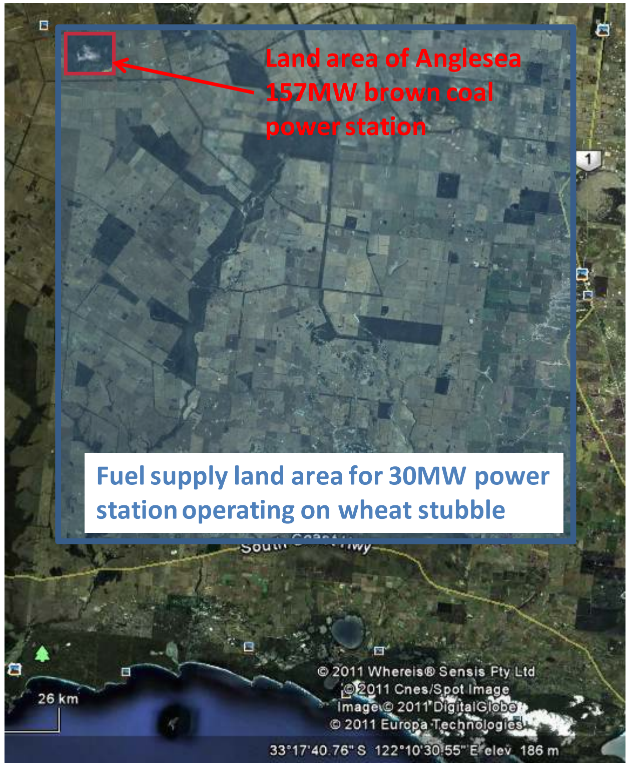


Source: derived from a combination of International Energy Agency Bioenergy (2009) and Stucley (2010) and Stucley et al. (2004) adjusted for latest capital cost data.

Even at 20 to 30 megawatts such plants require large amounts of biomass fuel to realise good capacity factors that are essential to offsetting the high upfront capital costs. While such volumes of feedstock are available, Figure 8.7 shows that that this requires the establishment of a fuel supply collection and delivery system over a large land area, much larger than what is typical for conventional fossil-fuel power stations (157 megawatt brown coal power station in Anglesea, Victoria used to illustrate comparison).

For a 30 megawatt power plant at a 70% capacity factor the land area would be around 240,000 hectares and involve nearly 500 average sized wheat farms.

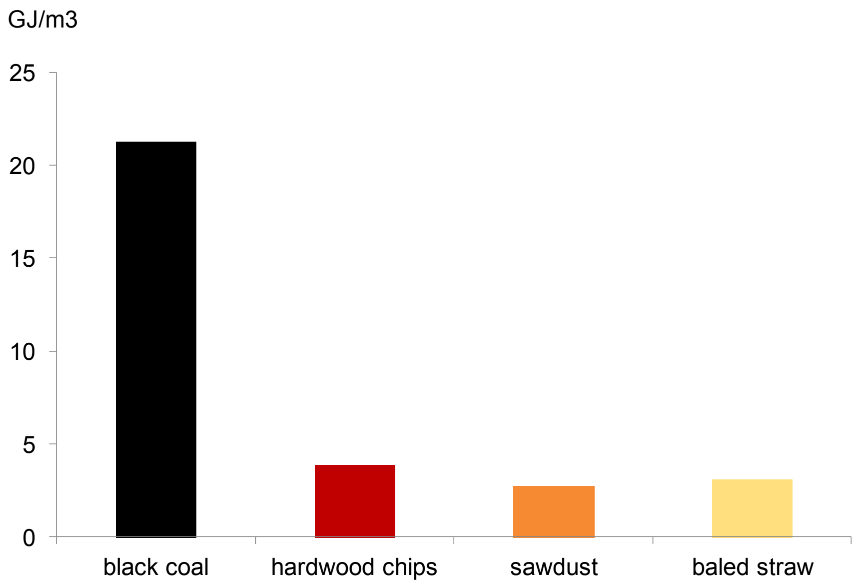
Figure 8.7 Land area required to fuel a 30 megawatt biomass power plant



Source: Farine et al (2010)

The dispersed nature of the energy available from biomass and the economies of scale involved in steam turbine power plants means that collection and transport is the primary challenge for this electricity source. Figure 8.8 illustrates how even once collected at a farm, the energy per unit of volume of various sources of biomass are substantially less than coal.

Figure 8.8 Energy density of biomass sources relative to coal

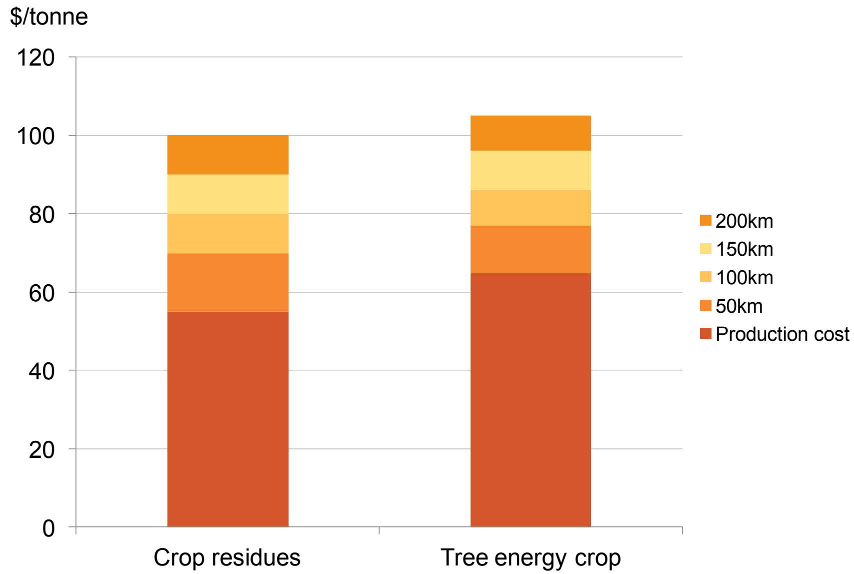


Source: Stucley et al. (2004), Cuevas-Cubria, Schultz, Petchey,Beaini and New (2011) Scurlock, J., Wright, L. (2008)

Consequently collection and transport costs figure prominently in the economics of Bioenergy. Figure 8.9, prepared for an

Australian Government biorefinery study, illustrates that if a power station were to draw upon fuel from 200km away rather than 50km, it would pay 35% more. While some Bioenergy experts believe long transportation distances are not as costly as suggested by this study, there is a general agreement that low energy density makes collection and transportation problematic relative to fossil fuels.[21]

Figure 8.9 Effect of transport distance on bioenergy fuel cost



Source: Parratt & Associates (2011)

[21] Pers Comm Stucley (2011)

In light of this challenge, there are two areas of capability where improvements are necessary in order to realise competitive costs:

1. Management of the biomass resource supply chain from production to transport and storage to reduce costs and improve reliability of supply; and/or

2. Development of fuel conversion and power generation technology that would enable scale-down of plants to modules of 5 megawatts or lower without increase in capital cost. This would reduce the difficulty and cost involved in managing fuel supply chains.

Both of these improvement pathways are likely to require more than a decade of further research and field experience to build up the capability required to achieve levels of cost and reliability that would make large-scale roll-out commercially feasible. Better management of the resource supply chain requires a large local component: the problem cannot be solved simply by importing overseas expertise and equipment. Global innovation in fuel conversion and power generation technology can be utilised in Australia, but some expertise and innovation is already taking place here. In addition there is a degree of customisation required to cater to the characteristics of the feedstock being employed which may vary between Australia and other countries.

A second-order barier is the difficulty of the grid connection process. Current network connection practices and expertise are not well prepared for a scenario of connecting a large number of relatively small power stations to the grid in regional areas.

8.4.1 Fuel supply resource

Conventional steam turbine combustion power plants can be used to generate power from cereal crop residues and from crops grown on marginal land or for salinity mitigation such as eucalypts. Analysis suggests that such plants could generate power at less than $150 per megawatt-hour, with a capacity factor higher than 70% and fuel delivered on a secure and reliable basis for around $5 per gigajoule). A review of a range of studies and discussions with Bioenergy experts suggests that there is potential to realise large quantities of cereal crop residues and energy crops at this cost,[22] but vastly improved supply chain capabilities will be required.

Providing large quantities of cereal crop stubble or energy crops to a series of power stations of at least 20 to 30 megawatts in size is a major logistical and commercial challenge for which Australia has little experience. No power projects operating in Australia use cereal crop residues for power generation, and only two have used energy crops. Both were small-scale pilots (Verve Energy's Narrogin plant; and Delta's Co-firing trial). At present the market and fuel supply chain for cereal crop residues is small, fragmented, and not of the scale and reliability required for multiple roll-out of 20 to 30 megawatt biomass power stations.[23]

A 2011 study examining the potential for co-firing of biomass within Queensland coal fired power stations explains how the logistics challenge for biomass was one that was significantly more complex than what coal-fired power station operators were familiar with:

"The quantity of biomass required is significant, even for low levels of co-firing. For example, co-firing 3 per cent of biomass (by energy content) in a 1000 MW coal-fired power station would require around 192 000 t of biomass annually. This poses significant issues both from a supply and a transport perspective. Coal-fired power stations can typically contract with one or two suppliers to meet all of their fuel requirements (millions of tonnes of coal). There is no single source of biomass that could deliver a generator's entire requirement at a price that is economically viable for sustained periods.

Biomass sources are dispersed and supply is variable in relation to quantity and timing. Coal-fired power stations are typically located directly next to the mine or supplies are delivered via rail. Economically moving close to 200,000 tonnes of biomass from disparate sources requires logistics solutions that are not standard practice for coal-fired power stations. There are also no commercially implemented aggregation and transport models to deliver the quantities required at an acceptable price ... Without such a model, generators will need to be actively involved in aggregating the required quantities of biomass. They are unwilling to assume this role.

Coal-fired power stations are experienced at dealing with large quantities of relatively homogenous coal types. Due to the quantity of biomass required, power stations would need to use a

[22] Schuck (2010); Pers Comm Stucley (2011); Pers Comm Grant (2011); Future Farm Industries CRC (2010); Bartle, J. and Abadi, A. (2010)
[23] McEvilly, Abeysuriya, Dix (2011); Merson. Ampt, Rammelt, & Baumber (2011)

range of biomass sources, which presents additional logistical challenges to power station operators".[24]

Such a complex optimisation process involving the establishment of new markets and transport systems is likely to require at least a decade of experience before both agricultural producers and power project developers become moderately adept. Until these capabilities are in place it seems a large scale roll-out of steam-turbine Bioenergy power projects would be prone to high financing costs and errors in project structuring and logistics.

The precise challenges involved that require time to be developed are spelt out below.

Contracting for secure, long-term fuel supply

Because of the high costs involved in transporting biomass long distances, biomass power plant developers are heavily dependent on the surrounding farms' for their fuel supply. In many respects Bioenergy power plants are not unlike mine-mouth, coal-fired power stations where vertical integration or long-term supply contracts are common. But instead of dealing with one supplier, biomass power project developers must deal with hundreds. This has not been a problem for sugar cane bagasse because farmers are typically tied to a single mill via existing train infrastructure and a legacy of farming co-operative ownership structures. But developers interested in feedstocks that are not transported to a central location as a by-product of food production have tended to struggle to tie up enough farmers to support a 20 to 30 megawatt power station. Without a contracted, secure supply of fuel developers have been unable to obtain lower-cost debt finance because of concerns that these fuel sources might be diverted to other buyers.[25]

Farm production and harvesting

Farmers seeking to sell stubble would need to change harvesting practices and invest in additional harvesting equipment to efficiently collect residues. Equipment is available that automates this process and incorporates it within the existing harvesting process as a one-step process (for example the Glenvar system developed in Western Australia) but this is not common in the Australian grain industry.[26] There are also trade-offs between capital and labour in the manner of residue collection. Determining the best approach will require further experience and analysis.[27] Farmers will also need to determine the right trade-offs between revenue from sales of residue and soil nutrient losses that stem from the process. These will differ depending on soil types.[28]

Finally, dedicated energy crops will involve establishment of a new agricultural industry in Australia. Some mallee eucalypts are grown in alleys between fields of wheat in the WA wheat belt for salinity control and as wind breaks, but at present they are not harvested as a crop.[29] Specialised harvesting equipment is still undergoing development for this crop and is only just at the pilot

[24] McEvilly, Abeysuriya, Dix (2011)

[25] Pers Comm Helps (2011); Edis (2011); SKM MMA (2011)
[26] Herr et al (2010)
[27] O'Connell,D. & Haritos, V. (2010); O'Connell et al. (2007)
[28] Herr et al (2010)
[29] Stucley (2010)

stage with further development required to increase harvesting speed.[30]

Agricultural research is also exploring the potential of other crops possibly suited to poor agricultural land but no significant plantings are in place in Australia.[31]

Integrating transport and storage networks with power station development and operation

While the logistics problem is similar to that of grain collection, it involves bulkier materials of lower value and needs to be incorporated within power production. This gives the logistics of Bioenergy fuels different dynamics to those of the grain market. Also, supply chain logistics will be more involved and complicated than those of traditional power projects. They may also involve multiple fuel sources. Developers will need to be able to analyse and trade-off decisions around power plant size, location and design with considerations of fuel type flexibility, costs of transport, and establishment of logistics infrastructure such as storage and intermediate processing plant such as palletisation or torrefaction. There is also a need to consider how to best co-ordinate the needs of power producers with those of farmers who will be more focussed on grain production than on the lower-value supply of energy byproducts.[32]

[30] Goss, K. (2010)
[31] Stucley (2010), Chivers and Henry (2011), Williams and Biswas (2010)
[32] Pers Comm Stucley (2011), O'Connell,D. & Haritos, V. (2010), O'Connell et al. (2007), McEvilly, Abeysuriya, Dix (2011)

Furthermore many of these issues will have distinct regional characteristics further complicating approaches to solving the likely problems that will emerge.[33]

Intermediate processing to improve energy density

Compression and drying of biomass can improve its energy density and lower the cost of its transport. Compression of biomass into small pellets is already common in Europe and North America and a global market exists for wood pellets.[34] In addition it is possible to convert biomass into a charcoal substance which is of high energy density and similar to coal in its characteristics.

