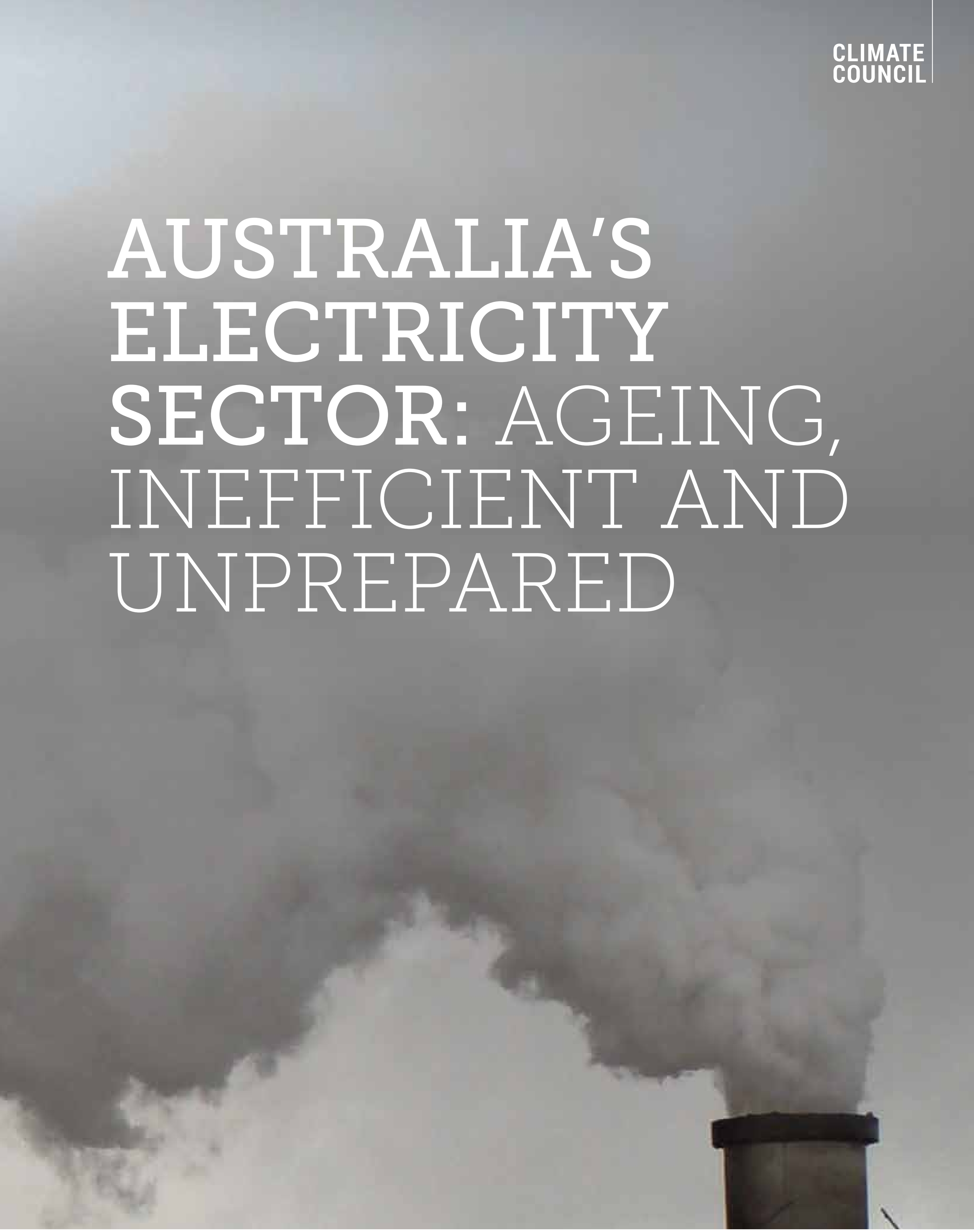
CLIMATE COUNCIL

AUSTRALIA'S ELECTRICITY SECTOR: AGEING, INEFFICIENT AND UNPREPARED



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WARNING: This report may contain the images of Aboriginal and Torres Strait Islander people now deceased.

This report is printed on 100% recycled paper.

Preface

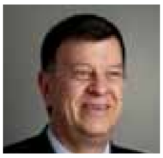
This is the third major report of the Climate Council. The Climate Council is an independent, non-profit organisation, funded by donations from the public. Our mission is to provide authoritative, expert information to the Australian public on climate change.

Internationally, the energy sector accounts for the largest proportion of greenhouse gas (GHG) emissions, which are the main drivers of climate change. Limiting temperature rise to a global average of 2 °C, the internationally agreed level that may avoid dangerous climate change, requires large scale changes in the electricity sector and a tripling of low-carbon energy by 2050. Yet, Australia's electricity is largely generated by ageing, inefficient coal-fired power plants and there are currently no plans, nor a national discussion on the future of the electricity sector and options to significantly reduce its emissions. Delaying the shift to a low carbon future increases the likely risks and costs of transition to a low carbon future in the electricity sector, where it typically takes a decade or more to plan, permit, finance and build major new power infrastructure. The transition to renewable energy has advantages beyond the important benefit of minimising changes to our climate, such as energy security, new jobs, reduced air and water pollution and land degradation, improved public health and lessening the impacts on ecosystems.

This report explores the relationship between Australia's electricity sector and its GHG emissions. It looks at the current situation, and the challenges facing Australia as its coal-fired electricity generators age. Next, the report looks at reducing Australia's electricity emissions, including renewable energy options such as wind, solar photovoltaic (PV) and concentrated solar thermal power, and carbon capture and storage. Nuclear is not considered in this report because of the focus on future options for the Australian electricity sector vis-à-vis fossil fuels and renewables. The report then examines large scale deployment of commercial low emissions technologies and compares costs for generating electricity from these different sources. Finally, the report discusses the urgent need to plan for replacing Australia's ageing fossil fuelled generators with low emissions electricity, as the country transitions to a renewable energy future.

I am very grateful to our team of reviewers, whose comments and suggestions improved the report. The reviewers were: Professor Mark Diesendorf (University of New South Wales), Paul Harris (Fulcrum Capital), Giles Parkinson (RenewEconomy), and Dr. Hugh Saddler (Pitt & Sherry). I am also grateful to Petra Stock and Climate Council staff for their many contributions to the production of this report.

The author retains sole responsibility for the content of this report.



Andrew Stock
Climate Councillor

Andrew Stock is a Climate Councillor, one of six eminent Australians that oversee the work of the Climate Council. Other Councillors include Professor Tim Flannery, Gerry Hueston, Professor Lesley Hughes, Professor Veena Sahajwalla, and Professor Will Steffen

In addition to his role with the Climate Council, Mr Stock is a company director and senior energy advisor — he is an experienced energy industry executive in oil and gas, power generation, renewables and petrochemical industries in Australia and overseas.

Introduction

The energy sector creates over 60% of global greenhouse gas emissions from human sources, mainly through the burning of fossil fuels. Increasing global demand for fossil fuels, particularly coal, has seen global emissions rising significantly in the last few decades. Greenhouse gas emissions trap heat, so as the concentration increases in the atmosphere they drive up global temperature.

To prevent catastrophic rises in global temperature humanity must substantially curtail the use of fossil fuels by 2050. The global community has agreed to cut emissions deeply to keep global temperature rise below 2 °C.

Australia's electricity is largely generated from coal. Our fleet is ageing and inefficient which means that most of Australia's coal stations are much more emissions intensive than other countries, including the USA and China. Within the decade, around half of Australia's coal fuelled generation fleet will be over 40 years old, with some currently operating stations approaching 60 years. This means that regardless of climate change, planning to replace Australia's coal-fired power stations needs to start this decade. Australia will need to plan and install new electricity generation to replace ageing generators. This offers us an opportunity to plan carefully for Australia's low emissions energy future.

This report explores a number of ways to reduce Australia's emissions from the power sector. Continuing to burn coal for power in the traditional way is incompatible with addressing climate change. There are several technologies being developed that aim to store emissions from power stations under the ground, called Carbon Capture and Storage Technology (CCS). However, given Australia's ageing plants, most are likely to be too out-dated and inefficient to be candidates for retrofitting. In addition, the cost of CCS means that coal plants will struggle to compete with renewable energy in the long term.

On the other hand, rapid deployment of renewable power, like wind and solar, is one of the most effective ways to reduce electricity sector emissions. Globally renewable energy is growing very quickly and is attracting billions in investment. Global PV capacity has been growing, on average, over 40% per year since 2000 and there is substantial potential for long-term (decadal) growth. Since 2000 the capacity of wind power globally has grown at an average rate of 24% per year. As more and more renewable energy is installed costs are also dropping dramatically. The drop in cost is then accelerating the trend toward more renewable energy.

Australia is the sunniest country in the world and one of the windiest, but has a very low share of renewable energy generation globally. South Australia is the only state with world leading wind capacity (28% of its energy generation). Australia achieving substantial emission reductions requires a step change to wind and solar combined with battery storage. Much of Australia's solar and wind resources exist in rural areas of low population and marginal agricultural land. Investment in transmission lines is needed to connect these resources with markets.

Australia's regulatory structures and network companies will need to adapt to these rapidly changing market dynamics. Regulatory structures should encourage the shift towards distributed, low emissions technologies by rewarding investments, whether it be smart grids to enable the best use of solar PV and batteries across distribution networks in our cities and suburbs, or major inter-regional transmission lines linking new wind resources to markets.

A vision, strategy and implementation plan for Australia's electricity generation sector is urgently needed to meet the duel challenges of climate change and ageing and inefficient energy fleet. Competitive low emissions electricity for modern Australia in the twenty-first century is fundamental to long term wealth creation.

Before 2020, industry planning and construction horizons dictate that Australia has to start serious planning on how it will replace its ageing coal electricity generators post 2030. In doing so, Australia has the opportunity to capitalise on the global forces now unleashed by technological change and emission reduction demands, shifting to a low emissions electricity future and participating in one of the greatest industrial and energy transformations since the industrial revolution.

As the world moves rapidly towards low emissions technology, Australia must act or risk being unprepared for the future.

Contents

Key findings

1. **Australia's electricity sector is ageing, inefficient, unprepared and requires urgent reform**

   - Australia must reduce its greenhouse gas emissions substantially to tackle climate change.
   - The electricity sector accounts for 33 percent of Australia's greenhouse gas emissions—the single biggest source of emissions.
   - Australia's coal-fired power stations are old and inefficient and will need to be retired or replaced in coming decades. This offers Australia the opportunity to fundamentally rethink our energy system.
   - The inefficiency of Australia's electricity generation means the country produces more greenhouse gas emissions per unit of electricity than almost any other developed country—as well as, China and oil-rich middle eastern nations.
   - Overall Australia is one of the world's ten biggest emitters of greenhouse gases from electricity and heat production, and of these major emitters, has the highest per capita emissions by a wide margin.

2. **Coal-fired power will struggle to compete economically with other sources of electricity as the world moves to limit emissions**

   - Continuing to burn coal for power in the traditional way is incompatible with deep cuts to emissions. It is unlikely to be practical or economic to retrofit most of Australia's old fleet of coal-fired power stations with Carbon Capture and Storage (CCS) technologies.
   - The least expensive zero emission option available at scale for deployment today in Australia is wind, closely followed by field scale solar PV. These costs are falling fast as take-up globally accelerates. Wind should be 20–30% cheaper by 2020, solar PV is expected to halve in cost.
   - Internationally, the costs of wind and solar PV renewables are generally lower now than coal plants with CCS.
   - With Australia's increasing gas prices, electricity generated from wind is already competitive with new gas plants, even without CCS, and lower cost than gas with CCS.

3. **The shift to renewable energy is underway, including in some of the largest economies in the world**

   - Worldwide, new capacity added in wind, solar PV and hydro is already far greater than fossil fuelled energy —over 100,000 MW (more than twice Australia's total power capacity) are being added each year.
   - Wind capacity is forecast to double worldwide by 2017. China will be the leading country, with capacity more than doubling to 185,000 MW, followed by the USA (92,000 MW), Germany (44,000 MW) and India (34,400 MW).

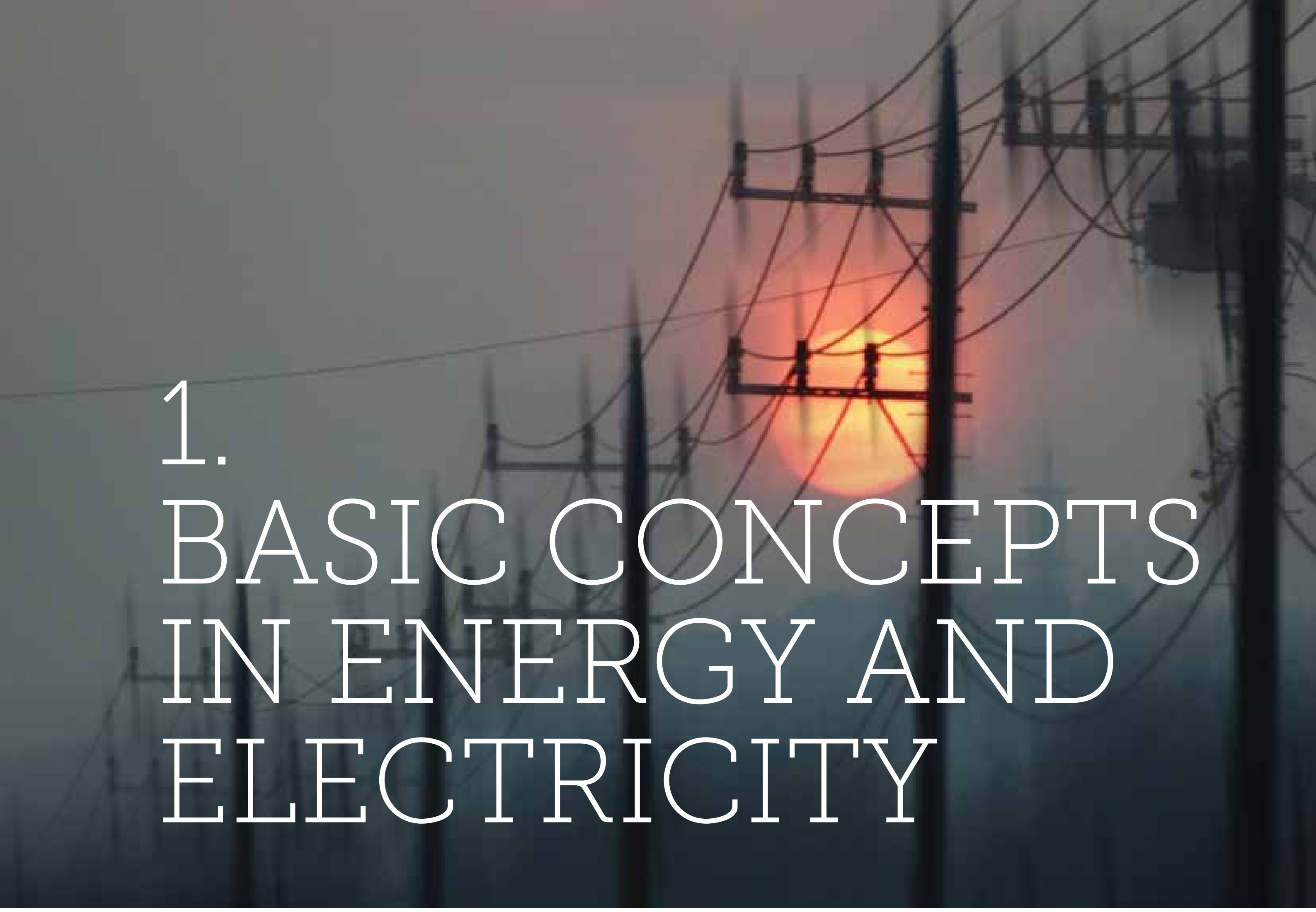
- Global PV capacity has been growing, on average, over 40% per year since 2000 and there is substantial potential for long-term (decadal) growth.
- In the USA, for the past five-years, solar thermal power capacity has been increasing at 45 percent per year.

4. There are substantial opportunities for Australia in renewable energy, which is already lowering the cost of electricity

- While Australia overall is not keeping pace with international investment and uptake of renewable electricity, there are some Australian jurisdiction exceptions where renewable leadership is world class. South Australia has world leading wind and solar power, Queensland is strong in solar generation, and the ACT is on track to make 90% of its power from wind and solar by 2020.
- By the end of 2013, over 1,100,000 Australian householders had installed solar PV on their roofs to reduce their exposure to higher power prices. 10,000–15,000 more homes add solar PV each month.
- During summer heatwaves in 2014 in South Australia and Victoria, electricity prices were at least 40 percent lower than they would have been without the contribution of wind energy.
- Over each full year, renewables reduce power prices in Australian states where wind and solar PV penetration is high. This is also true overseas, in places such as Texas and Germany.

5. Australia must act now to prepare its energy sector for the future

- Competitive low emissions electricity is fundamental to long-term wealth creation and a healthy future for Australians.
- Urgent action is required to prepare Australia's electricity sector for the near future—it takes over a decade to plan, design, finance, and build major new power infrastructure.
- Australia's market and regulatory structures will need to adapt to cope with the global shifts underway and accelerating growth in distributed low/zero emissions energy generation and storage.
- Strategic transmission infrastructure investments would open up vast untapped Australian renewable resources for development.



1. BASIC CONCEPTS IN ENERGY AND ELECTRICITY

This chapter explores a range of key concepts that underpin a detailed discussion on energy and electricity.

BOX 1: CAPACITY AND ENERGY GENERATED

Concepts of **energy generated** and **capacity** are often mingled and confused when energy technologies are discussed. When considering emissions from electricity generation, it is energy generated rather than capacity installed which is the more relevant measure. It is through reducing the emissions intensity of energy generated over time that emissions will be materially reduced.

Capacity, measured in megawatts (MW), means the amount of electricity that a power station is capable of producing when operating at maximum output. Capacity is determined during the design of the power station, and is set by the size of the plant constructed. This original "as built" capacity of a power station may then be affected by a range of factors including weather conditions, availability and temperature of cooling water or air, and the mechanical condition and degradation of the operating plant.

Energy generated, measured in megawatt hours (MWh), means the amount of electricity produced by a power station over a period of time. The energy generated over a period of time is affected by factors such as the capacity of the power station, the proportion of capacity being used, and the proportion of the power generated that is used within the power station to run ancillary services (such as cooling systems and boiler feed water pumps).

1.1 Emissions and emissions intensity

Emissions, measured in tonnes of carbon dioxide equivalent (CO_{2e}), from electricity generation are a product of the **energy generated** and the **emissions intensity** of the power station. CO_{2e} is a measure for comparing the global warming potential of emissions from various greenhouse gases (GHGs) based on their global warming potential and is usually averaged over a century. Emissions intensity is measured in tonnes CO_{2e}/MWh.

To reduce emissions from electricity generation, society needs to produce (and use) less electricity, and/or produce the electrical energy with lower emissions intensity.

Reducing emissions from the electricity sector requires:

SUPPLY SIDE: reducing the emissions intensity of generation through:

- Replacing old fossil fuelled plant with more efficient technologies.
- Capturing and sequestering emissions produced from existing or new fossil fuelled stations.
- Producing more zero emission renewable power.

DEMAND SIDE: reducing electricity demand and usage through:

- Using more efficient machines, processes and appliances.
- Using more efficient energy services (such as heating and cooling through installing insulation, and shading).
- Behavioural changes which use less electricity.

1.2 The electricity grid and balancing supply and demand

Electricity is delivered to consumers through a complex network of transmission and distribution wires, termed the grid. Generation and distribution systems need to maintain an instantaneous balance between supply and demand. If this does not occur, the system voltage or frequency may fall or increase, which may cause the system to become unstable, tripping out other generators, or causing consumer appliances to disconnect or fail to operate properly. Large electricity grids have protection systems installed to stop such imbalances escalating, but if these fail, widespread blackouts could occur.

Imbalances between demand and supply can occur for various reasons:

- Consumers increasing or decreasing the number of appliances operating (such as air conditioners during a heat wave, or factories finishing operations for the day).
- Other power stations producing less electricity (such as if a fossil fuelled power station suffers an operating failure, or deliberately changes how much it wishes to produce for commercial reasons, or if a renewable station produces less electricity due to changes in wind or solar input).

Australia's has two large interconnected electricity grids—the National Electricity Market (NEM) connecting Queensland, New South Wales, Victoria, South Australia and Tasmania and the South West Interconnected System (SWIS) in Western Australia.

At the grid level, power supply and demand are balanced through the use of back up power stations to maintain reliability. Back up may be provided almost instantly from a station already operating below full capacity by increasing its output ("spinning reserve"), or by starting up another power station such as a peaking power plant.

Until recent years, most small scale distributed generation located at a power user (such as a high rise building or a hospital), has been used to back up supplies in the event of the grid supply failing. Similarly, electricity storage in batteries has been provided in relatively small amounts for only the most essential services (for example, critical hospital services and instruments, critical control systems and internet servers) to ensure very high continuity of supply. Both of these were not usually integrated into grid operations, rather they were installed to back up if the grid supply failed.

1.3 How fuel supply affects how a power station operates

Power stations have different operating characteristics:

- Those having large fuel or other input energy storage which are able to operate continuously to meet the demand of the electricity system. These include coal and gas fuelled stations, which have large inventories of fuel stored in onsite stockpiles, adjacent mines or in pipeline systems, nuclear power plants, and hydro systems with large storage dams.
- Those reliant on energy incident at any point or interval of time to be able to operate. These include stations with low inventories of fuel, for example a gas "peaking plant" with gas supply limits caused by commercial or physical factors (for example, a small supply pipeline), run of river hydro systems, or stations which rely on other variable renewable energy supplies such as wind turbines or solar PV power.

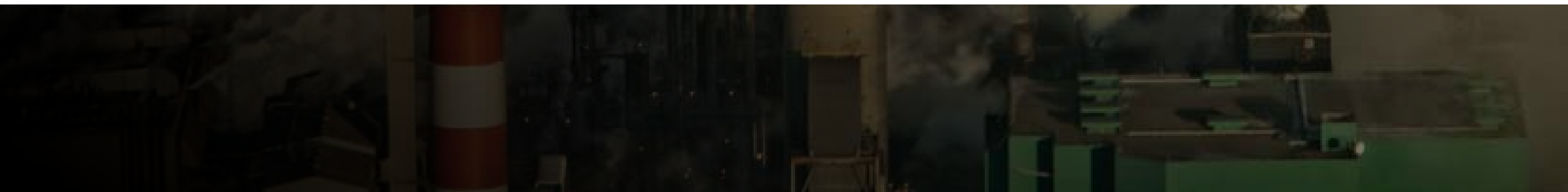
2. THE ENERGY SECTOR AND GHG EMISSIONS

The energy sector creates over 60% of global greenhouse gas emissions from human sources, mainly through the burning of fossil fuels. Increasing global demand for fossil fuels, particularly coal, has seen global emissions rising significantly in the last few decades. Greenhouse gas emissions trap heat, so as the concentration increases in the atmosphere they drive up global temperature.

To prevent catastrophic rises in global temperature humanity must substantially curtail the use of fossil fuels by 2050.

In Australia, electricity generation creates the lion's share of our emissions, with coal burning the primary source. Our electricity supply is one of the most emission intensive in the developed world. For instance, Australia generates 60% more emissions per MWh than the USA. Our electricity supply is also substantially more emission intensive than China. In addition, Australia's coal fleet is old relative to other nations and, even regardless of climate change, will need to be replaced in coming decades.

This chapter describes the crucial challenges for Australia's electricity sector. In a world that is moving rapidly to reduce emissions, the Australian electricity sector, particularly coal power, is inefficient, ageing and highly emission intensive. Carbon capture and storage technology, which could reduce the emissions of Australia's coal stations, may be impractical to apply to the nation's old fleet.



2.1 Global

The energy sector—which involves the extraction, manufacturing, refining and distribution of energy from petroleum, coal, gas, nuclear and renewable sources—creates over 60% of global anthropogenic GHG emissions, and over 75% for Annex 1 countries, that is, Organisation for Economic Co-operation and Development (OECD) member countries, plus countries with economies in transition (OECD/International Energy Agency (IEA) 2013a).

Globally, total primary energy supply and demand has doubled since 1970, with fossil fuels representing around 80% of this energy supply. Increasing global energy demand from fossil fuels, particularly coal, is a major reason why there is an upward trajectory in carbon dioxide (CO_2) emissions (OECD/IEA 2013a) (Figure 1). Over the past decade (2000–2010), annual anthropogenic GHG emissions have increased by 10,000 million tonnes CO_{2e}. Global CO_2 emissions from fossil fuel combustion are now running at 31,600 million tonnes (31.6 Gt, gigatonnes) annually in 2012, the highest on record (OECD/IEA 2013a; OECD/IEA 2013b).

Nearly all countries in the world have agreed to limit climate change by keeping the rise in global average temperature to 2°C above pre-industrial levels, the so-called 2°C guardrail (UNFCCC 2009), although there are likely to be significant impacts in many regions and across many sectors even at that temperature (IPCC 2014). Continuing with business-as-usual, without more mitigation measures and uptake of renewable energy, the global mean surface temperature may increase

Figure 1: Growth in global energy-related CO_2 emissions.

Source: OECD/IEA 2013c

by over 4°C by 2100 (IPCC 2013). In order to have a 66% chance of keeping global temperature increases to no more than 2°C by the end of the century, humanity must limit emissions from all sources to a total carbon budget of about 1,000 Gt C (IPCC 2013). This budget reduces to 800 Gt C when accounting for non-CO_2 forcings. Of this budget, an amount of 531Gt C was already emitted by 2011 (IPCC 2013), leaving 269 Gt C (986 Gt CO_2) in the budget. At current emission levels and growth rates, the world's carbon budget will be exhausted in the 2030s (Meinshausen et al. 2009; Carbon Tracker and the Grantham Research Institute 2013; Climate Council 2014).

To have a better-than-even (e.g. 66%) chance of meeting the 2°C target, the energy sector's carbon budget allows use of only about one-quarter to one-third of all current remaining proven reserves of oil, gas and coal (excludes probable and possible reserves) (Carbon Tracker and the Grantham Research Institute 2013). With major emission reductions needed, and substitutes for transport fuels more technically challenging, it is not surprising that renewable electricity technologies are being advanced and deployed globally at accelerating pace.

2.2 Australia

In Australia, in the year to September 2013, total GHG emissions were 542 million tonnes; emissions from the energy sector were 409 million tonnes (Commonwealth of Australia 2013a). Electricity generation represents nearly half (around 44%) of our energy sector emissions, is the largest single contributor to Australia's total emissions, and more than twice as large as the next sector. Add to this the emissions from extraction, processing and transport of the fossil fuels to produce electricity, and electricity generation is clearly the dominant contributor to Australia's GHG emissions.

Although there has been increased emphasis on renewable electricity supply in recent years, Australia's electricity is still overwhelmingly supplied by fossil fuelled power stations, mostly coal. In 2011/12, some 91% of Australia's electricity was generated by fossil fuels, with 75% from coal and the remainder from natural gas (Australian Energy Market Operator (AEMO) 2013b; ESAA 2013).

Australia is one of the top ten countries in the world for the amount of GHG we emit to produce electricity—ranked ninth (OECD/IEA 2013a)—and Australia ranks seventh when it comes to the quantity of CO_2 emissions we produce from coal fuelled power generation (Table 1). On coal fired power emissions, Australia sits in a grouping of five countries with emissions within a 10–20% band of each other, outside of the top three global emitters (OECD/IEA 2012a). When ranked on a per capita basis, Australia is first, by a very wide margin (OECD/IEA 2013a). Australia's per capita emissions from fossil-fuelled electricity are two to three times those of Germany, Japan and China, and around 30% to 50% higher than other large tonnage emitters like the USA, Russia and South Korea.

Table 1: Australia is in the top ten global emitters of CO_2 from burning fossil fuels for power generation and heat production.

Data	CO_2 Emissions from Electricity & Heat Production		
	From All Fossil Fuels		From Coal/Peat
	(Millions) (of Tonnes) (2011)	(tonnes) (per Capita) (2011)	(Millions) (of Tonnes) (2010)
China	4010	3.0	3017
United States	2212	7.1	1929
Russia	939	6.6	223
India	901	0.7	663
Japan	519	4.1	217
Germany	324	4.0	250
South Korea	300	6.0	150
South Africa	225	4.5	203
Australia	**208 Rank #9**	**9.1 Rank #1**	**203 Rank #7**
Saudi Arabia	189	6.7	-
United Kingdom	167	7.1	-
Poland	158	4.1	149

Source: OECD/IEA 2012a, OECD/IEA 2013a

2.3 Australia's electricity sector emissions —comparing emissions intensity

Australia's electricity supply is one of the most emissions intensive of any developed nation (Table 2). Australia generates 60% more emissions per MWh than the USA, and almost 100% higher than the OECD average. Australia's emissions intensity from electricity is notably higher than the emissions intensity of the electricity supply in China (often reported in Australian media as having poorly performing polluting power stations), or oil rich Saudi Arabia (OECD/IEA 2013a).

Australia is not reducing electricity emissions intensity as quickly as other countries. Over the decade to 2012, emissions intensity from electricity generation in China has reduced by 16%, while in Australia, the reduction has been less than 4%. Notwithstanding a decade of Australian policy encouraging renewable energy generation, which saw renewables' share of electricity generation grow from around 8% in 2000, to 10% in 2010 (Commonwealth of Australia 2013b).

Table 2: Australia's electricity sector is one of the most emissions intensive of any developed nation.

	Tonnes CO_2/MWh (2011)
Australia	0.823
China	0.764
USA	0.503
Russia	0.437
India	0.856
OECD Average	0.434
Germany	0.477
South Korea	0.545
United Kingdom	0.441
Japan	0.497
Saudi Arabia	0.754
Poland	0.780

Source: OECD/IEA 2013a

2.4 Australia's electricity sector emissions—what will the future look like based on current trends?

By 2020, assuming Australia's existing Renewable Energy Target (RET) is maintained, projections indicate Australia's electricity sector emissions will grow 15% (26 million tonnes CO_2 per year) above 2000 levels, and 55% (71 million tonnes per year) above 1990 levels (Table 3). By 2030, when the existing RET targets expire, electricity sector emissions are forecast to be 243 million tonnes per year, almost double 1990 levels—and this increase is on the Commonwealth Government's forecast assumption that new supply comes from coal and solar (Commonwealth of Australia 2013b).

Fugitive and direct combustion emissions from the production of fossil fuels (natural gas, liquefied natural gas (LNG) and coal for domestic consumption and export) are growing even faster—almost doubling 1990 levels by 2020, and almost trebling by 2030 to 234 million tonnes CO_2 per year (Table 3). Fugitive and direct combustion emissions will nearly equal the total emissions from Australia's domestic electricity sector by then (Commonwealth of Australia 2013b).

Australia's electricity generation fleet is dominated by fossil fuelled—coal and gas fired—power stations. With the Australian Energy Market Operator (AEMO) forecasting demand for electricity will remain flat, the high cost of natural gas going forward, and the risks in financing new fossil fuelled plant, it is unlikely any new coal fuelled or efficient combined cycle gas power stations will be built for at least a decade. Indeed, AEMO is forecasting that—with the exception of Queensland where additional capacity may be required by 2020/21 to meet Coal Seam Gas (CSG)/LNG demand—no other Eastern seaboard state will need additional capacity until beyond AEMO's 10-year modelling horizon (AEMO 2014b).

There has been little public discussion on the increasing age of Australia's coal fuelled power stations and how they are to be replaced. Australia's coal fired power stations are ageing units using less efficient technology. Currently, the average age of Australia's coal power station fleet is over 30 years. By 2020, around 40% will be over 40 years old, and 15% over 50 years in age, and by 2030, average age will increase to over 40 years, with 40% of the fleet then over 50 years old. 2030 and beyond may seem like a long way into the future, but not when one considers that it takes around a decade to plan, permit, finance and build new power stations.

Once power stations get 40 to 50 years old, it becomes increasingly expensive to continue to run them as they are inefficient to operate and costly to maintain. Most power plants currently this old are candidates for closure or have been mothballed. Some of Australia's oldest power stations are already around 50 years old (Table 4).

It is noteworthy to compare the age of Australia's coal fired power station infrastructure with global averages. More than half the global coal power plant fleet is less than 20 years old, whereas, in Australia, only around a quarter is less than this age (OECD/IEA 2012).

Table 3: Projected emissions in Australia (1990–2030).

	1990	2000	2020	2030
	Mt CO_2–e	Mt CO_2–e	Mt CO_2–e	Mt CO_2–e
Energy	294	367	498	584
Electricity	*130*	*175*	*201*	*243*
Direct Combustion	*66*	*75*	*119*	*134*
Transport	*62*	*75*	*99*	*106*
Fugitives	*37*	*41*	*79*	*100*
Industrial processes	26	26	37	45
Agriculture	99	105	106	123
Waste	21	17	15	15
Land use, land-use change and forestry	140	71	30	34
Total domestic emissions	580	586	685	801

Source: Commonwealth of Australia 2013b

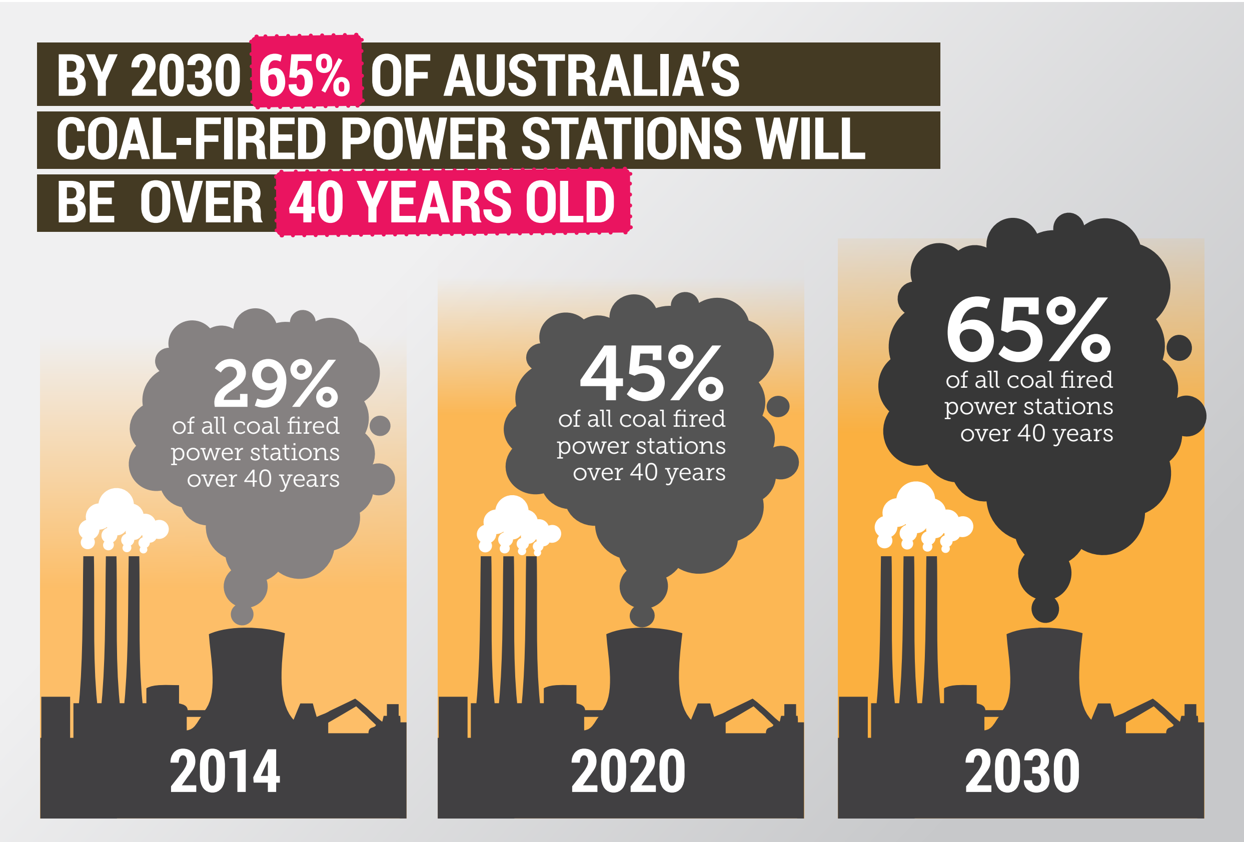
Note: Sub-totals may not sum due to rounding.

Table 4: Australia's oldest operating power stations

	State	MW	Fuel	Commissioned
Hazelwood	Vic	1600	Lignite	1964–71
Callide	Qld	1720	Black Coal	A—1965, B—'88
Liddell	NSW	2000	Black Coal	1971–73
Munmorah	NSW	600	Black Coal	1967–69
Playford	SA	240	Lignite	1964
Muja	WA	974	Black Coal	1966+

Source: Alinta Energy 2014; CS Energy 2014; Delta Electricity 2012; GDF Suez 2014; Macquarie Generation 2014; Synergy 2014

Figure 2: Ageing profile and projections of power stations in Australia.



Source: Data from AEMO 2011; AEMO 2012 and power plant operator websites

BOX 2: WHY IS AGE A PROBLEM FOR COAL FIRED POWER STATIONS?

There have been dramatic improvements over the years, significantly reducing the carbon intensity of fossil fuelled plant. However, ageing power stations are locked into inefficient, high emissions technology. While parts can be changed on an ageing coal-fired power station, the primary technology cannot be without massively expensive rebuilds, if more efficient technology becomes available.

With coal-fuelled power stations, the primary determinant of emissions today is the cycle efficiency. Cycle efficiency is determined by the steam temperature and pressure conditions at the limits of the cycle—subcritical, super critical, or ultra super critical. These establish the design conditions for critical components like the metallurgy for high temperature boiler and superheater tubes, and steam turbine operating conditions.

Because most of Australia's coal fired electricity generators are so old, the majority were built using now outdated sub critical technology, the prevalent technology when they were constructed. Australia's coal power station infrastructure is now one of the least efficient globally in terms of technology and efficiency (Table 5).

Table 5. Countries with highest coal-fired power station emissions and proportion of more efficient stations.