Yet both of these options involve additional cost and torrefaction is still at the pilot/demonstration stage.[35] More experience is required to learn whether the costs of this processing are worth the gains in reduced transportation costs and enhanced capacity to employ larger, cheaper power plants or even existing coal-fired power stations.[36]

8.4.2 Fuel conversion technology to reduce minimum economic scale

An alternative to tackling the low-energy density of biomass is to reduce the minimum economic scale of power plants to 10 megawatts or less. With a smaller power plant, the amount of biomass required to attain a high capacity factor is substantially

[33] O'Connell,D. & Haritos, V. (2010)
[34] IEA Bioenergy (2009)
[35] IEA Bioenergy (2009)
[36] O'Connell,D. & Haritos, V. (2010)

reduced, which in turn reduces the logistical and commercial challenges involved in managing fuel supply. The goal is to reduce the capital cost and improve the performance of equipment that can convert the biomass into a gaseous and liquid form. Once transformed it can be used to generate electricity via conventional reciprocating internal combustion engines which are available below five megawatts in size for less than $2 million per megawatt.[37]

The two alternative processes for converting biomass into liquid and gaseous form are pyrolysis and gasification. While these conversion technologies have been used for some time, their use with biomass is still considered immature. In the past these technologies have encountered problems with the gas and liquids produced being unsuitable for use in an engine without further treatment to 'clean' the fuel. This adds significant additional cost. Feedstocks of varying physical and chemical qualities have also led to problems around process control and fouling.[38]

Advances are being made in these areas both overseas and locally. Canadian and Finnish researchers have made a number of advances with the application of fast pyrolysis focussed on production of biofuels for transport.[39] Australian companies are making promising developments in slow pyrolysis, to produce electricity, and biochar[40] as a soil amendment and form of long-term carbon sequestration.[41] Slow pyrolysis and gasification are quite sensitive to the nature of the feedstocks being employed and Australia's most promising Bioenergy feedstocks are somewhat different to those in other countries. In particular, the use of eucalypts as a short rotation coppice energy crop holds greater promise in Australia than in other countries. Also, biochar (the left over material from pyrolysis) is likely to be of greater value in Australia's carbon and nutrient poor soils than in countries in Western Europe and North America.[42] International developments therefore will not have the same priorities as would be in Australia's interests.

It will probably require at least five to ten years of further research and field experience before there is sufficient commercial confidence to support a significant roll-out of these technologies. Field trials are required to prove-up pyrolysis at scale with the various feedstocks available in large volumes in Australia. Further trials are also necessary to confirm the agricultural gains of biochar under varying Australian conditions and sources of biochar.[43] Lastly farmers' willingness to pay for biochar in large volumes is yet to be practically tested. While existing trials and studies have produced some promising results, there is still substantial uncertainty around the viability of this conversion route.

[37] Pers Comm Burgess (2011)
[38] Pers Comm Burgess (2011), Stucley et al (2004)
[39] Pers Comm Stucley (2011)
[40] Biochar is a stable form of charcoal produced from heating natural organic materials (crop and other waste, woodchips, manure) in a high temperature, low oxygen process known as pyrolysis.
[41] Pers Comm Burgess, also see: http://pacificpyrolysis.com/
[42] Sanderman,J. Farquharson, R. and Baldock, J. (2010), Eady, S., Grundy, M., Battaglia, M. and Keating, B. (Eds) (2009)
[43] CSIRO (2011)

8.4.3 Transmission infrastructure and grid connection

Chapter 9 on transmission infrastructure explains that current regulatory rules need to be reformed to ensure timely and efficient resolution of transmission infrastructure requirements which may be important to supporting high levels of Bioenergy within Australian Electricity Markets.

Grid connection has typically been a difficult process for Bioenergy projects due to the following factors:

- They are usually located in areas that network businesses have considered as unlikely to host power generation and therefore have a relatively poor understanding of what is required to accommodate new power plants;
- They are small in size relative to conventional fossil-fuel plants and therefore the fixed costs of negotiating a connection agreement with network businesses can be significant proportion of overall project costs; and
- Australia's network regulatory frameworks are not well designed for providing transparent price signals about the value of using local power generation for meeting growth in energy demand as an alternative to network capacity upgrades.[44] This is of particular relevance to Bioenergy because its controllable fuel supply means it has greater ability than wind or solar PV of providing power capacity during localised peak demand periods.

Interviews with network engineering consultants, university electrical engineering academics, and power project developers suggest that network businesses' current resourcing and knowledge base is largely built around processing a relatively small number of very large power project connection applications in areas close to existing centralised generation hubs.[45] A large scale-up of Bioenergy involves a very different model, involving large numbers of relatively small power projects distributed across a wide geographic area. Each application requires its own lengthy process of individualised evaluation and negotiation where there is considerable asymmetry of information and power, to the disadvantage of Bioenergy project proponents.

The current Australian electricity market regulatory structure lacks clear, transparent price signals around the costs of transporting electricity which generators can readily use to inform where is the most attractive location for new power plants and their appropriate size. This is again left to individualised confidential negotiations with network businesses to determine the basis for and amount of network support fees for which a generator might qualify.[46] This also involves a major asymmetry in negotiating power to the disadvantage of Bioenergy project proponents. This is further examined in Chapter 9.

[44] SKM MMA (2011); Parer, Sims, Breslin, Agostini, D. (2002);

[45] Edis (2011)

[46] SKM MMA (2011), Biggar (2009)

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9 Transmission infrastructure

9.1 Synopsis

Transmission infrastructure is essential to transport electricity from the generator to customers and has a major influence over the economics of generator locations. Because transmission infrastructure involves significant upfront costs, long asset lives and low ongoing usage costs, there are major advantages to locating power plants nearby to existing transmission networks, rather than building new transmission.

The availability of transmission infrastructure does not represent a significant constraint to any of the low carbon technologies within the short term, with options for expansion available using existing infrastructure. However for wind, geothermal, large-scale solar and possibly biomass to provide a very large proportion of electricity supply over the longer term would require substantial new transmission capacity, including greater interconnection capacity between state regions to cater for variability in wind and solar.

While overcoming these transmission constraints is technologically straightforward and the need for major new capacity is not immediate, we can't afford to be complacent. The long-life of transmission infrastructure, its high cost, and long lead times involved in developing new transmission corridors, mean that decisions about its layout in the near term have implications for the relative viability of our technology options decades into the future. The current set of regulatory frameworks for how we manage the development of transmission capacity are not well suited to a situation where there is a wide range of options around generator locations, as is likely if renewable technologies become economically attractive. The characteristics of the current framework detailed below could act to frustrate efforts to decarbonise electricity supply in an efficient and timely manner:

- In practice, evaluations of the need for new transmission investments do not take into account the potential benefits from building-in flexibility to respond to several alternative future developments. They also don't tend not to account for benefits from transmission enabling greater competition between generators.

- Cost recovery for use of the transmission system by generators is biased in favour of fuel sources that can readily connect to the existing network and does not adequately account for co-ordination challenges associated with generator-initiated transmission line upgrades.

- The lack of a truly national approach to developing and paying for transmission networks hinders greater degrees of interconnection between states where they might be cost-effective.

- Planning tools require improvement to better model the need and cost of new transmission capacity under high penetration renewables scenarios where weather variability is important.

9.2 What are transmission networks?

Transmission networks are the large, high-voltage systems that connect electricity generators to cities, towns and other demand centres. Transmission networks are different to distribution networks – these are the lower-voltage systems that deliver electricity locally, to residential and smaller industrial customers.

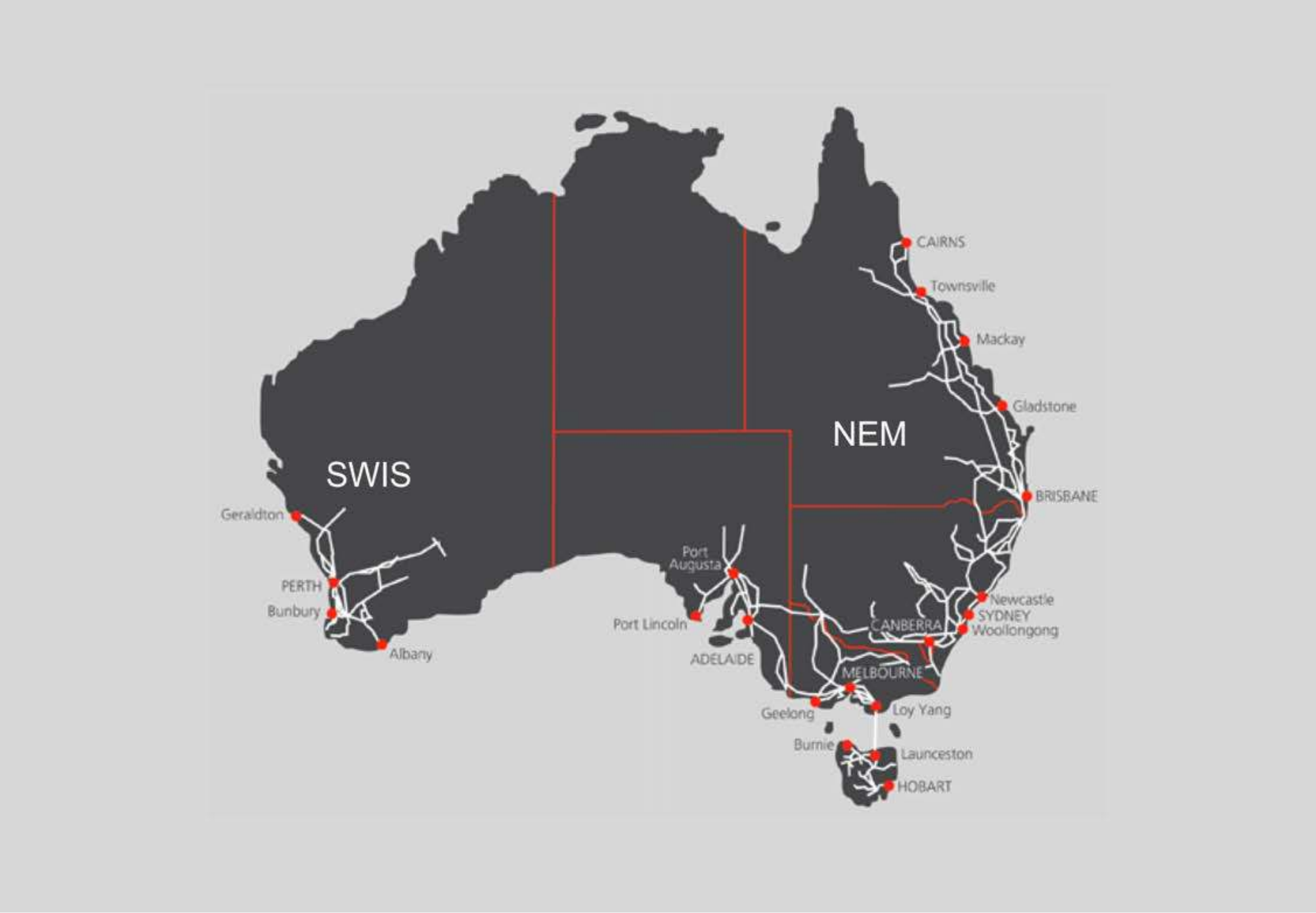
Figure 9.1 shows Australia's two largest transmission networks, the National Electricity Market (NEM) and the South-West Interconnected System (SWIS). The NEM connects the eastern states, the ACT, Tasmania and South Australia. This SWIS covers part of south-west of Western Australia, centred on Perth. After these the largest networks are the North-West Interconnected System (NWIS) and the NKIS, which extends from Darwin. There are also several smaller grids connecting regional communities and remote industrial operations, such as mining.