Proportion of Stations using More Efficient Super or Ultra Super Critical Steam Technology		
	Stations <20 years old (%)	All Stations (%)
China	27 *	25
USA	27	27
India	1	1
Germany	77	21
Russia	32	37
Japan	86	73
Australia	**38**	**10**

*Over 50% of recently built Chinese power stations <5 years old) use super or ultra super critical technology

Source: OECD/IEA 2012a

The age of Australian coal fired power stations also limits their potential to be retrofitted for Carbon Capture and Storage (CCS) technology. Given CCS technology is still relatively undeveloped, it may take 10 to 15 years for the technology to evolve to commercial maturity and for CCS retrofit projects in Australia to be permitted and constructed. By then, over half Australia's operating coal-fuelled fleet will be over 40 years old (AEMO 2011; AEMO 2012; OECD/IEA 2012).

Older power stations have limited remaining operating life (unless the power station is completely rebuilt) increasing the risk that the CCS investment will not be recovered. Thus such projects are much less likely to be progressed commercially. There are other costs and risks with CCS deployment, discussed in Sections 4 and 5.

2.5 Summary of challenges facing Australia's electricity generation sector

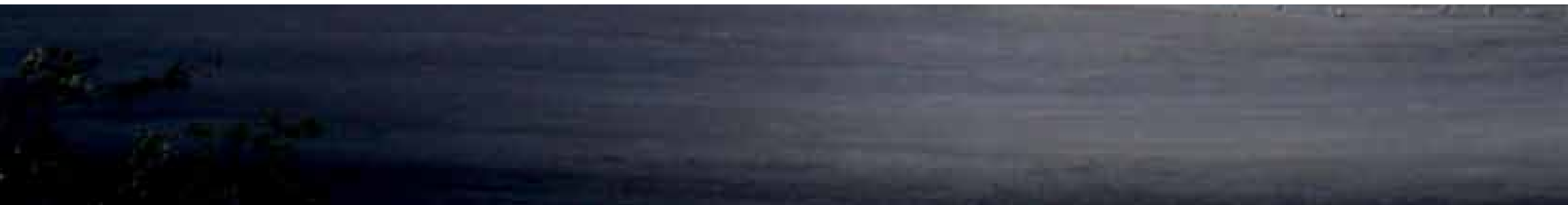
This section described how Australia's electricity generation sector faces crucial dilemmas:

- Australia's emissions from electricity generation places the nation in the top ten coal power emitters worldwide
- Australia's coal fired power station fleet is significantly older than the global average, and the technology that 90% of the coal fleet uses is obsolete.
- Australia's emissions per MWh are substantially higher than any other major global emitter
- Australia is a top 10 power plant GHG emitter by any measure—absolute tonnes CO_2, per capita emissions or per MWh
- The nation's older power stations cannot be made more efficient without vast expense, and their age limits the potential for retrofit CCS investment
- By 2030, around the time CCS may be implemented on existing Australian power stations:
  - Nearly half these stations will be 50 years old, and fleet average age over 40 years
  - Remaining operating lives of most stations will be too short to recover the substantial future CCS investment required
  - Pressures to abate emissions from fossil fuel industries (including power generation) will be intense.

In little more than a decade, Australia will have a fleet of old, inefficient, costly coal fuelled power stations unsuited physically and commercially to retrofit with CCS. Given the long planning horizons for the electricity industry, Australia needs to address these crucial dilemmas before 2020.

3. AUSTRALIA'S FOSSIL FUEL SECTOR

In considering Australia's response to both climate change and our ageing power stations, it is important to understand the contribution of fossil fuels. This chapter explores the contribution of coal and gas to Australia's emissions, as well as to society at large. Electricity from the burning of coal is the most emission intensive of any fuel source. Australia's coal fleet is much less efficient than many other nations as most stations are old and use out-dated technology. While there have clearly been enormous benefits from fossil fuel generation, there are also hidden costs, particularly to human health, agriculture and the environment.



3.1 Fossil fuels and emissions—coal and natural gas

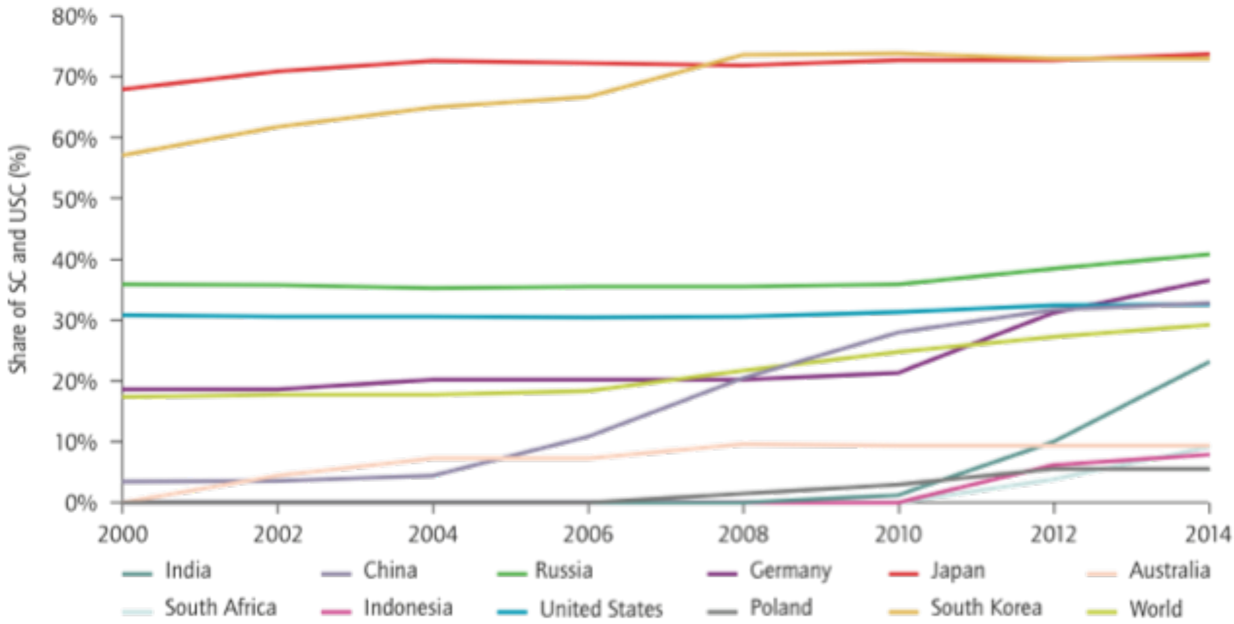
Electricity generated from burning coal produces the most GHG emissions per MWh of any fuel source. In Australia, black coal produces 0.85 to 1.1 tonnes of CO_2 per MWh, brown coal 1.2 to 1.5 tonnes/MWh. Gas turbine plants fuelled by natural gas produce less at 0.4 to 0.7 tonnes/MWh (more for open cycle plants, less for combined cycle) and nuclear, hydro, wind and solar technologies produce effectively no emissions per MWh (AEMO 2012).

Coal burnt to produce electricity, usually produces more emissions per MWh than natural gas, due to several factors (Table 6):

- The quality and characteristics of the fuels.
- Coal has a much higher carbon to hydrogen ratio than natural gas.
- Technology selected to burn the fuel. Some technologies used to produce power are intrinsically more efficient, and recent developments in design, materials and metallurgy enable greater electricity output from the same amount of fuel input. This can result in significantly reduced emissions intensity.
- Fugitive and direct combustion emissions from mining and production of the fuels themselves.

Australia's power plant fleet largely uses Sub Critical technology. Figure 3 shows how the major coal fired electricity generating nations compare in their

Figure 3: The share of supercritical and ultra-supercritical capacity in major countries.
Note: For India, achieving 25% SC and USC by 2014 is an ambition, with perhaps up to 10% likely to be achieved in practice.



Source: OECD/IEA 2012b; OECD/IEA 2012b and Platts 2011.

Table 6: Reasons why coal produces more GHG emissions than natural gas per MWh

Factor	Coal	Natural gas
Carbon dioxide produced per unit of energy (tonnes CO_2/MWh)	Higher—0.75 to 0.85 on black coals, and around 1 for brown coals in latest technology plants. In Australia this ranges from lows of 0.85 for black coal to as high as 1.5 for brown.	Less—0.35 to 0.7 in latest technology plants. In Australia this ranges from 0.4 to as high as 0.9.
Fuel quality	Comes in a variety of forms, with differing heat, moisture and ash contents.	Generally consistent in quality. Nearly all methane (CH_4).
Carbon to Hydrogen (C:H) mass ratio Note: When carbon burns, it makes carbon dioxide, while hydrogen, when burnt, produces water	Varies with the coal type. Some ranges are: Bituminous (Black) 15.2:1 Sub Bituminous 14.9:1 Lignite (Brown) 14.0:1 Predominantly carbon with some hydrocarbons. Much higher carbon content (compared with natural gas).	3:1 Produces less carbon dioxide per unit of energy (compared with coal) as much of the energy comes from the hydrogen component.
GHG emissions from mining or production of fuel	Underground carbon rich coal deposits often also contain volatile hydrocarbons such as methane, and other hydrocarbons which vapourise. When these coals are mined, the dewatering and fracturing of the coal deposits to extract and transport the coal allows these gases and volatiles to escape into the atmosphere. A small number of coal mines now capture and burn this mine vent gas, in some cases using it to generate electricity. Methane has a warming potential some 20 to 80 times higher than carbon dioxide, depending on the time horizon (IPCC 2013), so relatively small quantities of methane emissions in the coal mining and transport processes can have significant impacts on the overall emissions intensity of coal. Mining coal also uses significant amounts of energy in the form of diesel and electricity to extract the coal and transport it out of the mine and to distant markets by rail and sea.	Natural gas reservoirs underground often also contain carbon dioxide at levels varying from a few percent to up to 50% or more of the natural gas volume. This carbon dioxide is usually vented to the atmosphere once extracted from the natural gas. A small number of natural gas processing plants do capture and re-inject this carbon dioxide—Gorgon LNG on Barrow Island in Australia and Sleipner in Norway are examples. Water vapour and other valuable heavier hydrocarbons (e.g. ethane, liquefied petroleum gas, and condensate) also need to be removed so that the natural gas produced meets pipeline specification. Conventional natural gas separation processes require energy, which is usually sourced by burning some of the gas to make electricity and heat to drive the processes involved, consuming between 5 to 10% of the natural gas produced. Coal seam gas and shale gas production needs thousands of wells due to low well productivity compared with conventional gas. Well completion and fracture stimulation can lead to fugitive emissions of methane in significant quantities, given the large number of wells involved. LNG (made from conventional, coal seam or shale gas) needs stringent extraction processes and intensive processing to convert the gas to a super cold liquid. This uses 5 to 10% of the feed gas to power these processes.

Table 6: Reasons why coal produces more GHG emissions than natural gas per MWh (continued)

Factor	Coal	Natural gas
Technology used to generate electricity	Coal is burned today using the same thermodynamic cycle—called the Rankine Cycle—invented in the early stages of the industrial revolution, two centuries ago. Fuel is burnt in a boiler to raise steam at high pressure, which is then superheated above the boiling point, and passed through a steam turbine to drive a generator. The low pressure steam which emerges is then condensed (using cooling water or air) back to water. This water is then pumped back to high pressure again to the boiler to make more steam. Developments in materials have allowed higher temperatures and pressures to be used in the boiler and superheater tubes, and bigger steam turbines to be built with improved turbine blade aerodynamics. All of these effects have enabled more power to be generated from the same amount of fuel, increasing efficiency and reducing emissions intensity. Power cycles are described as: > Sub Critical (least efficient)—lower steam temperatures and pressures > Super Critical (more efficient)—higher steam temperatures and pressures > Ultra Super Critical (most efficient with highest steam temperatures and pressures—an Ultra Super Critical plant produces 20% more electricity than a Sub Critical station for the same amount of fuel). While figures vary depending on coal composition, local climatic conditions and elevation, the range of cycle efficiencies is generally regarded as (OECD/IEA 2012b): > Cycle Efficiency (Lower Heating Value (LHV), net) > Sub Critical Up to 38% > Super Critical 42–43% > Ultra Super Critical Around 45% Thus, an Ultra Super Critical power station will generate around 20% more electricity than a Sub Critical power station for the same amount of fuel and emissions.	Up until 30 or 40 years ago, power stations burning natural gas also used the same Rankine thermodynamic cycle as used to burn coal (In Australia, Newport, Torrens A and Torrens B stations are examples). This changed once gas turbine technology was invented and advanced. As in the case of coal power stations, significant technical advances in cycle design, using advanced materials such as ceramics and single crystal cast metals in turbine blades, has enabled higher efficiencies to be achieved. There are three main types of gas turbine power stations: > **Open Cycle Gas Turbine** (OCGT) where the gas is burnt in an industrial or aeroderivative gas turbine, much like an aircraft jet engine, to drive a generator, and hot combustion products go straight to atmosphere. > **Combined Cycle Gas Turbine** (CCGT) where the gas is burnt in the turbine, and the heat from the turbine exhaust gases is used to produce steam and drive a steam turbine (using the same Rankine cycle as in coal fired plant), thus getting two uses out of the fuel and combustion products > **Cogeneration** or Combined Heat and Power (CHP) which is similar to a CCGT, except that instead of wasting the low level heat from the condensation of the steam after electricity is generated, it is used to heat buildings or in industrial processes. As with coal, gas turbine based efficiencies will vary with machine selected and local conditions. However, latest power plant machine sizes have efficiencies in the range (Siemens, GE): > Cycle Efficiency (LHV, net) > OCGT 37 to 42% > CCGT 57 to 61% > CHP 75 to 85%

deployment of more efficient generating technology across their coal fuelled fleets. It is noteworthy that Australia is the third or fourth lowest among this group, and that countries like China are now building very efficient power stations by world standards.

Table 7 sets out the emissions intensities for actual Australian power stations built at different times. This table illustrates the impact of age and cycle technology on the emissions intensity of Australia's coal and gas electricity generation fleet.

Table 7: Emission intensities of selected Australian coal and gas power stations.

Fuel/Station	Cycle Type	Emissions Intensity Tonnes CO_2/MWh	Commissioned Year
Black Coal			
New South Wales			
Mt Piper	Sub Critical	0.935	1992–93
Bayswater	Sub Critical	0.992	1985–86
Eraring	Sub Critical	0.999	1982–84
Wallerawang C	Sub Critical	1.045	1976–80
Liddell	Sub Critical	1.081	1971–73
Munmorah	Sub Critical	1.157	1967–69
Vales Point	Sub Critical	1.032	1963–66
Queensland			
Kogan Creek	Super Critical	0.935	2007
Tarong North	Super Critical	0.864	2003
Millmerran	Super Critical	0.902	2002
Callide C	Super Critical	0.919	2001
Stanwell	Sub Critical	0.914	1996
Tarong	Sub Critical	0.936	1984–85
Callide B	Sub Critical	1.034	1988
Gladstone	Sub Critical	1.07	1976
Brown Coal (Lignite)			
Victoria			
Loy Yang B	Sub Critical	1.242	1993–96
Loy Yang A	Sub Critical	1.215	1984–87
Yallourn	Sub Critical	1.422	1973/4–81/2
Hazelwood	Sub Critical	1.527	1964–71
South Australia			
Northern	Sub Critical	0.948	1985
Playford	Sub Critical	1.511	1963
Natural Gas			
Smithfield	CHP	0.571	1996
Osborne	CHP	0.599	1998

Table 7: Emission intensities of selected Australian coal and gas power stations (continued)

Fuel/Station	Cycle Type	Emissions Intensity Tonnes CO_2/MWh	Commissioned Year
Black Coal			
Darling Downs	CCGT	0.417	2010
Tallawarra	CCGT	0.472	2009
Swanbank E	CCGT	0.434	2002
Pelican Point	CCGT	0.524	2001
Mortlake	OCGT	0.642	2012
Colongra	OCGT	0.737	2009
Uranquinty	OCGT	0.737	2009
Rankine Cycle Steam			
Newport	Sub Critical	0.617	1981
Torrens A	Sub Critical	0.839	1967
Torrens B	Sub Critical	0.912	1976

Source: AEMO 2011, AEMO 2012 and power plant operator websites

3.2 Fossil fuels and other societal impacts

The energy sector provides many benefits to society including the provision of electricity to heat and cool our homes, power for major public services such as schools and hospitals, and driving industry to deliver employment and economic opportunities for local communities. Yet there are hidden costs to fossil fuel power generation relating to, for example, the environment and human health (ATSE 2009; Lockwood et al 2009; Castelden et al 2012).

COAL

There has been comment in some media around the community impacts of renewable power, such as siting wind power stations. Fossil fuelled power has major and lasting impacts on communities beyond the GHG emissions it produces (NRC 2010; Lyster 2014). Over the past 20 years or so, 12,000 miners globally have lost their lives mining coal for electricity generation, heat and industrial uses (MacNeill 2008). In addition, miners' exposure to coal mine dust causes various pulmonary diseases, which can bring about impairment and premature death (Centres for Disease Control and Prevention 2011). Other studies overseas indicate mining communities are impacted by higher chronic heart, respiratory and kidney disease mortality. (Harvard College Global Health Review 2012). In addition, some studies overseas indicate positive correlations between coal mining and birth defects in the mountain top mining regions of Central Appalachia in the USA (Centre for Health, Environment & Justice 2013).

Figure 4: Mining activities in the Hunter Valley, NSW.

Figure 5: Removing overburden at the Bulga Coal Complex in the Hunter Valley, NSW.

Figure 6: Arial view of the Morwell open cut mine.

Figure 7: A fire in Victoria's Hazelwood open cut mine burnt out of control for a month in February 2014, with the smoke affecting residents in the nearby town of Morwell.

Open cut mining may impact large areas of directly affected and adjacent agricultural and native vegetation land for decades (Figures 4–7) (University of Tennessee 2012), and communities in coal mining regions are also concerned about impacts such as dust, noise, visual impacts and the loss of farming and native bushlands due to open cut mining, as well as associated aquifer dewatering (e.g. CSRM 2004, Hydrocology Environmental Consulting 2013). Additionally, concerns over the impacts from abandoned mines are significant (AusIMM 2011) and the disposal of saline water is an issue.

When coal is burned in power stations, it creates other waste products in addition to CO_2. While fines of solid ash and some toxic metals in the coals, such as chromium, nickel, arsenic, cadmium and lead left after the coal is burnt are mostly collected with the fine fly ash by filtration systems on the flue gas exhausted from the boilers, in Australia, other waste products such as nitrogen oxides, sulphur oxides, and volatile trace metals such as arsenic, mercury and selenium are not fully captured (CSIRO 2013a). Notwithstanding the potential known toxicity of these metals and compounds, there are very few studies on the actual quantities of trace metals emitted from Australian power stations and the health impacts of volatile trace metals from power station stacks on adjacent Australian communities. This is in contrast with the renewable sector, where studies (e.g. NHMRC 2010; NHMRC 2014) have been conducted on the wind industry's health impact, and concluded it is essentially benign. Following a review of current literature, the National Health and Medical Research Council (NHMRC) concluded in 2010 that "there are no direct pathological effects from wind farms and that any potential impact on humans can be minimised by following existing planning guidelines" (NHMRC 2010, p. 2). In February 2014, the NHMRC, following a systematic review of seven global studies of wind farm impacts on health, issued a consultation draft which further concluded that there is no reliable or consistent evidence that wind farms directly cause adverse health effects in humans (NHMRC 2014).

Other risks around the coal (and LNG) fuel to power station cycle include those associated with transportation of the fuel. There are studies indicating fine coal dust levels are material along the routes of coal train lines which may impact on communities when these train lines pass through built up urban areas, such as for Hunter Valley coal transport routes (for example, CTAG 2013—Coal Train Signature Study).

In the case of marine transport, impacts include the dredging of harbours and disposal of dredged soils on marine ecosystems and Great Barrier Reef as in the case of Gladstone Harbour dredging for LNG and coal exports, and the Abbott Point port expansion dredging proposed to be undertaken for the development of Galilee Basin coal deposits, respectively (for example, The Australian 16 February 2013; The Courier Mail 21 January 2014; Sydney Morning Herald 23 March 2014).

NATURAL GAS

In the case of conventionally extracted natural gas, the impacts on land may well be less than when coal is mined, but this is less the case when unconventional gas such as shale gas or coal seam gas is concerned. In both these cases, the productivity of unconventional gas wells is orders of magnitude less than conventional gas wells, so many more wells need to be drilled (Figure 8).

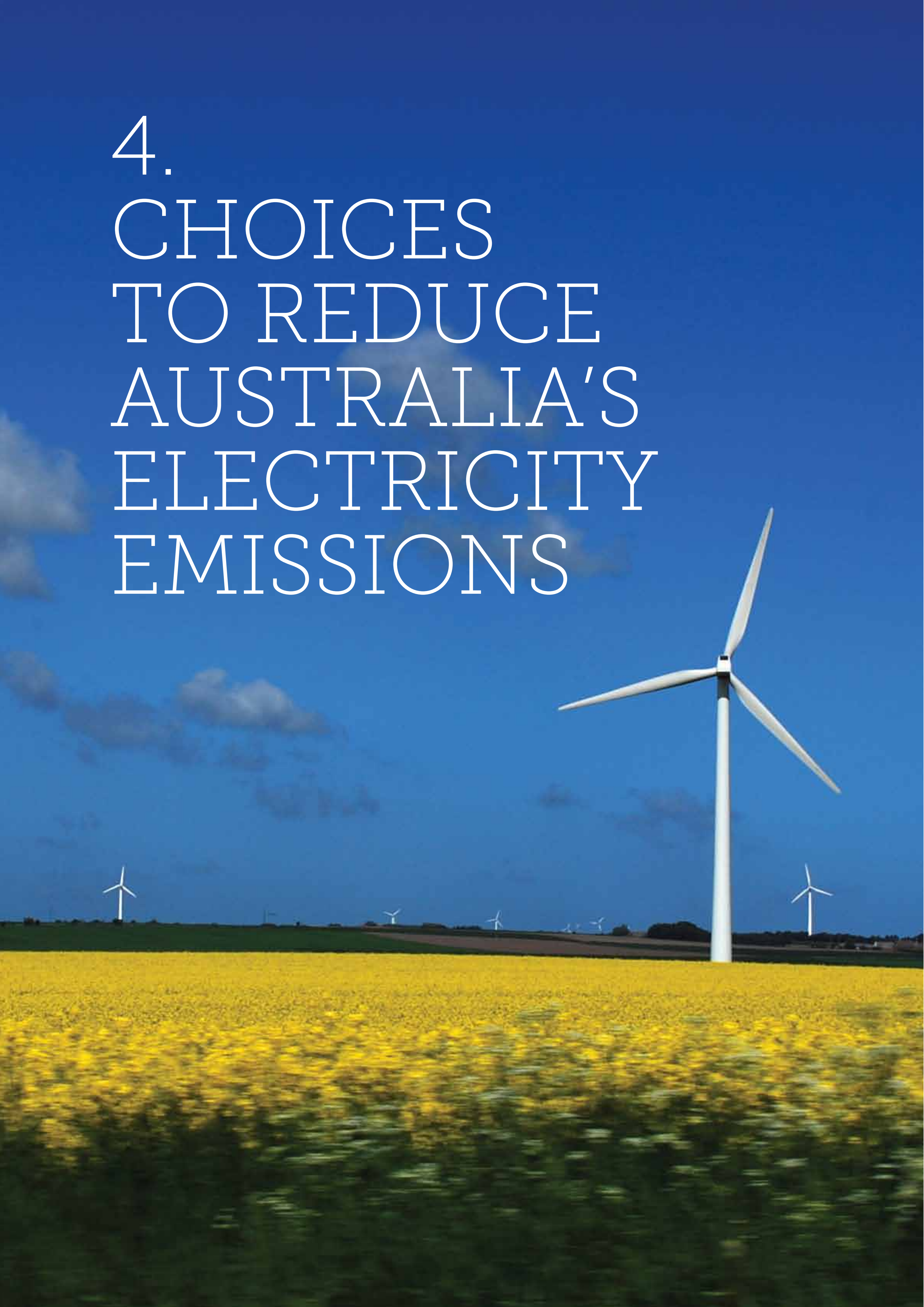
The production of CSG requires that coals containing methane be dewatered first to allow the gas to desorb from the coals and be extracted. The water quality is variable, but typically includes a range of dissolved salts, which need to be dealt with. A range of methods is being used, including reverse osmosis desalination, evaporation in storage in ponds and re-injection of concentrated brines into underground saline aquifers. The amounts of water and salt involved are considerable, with some estimates placing these at 140 to 200 gigalitres per year (equivalent to 0.3 to 0.5 Sydney harbours per year) (Klohn Crippen Berger 2012) and up to 20 million tonnes of salt, respectively over the life of the Queensland LNG projects.

Figure 8: Shale oil and gas production wells, Eagleford Field, Texas, USA.

Some communities are also concerned about the impact of fracture stimulating the coals to increase the recovery and flow rates of gas. Concerns include the chemicals injected with the fracture fluids, and the impact of fracturing on the rock seals between the coal seams being dewatered, and adjacent potable water aquifers used to source water for farming and domestic uses. The concerns include risks that the potable aquifers will also be dewatered, and that fractures will bypass rock seals adjacent to the coal seams, allowing methane and chemical fracture fluids to ingress into these adjacent potable aquifers. There is much community concern and debate in areas impacted by unconventional gas development across Australia and in other countries around these perceived risks (for example, The Guardian 14 February 2014; The Age 14 November 2013).

In addition, there is concern in some quarters that fugitive methane emissions may increase around such unconventional gas fields due to the relatively shallow nature of the reserves, the very large number of wells to be drilled, tested and completed, and the fracture stimulation taking place. There is no comprehensive data set relating to the true scale of fugitive emissions from the CSG industry in Australia, but estimates place such emissions in the range of 1.5% to 2% of production (Day 2012). As methane has a global warming potential some 20 to 80 times that of CO_2—at least in the 100 year timeframe (IPCC 2013), the impact of methane losses of such magnitude is considerable. Due to these fugitive emissions, the potential GHG savings of the CSG to natural gas fuelled power generation cycle relative to coal generation are likely to be much less than previously thought, and may approach the GHG intensity of sub critical coal fired power generation if fugitive emissions are in line with reported USA levels (Hardisty 2012).

4. CHOICES TO REDUCE AUSTRALIA'S ELECTRICITY EMISSIONS



There are three main ways to significantly reduce Australia's emissions from power generation:

1. Shut down old technology coal and gas fired plants (and replace with low or zero emissions plants).
2. Capture and sequester (for geological time) CO_2 from coal and gas fired power plant, and associated fuel mining and production processes.
3. Switch generation fuels from high emitting fuels like coal to lower emitting fuels like gas, or zero emission fuels like renewables.

In comparing power generation technology choices in a carbon constrained world, comparisons need to be 'like' with 'like', that is, attributes and costs for low emissions outcomes (for example, fossil fuel with CCS compared with renewables). This report reviews the status of development and deployment of each of these choices.

While CCS is essential for any new power station, it is unlikely to be a viable option for much of Australia's fleet, given the fleet age, high costs and lack of suitable locations to apply the technology.

Rapid deployment of renewable power, like wind and solar, while retiring old coal plant, is one of the most effective ways to reduce electricity sector emissions. In Australia achieving substantial emission reductions requires a step change to wind and solar combined with battery storage.

Globally renewable energy is growing very quickly, is attracting billions in investment and costs are dropping rapidly.

- Global PV capacity has been growing, on average, over 40% per year since 2000 and there is substantial potential for long-term (decadal) growth.
- Since 2000 the capacity of wind power globally has grown at an average rate of 24% per year.
- China is leading the world in wind with 45% of the total installed capacity.
- The potential for wind power to supply more electricity is immense and wind capacity is forecast to double by 2017.
- Solar thermal power (plants that provide energy 24 hours a day) capacity has been growing at 45% per year, mainly in the USA and Spain.

Australia is the sunniest country in the world and one of the windiest, but has a very low share of renewable energy generation globally.

- Over 1 million Australian households have installed solar PV.
- South Australia is the only state with world leading wind capacity (28% of its energy generation)
- If the current national renewable energy target remains in place wind power could reach 10.5% of Australia's total power by 2020, reducing CO_2 emission by 30 million tonnes—equivalent to two coal fired stations.

4.1 Carbon capture and storage (CCS)

There are several technologies being developed to capture and store CO_2 emissions. This process, termed CCS is mostly suited to coal fired power stations but also can be used to capture CO_2 emitted from natural gas extraction and industrial processes.

The CCS process involves the following steps:

1. CAPTURE: CO_2 is separated out from other combustion products like sulphur, ash and nitrogen. In newly built power stations, capture technologies include:

   » Integrated Gasified Combined Cycle—(IGCC) where coal is gasified with steam and oxygen in a reactor and CO_2 is separated from the other products. The resulting purified gases, mostly hydrogen with some carbon monoxide (CO), are used to fire a gas turbine in a power plant, much like a CCGT gas plant

   » Oxyfiring—where coal is burnt in a boiler using an oxygen-enriched air stream or a mixture of oxygen and recycled flue gases to concentrate the CO_2.

   Both of these technologies use oxygen enriched environments rather than air (which is mostly inert nitrogen) to burn the fuel, meaning the CO_2 produced is in a concentrated form. A large air separation plant is required to provide the massive amounts of oxygen needed.

   In existing coal power stations, capturing CO_2 may involve retrofitting with flue gas treatment processes to purify the waste stream, followed by the use of conventional amine or other CCS processes to remove the CO_2 for storage.

2. TREAT, COMPRESS: After capture, CO_2 needs to be dried, other combustion by-products like sulphur oxides, ash and vapourised metals are removed (reducing its corrosive properties for pipeline transportation). Then the CO_2 is compressed for transport and storage.

3. TRANSPORT: CO_2 is transported to suitable storage locations, usually requiring large new gas pipelines.

4. STORE: CO_2 is then further compressed to high pressures and injected deep into suitable, underground geological formations. In Australia, storage locations are likely to be depleted gas reservoirs or deep saline aquifers, where the CO_2 is intended to remain for geological time (thousands or millions of years without leakage) as a supercritical fluid. In some overseas locations, the CO_2 may be able to be injected into depleted oil reservoirs to allow more oil to be extracted.

CCS technology may also be able to be applied to capture and store CO_2 emitted during natural gas extraction (by treating and re-injecting the CO_2 removed from the raw gas stream). This is being applied at the Gorgon LNG project, and at Sleipner in Norway.

CCS also has potential to be applied to industrial processes such as cement, steel and fertiliser manufacture which produce large, concentrated volumes of waste CO_2.

New and retrofitted gas power stations are less suited to CCS as gas turbines run with large amounts of excess air, increasing the volumes (and associated costs) of exhaust gas treatment to capture the CO_2, and creating back pressure on the turbine exhaust which adversely impacts efficiency.

OPERATING CCS PROJECTS

There are currently twelve commercial scale CCS projects operating globally which capture and store approximately 15–20 million tonnes of CO_2 emissions per year. Of these projects, eight operate in natural gas processing (to enhance the recovery of oil) and four in other industries.

There are currently no operating commercial scale projects capturing emissions from electricity generation. Two CCS electricity generation projects are currently under construction in Canada and the USA at Boundary Dam and Kemper County respectively. These will capture CO_2 and inject it into underground reservoirs to enhance the recovery of oil.

The number of CCS projects in operation are projected to increase to 21 by 2020 (Global CCS Institute 2014), and forecast to capture around 30 million tonnes per year globally. Of these 21 projects, only two will be sited on power generation, capturing 4.5 million tonnes per year (in contrast to the more than 1900 million tonnes per year of CO_2 produced by burning coal for power generation in the United States alone (OECD/IEA 2012a)).

CCS DEMONSTRATION PLANTS

Limited progress continues to be made with commercial scale CCS technology demonstration plants in the power generation sector globally.

› In North America, two projects are at advanced stages of construction (Boundary Dam and Kemper County —discussed in following section), and the US Department of Energy has approved US$1 billion of funding towards FutureGen 2.0, a US$ 1.65 billion rebuild of an idled 200MW power plant to retrofit it with oxy-firing (166MW net) and CCS (Global CCS Institute 2014; FutureGen 2.0 2013)

› In Europe, a number of commercial scale demonstration projects which would have captured 4 million tonnes of CO_2 per year from power plants, have recently been cancelled or put on hold. The number of operating or prospective CCS projects in Europe fell from 14 in 2011, to just 5 in 2014 (Global CCS Institute 2014) One of the remaining projects being planned for the power generation sector is the ROAD project near Rotterdam, where final investment decision has been pending since 2012. Reasons for the delay include increases in capital and operating costs relative to fixed grant/support funding, creating a substantial funding gap, low carbon certificate prices in the European Union (EU), and energy policy uncertainty (Ragden 2014). A further project, the DRAX White Rose project in the UK, is currently progressing through public planning processes, and seeking UK and EU funding support (White Rose 2012–2014)

CCS IMPACTS ON COAL POWER STATION EFFICIENCY

Over the past four decades, advanced metallurgy and materials have led to a 20% gain in coal fuelled power station efficiency. These efficiency gains will largely be eroded by CCS, as some 20–25% of the energy produced by a CCS power station will need to be used to drive the carbon capture and storage processes.

This has flow-on effects—increasing fuel needs and CO_2 produced, the size of power plants and capital expenditure per net MWh produced, or on retrofits, significantly reducing net power output and efficiency.

COST AND FINANCING OF CCS

The costs of applying CCS technology to Australian coal fired power stations have high levels of uncertainty due to the limited deployment of the technology globally, and Australian construction conditions. Australia's principal potential storage locations are under the Bass Strait and off the Western Australian coast (Commonwealth of Australia 2010). The long-distance transport of CO_2 from coal-fired power stations in NSW and Qld would add substantially to the cost of CCS in these states.

In addition to electricity cost and efficiency challenges, there are a number of other hurdles to the rapid deployment of CCS globally and in Australia. As is the case overseas, new power stations incorporating CCS in their design will be challenging to finance in the Australian market because of the substantial capital investment needed, and the lack of a long operating history of overseas facilities. CCS has not yet been proven on an integrated basis in a commercial power plant (World Energy Council 2013a). In North American and European developments the captured CO_2 has a value through either, being used to increase oil recovery from depleted reservoirs, or through a price on carbon. In Australia, there are few, if any suitable oil reservoirs and the absence of a carbon price would mean the CO_2 captured has no value, creating an additional barrier to CCS deployment.

Figure 9: Boundary Dam Carbon Capture and Storage Facility, Canada.

Three integrated generator—retailers dominate the Australian electricity market. It is most likely that one of these companies would need to fund, or at least contract financially to take power from a new large power plant with CCS. The balance sheet exposure from developing a new CCS power plant in Australia could be substantial, from two perspectives. Firstly, to fund the construction of the plant, and secondly, to manage the integrated electricity supply risk to the retail business if its operating reliability were less assured than conventional power plants.

In considering capital expenditure for coal fuelled power stations with CCS in Australia, it is noteworthy to review the latest published cost to complete information for the two commercial scale CCS power projects being built.

The 582MW (net) Kemper County Integrated Gasification Combined Cycle (IGCC) power plant in the USA is a totally new power plant now under construction (around 80% complete), with operations delayed until later 2014. The plant is forecast to cost over US$ 5 billion, a substantial over-run on the original estimate (Reuters 2014a) This is a new power station expected to capture around 65% (3.5 million tonnes CO_2 per annum) of the CO_2 emissions produced, with CO_2 to be injected into an existing oil field to improve oil recovery. The project capital cost overruns have required the parent, Southern Company, to raise an additional $1.14 billion in equity to inject into the project, in order to preserve gearing levels and credit ratings of the parent company (Mississippi Business Journal 4 November 2013). The unit cost of the project—US$ 8.6 million per MW of capacity.

The 110MW (net) Boundary Dam power plant in Canada (Figure 9) is a retrofit of one boiler and steam turbine out of an existing coal fuelled power plant built in the early 1970s. The project involves replacing the old boiler and steam turbine, and adding new ash, sulphur dioxide and carbon dioxide removal equipment and compression to allow carbon dioxide to be injected into an existing oil field to improve oil recovery. Specialised equipment used to build the plant is some of the largest of its type, reported the lead contractor on the project (SNC-LAVALIN 2013). The project will generate 110MW net (139MW before internal power usage, including the CO_2 compressor which uses 15MW alone), and will sequester around 1million tonnes per year of CO_2. The project was reported in late 2013 as being on track for April 2014 completion, but the cost estimate to complete has increased to C$ 1.355 billion (Leader-Post 18 October 2013). The unit cost of the project—C$ 12.3 million per MW of capacity.

CHALLENGES DEPLOYING CCS ON AUSTRALIAN POWER STATIONS

Given the risks involved in deploying new CCS technology in Australia, it is likely that costs seen overseas would be significantly higher if plants were built domestically. Australian construction costs for large complex processing projects are typically significantly higher—up to 50% more than USA, Gulf or Canadian oil field costs for the same plant types (BCA 2013).

It is most likely that one of the three large Australian integrated generator—retailers would need to fund, or at least contract financially, to take power from a new large Australian power plant with CCS.

- Based on Kemper County costs for a 580MW new power station, (without adding extra for the Australian location factor), the capital cost would represent 40 to 70% respectively of Origin Energy's or AGL Energy's market capitalisation (in the case of Origin Energy, approaching its share of the Australia Pacific Liquefied Natural Gas (APLNG) project cost). This size of investment would stress the balance sheet of these companies, particularly as the capacity to secure debt finance for such a development would likely be limited given the new technology operating risks. A second critical aspect of managing risks that these integrated generator—retailer businesses consider is the risk of having a power plant shut down when retail market demand, and prices, are high. A new technology plant would increase risk of potential outages at times of high demand, a costly contingency to insure against.
- Using the Boundary Dam project as broadly indicative of the type of work needed to implement CCS as a rebuild on an existing power station, say one 200MW unit at the Hazelwood power station, the indicative cost of that work may be conservatively of the order of A$ 2–2.5 billion. While this sort of investment is likely to be able to be supported by owner GDF Suez's balance sheet, the company would need to consider whether spending such a large amount of money on such an old depreciated power plant as Hazelwood is financially worthwhile.
- Added to CCS power plant costs are the costs to transport CO_2 to the sequestration fields, and to build the infrastructure to inject it. Within Australia, in the absence of carbon pricing, it is unlikely a value for the CO_2 injected will be realised through additional extraction of oil in enhanced oil recovery schemes. There are few if any suitable oil reservoirs close to power generation CO_2 sources. Australia also has few suitable depleted gas reservoirs or aquifers to store CO_2 located close to existing NSW generation or generation in the Gladstone region of Queensland. CO_2 transport and injection costs for these plants were estimated some years ago at $50/tonne, with costs for Victorian plants as low as $10–$15/tonne of CO_2 with the Gippsland Basin closer (Allinson 2009).