The present-day SWIS and NEM are best suited to use of coal-fired power and use of existing hydro capacity, and their capacity to trade electricity across state boundaries is constrained. The governing logic has been to use local (fossil-fuel or hydro) resources and to maintain regional self-sufficiency, an objective of State government-owned electricity utilities. This has resulted in a grid characterised by very high capacity central transmission corridors (500kV and 330kV lines), largely between coal deposits and capital cities. While the grid extends across a much larger area, the capacity for these lines outside of the central corridors to connect new generation is constrained. Australia's networks have been largely state-based, with limited (but growing) need for connections between them.

So far this approach has served Australia quite well, permitting efficient use of Australia's cheap and abundant coal resources. It has also accommodated increasing deployment of gas-fired electricity generation, as gas can be inexpensively piped to locations with transmission capacity.

Unlike the generation and retail parts of the electricity sector, transmission networks are natural monopolies, not readily amenable to competition. There is generally one Transmission Network Services Provider per state, several of which are also state-owned. As there is effectively no competition in transmission services, these are regulated by a public entity - in the NEM, this is the Australian Energy Regulator (AER). Market rules and regulations are created by the Australian Energy Market Commission (AEMC).

Figure 9.1 The National Electricity Market and the South-West Interconnected Network



Source:AEMO (2010a; Grid Australia (2011)

9.3 Where we build transmission infrastructure strongly influences our energy generation choices

Transmission lines are to electricity what road or rail infrastructure is to a market for a farmer's produce. For producers, if there is no transport access to a market it really doesn't matter how fertile the land might be. For consumers, more transport access makes for greater competition, greater reliability and lower volatility in prices. The same principles apply to transmission and energy generation, and so the location of transmission networks heavily influences where generators choose to develop their projects.

If transmission infrastructure were easy and inexpensive to build, or needed to be regularly replaced, there would be little need to worry about its role decarbonising Australia's electricity supply. We could quickly adapt our networks according to changing conditions, as new generating technologies emerged.

But the opposite is true. For the reasons set out below, decisions we make in the near-term about where we expand the transmission network will have long-term ramifications for the cost generating electricity in different locations. The lack of clarity and credibility about carbon pricing creates considerable challenges in making such decisions.

The upfront cost for transmission infrastructure is high

Depending on capacity and terrain, the cost of building new lines ranges from about $0.5 - $2.75 million/km.[1] Long lines are often more expensive per unit of distance, because they need to be rated higher in order to manage thermal losses.

Transmission lasts a very long-time

Transmission lines usually have design lives of thirty to fifty years. In Australia transmission lines built in the 1960s and 1970s are still in service today and are expected to continue to provide useful service for some time to come.

Major new transmission capacity takes several years to roll out

Major new transmission infrastructure can involve long lead times of several years, due to significant preparatory work and construction time. Regulation can be an additional brake on transmission deployment. Construction of transmission lines is governed by an approval process that sets out what transmission companies can and cannot build, working in five-year periods. This could produce time lags for both generator and transmission deployment, which in turn would increase uncertainty and could increase overall costs.

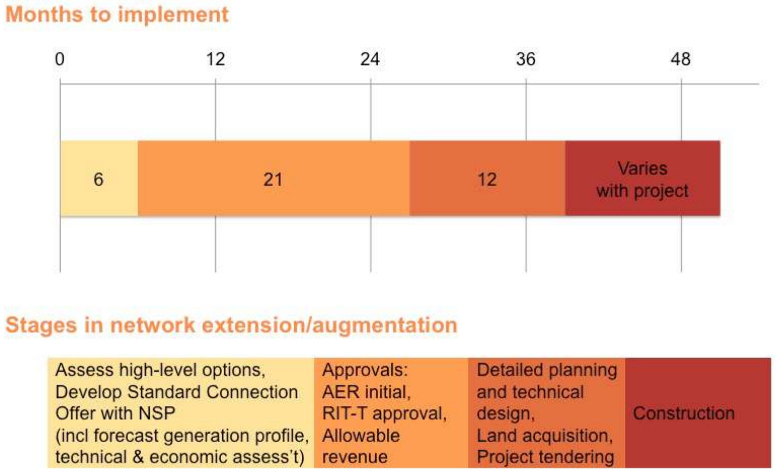
The time needed to build new network capacity depends on the size and complexity of the project. Figure 9.2 sets out a general estimate for this, based on the upgrades proposed by Worley Parsons et al. (2010) to support an additional 2,000 MW of wind deployment in the Eyre Peninsula, South Australia.

[1] ElectraNet and AEMO (2010)

Actual experience with major augmentations suggests the time period can be much longer. For a project of this scale, gaining regulatory approvals constitutes a significant hurdle, and it can take up a large proportion of the overall project timeline. There could also be a lag of several years before the regulator might be willing to consider the proposal, because of the system of five-year periods mentioned above. For any given project, there may also be issues related to gaining easements to the required land, especially if it passes through built-up areas and raises problems for environmental and planning approval. This can be a challenge where upgrades are not planned well in advance and the appropriate land reservations are not obtained.

An example of direct relevance to wind power expansion is the $383m proposal to upgrade the transmission line north of Perth to Geraldton, in Western Australia. Western Power highlighted the potential need for this upgrade in 2006 (expecting completion in 2010) and made a formal proposal for regulator approval to construct the line in early 2007.[2] It took until February 2011 for the regulator to deem that the project was justified, but in November 2011 it made a draft determination that Western Power could not charge the amount of project costs to end consumers that was proposed. So after around five years this project is still yet to pass through the regulatory approvals stage.

Figure 9.2 Estimated time to build a major transmission extension



Source: based on estimates in Worley Parsons et al. (2010)

Pressure to speed up transmission delivery could occur if in the future Australia needed to rapidly decarbonise its electricity sector, and there were a need to build large amounts of new transmission infrastructure very quickly. This could be problematic. Network augmentation projects are generally both large and complex. On short timeframes, the risk of making costly strategic and engineering mistakes is much higher.

[2] Western Power (2007) Notice: Invitation for submissions – Proposed improvements to the Mid West region's transmission network, 22 March 2007, Western Power

9.4 Transmission presents a particular barrier for renewable energy, and a carbon price is unlikely to resolve this

Transmission capacity is essential to renewable energy technologies because their fuel cannot be transported economically. The only viable means to transport their energy is as electricity.

The best quality solar and geothermal resources tend to be located far from significant transmission network capacity. Wind faces less difficulty, but nonetheless there are locations containing rich wind resources where transmission capacity is heavily constrained.[3] Both wind and solar power would benefit from greater interconnection between Australian states, as this would help to mitigate variable output due to weather changes. Biomass is more readily transported, but as outlined in Chapter 8, its low energy-density makes transport significantly more costly than fossil fuels. As such, it is more viable to locate bioenergy power plants close to their fuel source. To date there has been limited analysis of the capacity of Australian networks to connect generation in areas rich in prospective biomass resources. The appendix to this chapter provides a detailed explanation for why there is a need for substantial additional transmission capacity in order for renewables to supply a very large proportion of Australia's electricity needs.

The availability of transmission capacity is not such a problem for gas, coal or nuclear power. For these technologies it is more common to physically transport fuel over long distances, by rail, ship or pipeline. Coal power also benefits from the fact that Australia's electricity network has been built with the intention to connect major coal basins to capital cities.

In the near term there is potential to expand Australia's use of renewable technologies without major transmission augmentation. For example, modelling undertaken by ROAM Consulting suggests that major transmission augmentation is largely unnecessary for wind to reach over 10% of NEM electricity supply.[4] Also there are some locations in Australia with both good quality solar resources and transmission capacity, sufficient to support one of two significant solar power plants. The issue is more about reaching very high penetration of renewable energy, where these technologies each represent significant components of Australia's electricity mix. For each fuel type to reach levels beyond 20% market share, transmission capacity constraints appear likely to inhibit cost-effective exploitation – although detailed modelling is still needed to explore this type of scenario thoroughly.

We don't yet know which low-emissions technologies will be best for Australia. Given that building transmission networks involves significant cost, it would be unwise to commence today building out transmission infrastructure in order to remove possible future constraints to large amounts of renewable energy. Equally, it would also be unwise to do nothing to improve the grid's capacity to exploit these technologies until we are certain about their

[3] eg North of Perth and the Eyre Peninsula of South Australia

[4] ROAM modelled up to 11.5 GW of installed wind power capacity. Assuming an average capacity factor of 32%, this equates to 32 TWh, about 13% of projected total demand. The study found that while it is possible to install this level of capacity without network augmentation, some upgrades might still be justified and could overall reduce costs.

viability. The extent of network expansion required for a very large scale deployment of concentrating solar thermal, wind or geothermal is very large (and may also be significant for bioenergy), and undertaking such an expansion is likely to take a long time. The challenge is to develop planning and regulatory processes that achieve efficient outcomes in the present but also maximise the network's capacity to adapt to the possibilities of the future.

Progress is occurring on this front, with a number of official reviews underway at the time of writing. These notwithstanding, there is significant room for improvement on the points below:

- In practice, evaluations of the need for new transmission investments do not take into account the potential benefits from building-in flexibility to respond to several alternative future developments. They also don't tend to account for benefits from transmission enabling greater competition between generators;
- Cost recovery for use of the transmission system by generators is biased in favour of fuel sources that can readily connect to the existing network and does not adequately account for co-ordination challenges associated with generator-initiated transmission line upgrades;
- The lack of a truly national approach to developing and paying for transmission networks hinders greater interconnection between states where that would be cost-effective; and
- Planning tools require improvement to better model the need and cost of new transmission capacity under high penetration renewables scenarios.

For the most part, addressing these points makes good sense, irrespective of how renewable energy technologies develop over the longer term. For instance, interconnectors between state regions will most likely need to be upgraded over time, whatever the future energy mix is. Power plants employing CCS technologies would have to trade off proximity to CO_2 storage sites against proximity to transmission and coal and gas deposits. And while economically and technically it might make sense for nuclear plants to be located in the same place as existing coal plants, community acceptance problems may mean more remote locations are necessary. Yet the prospect of renewable technologies becoming more important to our supply mix makes addressing these points more pressing, because it will impose greater demand for change in the layout of Australia's transmission infrastructure.

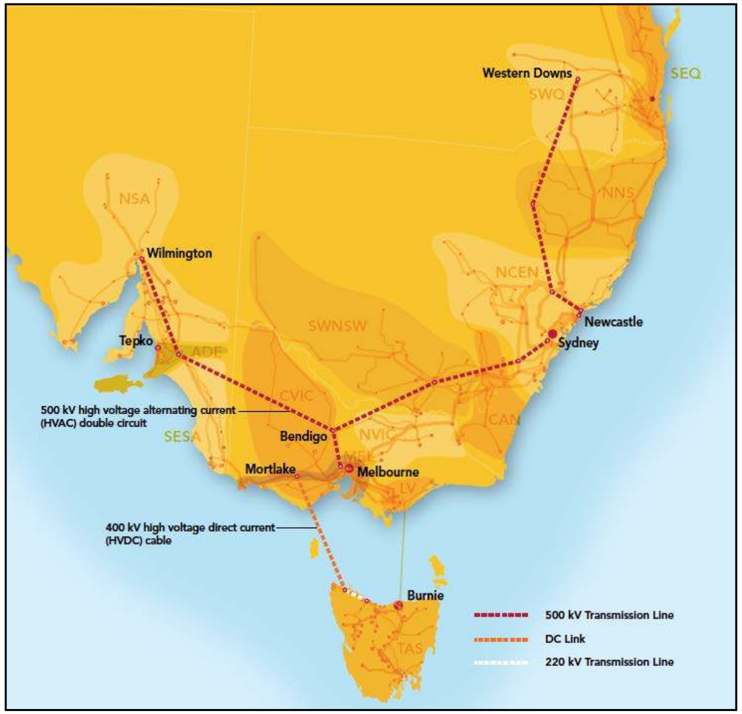
9.4.1 In practice, decisions on transmission development do not account for benefits from future network flexibility and greater competition

As outlined by Garnaut (2011), there can be longer-term economic advantages to building larger transmission capacity than would be immediately justified, or over a different route, because additional generator deployment in the area is likely and additional transmission capacity would be needed.

One example is the NEMLink proposal, a $8.3 billion national-scale transmission project outlined in the AEMO's (2010b)

National Transmission Development Plan which would substantially strengthen interconnection across the states within the NEM. The NEMLink offers the prospect of substantial future benefits, such as capacity to balance variable wind and solar power with hydro power in Tasmania, and greater connection between NEM regions, which would allow sharing of reserve capacity. AEMO's evaluation of NEMLink suggests that it is not viable to build in the short-term. However, a strong carbon price would strengthen its case and further evaluation may be warranted. Other upgrades under consideration (such as a SA-Victoria upgrade) could be designed as parts of NEMLink.

Figure 9.3 The NEMLink concept



Source: AEMO (2010b)

In effect this kind of flexibility can reduce barriers to deployment by capturing economies of scale in transmission construction. This might include measures to reduce the time and costs of expanding transmission capacity at a later date. These could include acquiring easements over land that is (or will be) densely populated, building transmission towers with capability to carry a second line, or building towers high enough to carry 500 kV lines in the future. A practical example of this is in Western NSW, where NSW's largest transmission project made use of infrastructure for which planning began thirty years earlier.[5]

Building in this way can decrease project risk for generators and, potentially, make smaller projects more viable. For some generation projects transmission makes up a significant proportion of overall project cost – most particularly for remote projects such as geothermal power or CSP.[6] There may also be option-value in having transmission capacity in or closer to a region that has prospective resources for a range of generation technologies.

However, designing transmission projects to take advantage of scale economies can be expensive and the burden is borne ultimately by electricity consumers. To justify building additional 'option-value' capacity, the costs have to convincingly stack up against current and possible future benefits. Choosing the 'right-size' for multi-purpose extensions is not easy.

The regulatory instrument for evaluating proposals for transmission investment, the RIT-T (Regulatory Investment Test – Transmission) allows planners to do this kind of analysis. The RIT-T provides scope to use real options analysis as part of the cost-benefit calculation for new transmission infrastructure. However as Garnaut (2011) notes, to date this technique has not been used. A similar situation exists for the competition benefits that new transmission may deliver. Competition can bring tangible benefits, as introducing more generators into the market is likely to increase efficiency and make electricity prices cheaper. But while a framework for valuing these benefits has existed for several years, it has never been applied as part of a successful justification for transmission investment.

The lack of application of and experience with these techniques is itself a barrier. Superficially, addressing this seems quite simple. However, in practice changing behaviour and work practices can require several years to build up staff capability and comfort with what is a more complex approach to network planning and regulation than what has prevailed to date. Furthermore, regulators may focus on benefits that are more easily quantified. It can be difficult to explain to politicians and the community how an options approach can justify large additional costs now, because of what might happen in the future. Changes to the RIT-T may also assist, such as requiring proponents to identify the economic impacts of proposed investments on market participants and customers.[7]

[5] Transgrid (2009)
[6] There are also other barriers to building new network extensions - these are highlighted in later in the section. Transmission costs for remote generation are discussed in the appendix to this chapter.
[7] This proposal is a reform option under consideration in AEMC's Transmission Frameworks Review AEMC (2011a)

9.4.2 The system for cost recovery works against new entrant generation outside of existing major transmission corridors

Incumbent generators do not pay for use of the transmission system, but new entrants will often be required to pay for any new capacity that they require

At present in Australia electricity generators connected to the existing transmission network do not pay any fee for their use of the transmission network, as the costs are charged to consumers. However, those requiring new network capacity must pay the full cost of providing that infrastructure. Even if a new generator has paid for a range of upgrades to existing line, it is still not guaranteed of ongoing access.[8]

Ideally those using existing capacity and those requiring new capacity should both pay a cost-reflective price for using transmission capacity – otherwise the location of investment in generation is likely to be distorted. This was the conclusion of the Parer Review in 2002 and also the AEMC in 2009.[9] Yet this distortion remains in Australia's electricity market and resolving it has proven difficult, as incumbent generators prefer the current arrangement.

[8] The line may become congested if more generators connect or if existing generators increase their output.
[9] Parer (2002), AEMC (2009)

Extending transmission lines to new areas encounters co-ordination difficulties between multiple beneficiaries

There is a significant absolute cost involved in constructing extensions to the transmission network. But this cost can be moderate per megawatt-hour of electricity transported, provided the extension are built to service several hundred or thousand megawatts of generating capacity.

However, coordination difficulties can make commercial construction of extensions challenging. As outlined above, transmission network extensions often have potential to benefit multiple parties, both now and in the future, and major economies of scale are possible. In theory these parties could pool their resources to jointly fund a line that meets all their needs. But in practice getting the timing right can very difficult. Particularly for major electricity generators/consumers that can pay for large transmission upgrades (such as large mining projects), the timing of power requirements may differ by several years.

This difficulty is one reason that transmission network companies are often reluctant to build network extensions sized for the needs of future customers, as well as current customers, when returns are not guaranteed through regulation. Australian transmission companies are structured around delivering highly reliable, low-risk returns to investors based on earning a government-regulated rate of return. Constructing a major new transmission line may represent a significant increase in risk for these firms.[10]

[10] A major new transmission project may involve investment of hundreds of millions of dollars, with returns contingent on future generation projects occuring

This problem has been recognised, for instance by Garnaut (2008) and the AEMC (2009). In fact, the Ministerial Council on Energy requested a rule change in this area, noting that TNSPs *"currently have no commercial incentive to build network connections to an efficient scale in anticipation of future connection."*[11]

To address this, the AEMC proposed *Scale Efficient Network Extensions* (SENEs), a mechanism to build new transmission lines sized to meet the needs of multiple likely power projects, in advance of all of all projects being constructed. Under this proposal, generators connecting to the network would have to pay for the proportion of SENE cost equal the capacity that they use. The cost of the surplus capacity built to meet the needs of future power projects would be recovered through a charge levvied on all electricity consumers, until such time as those power projects were built. Generators subsequently connecting to the line would pay a connection cost, which would be used to refund end-users.[12]

However the AEMC's final determination on the SENE rule, in June 2011, established that energy project developers must fund the cost of network extensions themselves – a significant departure from the original rule proposal.[13] The main argument for this approach is that the benefits of an extension are primarily linked to the profitability of the generation project(s) that it connects. Therefore it is appropriate for the developer to take on the risk of building the required extension. This approach rejects socialising of the transmission cost as is done for other, regulated upgrades, on the basis that network extensions are more speculative and end-users should not carry the higher risk.

There is a range of views about the current SENE rule. One is that the current rule is still new and it is still too early to tell whether or not it is sufficient. Others are strongly for or against it.[14] At the very least, it seems that current arrangements will make development of remote generation more challenging. This could serve to slow down the rate of low-emissions generation deployment.

9.4.3 The lack of a seamless national approach to developing and paying for transmission networks hinders interconnection between states

While the NEM is in name a single market structure, it is comprised of distinct state-based systems which evolved independently with their own regulatory institutions and electricity companies. State-based networks have a degree of interconnection, to trade some electricity, but for the most part states meet their own power needs. Attempts at a creating a uniform market structure and set of institutions only commenced in the 1990s. There are still two major constraints to optimising the system on a national basis rather than state-by-state.

at the right time and place. In some cases, these would also be based on a highly uncertain carbon price.

[11] MCE (2010)

[12] The original proposal was developed in response to a request from the Ministerial Council on Energy. See AEMC (2010) for details.

[13] AEMC (2011b).

[14] eg submissions to the AEMC by Infigen Energy (2011) and AGL (2011)

Firstly, while AEMO lays out a national plan for the transmission system that it considers optimises overall system costs and reliability, state-based transmission companies have no obligation to follow it. In fact, they may have a disincentive to follow the plan if it reduces the amount of new transmission capacity required within their own state, even if it might provide lower costs for the system as a whole. In addition, states can set their own electricity reliability standards – this can serve to complicate national transmission planning. Yet there seems to be little evidence suggesting that loss of supply is more costly in one state than another.

Secondly, at present any transmission upgrades located in a particular state are by default paid for by the consumers within that state. This is the case even where they provide substantial benefits to consumers elsewhere, by enhancing capacity for inter-state trading of electricity. While there is a scope for adjacent regions to negotiate to share the costs of an upgrade, it would be better to have an automatic charging mechanism in place such that transmission companies could toll the adjacent state region for the cost of exporting electricity. A proposal to do this is currently being considered by regulatory authorities, as recommended by the AEMC in its (2009) review.

9.4.4 Transmission planning tools need to better incorporate the possible effects of weather variation and potential requirements of bioenergy projects

It is only recently, with the institution of the 20% Renewable Energy Target, that there has been a pressing need to evaluate how large amounts of renewables might affect Australian electricity systems. Consequently our tools to model the physical and economic effects are still relatively immature and require improvement in order to thoroughly evaluate the implications from greater use of fuel sources subject to short-term weather variation. To date the policy debate on the impact of large amounts of wind and solar power on the electricity system has often been based on speculation or crude generalisation, rather than detailed analysis of actual Australian weather data.

AEMO is responding to this issue by upgrading its tools and techniques used to create the annual National Transmission Network Development Plan and undertaking a range of additional studies to explore particular scenarios of interest. This includes commissioning CSIRO to analyse various scenarios of wind power capacity based on historical wind data at a wide range of geographic sites. The West Australian grid operator, the Independent Market Operator and the AEMC have commissioned similar studies.

These steps represent a large improvement. However such studies could be usefully broadened to include the impact of large amounts of renewable energy generation on new transmission requirements and timing, as well as balancing capacity and costs. This could include:

- examining higher levels of wind penetration well beyond what is currently being implemented;
- detailed weather-based analysis of high penetration of solar thermal and solar photovoltaic technologies;
- The extent to which network capacity in areas rich in bioenergy resources could absorb new power generation;

- the implications of widespread availability of cheap electrical storage (for example through large-scale uptake of electric vehicles) for management of high levels of solar and wind power; and

- Incorporating more detailed and accurate weather data into the models, possibly through additional weather monitoring stations.

The recent commitment by the federal government to have AEMO model the energy market and transmission planning implications of moving towards 100% renewable energy may help address the points above.

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10 Appendix – Possible transmission requirements for large-scale deployment of wind, solar and geothermal power

This appendix uses examples to very roughly sketch out why it is likely that major new network infrastructure would be needed to support large-scale deployment of wind, solar and geothermal power in Australia.It is intended as an indicative analysis, and is not a replacement for the rigorous quantitative modelling which AEMO should undertake in addressing the government's commitment to examine scenarios involving renewable energy making up 100% of electricity supply. This very preliminary analysis suggests that there would be a need for a number of major extensions to the transmission network and substantial strengthening of interconnectors between states within Australia.

The large scale of the change involved and the significant lags that are likely to be involved in rolling out this transmission infrastructure suggests that Australia needs to plan for such changes well in advance. This is not to suggest that renewables are an unviable option. From a technical perspective there would be little difficulty in providing the expansions in transmission capacity our analysis indicates may be necessary. Also the cost of this new infrastructure, while large in absolute terms, can be offset against the delivery of a very large quantity of electricity over many decades. But to execute this change in an efficient and timely manner it is important that in the near-term we address many of the current inadequacies with our current framework for governing the construction and payment for transmission infrastructure.

The primary reason for why transmission would be a genuine issue is the distance of high-quality resources from existing transmission and demand centres.[1] As part of this, wind, solar and geothermal are often in different locations to each other. Also, it can be attractive for renewable generators to be geographically dispersed, in order to smooth out variations in the local wind or solar resource.

Some of the shared network upgrades would equally be needed under other energy generation scenarios. Wind, solar and geothermal power are not the only reasons to build these projects. However, we discuss them here because they would still be need to be built – for one reason or another - in order to deploy wind, solar or geothermal power on a large scale.

[1] This recognises that when making location decisions, generators with fuels that are not easily transported will not necessarily choose the best resource, as this often requires the largest investment in transmission. Instead generators make trade-offs between factors like resource quality, distance to existing transmission, transmission losses and investment in any new transmission capacity. But if penetration of fixed-fuel generators were very high, significant amounts of new transmission capacity would be unavoidable.