FOSSIL AND RENEWABLE POWER COST COMPARISONS NEED TO BE 'LIKE' WITH 'LIKE'

Commentators asserting that renewables are an expensive way to generate electricity usually fail to compare like with like. Comparing wind or solar power capital costs to coal or gas fuelled power without carbon capture and sequestration is an unequal comparison. The former produce electricity with no emissions, the latter, substantial and ongoing emissions over their operating lives of up to 50 years. The only valid comparison to be made on costs is zero carbon renewables with zero (or low) carbon fossil fuelled power (that is, with CCS). On this basis, actual capital costs of the only two "commercial" sized CCS power projects under construction globally are 2–3 times higher per MW than the capital costs of new commercial renewables. Wind and solar also have much lower operating costs than fossil-fuelled power stations with CCS.

Visual amenity is also an important community attribute to ensure like for like comparisons are made. When people weigh the visual impact of renewables like wind, it is appropriate to contrast these perceptions with those of open cut coal mines and coal power plants with CCS. Rather than looking like a conventional coal fired power plant, coal plants with CCS will look like massive oil refineries or petrochemical plants.

4.2 Renewable power technology choices

There are many forms of renewable power generation. The IEA and IPCC have determined that rapid deployment of renewables is one of the most effective ways to make major reductions in electricity sector emissions in the near to medium term (OECD/IEA 2013a; IPCC 2014). The technologies addressed by this study are proven technologies being deployed at large scale globally, with the potential to materially impact in the near term on the emissions reduction task.

These technologies are:

- Large scale hydro
- Large scale wind
- Solar PV—both centralised and distributed
- Concentrated solar thermal.

A related storage technology, batteries, which shows great promise to economically firm intermittent renewables such as wind and solar PV will also be considered.

Figure 10: Three Gorges Dam in China.

Comparatively, Australia, despite having major world-class renewable resources in wind and solar, has a very low share of renewable electricity generation, ranking seventh lowest among the 28 member countries of the IEA (AER 2012).

The relative costs of these technologies and comparisons with fossil fuel technologies are considered in Section 5.

4.2.1 Large scale hydro

HYDRO IS THE LARGEST GLOBAL RENEWABLE

Hydro power supplied around 15.8% of the world's electricity demand in 2011, the third largest share after coal and gas fired power (OECD/IEA 2013d), with around 990,000 MW operating. The top five countries in terms of hydropower installed capacity are:

Table 8: Hydropower global capacity (2012)

Country	Global Share (%)
China	23
Brazil	8.5
United States	7.9
Canada	7.8
Russia	4.6

Source: REN21 2013

Global hydro capacity has been increasing around 3% per year, with capacity additions of 30,000MW in 2012, led by China (15,500MW added 2012), followed by Turkey, Brazil, Vietnam and Russia (REN 21 2013).

In Australia, 8186MW of installed hydro capacity represents around 16.1% of the nation's grid connected power station capacity of 50,815MW (ESAA 2014), with over half (55%) in New South Wales and 29% located in Tasmania (Ecogeneration 2011). Hydro supplies 4.8% (2008–9) to 6.6% (2010–11) of Australia's electrical energy (BREE 2013a). The amount of energy supplied varies with precipitation in Australia as rainfall patterns change from year to year as our weather cycles between El Niño drought cycles and La Niña wet cycles.

MOST GLOBAL UNDEVELOPED HYDRO POTENTIAL LIES IN DEVELOPING NATIONS

In developed nations, most large-scale hydro potential has been exploited through large dam developments built in the industrial development phase last century when global populations, environmental pressures and sensitivities were much less than today. These developments took place on large rivers where impacts on established populations were less, such as in relatively unpopulated or wilderness areas like Australia's Snowy Mountains Scheme, or the Hoover Dam on the Colorado River in the United States. There is little undeveloped hydro power potential remaining in Australia, with the largest addition in recent years being the "run of river" 140MW Bogong Power Station completed in the Snowy Mountains in 2009.

Large undeveloped hydro potential remains in many less developed countries (Figure 10) but development is potentially contentious due to:

› Global population pressures—the fact that many of these large rivers run through several countries, or support large rural populations with food, (for example, Mekong River, Amazon River).

- Associated inundation means traditional communities which have built up along river systems for food and transport need to be resettled (for example, Three Gorges Dam in China, proposed Purari scheme in Papua New Guinea).
- Impacts on remote wilderness area values and natural species, possibly unique to the region to be flooded e.g. Yangtze River Dolphins downstream of the Three Gorges Dam—(Time 10 August 2007), or natural wilderness landscapes such as the wild rivers in Patagonia, Chile, (e.g. HidroAysen and Energia Austral proposals) or the Franklin River in Tasmania.

Domestic or international opposition can make such large scale development projects increasingly problematic and commercially risky to advance, with intense social opposition resulting in changes to governments, or companies losing their social licence to operate.

Pumped storage is a variant of hydro power systems. Water is stored in two dams, one higher than the other, and allowed to flow from the upper to the lower to produce electricity (as in a conventional hydro station) at times when demand is high, and then is pumped back to the higher dam (using surplus electricity to power the pumps) when demand is low. Around 138,000MW of pumped storage exists globally, with 3000MW of capacity added globally in 2012. China accounted for over half of the 2012 additions, and is currently constructing the world's largest pumped storage scheme of 3600MW capacity (REN21 2013). Many investigations are looking at additions to pumped storage schemes around the world to help balance system requirements as more renewable generation comes onstream.

4.2.2 Large scale wind

GLOBAL STATUS OF WIND POWER DEPLOYMENT

Wind technology is one of the fastest growing sources of renewable power, supplying 2.5% of world electricity demand in 2011 and approaching 300,000MW of cumulative installed capacity globally (OECD/IEA 2013e). Since 2000, the capacity of wind power globally has grown at an average rate of 24% per year, doubling installed capacity every three years. By 2017 it is predicted to supply 5% of the world's electricity (OECD/IEA 2013e).

In 2012, 45,000MW of wind power was installed, up 18% on year earlier levels, an investment of US$ 76 billion (BP 2013). The USA and China each added around 13,000MW, followed by Germany and India. In 2012, the USA added more wind generation than natural gas power (Navigant Research 2013; Clean Technica 2013). In 2013, additions totalled 35,000MW—China leading with 16,100MW, or 45% of the global total (GEWC 2013).

Table 9: The top five countries for installation of wind power in 2012 and 2013.

	Capacity Additions (MW)	
	2012 (REN 21)	2013 (GWEC)
China	13,000	16,100
USA	13,100	1,084
Germany	2,400	3,238
India	2,300	1,729
United Kingdom	1,900	1,883

Source: GWEC 2013

In the top five countries—by installed capacity at (GWEC 2013; Table 9), the wind industry employs over half a million people (Table 10).

Table 10: Global wind industry employment.

Country	Installed Capacity	Global Share	Employment (OECD/IEA 2013e, IRENA 2013)
	(MW)	(%)	(Direct & Indirect)
China	91,424	28.7	265,000
USA	61,091	19.2	81,000
Germany	34,250	10.8	118,000
Spain	22,959	7.2	28,000
India	20,150	6.3	48,000
World	35,000	-	753,000

Source: OECD/IEA 2013e

Wind capacity continues to grow rapidly—forecast to double again by 2017 to 600,000MW, then accounting for 5% of total global electricity usage. China will be the leading country, with capacity more than doubling to 185,000MW, followed by the USA (92,000MW), Germany (44,000MW) and India (34,400MW) (OECD/IEA 2013e).

Six countries dominate the top ten global wind turbine suppliers (Table 11). One major supplier is based in each, except for China, which has four suppliers in the top ten, and is the largest supplier country (Navigant Research 2013; REN21). The only supplier not based in one of the top five countries where wind is deployed is Vestas in Denmark—the leading country developing and deploying large scale wind technology two decades ago. This early leader status means Vestas remains the number two supplier today.

The potential for wind to supply much more power in most countries is immense. Contrast wind's share of electricity supply in some European nations (15–30%) with its low global share (2.5%) and similar low levels

Table 11: Top ten global suppliers of wind turbines (2012).

Turbine Supplier	Country	Market Share (%)
General Electric	USA	15.5
Vestas	Denmark	14.0
Siemens	Germany	9.5
Enercon	Germany	8.2
Suzlon Group	India	7.4
Gamesa	Spain	6.1
Goldwind	China	6.0
United Power	China	4.7
Sinovel	China	3.2
Mingyang	China	2.7
Total		**77.3**

Source: REN 21 2013

in the USA and China (2–3.5%). Even the forecast capacity increases of 50–100% in USA and China over the next 5 years will only bring wind's share to 5% of each country's power supplies. Many forecasts indicate wind power deployment by 2020 will be 2–3 times 2012 global capacity (World Energy Council 2013).

Table 12: Wind penetration levels.

	% of yearly electricity supply	
	2008	2012
Global	1.3	2.5
Europe	4.0	6.0
Of which		
Denmark	20	29.9
Portugal	9	20.0
Spain	9	17.8
Ireland	9	14.5
Germany	9	11
United States	1.9	3.5
China	<1.0	2.0

Source: OECD/IEA 2013e

Examples of the increasingly mainstream business investment in wind power include:

- The 17 December 2013 announcement by MidAmerican Energy Holdings Co, the power unit of Warren Buffett's Berkshire Hathaway Inc, that it had signed a contract to purchase over US$ 1 billion of wind turbines from Siemens AG for 5 projects in Iowa —representing Siemens' largest ever order for land based wind equipment. Siemens will supply 448 2.3MW turbines with a total capacity of 1,000MW, enough to supply the power needs of 320,000 households (Bloomberg 2013). Buffett is generally regarded as one of the most successful investors and managers of capital in the USA.
- Texas has opened up to development, the excellent vast west Texas wind resources through the Competitive Renewable Energy Zone initiative. Commenced in 2008, new transmission lines built at a cost of US$ 7 billion over 5700 kilometres connect these remote areas with excellent wind resources in the west of the state to the heavily populated east

(Texas Tribune 2013). The transmission lines will allow 18,500MW of new wind developments to take place, adding over 50% to Texas' current wind capacity, already the largest of any state in the USA. With just on half of the capacity of the new transmission lines taken up with new wind farms, wind is now setting records for supplying almost 40% of the state's power needs (Texas Tribune 2013).

- The mid November 2013 announcement by General Electric (GE) that it was supplying a yield enhancement product to E.ON to install on 469 previously supplied GE 1.5–77 turbines to the utility for its US wind farms. The product increases the output of wind farms by 5%. GE has also announced that it will offer to supply battery storage of 15–16 minutes on every turbine it sells, as well as a storage retrofit on existing machines (Wind Power Monthly 1 December 2013). This adds to GE's US$1.4billion contract to supply wind turbines to the 845MW Shepherd's Flat wind farm for installation in 2011–12, the United States' largest wind farm to date.

AUSTRALIAN WIND DEPLOYMENT TRAILS WORLD LEADERS

Australia had 3,120MW of wind capacity installed by May 2013—the majority in two states—South Australia with 1,205MW (39%) and Victoria with 884MW (28%) (AEMO 2013a). Wind power generated over 6,000 GWh in 2012/13, at an average capacity factor of over 34% (AEMO 2013b). South Australia is the only state with wind penetration at world leading levels (28% of its electricity generation in 2012/13). In the rest of Australia, wind's share is low by world standards—despite most National Electricity Market (NEM) states and WA having top quartile world class undeveloped wind resources across vast areas.

Table 13: Wind penetration levels in Australia.

	% of electricity supply	
	2008/9	2012/13
Australia(*)	1.3	2.8
Of which		
South Australia	14.2	27.9
Tasmania (**)	6.1	3.7
Victoria	0.4	2.3
New South Wales	0	0.6
Queensland	0	0

Source: OECD/IEA 2013e; AEMO 2013b

(*) NEM States Only

(**) Tasmania share fell due to higher hydro production in 2012

Under the stability of the RRenewable Energy Target (RET) policy, which has had bipartisan support from the major political parties, Australia's wind capacity grew at 18% per year from 2008/9 to 2012/13 (AEMO 2013b), with over 2,000 employed in the industry in Australia (Clean Energy Council 2013). If the RET continues, the Australian Energy Market Operator (AEMO) forecasts 8,900MW more wind capacity would be installed by 2020 (AEMO 2013a), representing around 10.5% of electricity generated —placing Australia well behind most developed nations in expected wind deployment as a percentage of power supplied. Nevertheless, by 2020 in Australia, wind could be abating 30 million tonnes of CO_2 annually —more than the combined annual emissions from Loy Yang A and B power stations in the Latrobe Valley.

EXPERIENCE AND STUDIES SHOW FEW HURDLES TO INCREASING WIND PENETRATION, EVEN UP TO 40%

Global and domestic experience confirms that few physical changes to power systems are needed with wind penetration levels less than 20% of total grid capacity (OECD/IEA 2013e; AEMO 2013a, NREL 2012b). Overseas studies have concluded that integration of wind at levels up to 40% of system peak can be achieved at modest cost, with lower ranges of costs expected in the larger balancing grids (NREL 2013b). In most instances, balancing reserves (such as OCGT or pumped hydro storage) are typically much less than 15% of the wind power nameplate capacity, and often considerably less than this (US Department of Energy 2012).

A major study looking at the Western North American Grid (WNAG) concluded that wind and solar energy penetration of 33% of the US grid (equivalent to 24–26% of the WNAG—90,000MW—105,000MW of extra renewables) would result in annual fuel bill savings of US$ 7 billion, marginally offset by increased fossil fuel power station operating costs due to more cycling by US$ 0.47 — US$ 1.28/MWh (NREL 2013).

In Australia, AEMO concluded that it could potentially manage 8,900MW of additional wind generation on the Eastern Australian power grid within existing systems and processes, together with some changes to regulatory instruments and modest investments in synchronous condensers and control systems (AEMO 2013a). As actual South Australian and Denmark experience has shown, levels of wind power well above 20% are entirely achievable whilst maintaining system stability.

Computer simulations by a research group at University of New South Wales found that the least-cost mix of 100% renewable energy technologies had a wind contribution of 46% of annual electricity generation, while still meeting the reliability criterion of the National Electricity Market (Elliston et al. 2013).

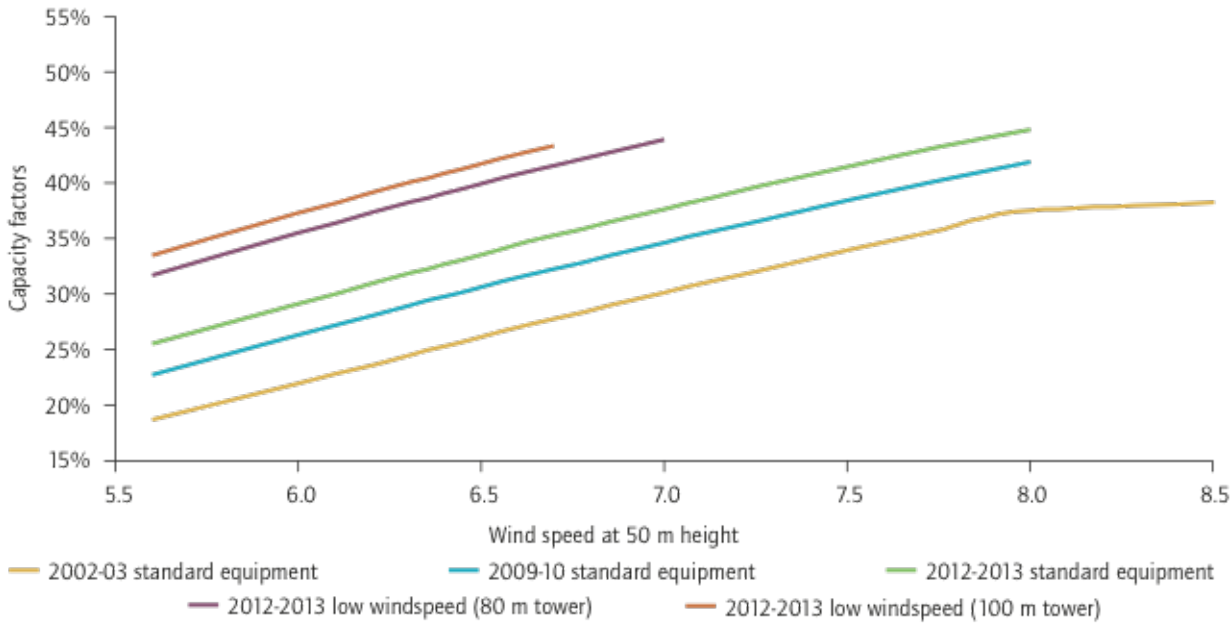
Earlier concerns that wind generation may adversely impact grid stability at much lower penetration levels have proved groundless, as have claims that new open cycle gas fired generation is needed to back up intermittent wind. In South Australia, no new open cycle plant has been added to back up wind despite wind installed capacity doubling between 2008/9 and 2012/13.

WIND TECHNOLOGY CONTINUES TO MAKE BIG GAINS IN PERFORMANCE

Continuing developments in wind turbine technology have seen yield and capacity factor (measures of the amount of energy a wind turbine is able to capture from a given wind regime) increase from around 20% a decade ago, to between 30% and 40% today (Figure 11). Recent manufacturer announcements claim capacity factors for latest designs of over 50 % (Clean Technica 1 July 2013).

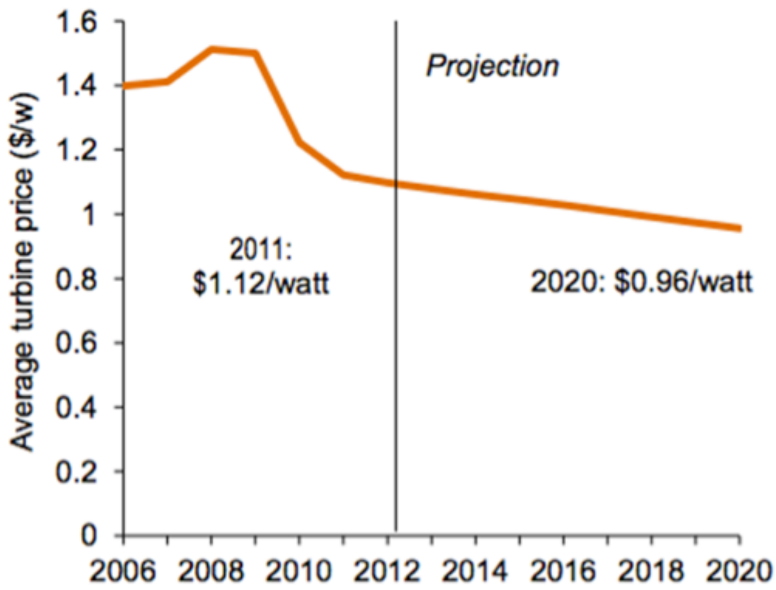
Capital and operating costs of land based wind turbines also continue to decline with advances in technology and additions to equipment supply capacity. From late 2008 to 2013, capital costs have fallen 33% or more. Operating and maintenance costs have shown even higher declines—up to 44% over the same five year period (OECD/IEA 2013e).