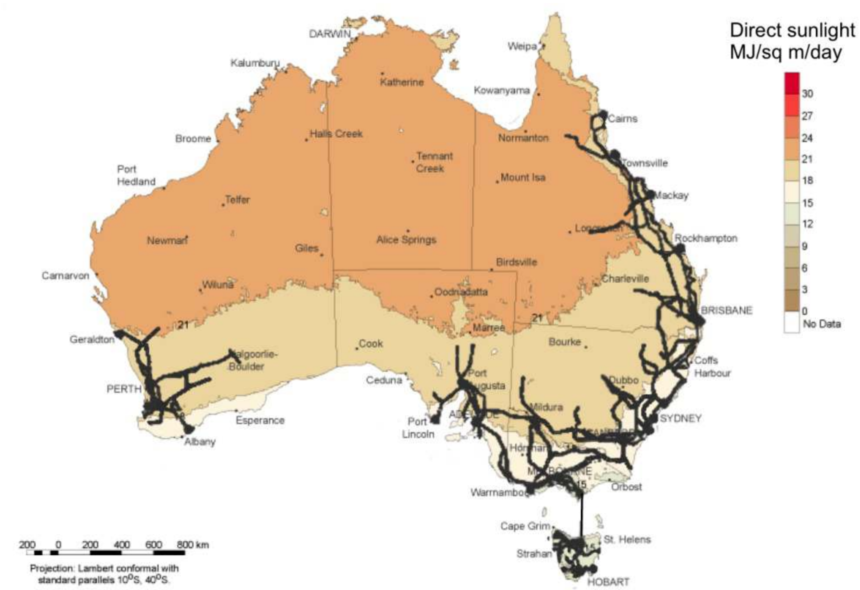
Large-scale solar power

This analysis focuses primarily on the use of solar thermal technology. While solar PV can be deployed in large arrays, it is more likely to be installed at medium or small scale, much closer to demand. Given this, it is not a focus for this discussion.

Figure 10.1 illustrates the distance of high quality solar resources from the NEM and SWIS networks. While the large parts of Australia have good quality solar resources relative to the rest of the world, the best solar locations are generally far inland and/or to the north.

As a result, solar power deployment faces a trade-off between resource quality and the capital cost of establishing a plant: Poorer quality sunlight requires a larger solar array, which is a large part of overall plant cost. However, better quality sunlight usually means higher transmission connection cost. In addition, access to water can also be important for solar thermal generators because wet cooling technology involves lower cost penalties than dry-cooling. This is another dimension to the trade-off that needs to be balanced.

Figure 10.1 Map of Australia's daily solar exposure (yearly average), NEM and SWIS transmission networks



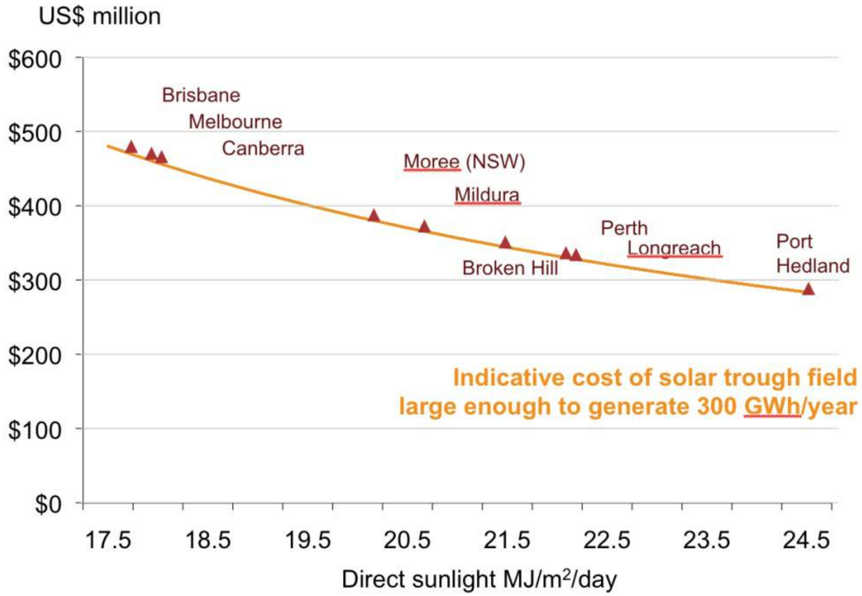
Source: DRET (2010), Grattan Institute

Figure 10.2 shows how – for a fixed level of output - the cost of a solar array would change in different locations across Australia.[2] While places like Longreach, Port Hedland and even Perth require a relatively smaller solar field, cooler and more cloudy population

[2] This figure is intended to be indicative only. It does not necessarily represent current solar field costs in Australia.

centres like Melbourne and Brisbane produce somewhat higher costs.

Figure 10.2 Estimated cost of solar field, varying size to generate the same output in different locations across Australia



Source: IT Power (2011), Bureau of Meterology (2011), Grattan Institute analysis

A recent study of five potential solar generating areas in NSW found that, as for wind power, the costs of transmission connection vary, depending on distance, the size of the generator and existing transmission capacity (Table 10.1).[3] For instance, connection cost for a 250 megawatts plant tends to be lower, but only where it can make use of existing network capacity (eg Darlington, Tamegawattsorth and Broken Hill). At 1,000 megawatts scale transmission costs can increase significantly – particuarly where new transmission capacity is needed over long distances (eg at Broken Hill).

Table 10.1 Transmission connection costs for large-scale solar generation in NSW

Area	Total cost 250 MW	Total cost 1,000 MW	$ per MWh 250 MW	$ per MWh 1,000 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	$13m	$25m	$52,00	$25,000	✔

Source: AECOM (2010)

A study of potential large-scale solar sites in Queensland produced results in the same vein. Depending on the site,

[3] AECOM (2010). As a rule of thumb, a 250 megawatts plant can connect to a 220 kV transmission line. A line of at least 330 kV would be needed for a 1,000 megawatts plant

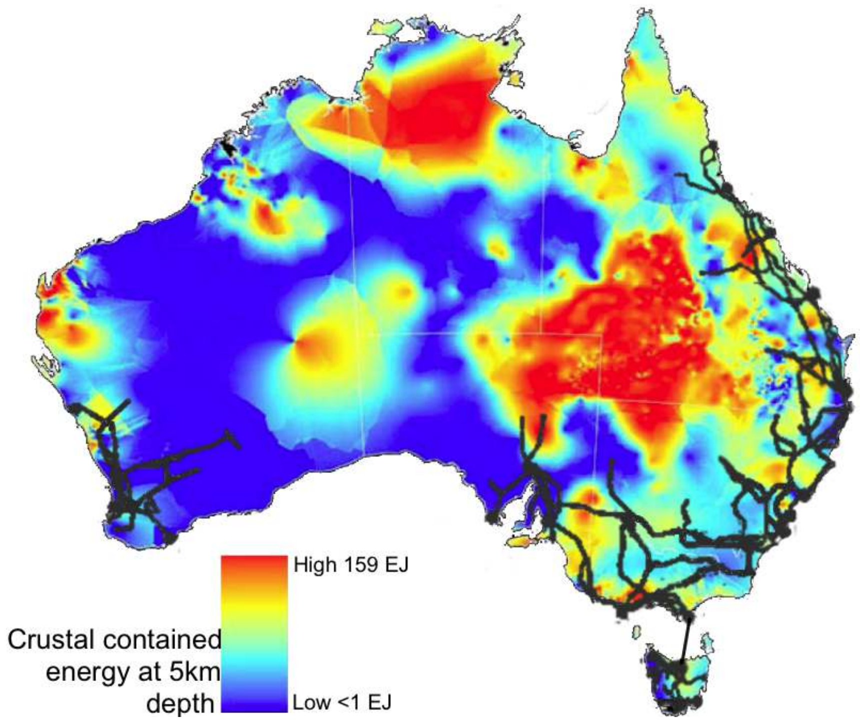
transmission connection costs could range from about $100 million - over $450 million. The study, commissioned by the Queensland government, concluded that the costs of transmission and other infrastructure make the lower quality, less remote sites more attractive overall. If transmission were funded separately, the sites further inland provide significantly better outcomes.[4]

Geothermal power

Development of geothermal power faces similar trade-offs. As Figure 10.3 illustrates, while there are some prospective sites that are near to load, the highest quality resources are generally far from demand centres.

The coastal geothermal resource is still significant. For example, the Otway Basin in Victoria has a significant geothermal resource.[5] As for solar energy generation, using lower-quality resources generally means high up-front capital costs, in the number of geothermal wells that would need to be drilled.

Figure 10.3 Map of Australia's geothermal resource, NEM and SWIS transmission networks



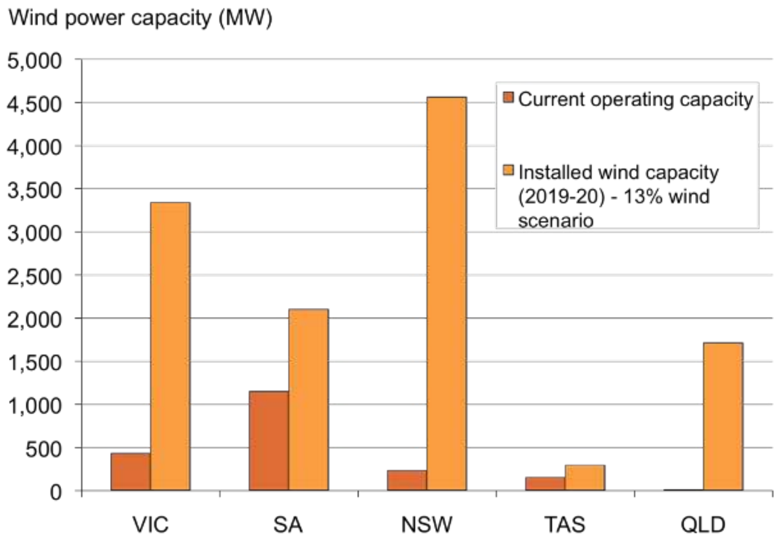
Source: DRET (2010), Grattan Institute

[4] Parsons Brinckerhoff (2010)
[5] SKM-MMA (2010)

Wind power

According to modelling by ROAM Consulting (2010), the NEM might be able to achieve about 13% wind power by 2020 without undertaking major network upgrades.[6] This is illustrated in Figure 10.4.

Figure 10.4 Modelled distribution for wind power sufficient to meet about 13% of NEM demand by 2020



Source: ROAM Consulting (2010)

However, achieving this depends on being able to near-optimally locate wind farms across the NEM. If more concentrated, sub-optimal deployment does occur[7], some transmission upgrades would be justified to reach the same level of wind power penetration. This is because more concentrated development would lead to higher costs, from factors like increased competition during low demand periods, more frequent spilling of output due to transmission constraints, and from using sites with lower quality wind resources.

Looking beyond this, wind power has potential to provide a significant proportion of low carbon emissions electricity in Australia – overseas grid integration studies (profiled in Chapter 2 on wind) suggest 20 to 30% is manageable at moderate additional balancing costs. This would mean a very large increase of wind power deployed in the NEM – from the current level of just over 2,000 megawatts to about 35,000 megawatts.[8]

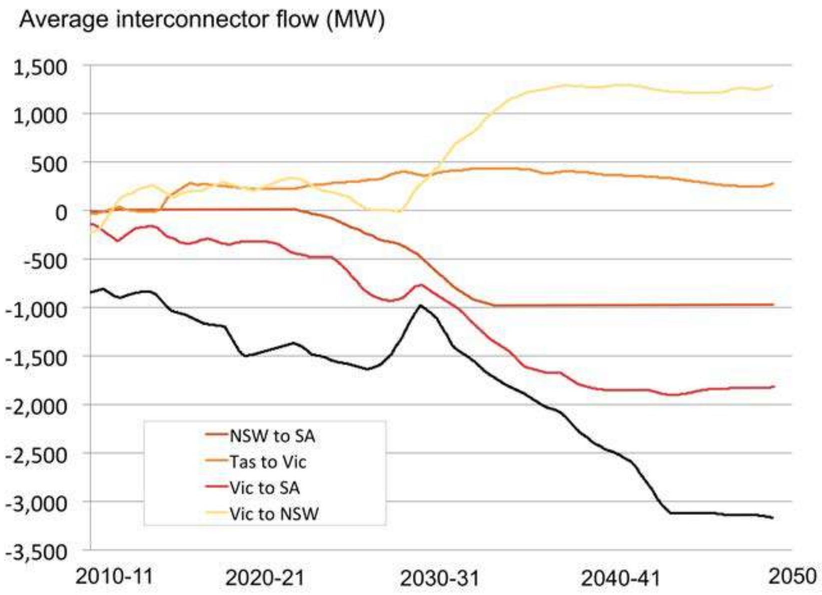
Major transmission investment would be required to support this. This is illustrated by Figure 10.5, which describes a major increase in the amount of power flowing across interconnectors in the NEM over the next 40 years. This scenario, modelled by ROAM for the Commonwealth Treasury, considered about 24,000 megawatts of wind capacity in the NEM by 2050, along with other new generators.

[6] ROAM modelled up to 11.5 GW of installed wind power capacity. Assuming an average capacity factor of 32%, this equates to 32 TWh, about 13% of projected total demand. The study found that while it is possible to install this level of capacity without network augmentation, some upgrades might still be justified and could overall reduce costs.

[7] State-based planning and regulation could lead to some distortions in wind power deployment. One possible example is the recent regulatory changes in Victoria, where a 2km wind power exclusion zone around residential areas has recently been introduced.

[8] This is a rough estimate only. Further details are contained in Appendix A.

Figure 10.5 Interconnector flows under High Price scenario



Source: ROAM Consulting (2011)

In addition to the very large scale of new infrastructure, the timing and sequence of upgrades is also important. At any point in time, evolving transmission constraints and the limits of local demand will act to push wind farm development towards locations that offer the best returns currently and in the foreseeable future. Network constraints can lead to developers selecting sites with less congestion, but also lower wind speeds and higher generation costs. Such constraints are already shifting interest from SA to NSW and could be readily reached in Tasmania, with the addition of one or two large wind farms. Implementing a network upgrade could act to draw development interest back to higher quality wind sites.

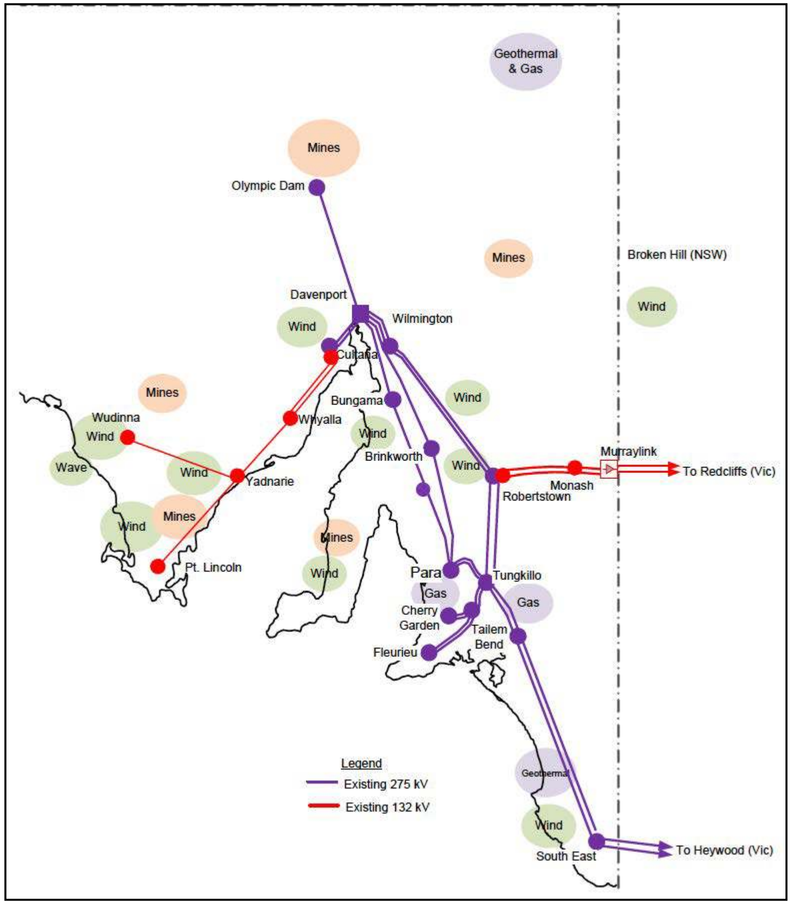
This is no zero-sum game: different sequences of development could produce quite different outcomes for the renewable energy landscape, in terms of location, costs, jobs and future opportunities. The choices to be made about the timing and sequence of network upgrades, while beset by uncertainty, will need both clear foresight and great care.

The following sections provide an indicative evaluation of the potential scale and cost of transmission upgrades in several state-based markets - South Australia, Victoria, Tasmania, New South Wales and Western Australia.

South Australia (SA)

SA already has about 1,100 megawatts of installed wind power, the largest complement in Australia. It also has many high quality wind sites that could be exploited in the future. However, this potential is constrained by limited local demand and limited transmission capacity, either to expand deployment or to export excess wind power into Victoria.

Figure 10.6 The SA transmission network



Source: ElectraNet (2011)

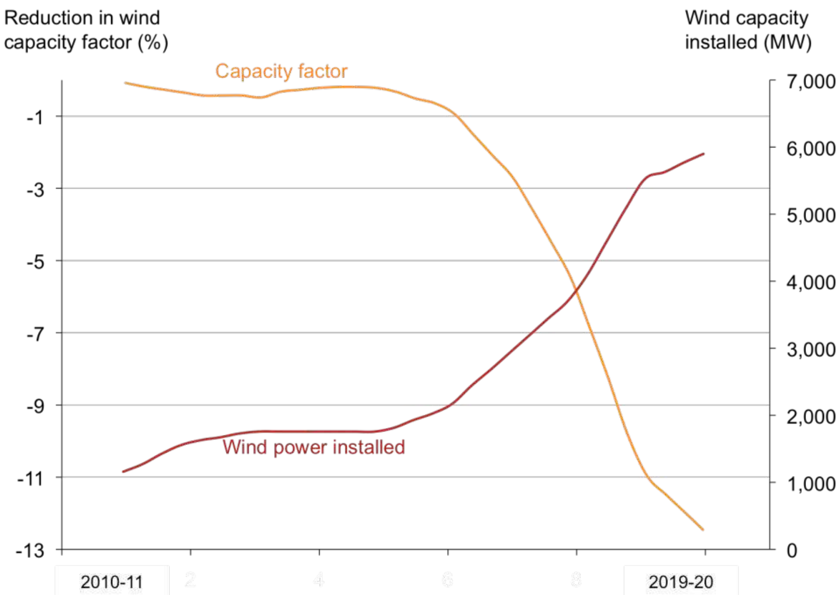
These factors have begun to limit interest in developing wind farms in SA – for instance, in 2008 transmission constraints on the Yorke Peninsula are known to have led to suspending development of the Shea Oak Flat and Wattle Point 2 wind farms.[9] Grattan Institute's interviews with developers indicate that they are increasing their focus on Victoria or NSW, as the probable economic returns in SA are eroding.

According to a consortium study led by Worley Parsons, SA has capacity to absorb about 1,000 megawatts more wind capacity before network constraints begin to curtail wind farms.[10] This is reflected in ROAM findings for SA, which show a dramatic drop-off in capacity factor beyond about 2,000 megawatts (Figure 10.7).

Given that SA has about 50 megawatts of capacity under construction and a further 2000 megawatts in development, this level could be not far off.[11] New transmission infrastructure would be required to reach ~4,000 megawatts of installed capacity in SA. This would include the upgrading interconnection with Victoria, and possibly the backbone line on either side of the border.[12] It could also require upgrading the line on the Eyre Peninsula, which has ample wind resources, as well as strengthening connections to Torrens Island.[13]

[9] ROAM Consulting (2008)
[10] Worley Parsons et al. (2010), ROAM Consulting (2010)
[11] Grattan Institute power plant database
[12] Worley Parsons et al. (2010), ElectraNet and AEMO (2010)
[13] Worley Parsons et al. (2010), AEMO (2010)

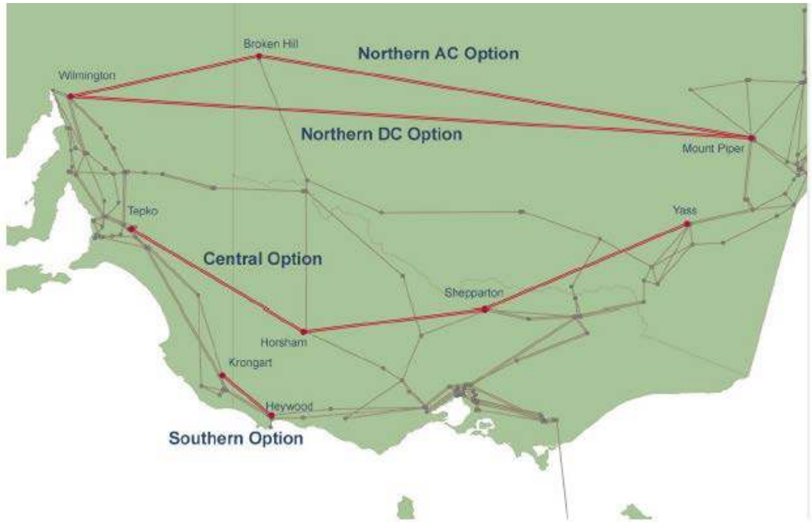
Figure 10.7 South Australia reduction in capacity factor with installed wind capacity (scenario Wind 1 - max capacity factor)



Source: ROAM Consulting (2010)

It is widely thought that an upgrade of the SA-Vic interconnector will be justified in the near to medium term. Augmenting the interconnection could begin with relatively smaller transformer upgrades, which are comparatively low cost, under $100 million. However, to support higher total capacity in SA, of the order of 4,000 megawatts, a larger upgrade option would certainly be needed, such as those illustrated in Figures 10.6 and 10.8.

Figure 10.8 Options for high capacity augmentation SA-Victoria and SA-NSW



Source: ElectraNet and AEMO (2010)

There is a range of options for these upgrades, all of which make trade-offs between cost and capacity, as well as assumptions about future transmission need. Table 10.2 provides some indicative costs, which range from $500 million to as much as $3.5 billion for the largest project, a 500 kV double circuit connection from SA to NSW via central Victoria.

Cost estimates can vary significantly - at a basic level, this is because the underlying assumptions about building transmission are uncertain – such as cost of material or finance. For example, SKM (2010) notes that its estimates are accurate only to ±30%.

To achieve about 30% wind power in 2030-40, between 5,500 and 6,500 megawatts of wind power could be required in SA. Clearly this could require upgrades of at least the scale and cost outlined above.

Table 10.2 Estimated capital costs for SA-Vic interconnector upgrade options

Study	Option	Description	Estimated capital cost
Worley Parsons et al. (2010)	Stage 1	Davenport (near Port Augusta) to Heywood (Victoria) 500 kV	$840 m
	Stage 2	Davenport to Mt Piper (NSW) HVDC	$1,853 m
ElectraNet and AEMO (2010)	Southern Option	Krongart to Heywood 500 kV AC double-circuit	$530 m
	Central Option	Tepko (SA) to Yass (Vic) via Horsham and Shepparton (Vic) 550 kV double circuit	$3,500 m
	Northern DC Option	Wilmington (near Davenport) to Mt Piper HVDC (same as Green Grid Stage 2)	$3,000 m
SKM (2010)	Option 5	Wilmington to Krongart	$2,274 m

Source: Worley Parsons et al. (2010), ElectraNet and AEMO (2010), SKM (2010)

Victoria

Victoria has about 430 megawatts of wind power capacity in operation. This is not a large amount relative to the state's minimum demand of 4,000 megawatts, suggesting that the Victorian network could absorb significantly more wind power in the coming years.[14]

Minimum demand indicates a level where economic integration of wind power could start to be a challenge. To illustrate, high wind power output events coincide with low demand (and no export options), there is a risk that wind farms would need to be curtailed, if they exceed total system demand. Curtailment also happens near to total demand. While at these times wind power is generally cheaper than other generation, some dispatchable, on-demand generation (usually thermal) must be kept online, so as to be able to maintain overall reliability within regulated limits. However, regularly curtailing wind farms undermines their commercial viability - this acts to limit interest in developing new wind power projects.

There is a considerable pipeline of projects in Victoria.[15] In mid 2011 there were about 490 megawatts of projects at or near construction stage and a further 2,140 megawatts that in planning with a project site.[16] AEMO recently projected that about 2,500 megawatts of capacity would be installed by 2020.[17]

[14] AEMO (2011b)
[15] Recent changes to Victorian planning regulations may change the prospects for several of these projects.
[16] AEMO (2011a)
[17] AEMO (2011b)

The current Victorian grid can probably support a total of 3,000 – 4,000 megawatts of wind power. In 2007 Vencorp (now part of AEMO) found that can accommodate about 3,000 megawatts of installed wind power by applying a range of low-cost technical solutions, rather than network augmentations. Vencorp suggested that 4,000 megawatts of capacity might be possible, depending on where projects were located.[18]

Beyond this level, generation in Victoria starts to impact on capacity elsewhere in the NEM. ROAM's report for the Clean Energy Council (2010) suggested that Victoria could reach up to 5,000 megawatts, while maintaining average capacity factor above 32%. However, this scenario (Wind 3) required a trade-off: substantially less deployment in both SA (~2,600 megawatts) and NSW (~1,700 megawatts) to help offset the large amount of capacity in Victoria.