Figure 11: Capacity factors of selected turbine types.



Source: OECD/IEA 2013e and Wiser et al. 2012

Figure 12: Forecast for average wind turbine costs.



Source: Citigroup 2013

4.2.3 Solar PV

GLOBAL STATUS OF SOLAR PV DEPLOYMENT

Solar PV power is growing even faster than wind. By 2013, 137,000MW of solar PV plant was installed, with growth rates of 50–80% per year consistently since 2005 (Eco-Business 2014; Bloomberg New Energy Finance 23 January 2014; Statista 2014; Table 14).

In 2012, 30,000MW of solar PV was installed globally, with seven countries each adding more than 1,000MW (REN 21). 2013 saw 39,000MW added worldwide (Bloomberg New Energy Finance 23 January 2014), led by China with over 11,000MW, followed by Japan and USA. Industry forecasts indicate around 40,000 to 45,000MW will be installed in 2014.

Over one million people are employed in leading countries installing solar power in 2012 and 2013 (IEA 2014; IRENA 2013; Clean Energy Council 2013; Table 14).

The solar PV industry has been growing at rates of 25% per year at least two decades prior to 2005. Back then, volumes of panels deployed were small —seen very much at the margin of power supply. This is not the case today and will not be in the future.

Solar PV is now not only growing faster. In absolute terms, it is now bigger than some other large power generation technologies, for example:

› GE, in a recently released Global Strategy paper on distributed generation, estimates that more solar PV was installed in 2013 than

Figure 13: Australia is losing the 'Global Solar Race'

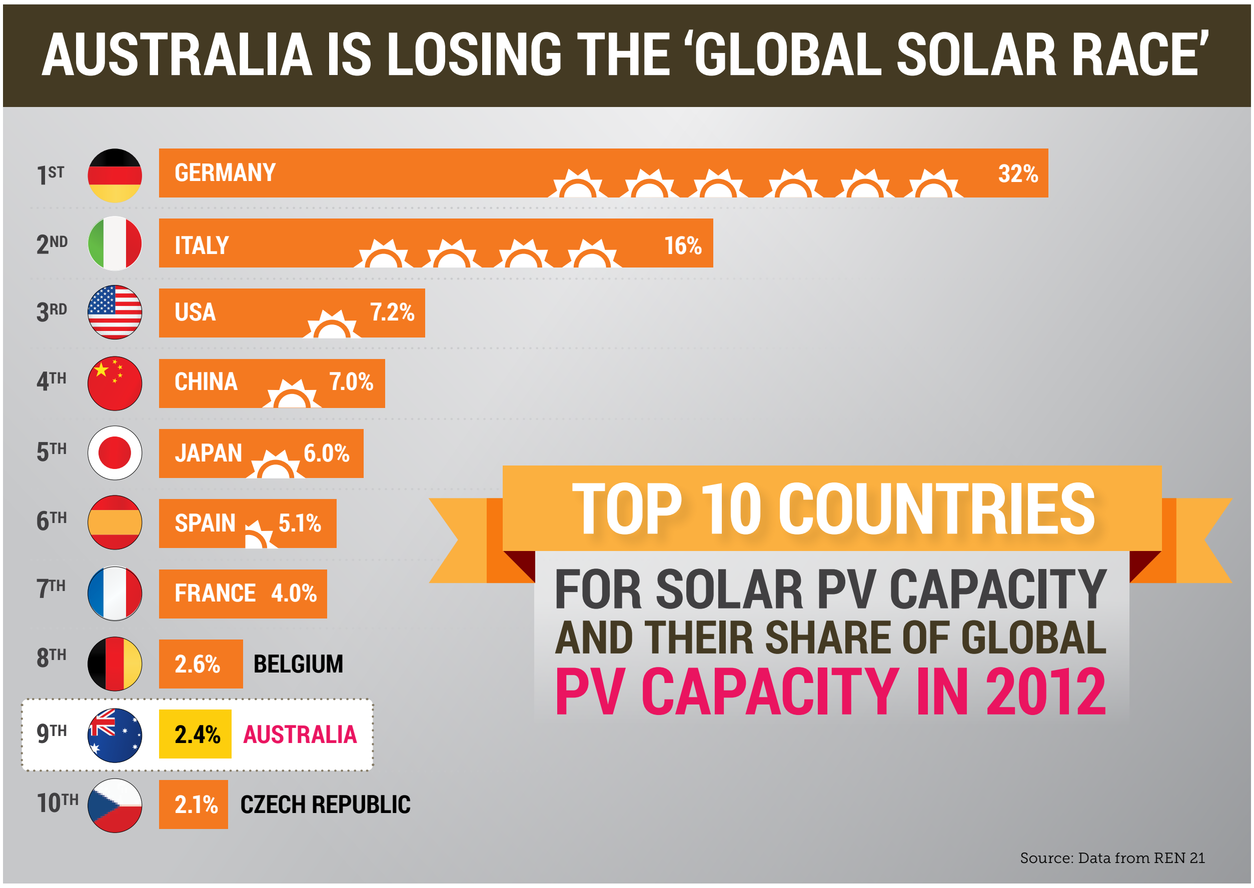


Table 14: Solar PV deployment and industry employment.

	Solar PV Power Capacity Added ('000MW)		Total Capacity ('000MW)	Employment Direct & Indirect
	2012	2013	2013	
China	3.6	11.3	27.6	300,000
Japan	2.0	6.9	13.9	na
USA	3.3	4.2	11.9	90,000
Germany	7.6	3.3	35.7	88,000
Italy	3.6	1.1	17.4	*
France	1.1	0.6	4.0	*
UK	1.0	1.5	1.8	*
Australia	1.0	0.7	3.1	16,800
Greece	0.9	1.0	1.5	*
India	0.9	1.2	2.4	112,000
Top 10 Countries	80% of global capacity additions		85% of global Installed capacity	
Total World	30	39	137	1,360,000
Total EU (excl Germany, Spain)				* 212,000

Source: (see notes below)
Notes:
* EU employment data includes these countries
2012 data from: REN 21; IEA 2013
2013 capacity data from: Eco-Business 2014; Bloomberg New Energy Finance 23 January 2014; Statista 2014
2013 employment data from: IEA 2014, IRENA 2013, Clean Energy Council 2013

worldwide sales of aero-derivative gas turbines for power generation (GE 2014).

› More solar PV was installed than wind in Europe in 2012, where installations of solar were second only to new gas plant. By 2013, due to rising gas prices, gas plants were being mothballed, but solar PV installations continue, albeit at lower growth rates than the year before.

Most major manufacturers of solar PV panels are centred in nations leading installations—much as in the case of wind. The degree of consolidation in the PV manufacturing/supply sector is much less though. The top ten solar PV manufacturers represent 43% of the global market (roughly half that for wind, where the top 10 account for 80%).

Forecasts of future global growth for solar PV predict a doubling to trebling of capacity within 5 years (EPIA 2013). Considering the low solar PV penetration across major markets relative to wind, realising this sort of growth seems entirely likely. Cost reductions coming with accelerating growth will positively feedback into stimulating further global demand.

Solar PV is installed around the world now in two main market sectors:

› Distributed power systems on domestic and commercial premises, usually on the customer side of the meter and connected to the grid at low voltage

Table 15: Top ten global suppliers of solar PV in 2012.

PV Supplier	Country	Volume (MW)	Market Share (%)
Yingli	China (*)	2300	7.7
First Solar	USA (*)	1800	6.0
Trina Solar	China (*)	1600	5.3
Canadian Solar	Canada	1550	5.2
Suntech	China (*)	1500	5.0
Sharp	Japan (*)	1050	3.5
Jinko Solar	China (*)	900	3.0
Sunpower	USA (*)	850	2.8
REC Group	Norway	750	2.5
Hanwha SolarOne	South Korea	750	2.5
Total			**43.5**

Source: RenewEconomy 15 April 2013

(*)—Top 5 Nations for Installations

Table 16: Solar PV penetration as a percentage of electricity supply and contrasted with wind.

Country	Solar PV 2012 (%)	Wind 2012 (%)
China	0.14	2.0
Japan	0.77	-
USA	0.25	3.5
Germany	5.57	11
Italy	5.75	-
France	0.78	-
Australia	1.23	2.8
India	0.33	-

Source: IEA 2013, OECD/IEA 2013d.

Note:

Penetration of solar PV in electricity markets is still relatively low around the world. Comparisons with wind indicate the solar PV market has the capacity to grow manyfold for many years to come.

› Large field scale power plants up to 50MW in size, usually connected to the grid at high voltage transmission or distribution level.

Globally, all twenty-two field scale solar PV power plants over 100MW were completed in 2011 or later. Nearly all of the plants with more than 50MW were completed in the past five years (PV Resources 2001–2012). The combined capacity of these plants totals 3,870MW, with the largest plant to date, the Topaz Solar Farm in the USA (Figure 14), over 550MW with 300MW completed through to January 2014 (Clean Technica 2 March 2014). The statistics on these plants are impressive (Table 17).

Table 17: Largest Global Solar PV Power Plants

	>100MW		>50MW (incl >100MW plants)	
Country	Capacity (MW)	No. of Plants	Capacity (MW)	No. of Plants
USA	2,360	11	2,630	15
China	721	5	771	6
Germany	439	3	1,208	14
India	130	1	185	2
France	115	1	298	4
Ukraine	106	1	314	4
Canada	-	-	165	2
Italy	-	-	154	2
Total	**3,871**	**22**	**5,725**	**49**

AUSTRALIAN SOLAR PV INSTALLATION

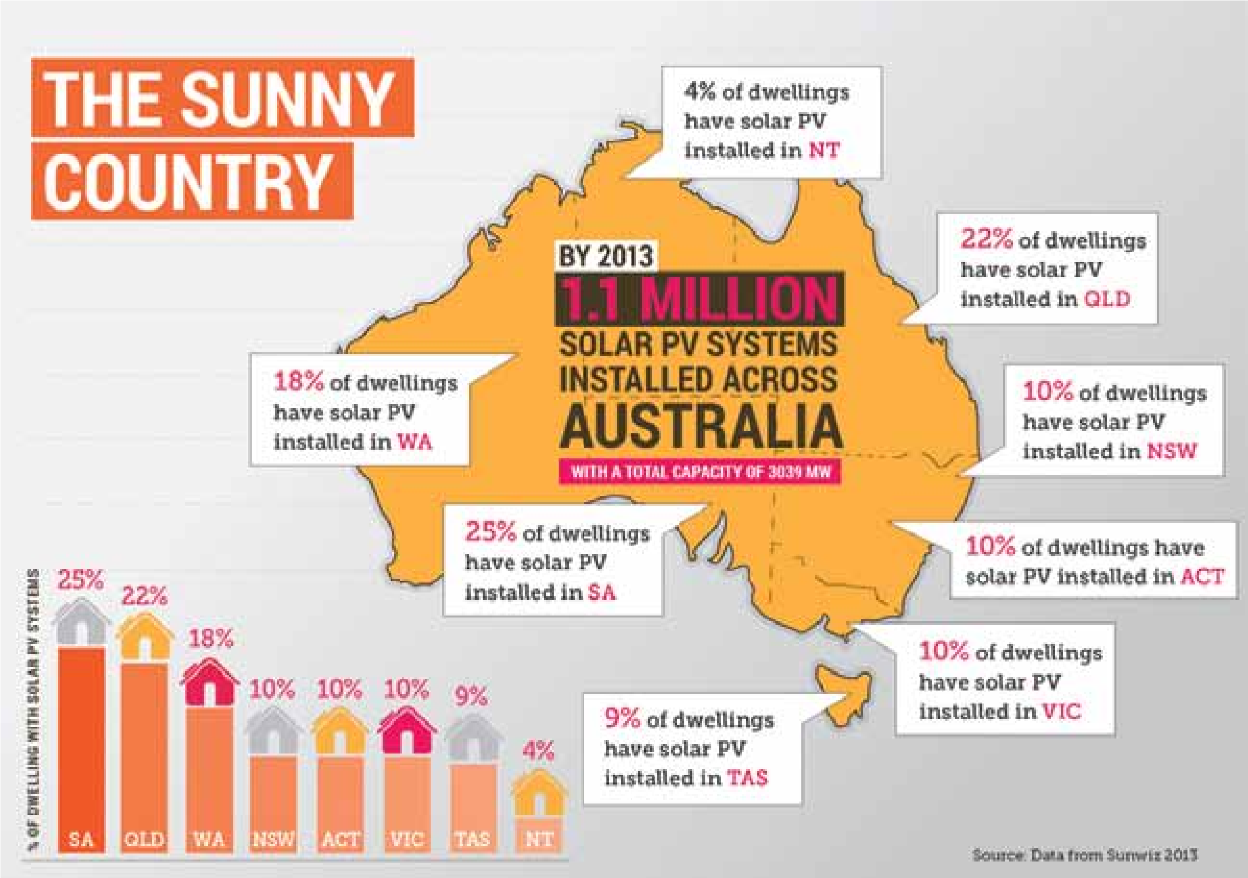
Over 1,157,000 Australian households had installed 3,039 MW of solar PV by end 2013. By February 2014 households had added another 400MW to rooftops.

South Australia leads in the proportion of domestic dwellings with solar, Queensland leads in total MW (Sunwiz 2013; RenewEconomy 4 December 2013; Figure 15).

3,000MW represents an estimated investment of over AUS$ 7 billion by

Figure 14: Topaz solar farm in the USA.

Figure 15: Australia: 'The Sunny Country'. Solar PV systems installed by state.



private households in reducing their exposure to rising grid electricity costs experienced by consumers in all states and territories over recent years. More solar PV capacity has been added than gas fired generation capacity to the national electricity market in the past five years (and no new coal fired capacity has been added).

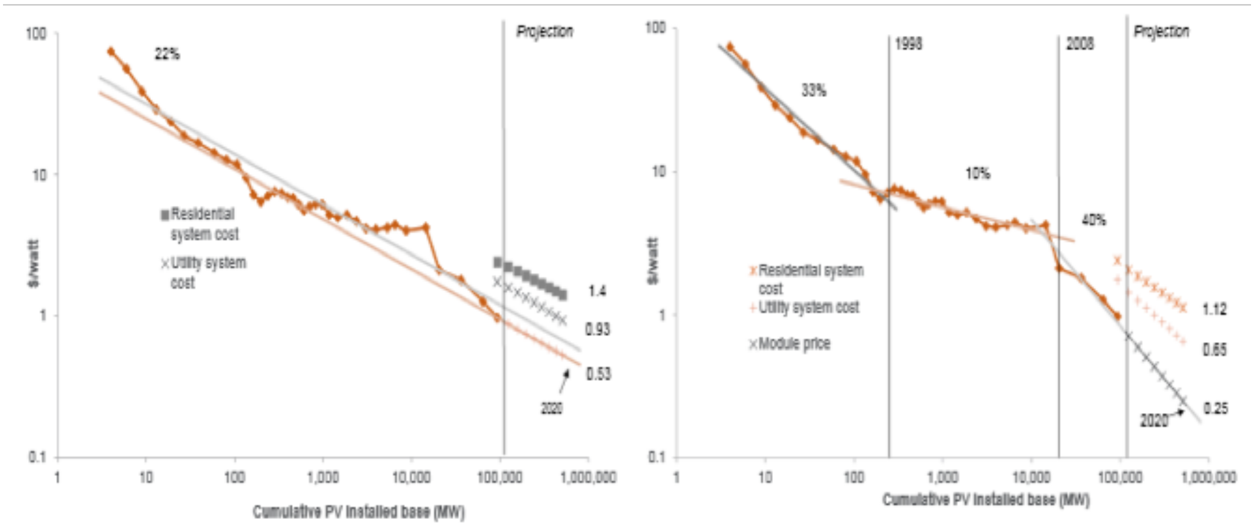
Australian solar PV installation rates have slowed somewhat in recent months after big reductions in feed-in tariff rates. However, forecasts made for AEMO by industry experts indicate that by 2020, solar PV systems installed in Australia could double or quadruple, to between 6,000 to 12,000MW. Recent actual installations since the forecast was made suggest outcomes at the higher end of this range (Sunwiz Consulting 2012).

Australia has seen very few field scale solar PV installations to date—one 10MW station at Greenough River in WA, and a 1MW project at Uterne in the Northern Territory. Two larger solar PV projects are now under construction—a 20MW project at Royalla in the ACT, and a 102MW project at Nyngan in New South Wales. A further 53 MW project at Broken Hill will commence construction in July 2014 (Fotowatio Renewable Ventures 2013, AGL 2014).

Figure 16: The global solar PV module price learning curve for crystalline silicon (c-Si) wafer-based and cadmium telluride (CdTe) Modules, 1979 to 2015.

Source: IRENA 2012a based on data from EPIA and Photovoltaic Technology Platform 2010 and Leibreich 2011

Figure 17: (a) Solar module price declines from 1972 show an overall learning rate of 22% (b) though in recent years that learning rate has increased to 40%.



Source: Citigroup, from Citi Research, Bloomberg New Energy Finance

Two further projects of 13 MW and 7 MW are also being developed in the ACT (ACT Government 2013) and a 6.7 MW solar PV-diesel hybrid project at Weipa in Queensland was recently announced (First Solar 2014b). However, installation of field scale solar PV in Australia relative to residential deployment remains low (<1%) by contrast with overseas markets (USA 22%, Germany 3.5%, China 3%) where higher levels of field scale solar PV capacity have been deployed.

GROWTH DRIVES SOLAR PV COSTS LOWER, STIMULATING EVEN MORE GROWTH—A VIRTUOUS CIRCLE

A key reason why PV continues to grow in grid-connected markets globally is the ongoing reductions in product costs which occur as the volume of systems supplied grows. In markets for manufactured goods, costs decline as experience is gained in manufacture. In the case of solar PV, long-term trends indicate that real costs decline around 22% with every doubling of cumulative installed global capacity (IRENA 2012a; Figures 16 and 17). Relatively small volumes of solar PV deployed and high annual growth rates mean the costs of PV panels have reduced 20% every 3–4 years, more than halving over the decade to 2012 (Feldman 2013).

In recent years in many retail electricity markets around the world, solar PV has achieved, or is close to achieving "socket parity" (Figure 18)—the point at which it makes better commercial sense for a consumer to install PV to make their own power on site rather than buy off the grid. This creates a "virtuous circle" where, as the more grid markets open to competitive solar PV supply, volumes grow more rapidly and costs reduce further and faster. The consensus of various forecasts of solar PV module price declines in coming years suggest it is likely that prices will halve again within five years (IRENA 2012a; McKinsey & Company 2012).

AUSTRALIANS MOST EXPOSED TO GRID POWER PRICE RISKS HAVE HIGHEST SOLAR PV UPTAKE

Surveys indicate the primary reason 70.4% of Australian households purchased solar PV systems was to save money on their power bills (CSIRO 2013b; ACIL Allen Consulting 2013). A further 11.7% wanted to reduce their carbon emissions. Uptake of solar PV by households was positively correlated with economic factors, such as:

- Income from pensions—retirees are much more likely to adopt PV than other households
- Increases in average income up to $77,500 per year, with a slight inverse relationship above that income level —low to middle income households are more likely to install solar
- Owners of detached and semidetached dwellings were more likely to install solar
- Higher uptake rates for solar in regional communities and outer metropolitan mortgage belt suburbs (RAA 2012).