Avoiding this situation would likely require substantial augmentations within Victoria and possibly to the interconnectors between Vic-SA and Vic-NSW. In particular, areas of western Victoria are the state's most prospective for wind power generation and are most likely to need stronger transmisison capacity.

For instance, according to AEMO Victoria's South-West Corridor can still integrate about 2,000 megawatts of new generation (see Figure 10.9).[19] However, almost half of that capacity is accounted for - committed projects in the region already total 970 megawatts.[20] When projects at the announcement stage are counted too, this rises to 3,700 megawatts, well above the level that existing transmission can support.[21]

Further north, in the Regional Victoria zone, there is a range of augmentations that would be needed to reinforce capacity. This would include, for example, replacing the single circuit 220 kV lines from Ballarat-Waubra-Horsham, Ballarat-Bendigo and Kerang-Wemen-Redcliffs with double circuit lines when 500 megawatts or more of new generation is installed in north-western Victoria.

New infrastructure on this scale would come at significant cost. Putting all of these together, AEMO's indicative augmentation plan contemplates upgrade costs within Victoria in the order of $1,800 million over the medium-longer term.[22]

However, augmented Victoria-NSW interconnector capacity could also be needed. Significant wind power deployment in SA and consequent upgrading of the SA-Vic interconnector could lead to SA exporting excess wind power to Victoria. This in turn could lead to Victoria exporting displaced capacity to NSW, increasing Vic-NSW interconnector flows.

This situation could create a case for upgrading existing Vic-NSW interconnections to bypass NSW's congested Snowy region.

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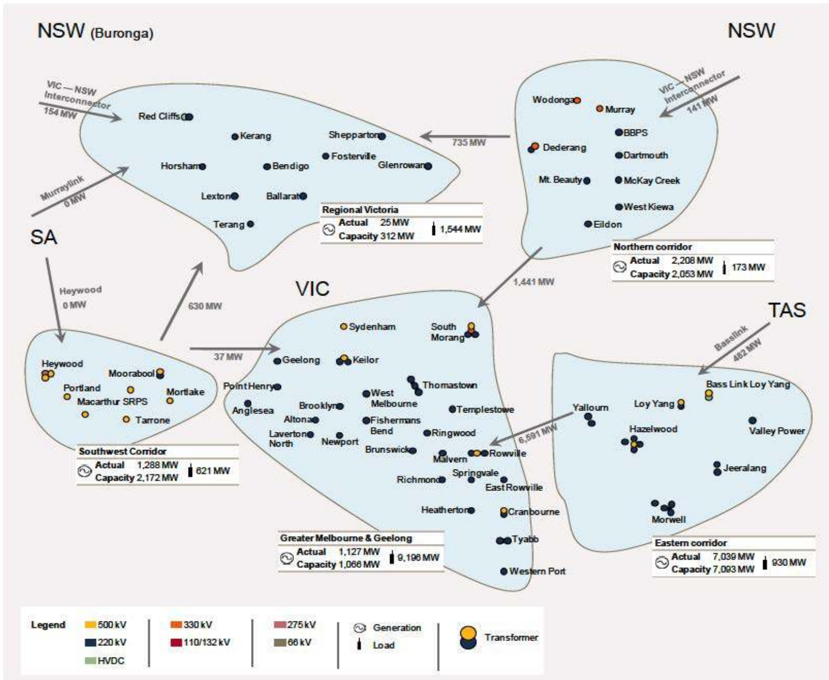
[18] Vencorp (2007)
[19] AEMO (2011b)
[20] Origin Energy's Mortlake OCGT plant (550 megawatts) and AGL's MacArthur wind farm (420 megawatts)
[21] The combined capacity of announced wind farms in the region equals ~1,800 megawatts and there is also 1,000 megawatts of gas powered generation proposed (AEMO (2011b)
[22] AEMO (2011b), ROAM Consulting (2010)

Future requirements in NSW would also add the case – these are discussed in the following section. Interconnector augmentations could include a third South Morang-Dederang line, an additional Dederang-Jindera line, and on the NSW side, an additional sections from Jindera to Wagga and Wagga to Bannaby.[23]

Figure 10.9 Conceptual diagram of the Victorian transmission network. Includes AEMO forecast for total Victorian generation, load and flow in 2015-16

Figure A3-2 — Generation, load and interconnector flow: 2015/16 forecast year



Source: AEMO (2011b)

Interconnector upgrades on the Victorian side of the border were modelled as part of ROAM's long-look study for Commonwealth

[23] ElectraNet and AEMO (2010).

Treasury (2011).[24] Wind power deployment on this scale required upgrades that would increase power transfer capacity significantly, by about 2,700 megawatts (from NSW to Victoria) and 960 megawatts (from Victoria to NSW), at a cost in the order of $1,500 millon.[25]

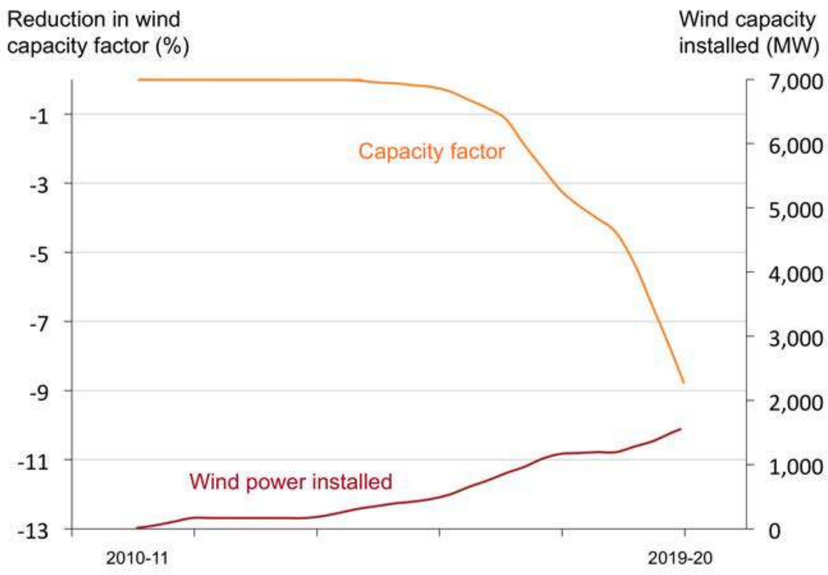
To put this all in perspective, at least this level of wind power would be needed in Victoria to reach the 30% benchmark across the NEM, and possibly as much as 9,000 or 10,000 megawatts. Absorbing wind capacity on this scale would require at least this level of network augmentation.

Tasmania

Tasmania currently has just over 140 megawatts of installed wind power capacity. While Tasmania has excellent wind resources, it also has limited electricity demand, reaching levels as low as 1,100 megawatts in summer. In addition, capacity for short-term export to mainland Australia via Basslink is constrained to 630 megawatts. As a result, Tasmania has limited capacity to support high levels of wind power development. This is reflected in Figure 10.10, which shows a rapid drop-off in wind farm capacity factor as installed capacity exceeds 800megawatts. In absolute terms, capacity factor reaches ~28% by 2019-20 - nearing the fringe of economic viability for a wind farm.

[24] This considered a projection for the 2050 generation mix, comprising about 5,500 megawatts of wind power in Victoria, 7,300 megawatts in NSW and 5,500 megawatts in SA. ROAM Consulting (2011)
[25] ROAM Consulting (2011)

Figure 10.10 Tasmania reduction in capacity factor with installed wind capacity (scenario Wind 1 - max capacity factor)



Source: ROAM Consulting (2010)

Presently there are over 800 megawatts of wind power projects announced for Tasmania. Accomodating this level of development would require network augmentations within Tasmania and possibly to the mainland as well.

AEMO's 2010 NTNDP considered up to 1,540 megawatts installed in Tasmania by 2030. Under this scenario - and in fact all scenarios modelled in the NTNDP - several augmentations would be needed within Tasmania. These include upgrading the 110 kV

Norwood-Scottsdale line, the 220 kV Sheffield-Burnie single circuit line and building a new 220 kV Palmerston-Sheffield double circuit line. These upgrades would be necessary to support future wind farm development, as well as potential development of some Tasmanian geothermal resources.[26]

Tasmania's wind regime coincides with wind in Victoria a little over half the time (correlation coefficient 0.55), which could reduce the scope for Tasmania to export excess wind power during periods of low demand. Large amounts of wind power in Tasmania may also create technical issues for Basslink and its ability to change direction in response to market signals – this would need to be resolved.[27]

However, upgrading Basslink would increase the level of capacity that could be installed in Tasmania. ROAM Consulting's modelling for Commonwealth Treasury (2011) considered installing close to 2,500 megawatts of wind power in Tasmania. This included doubling Tas-Vic interconnector capacity, to about 1,000 megawatts, at a cost of at least $720 million.

New South Wales (NSW)

The NSW network has the highest load in Australia, with minimum demand resting at about 6,000 megawatts. However, NSW has little installed wind capacity, at present about 200 megawatts, meaning that it has ample demand to absorb more wind powered generation capacity.

Developers have been less interested in NSW largely because NSW's wind resource is generally less attractive than those of the south-eastern states. However, NSW still has much to make it attractive to wind power development – large minimum load, good quality wind sites near to existing transmission capacity and capacity to absorb wind power without depressing pool prices. As development options become more constrained in the south, interest in NSW sites will grow – while there is only about 50 megawatts of wind power under construction in NSW, there is about 2,700 megawatts in development phase.[28]

[26] AEMO (2010), Transend Networks (2011)
[27] Transend Networks (2011)
[28] Grattan Institute power plant database

Figure 10.11 The NSW transmission network

Source: Transgrid (2011a)

While NSW has ample capacity to absorb new wind power, there is reason to think that substantial deployment would still require transmission upgrades - particularly in southern NSW and particularly if there were substantial new capacity installed in Victoria and SA.

The majority of favourable areas for wind power generation in NSW are in the south and west of the state – in the southern tablelands, the Canberra-Snowy area, the NSW-Vic border area, and far western NSW, near Broken Hill. However, transmission linking southern parts of NSW with the rest of the state is already congested. NSW relies on importing power from its southern areas to supply high loads elsewhere in the State. Under hot summer conditions, this capacity (the four 330 kV lines immediately north of Snowy) is limited to about 3,300 megawatts. At times of peak load in NSW this constraint is already being reached.[29]

To put some indicative numbers to this, ROAM (2010) has suggested that it is possible to install just over 5,000 megawatts of capacity in NSW without major network upgrades, while still maintaining average capacity factor at between 28 and 31%. However, this scenario[30] managed congestion in part by curtailing deployment elsewhere in the NEM. While around 4,000 megawatts of wind power is allowed for in Victoria, deployment in SA was limited to under 1,500 megawatts and Tasmania to about 200 megawatts.

This type of distribution seems unlikely – all other factors being equal, wind power developers will select sites that maximise their returns, rather than minimise network congestion overall. According to the NSW network operator Transgrid, network upgrades will probably be required to support 'significant' wind power deployment in the south and far west of NSW – especially if imports from Victoria increase and new gas powered generation plant were built to the south of Sydney.[31]

[29] Transgrid (2011b)
[30] Wind 2 – Minimise congestion
[31] Transgrid (2011b)

At high levels of wind power deployment in NSW – such as the 7,000+ megawatts considered in ROAM's modelling for the Commonwealth Treasury (2011) - upgrades would clearly be needed. In the south, this would continue development of the major 500 kV network plan that commenced in the 1980s, including new double circuit 500 kV lines from Wagga to Yass, Yass to Bannaby and Bannaby to Western Sydney. Further north, the 500 kV system is planned to include a ring around Sydney, Newcastle and Woolongong, which would facilitate connection with a range of new generation to the north of Sydney. There is also a number of smaller upgrades that could be needed across parts of NSW.[32]

Increasing interconnector capacity is also likely to be part of this, as outlined in the preceding sections. Stronger interconnection with NSW is likely to be important in the future, simply because wind, solar and geothermal resources are not distributed in the same way as demand. Figure 10.5 highlights this, showing how power flows into NSW increase over time under ROAM's High Price scenario (7,000+ megawatts in NSW).