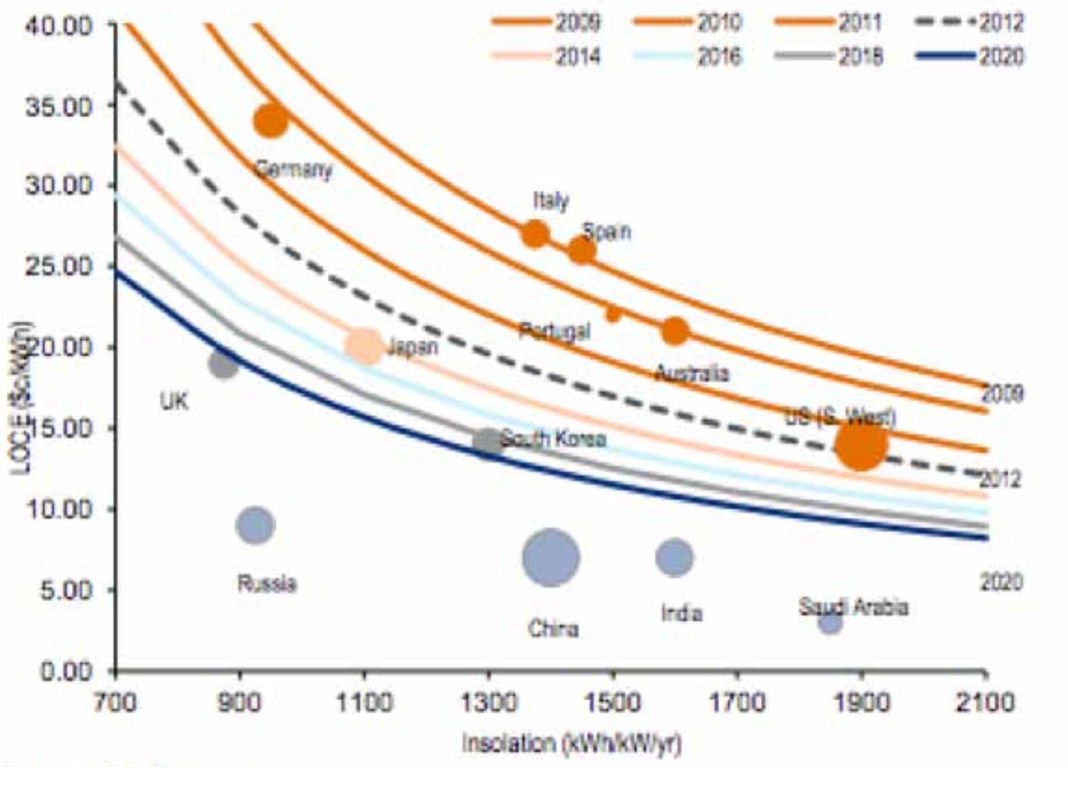
These survey results counter misperceptions, that the feed-in laws which encourage the private uptake of solar PV are a cross subsidy from the less well off to the more well to do. Rather, the reality appears to be that those most exposed to increasing grid power prices as a percentage of disposable income, those with mortgages and growing families, retirees and pensioners, and mortgage belt communities on the fringes of our major cities, are most likely to install solar PV to reduce their exposure to past, and expectations of future, increases in grid power costs.

There is likely to be further substantial uptake of solar PV by Australian households for economic reasons. Increases in retail electricity prices over recent years, caused largely through increases in network costs and allowable generation costs will likely be followed by potential future power price increases as the expected doubling or trebling in gas prices on the eastern seaboard flows through to power prices.

Solar PV has already reached parity with retail electricity prices in countries which have high solar insolation and relatively high power prices. This increasing demand is going to drive solar PV costs lower, opening up even larger markets globally.

Network companies and fossil fuelled electricity generators, both in Australia and overseas, are being impacted by consumer uptake of solar PV (and wind).

Figure 18: Domestic "socket" parity has already been reached in Germany, Italy, Spain, Portugal, Australia and the southwestern states in the USA.



Source: Citigroup 2013 from Citi Research, Bloomberg New Energy Finance

Traditional integrated utility models are coming under pressure as renewables with low marginal costs increase market share as power demand stagnates (Boston Consulting Group 2013, Reuters 2014b, Edison Electric Institute 2013). Given the high potential consequences of these powerful disruptive challenges, industry associations and some major incumbents are increasingly lobbying regulators and politicians to place barriers in the way of this accelerating trend, hoping to stall the economic drivers for solar and emission drivers for wind. Other incumbents, seeing the changes ahead and the potential business opportunities they open up, are innovating and working with regulators to enable their businesses to benefit from the changes.

However, consider recent commitments by major overseas markets to the continuing deployment of solar. In China for example, the government's target is for 35,000MW of solar PV to be installed by 2015 (contributing to a 30% target of non-fossil fuelled energy of total electric power generation by 2015) a target which China has already exceeded (Power and Energy Solutions 2014). China's 2014 target is for 14,000MW of solar PV to be installed. In Japan, the country has set a target of 28,000MW of solar PV to be installed by 2020, with the target increasing to 53,000MW by 2030 (Power and Energy Solutions 2014).

Arguably, the deployment of solar PV, coupled increasingly with battery systems, will be truly transformational for developed grid networks, much in the same way mobile telephones and the internet have superseded fixed line telephone communication systems.

4.2.4 Concentrated solar thermal

Globally, concentrated solar thermal power continues to advance, but levels of capacity added are well behind those for hydro, wind and solar PV. By 2012, 2,550MW had been installed, up 60% on year earlier levels, and a year later, had grown to 3530MW, a 40% increase. For the past five years, solar thermal power capacity has been increasing at 45% per year—most major additions taking place in Spain and the USA. Parabolic trough technology is used in 95% of operating plants at the end of 2011, and 75% of plants under construction by mid-2012 (REN21).

In 2013, there were several landmark solar thermal plants commissioned in the USA, adding more than 900MW of new capacity, as well as a number of other projects globally. These included:

- 280MW Solana parabolic trough plant with integrated storage at Gila Bend, Arizona.
- 391MW Ivanpah project in California's Mojave desert, a solar heliostat/power tower plant (EIA 14 November 2013; Figure 19).
- 100MW Shams1 parabolic trough project in Abu Dhabi.

A number of other large projects under construction are expected to be completed in early 2014, including the 280MW Mojave Solar and 110MW Crescent Dunes projects in the USA, two projects totalling 150MW in South Africa and several in China (Renewable Energy Focus 2013).

Figure 19: Ivanpah solar plant, USA.

Table 18: Concentrating solar thermal power plants—global capacity.

Country	Capacity Added (MW)		Capacity (MW)
	2012	2013	Total
Spain	950	-	1,950
USA	-	890	1,390
Abu Dhabi	-	100	100
Algeria	-	-	25
Egypt	-	-	20
Morocco	-	-	20
Australia	9	-	12
Chile	10	-	10
Total	969	990	3,530

Source: REN21 2013, plus author additions for 2013

A key advantage of solar thermal plants is their ability to produce electricity 24 hours a day through adding a combination of storage and/or gas boosting. For example, the 280MW Solana plant includes 6 hours of molten salt storage allowing it to produce electricity well into the night and early morning to meet market needs. The 20MW Gemasolar project in Spain recently set a record of operating for 36 consecutive days with around the clock power generation (RenewEconomy 8 October 2013).

4.2.5 Battery storage

Because the sun and wind vary, power from wind farms and solar is intermittent. Broadening the geographic spread of renewable wind and solar will provide a steadier output. Nevertheless, it is highly desirable to firm up supplies from these power generation sources. Currently, supplies from other generators like hydro, or gas peaking plants tend to be used. As higher levels of carbon abatement are required, other forms of low emissions capacity will be needed.

Historically, batteries have been used to firm supply in circumstances where highly reliable power is essential for example, in hospital operating theatres, and for large chemical and other plant (such as nuclear) critical control systems. However, these systems are usually only of limited size due to their costs.

A number of relatively new battery systems are now being developed, and one of the more prominent is the lithium ion battery. Most mobile applications today—for example, hybrid or battery powered cars, mobile phones, laptops and tablet devices—use lithium ion battery systems.

The increased rollout of these battery systems in mobile phones, laptop and tablet computing devices, preceded automotive applications. This accelerating take up in preference to other rechargeable battery types (e.g. Ni-Metal Hydride) has seen costs of lithium ion batteries fall around 85% in the decade from 1995 to 2005. Higher energy density lithium ion batteries have been developed for hybrid and electric vehicle markets, increasing production volumes dramatically.

Experts agree that lithium ion batteries will become dramatically cheaper in the coming decade. Based on conservative assumptions for hybrid and electric vehicle market growth, the cost of battery systems for a medium sized electric car is likely to fall by half to two thirds in the decade to 2020 (McKinsey Quarterly 2012), and roughly halve again in the decade after that (Element Energy 2012).

As battery systems drop in price, uptake of battery storage in distributed power and grid applications is expected to accelerate. Adding storage to distributed solar PV systems will allow them to better match electricity supplies to local demand. In grid networks, batteries will optimise the use of networks and central generation, substantially improving network load factors and lowering costs. This will be achieved by peak load shifting—moving renewable generation from periods of low demand to higher demand by storing surplus electricity at low demand times, and drawing on it when demand is higher. In the same way, power grids could better use their assets by charging distributed batteries and re-drawing energy when needed at peak times.

Currently, network managers add wires and transformers to meet forecast future peaks in demand for power. Demand for electricity is now falling, something which has caught experts by surprise for several years now (AEMO 2013c). So adding additional network capacity, which may only get used a few days a year, if that, is a very expensive and risky investment. However, when returns on this very expensive and risky investment are underwritten, as is the case with network investments, retail electricity customers pay (Grattan 2013) This is the main reason power prices have grown so rapidly in Australia (AEMC 2013; Grattan 2013). Allowing networks to fund battery storage (either on the networks, or in customer premises) instead of more wires and poles would significantly improve network capacity usage and lead to lower costs.

Countries with a high penetration of renewables, such as Germany, are now implementing regulatory structures and incentives to encourage the uptake of storage batteries as battery systems become cheaper. These changes will revolutionise how networks are managed and capacity utilisation optimised. The opportunity to achieve collaborative synergistic gains between network owners, users and distributed PV power generators could result in a paradigm shift in residential and commercial power system supply.

4.2.6 Challenges for large scale deployment of commercial low emissions technologies

While great strides have been made, it is still challenging to roll out widespread use of renewable and low emission fossil fuel power generation technologies. However, to meet the key challenge of keeping electricity emissions down so the world does not exhaust the 2°C global carbon budget by 2035, these challenges must be faced and overcome urgently.

Five or ten years ago, most would not have predicted the scale of today's rollout of major renewable technologies.

Table 19: Low and zero emission power generation technologies.

	Current Global Deployment	Annual Addition Rate
	2013 (MW)	2013/14 (MW)
CCS	0	690 (*)
Renewables		
Large scale hydro	990,000	30,000
Large scale wind	300,000	35–45,000
Solar PV	137,000	30–40,000
Solar thermal	3,500	990

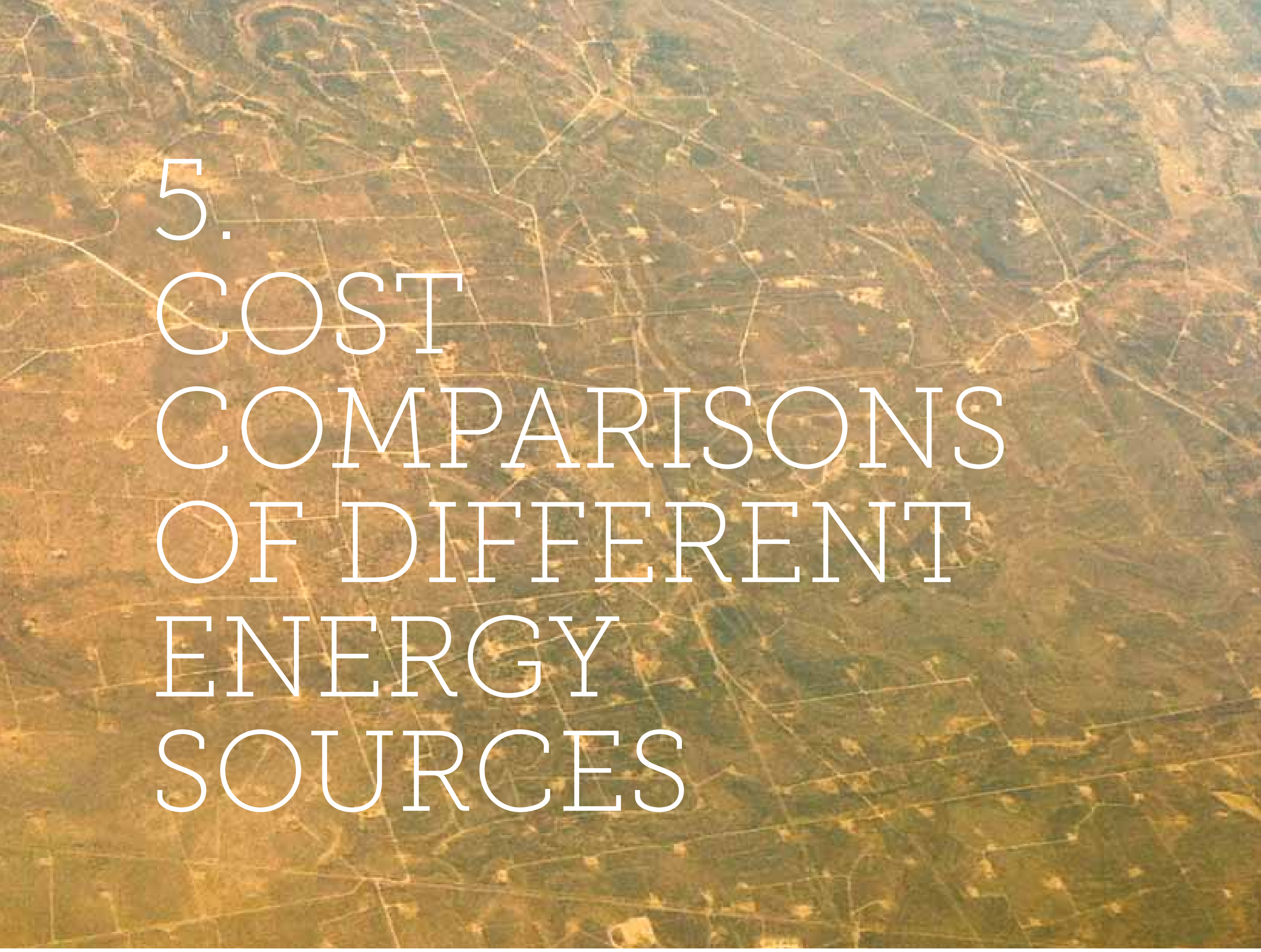
Source: (Refer to the above tables in the subsections)

(*) Equivalent to 480MW of renewables as Kemper County only sequesters 65% of emissions produced. Compared to the renewables figures above, more like 100MW per year as only two CCS power projects (totalling 692 MW) currently approved and funded for completion by 2020.

Global deployment of hydro, wind and solar PV is now challenging the annual rollout of fossil fuelled power plants. In 2013, combined new capacity of hydro, wind and solar PV added 90,000MW to global power supply, virtually matching the gross additions of fossil fuelled power plants at 95,000MW. However, around 60% of the fossil fuel additions were replacing existing old plant which was being retired and scrapped, leaving net fossil fuel additions at around 40,000MW. The investment in new renewable power plants in 2013 is estimated at US$ 192 billion, substantially greater than that for net fossil fuelled plant at US$ 102 billion. The share of new renewables (wind and solar PV, but excluding large scale hydro) of total global power generation capacity has increased by 80% in 6 years, to 13.7% (around 20% including hydro) (Frankfurt School of Finance & Management 2014).

Current capacity and rollout rates globally will see renewables exceed the IEA's '4 for 2°C' report forecasts of 27% of global power generation in 2020, by a considerable margin (OECD/IEA 2013b). It is noteworthy that this is considerably higher than renewables share of Australian electricity production, which sits at around 13% in 2012 (Clean Energy Council 2013)—a figure which could be an outlier because of a boost in hydro electricity production after heavy rainfall in 2012.

For the electricity generation sector to achieve sustained reductions in emissions globally and within Australia, large scale hydro, wind and solar PV are the three technologies best placed to be deployed at scale this decade and next. Australia has limited remaining undeveloped hydro, and an ageing inefficient coal fired power plant fleet. The heavy lifting to achieve deeper emissions cuts from the electricity generation sector will need to largely be done by a step change in the rollout of wind and solar power combined with battery storage. Installing CCS on coal fired plant is also essential if it is cost competitive with large scale deployment of wind and solar PV. However, a recent study by Elliston et al. (2014) suggests that CCS may not be competitive with renewable energy in most of Australia. Whichever low emissions technology choices are deployed though, consistent with the International Energy Agency's proposals for halving global coal fired power generation by 2035, Australia's older, more emissions intensive, less efficient and higher cost generators are likely to be progressively closed in the face of growing global and domestic pressures to make deep cuts to GHG emissions. Some states and territories, such as South Australia and the ACT, have adopted policies that have been successful in significantly reducing the carbon intensity of their power supplies, thereby showing what can be achieved when progressive policies are adopted and implemented—and the ACT is on track to generate 90% of its electricity supply from renewables by 2020, accounting for a 40% reduction in GHG emissions by 2020 (ACT Government 2014). However, the cuts to emissions required across Australia must encompass the whole of the interconnected grid markets—the NEM and SWIS. Otherwise, gains in one area may well be offset by increased emissions elsewhere. This calls for a national planning approach for progressive orderly retirement of older fossil fuelled plant, offset by increasing renewables' share of electricity supplied, and implementing CCS retrofits to existing newer technology coal plants.



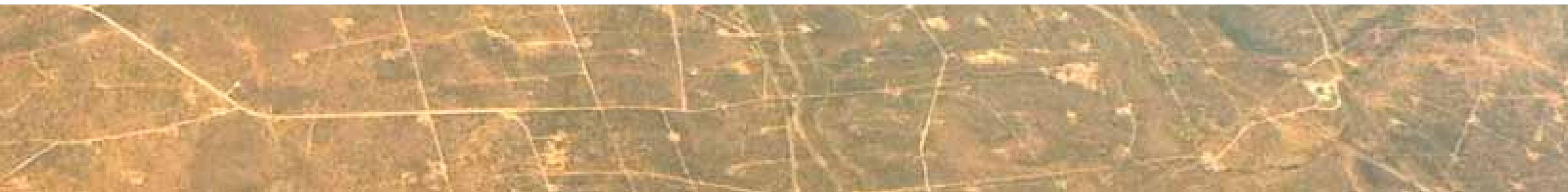
5. COST COMPARISONS OF DIFFERENT ENERGY SOURCES

Cost is the key factor that underpins discussions about electricity generation. It is a complex topic, made all the more so by the difficulty of factoring in costs that are hard to quantify, such as the cost to the community of greenhouse gas emissions.