Arguably, augmenting Vic-NSW interconnection would be needed to increase satisfy reliability requirements in northern and southern NSW by importing power from Victoria. On the NSW side, this could include a new 500 kV connections from Wagga to either Jindera or Finely.[33] Interconnection with SA could also be justified, to directly match load growth in NSW with wind power capacity in SA. Options for this include a long-distance 500 kV AC or HVDC link between Wilmington and Mt Piper, possibly via Broken Hill (see section on South Australia above). However, the route may be influenced by future solar and geothermal generation in remote areas of SA, NSW and southern Queensland. If these projects became viable, one option would be to use a SA-NSW link as a means to connect them into the NEM. The implications of this are discussed in the following sections.

Western Australian South West Interconnected System (SWIS)

The SWIS covers the south-west of Western Australia, taking in the area from Albany to Geraldton and Kalgoorlie in the east. Although there are good wind resources in practically all coastal areas of the SWIS, the current network requires upgrading to properly exploit the available wind resource.

The most prospective areas for wind farm development tend to be in between Perth and Geraldton, and the southern and eastern sections of the SWIS. Yet transmission capacity to the north and south of Perth is already operating near its limit and needs development.[34] The planned upgrade of the line to Geraldton should considerably improve the capacity to develop new wind farms in this region. But as outlined in section 2.4.5 of Chapter 2, on Wind power, in order to keep balancing costs to moderate levels there is a need for wind farm development to be spaced out across other regions as well.

[32] Transgrid (2008)
[33] Transgrid (2008)
[34] Synergy (2010), Western Power (2010)

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11 Appendix – Expert contributors

Our analysis has drawn on the expertise of many individuals from industry, government and academia. We are grateful for their time and input. The following individuals agreed to be thanked in our report.

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12 Glossary and acronyms

This glossary draws upon previous Grattan Institute reports, the Australian Government's CPRS White Paper (2008), the Garnaut Climate Change Review (2008), UNDP (2008)[1] and Planete Energies.[2]

Terms in a definition that appear elsewhere in the glossary are italicised.

AEMC	Australian Energy Market Commission – an independent national body responsible for rule-making, market development and policy advice concerning the *National Electricity Market (NEM)* and gas market and infrastructure.
AEMO	Australian Energy Market Operator – since 2009 AEMO has managed the operation, development and planning of the *National Electricity Market (NEM)* and Victoria's gas transmission network. AEMO is responsible for national transmission network planning for electricity.
Arbitrage	The simultaneous purchase and sale of the same commodity (e.g. carbon) to take advantage of price discrepancy at minimal risk.
Balance of systems (BOS)	BOS generally refers to the components of electricity system that move and convert energy, including cables, switches and fuses. BOS can include the labour to install those components.
Bioenergy	The usage of any biological material ("biomass"), such as wood, food waste or sewerage, to produce energy (electricity, heat or transport fuel). See chapter XX.
Business as usual	An estimate of the future pattern of activity (e.g. energy consumption, greenhouse gas emissions) which assumes that there will be no major changes in practices, attitudes and priorities of individuals, firms and government.
Capacity factor	The ratio between the actual electrical energy produced by a generating unit for a given period of time (usually one year) and the theoretical electrical energy that could have been produced at continuous full power operation during the same period.
Carbon price	The price at which a 'carbon' or emissions tax is set or at which emissions permits can be bought, nationally or internationally.
CO_2-e	Carbon dioxide equivalent – a common measure for greenhouse gas emissions that reflects their different global warming potential.
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CSP	Concentrated solar thermal power – uses mirrors to concentrate and convert sunlight into heat to drive an electricity generator. There are four types: linear Fresnel reflectors, power towers, parabolic dishes and troughs. See chapter XX.
CCS	Carbon capture and storage – technologies that capture carbon dioxide emissions from energy

[1] Mitigation Technology Challenges: Considerations for National Policy Makers to Address Climate Change Martina Chidiak and Dennis Tirpak august 2008, An Environment & Energy Group Publication
[2] . http://www.planete-energies.com/en/glossary-200053.html

	production or industrial processes, and inject carbon dioxide into underground geological formations below land or the sea.
DNI	Direct normal irradiance – a measure of the amount of solar radiation received per unit area by a surface held perpendicular ('normal') to the rays that come in a straight line from the sun at its position in the sky at a particular time.
Dispatchable	Dispatchable electricity generation can be dispatched upon request (e.g. from the plant owner or the market operator). It can be turned on and off, and power output can be adjusted at short notice, for example, to meet demand (or follow load) at a particular time. This contrasts with intermittent or variable generation, such as wind and solar PV, which have output that cannot be directed or scheduled.
Diurnal intermittency	Fluctuations in electricity generation during a day
Emissions intensity	A measure of the amount of carbon dioxide, or other greenhouse gases, emitted per unit of something (e.g. electricity output).
Fissile	Fissile materials are materials capable of sustaining a chain reaction of nuclear fission (splitting atoms). The fuel for a nuclear power reactor fuel must fissile.
Flue gas	Smoke resulting from combustion in a furnace or boiler, consisting mainly of carbon dioxide, carbon monoxide, and nitrogen.
Fracturing (or frac'ing)	Injecting water or another fluid at high pressure to create fissures and fractures in a rock to increase the flow of liquid through the rock to the production well, resulting in greater extraction of the resource (e.g. heat for *geothermal* energy).
Fuel switching	Substitution one fuel type for another (e.g. coal for gas, gas for solar).
Fossil fuels	Carbon-based fuels from fossil carbon deposits, including coal, oil, and natural gas.
Fugitive emissions	Greenhouse gases that are released in the course of oil and gas extraction and processing, through leaks from gas pipelines, and as waste methane from black coal mining.
GCCSI	Global Carbon Capture and Storage Institute – Australia-based international institute to facilitate development of *CCS* technology through demonstration projects and research, including on regulator settings and frameworks.
Generated electricity	The total amount of energy an electricity generator produces, including internal consumption of electricity (*parasitic* load). Actual electricity output will be less than what is generated.
Geothermal	Energy from the heat below the Earth's surface. There are two types in Australia: Hot Sedimentary Aquifer (*HSA*) and Hot Rocks (*HR*). HR resources are deeper (generally more than 4 kilometres) and are hotter than HSA resources. Fluid is pumped down a well, across the hot rocks, and pumped to the surface to generate steam and electricity.
Gigawatt (GW)	A unit of power equal to one billion *watts*. May be used to measure the generating capacity of a power station.
Gigawatt-hours (GWh)	A unit of energy equal to one billion watt-hours (power delivered over a period of time measured in hours, usually equal to one year).

Heat transfer fluid	A gas or liquid that can absorb and transport heat from two points (e.g. from a solar collector to the turbine).
HR	Hot Rocks – deep, less permeable Australian *Geothermal* resource.
HSA	Hot Sedimentary Aquifer – shallower, more permeable Australian *Geothermal* resource.
HVAC	High-Volatage Alternating Current, a transmission infrastructure technology
HVDC	High-Voltage Direct Current, a transmission infrastructure technology. Compared with HVAC, it can transport large amounts of electricity with minimal losses, but is more economic for long-distance, point-to-point connections.
Hybrid (or hybridisation)	A hybrid electricity plant use two fuels (e.g. gas and solar) at the same time, or separately, to create electricity from a single turbine.
IAEA	International Atomic Energy Agency – an organisation that aims to promote the peaceful use of nuclear energy and to limit how nuclear energy is used for military applications.
IEA	International Energy Agency – an inter-governmental organisation created in 1974 to coordinate information, research and policies on energy between member countries.
IGCC	Integrated gasification combined cycle – converts a low-value fuel (e.g. biomass, some coal) to low heating value, high-hydrogen gas through gasification (a type of combustion). The gas then becomes the primary fuel for a gas turbine that produces electricity. IGCC reduces some emissions and particulate matter and improves efficiency of burning these fuels.
Insolation (or irradiance)	The amount of solar radiation reaching a given surface area over a period of time, often expressed in watts per square metre. Insolation varies depending on the positioning and angle of solar collectors and the time of day.
Installed capacity	The electricity production capacity of a particular facility, using any fuel source. It is usually expressed in *Megawatts.*
Investment	For the economy, it is the purchase of capital equipment and the construction of fixed capital, designed to increase output. For an individual, investment is expenditure usually designed to increase the individual's future wealth.
Kilowatt (kW)	A unit of power equal to one thousand *watts.* May be used to measure the generating capacity of a power station or power unit such as a solar PV panel.
Kilowatt-hours (kWh)	A unit of energy equal to one thousand watt-hours (power delivered over a period of time measured in hours, usually equal to one year).
LCOE	Levelised Cost Of Electricity is a measure of the average cost of electricity generation over the lifetime of a system's operation. It is calculated by dividing the net cost to install an electricity system (including initial capital, labour, cost of fuel and operation and maintenance) by its expected life-time energy output. The price is normally expressed in units of local currency per unit of electricity (e.g. $/*MWh* for large scale generation)
Load	Also called 'demand', an electrical load is anything that uses power. The size of the load is affected by

	the type of electrical appliance or activity, and the way it is operated.
Low-emissions technology	Technology which produces a product (e.g. electricity) with minimal greenhouse gas emissions. All technologies in this report are considered low emissions.
Megawatt (MW)	A unit of power equal to one million *watts*. May be used to measure the generating capacity of a power station. Variations include MWe (megawatt equivalent) or MWt (thermal output from a reactor or heat source, typically around three times the MWe figure).
Megawatt-hours (MWh)	A unit of energy equal to one million watt-hours (power delivered over a period of time measured in hours, usually equal to one year).
NEM	National Electricity Market – is a wholesale market for the supply of electricity to retailers and end-users in the interconnected regions of Queensland, New South Wales, the Australian Capital Territory, Victoria and South Australia. It began operating in December 1998.
Nuclear energy	Energy produced from heat released during fission of uranium atom nuclei (in a nuclear reactor), which is combined with water to produce steam to drive a turbine.
OECD	Organisation for Economic Co-operation and Development
Off take agreement	A legal document for the delivery and sale of a particular quantity of a good or service (e.g. electricity) from one party (generally the project developer), and its receipt and purchase by another (e.g. an electricity retailer) at an agreed price, over a period of time. A power purchase agreement is a common type of off take agreement.
Parasitic (electricity load or consumption)	Electricity consumed by an electricity generator itself in its own operation (e.g. through pumping working fluid, lighting, cleaning) and not included in electricity output.
Permeability	A property of rocks relating to the ability of liquids to circulate inside them. Higher permeability improves flow rates and resource extraction from the reservoir.
Pulverised fuel boiler	A common form of existing combustion and conversion system, where the fuel (e.g. coal) is ground (pulverised) to a fine powder, then blown with parts of the combustion air into the boiler, where combustion takes place at temperatures from 1,300 to 1,700°C. This boiler type is relatively flexible, and can respond to changes in load, making it highly *dispatchable.*
R&D	Research and development in science or technology to develop new production processes or products, including demonstration tests and pilot plants. RDD&C extends to the later parts of the process or product lifecycle, including its widespread deployment and commercial-scale development.
RET	Australia's Renewable Energy Target scheme places a legal obligation on parties who buy wholesale electricity (retailers and large users) to source a certain percentage of their electricity purchases from renewables-based generation. The annual targets are legislated in *gigawatt hours* of electricity.
Renewables	Energy sources that, within a short time frame

	relative to the Earth's natural cycles, replenish themselves from a stock or through other means (e.g. *solar*, wind, *bioenergy*).
SWIS	The South West Interconnected System is the main electricity network in Western Australia, supplying most of the South-West region.
Smoothing	Electricity *load* (demand) and output of some types of electricity generation vary over time. Smoothing refers to evening out the output or *load* to make it more stable and consistent. This can avoid the high costs associated with infrastructure *investment* to meet peak output or demand. Options include changing behaviour, operating appliances at different times or using storage for excess power.
Solar PV	Solar photovoltaic converts light from the sun into electricity using photovoltaic (PV) cells that contain a semi-conductor material (e.g. silicon). Unlike other types of generation, there is no thermal stage that involves a turbine; the resource (sunlight) is converted directly into electricity. See chapter XX.
Pyrolysis	The reaction whereby wood or another form of biomass decomposes through the application of heat (around 400°C) in the absence of oxygen.
t	Tonne
Terawatts (TW or TWh)	A unit of energy equal to one trillion watts (or watt hours)
US$	United States dollars
Watt-hour (Wh)	A unit of energy, especially electrical energy. A single watt-hour is equal to the work done by one watt acting for one hour, equivalent to 3,600 joules.