In examining cost, this section looks at two main topic areas: (i) Methods of comparing costs of producing electricity (Section 5.1) and (ii) Forecasts of electricity generating costs (Section 5 .2).

Key findings include:

- Existing fossil fuelled plants in Australia cannot economically compete in the long term against renewables once deep carbon abatement is required.
- Worldwide, the costs of power from wind and solar PV renewables now are generally lower than the estimated future cost of power from new or refurbished coal fuelled generation plants with carbon capture and storage (CCS) technology.
- When gas prices are at Asian LNG price levels, wind (and in some recent cases, solar PV too) is competitive with new gas plants without CCS.
- The least expensive zero emission option available at scale for deployment today in Australia is wind, closely followed by field scale solar PV.
- In South Australia and Victoria, during the summer heatwaves in 2014, electricity prices were at least 40% lower



than they would have been otherwise without the contribution of wind energy.

- Also, over each full year, renewables are reducing wholesale electricity prices, not only in Australian states where wind and solar PV penetration is high, but in many overseas markets (e.g. Denmark, Texas and Germany).

5.1 Comparing costs of producing electricity

Comparing the cost of electricity generated by renewables, such as wind and solar with electricity from existing fossil fuel power stations is not a fair, or like-for-like comparison, as:

- Existing coal fired power stations and the transmission lines connecting these generators into the grid were generally paid for and built by Australian governments long ago.
- Companies installing new power stations, such as renewables, must fund the cost of the generating infrastructure (turbines or solar panels) as well as their connection into the electricity grid (transmission lines and substations).
- In the absence of a substantial carbon price, there is generally no consideration of, or value placed on the cost of GHG emitted by existing fossil fuel power plants on the community.
- Fuel mining subsidies (e.g. immediate exploration tax write-off, accelerated depreciation, diesel fuel rebate) help keep power prices from fossil fuel generators artificially low.

Electricity from coal is likely to be more expensive than renewables, if the cost of retrofitting CCS technology is factored in, or if new fossil fuelled stations with CCS are built. Furthermore, even new gas fuelled power plants in Australia without CCS may become more expensive than new renewables now that gas prices are increasing, as gas producers can choose to export that gas at much higher LNG export prices (Elliston et al. 2014).

KEY COMPONENTS OF ELECTRICITY PRODUCTION COSTS

Producing electricity from a new power plant involves three main types of costs:

- **Capital costs**—the investment to permit, develop, construct and commission the power plant and its connection to the electricity grid. This investment needs to be financed, requiring debt and equity, and these funding sources need to be serviced and ultimately repaid.
- **Operating costs**—labour and materials to operate and maintain the plant, and for fossil fuelled plants, added costs like procuring fuel, permits to emit GHG, and other impurities such as sulphur emissions from the plant to allow the plant to generate.
- **Remediation costs**—to re-instate land on which the power station is located (and possibly the fuel supply infrastructure, such as a dedicated mine) to a standard acceptable to the community at the end of the power station life.

There are many different technologies, and each has different associated capital and operating cost characteristics. How do power planners compare these?

Key measures for determining cost

Levelised Cost of Energy (LCOE) and Long Run Marginal Cost (LRMC)
Measures used to determine the full cost of electricity from new power plants—(Box 3)

Short Run Marginal Cost (SRMC) Cost of operating power plants each day (Box 4)

BOX 3: LEVELISED COST OF ENERGY (LCOE) AND LONG RUN MARGINAL COST (LRMC)—FULL COST OF ELECTRICITY FROM NEW POWER PLANTS

For new power plants, one way of comparing different plants, differing technologies, capital and operating cost projections over time, is through a measure called the Levelised Cost of Electricity (LCOE). While it is beyond the scope of this paper to give a detailed narrative on how LCOE is calculated (see the formulas in Diesendorf 2014), in essence: future costs associated with building and operating the power plant are discounted back to today's dollars, summed, and divided by the amount of power produced by the plant over that same operating life (which has also been discounted back to today using the same discount rate). LCOE allows a direct comparison of the present value unit cost per MWh of generating electricity from different power plants, with different characteristics.

Another method of calculating and comparing costs (capital and operating) per MWh is termed the Long Run Marginal Cost (LRMC). Some regulators of retail pricing in Australian electricity markets have used LRMC as a proxy for the marginal cost of the next unit of generation in determining the allowance for wholesale electricity purchased by retailers. While LRMC may have legitimacy in a rapidly growing market where new power plants need to be built soon, it provides little basis for establishing allowable retail prices when markets are over-supplied with capacity for long periods of time.

LCOE and LRMC allow a comparison of theoretical new build power plants when modelling choices for the future, but these methods also have limitations:

- In reality, no one knows what a power station will cost to build until one has actually been permitted and built. Engineers and cost estimators endeavour to make their best estimates of these costs in desktop studies (and academics and economists will frequently rely on, or selectively quote from these studies), but the reality is that until a plant has been built, staffed, and its operating performance measured, it is not possible to determine its true costs of electricity.
- These methods do not deal with existing power plants (which comprise most of any country's operating power plant fleet). Many existing plants are bought and sold at the market prices prevailing at the time (prices which are often much less than new build costs), frequently changing hands several times over their operating life. Most electricity systems the world over comprise a portfolio of existing assets, and many of those systems are balanced between supply and demand, needing little new capacity. For example, AEMO, in its latest forecast for the NEM, does not see a need for any new capacity until at least 2020/21. So in these circumstances LCOE and LRMC comparisons are of little practical relevance.
- LCOE and LRMC also fail to deal with the relative cost structures and competitiveness of power plants bidding into an electricity supply pool for economic dispatch, such as in the NEM on Australia's Eastern Seaboard, or South West Interconnected System (SWIS) in WA.

BOX 4: SHORT RUN MARGINAL COST (SRMC)—COST OF OPERATING POWER PLANTS EACH DAY

When bidding to supply electricity into power markets, short term operating costs become more important. Short term costs relate to starting and stopping the power station, increasing or decreasing its output between different bands of production, as well as other operating costs such as fuel, labour and maintenance. If permits to emit GHG are also a feature of a power market (as under the Carbon Tax), then fossil fuel power stations will also need to purchase the necessary number of permits. Electricity generated from coal as opposed to gas is more emissions intensive, so coal power stations incur more emissions costs than gas and older inefficient stations more than modern efficient ones. Collectively, these costs are termed the Short Run Marginal Cost (SRMC).

Power stations bidding into power markets will theoretically bid prices which cover SRMC and a profit margin (i.e. a capital return). However this concept has limitations in markets such as the NEM where there are high degrees of vertical integration (companies which cover many aspects such as generating and retailing) and long term financial contracts for offtake between integrated generator retailers, as well as merchant generators and retailers. These contracts significantly impact in the short to medium term on how generators will price the electricity they bid into the pool. A generator which bids a tranche of its power above the pool clearing price will not get to dispatch that power at all, losing out on all income.

Renewable generators like wind and solar have very low (close to zero) SRMC as they do not need to buy fuel or emissions permits. This means at any point in time, renewable generators can bid very low prices to ensure they get dispatched, whereas a coal or gas fuelled power station will need to bid higher prices to cover fuel (and emissions) costs.

In addition to these complicating factors, the power generation industry is one with high entry and exit barriers. It takes a lot of effort and capital to plan and build or buy generators, as well as high costs incurred on exit for mine remediation and asset decommissioning. In markets like Australia, where there is overcapacity and a sizeable number of participants, generators will bid lower prices than they might otherwise do in a balanced or highly concentrated market. This depresses returns on capital for all participants. In such circumstances, generators which have higher SRMCs may have difficulty surviving as they are not able to bid at prices which cover their cash costs.

UNCERTAIN FUTURE FOSSIL FUEL PRICES LINKED TO INTERNATIONAL COMMODITIES

The costs of buying fuel are the major cost for a fossil fuelled power station over its 40 to 50 year operating life—generally much higher than the cost of building it. Linked to international commodity prices, these costs are inherently unknowable in the long term. Australian gas and black coal prices are now linked to international prices of LNG (oil related) and steaming/thermal coal. Gas producers are unlikely to contract and sell gas domestically for prices less than LNG export netback (delivered price, minus transport costs). This means Australian gas prices are linked to international oil prices which are inherently volatile and uncertain, with no relationship to the competing fuels in the domestic power generation market.

As international LNG prices in Asia are much higher than current Australian domestic prices, it is likely that Australian wholesale gas prices will double or treble in eastern Australia in the coming decade—from around \$3–4/GJ (GigaJoule = one thousand million joules) to around \$8–12/GJ. This will make it difficult for gas fired generators to compete with renewables or coal except at times of very high electricity demand, when power prices are much higher (set by market bearable considerations, rather than cost of supply). Similar considerations may apply to coal, if the supply of coal can be redirected to export markets.

Concepts such as SRMC and LRMC do not well handle the premium on costs of this inherent uncertainty and volatility in fuel pricing. Option pricing methods must be applied, adding an additional cost factor to current fuel pricing when considering long term fossil fuelled power station selection decisions.

So in a very uncertain world, where the industry structure makes entry and exit difficult, fuel prices are inherently uncertain but likely to be increasing, carbon produced by power stations may or may not be priced at some level in the future, and competing renewables have very low to zero marginal costs (both for fuel and emissions) one can see why incumbent fossil fuelled power generators argue so vehemently against pricing GHG emissions and other arrangements which facilitate increased uptake of renewable power such as wind and solar. Effectively, these existing fossil fuelled plants simply cannot compete in the long term against renewables in growing power markets which are oversupplied. They are faced with continuing losses, mothballing capacity (which may avoid or defer remediation costs), or closure.

5.2 Forecasts of electricity generating costs

This report considers trade-offs between conventional fossil fuelled coal and gas fired stations, established renewable technologies deployable at scale in Australia—wind, solar PV and solar thermal—and emerging CCS technology (given the extent of deployment of existing coal fired generation plants).

CAPITAL AND LCOE COST COMPARISONS

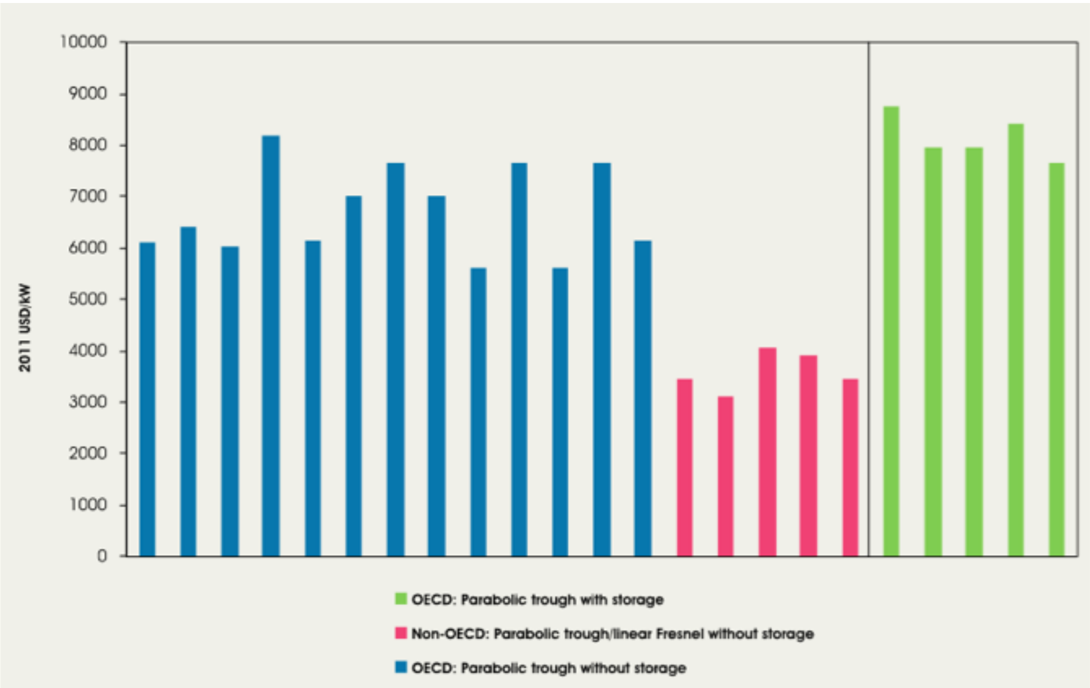
The following tables summarise and compare the capital costs and LCOE of different electricity generation technologies from both domestic and international studies: It is important to note that these are studies, and that actual costs will vary from these estimates.

CAPITAL COSTS

The comparative unit capital costs (excluding operating costs) detailed in Table 20 indicate:

- Actual capital costs for fossil fuel projects recently delivered have come in 30% to 60% higher than estimated from desktop studies.
- Actual costs for large scale renewable projects appear to be coming in at or below desktop estimates.
- Solar thermal projects with 6–8 hours storage or gas boosting have similar characteristics to fossil fuelled plants with CCS in that both technologies provide near base load power delivery with low emissions. The costs of coal with CCS and solar thermal with storage are not dissimilar at a desktop level, but the higher capital costs for the two actual commercial scale fuelled CCS power projects suggest that these may be more expensive per MWh than renewable solar thermal projects with storage.

Figure 20: Total installed costs for recently commissioned or proposed solar thermal plants—parabolic trough and linear Fresnel plants, 2010 to 2012.



Source: IRENA 2013

Table 20: Current estimates of capital costs of low emissions and renewable power generation ($'000/MW of capacity)

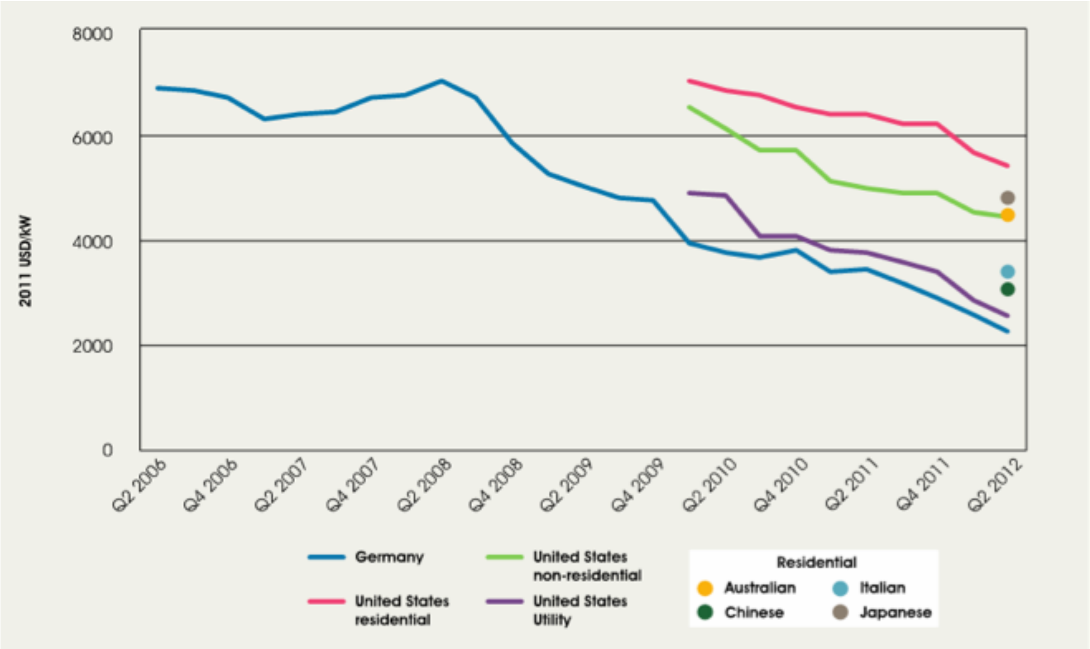
Study	Worley Parsons 2012	CSIRO 2012	BREE 2012/13	Frontier Economics 2013	ACIL Allen 2013	Lazard 2013	BNEF 2013	WEC 2013	Recent Actuals 2010–13
Coal									
IGCC Black C +CCS	7330		7330		7330	6820–7500			9540
SC Black C +CCS	5434	6180	5434		5434	8400			
IGCC Brown C +CCS	8600		8616		8616				
SC Brown C +CCS	7766	9100	7766		7766				12300
SC Black C w/o CCS				2880–3070		3000	2300–3380	2510–3700	
Gas									
CCGT +CCS	2772	3420	2772		2770	2470			
CCGT w/o CCS	1062	1070	1062	1246	1100	1006–1320	1060	1160	1440
Solar Therm PBT + 6hrs storage	8950	6850	8950	6190	8950	9000	9980	6000–10900	7500–8500 Refer to Figure 20
Solar Tower + 6hrs storage	8308		8308		8310	9000	8490	6000–8660	9000 (5800—6400 w/o storage)
PV Field	3380	5010	3380		2700	1750	2200	2410	Refer to Figure 21
Wind	2530	2810	2530	2399	2310	1500–2000	2080–2240	2270–2450	Refer to Table 21

Source: Data generated from Worley Parsons (2012); CSIRO (2012); Bureau of Resources & Energy Economics (2012, 2013a); Frontier Economics (2013); ACIL Allen Consulting (2013b); Lazard (2013); Bloomberg New Energy Finance (2013a); World Energy Council (2013)

Notes:

- US$ study costs and actual offshore plants converted to A$ at $A1=$US1, $A1=$C. While this is a broad approximation, the levels of uncertainty in most of these estimates are much wider than a 5–10% variance due to FX rates.
- No location factors have been applied. Australian costs for complex processing plant construction, such as coal, gas and CCS power plants, have been assessed at up to 50% higher than US/Canadian levels for various reasons.
- The Recent Actuals costs are taken from recent literature of international or, where available, Australian projects.
  - IGCC Black C + CCS—Kemper County project
  - SC Brown C + CCS—Boundary Dam (includes retrofit costs)
  - CCGT w/o CCS—Darling Downs Power Station in Australia (2010 completion)
  - Solar Thermal PBT + Storage—(e.g. Solana Project 2013)
  - Solar Tower + Storage—(Crescent Dunes project 2014, Ivanpah 2014 (w/o storage—gas boosted))
- The CCS projects exclude the capital costs of constructing gas pipelines and compression to transport and sequester the CO2, understating the capital costs involved. The costs of transporting and sequestering the CO2 were estimated in 2009 to lie in the range of $15 to $50/tonne of CO2 sequestered for large quantities (Allinson 2009).
- The PV costs are for large scale (multi MW) field installations and do not relate to residential or commercial building installation costs.

Figure 21: Solar PV system price trends by sector and country, 2006 to 2012.



Source: IRENA 2013, from BSW 2012; Photon Consulting 2012; SEIA/GTM Research 2012

Table 21: Typical total installed costs for wind farms by country.

	Year for costs	New capacity 2011 (GW)	Cost range (USD/KW)
China	2011	17.60	1114–1273
Australia	2011	0.23	1600–3300
Austria	2011	0.07	2368
Brazil	2011	0.58	1650–2850
Denmark	2010	0.18	1600–1700
Europe (weighted average)	2010	10.28	~1600
Ireland	2011	0.24	2000 to 2600
Italy	2011	0.95	1941–2588
Japan	2011	0.17	3900
Mexico	2011	0.05	2000
Norway	2011	0.08	1900–2000
Portugal	2011	0.38	1810
Spain	2009	1.05	2000
United States	2011	6.81	2100

Source: GWEC 2012; IEA Wind 2011A, 2011b; EWEA 2011

LCOE ESTIMATES

The comparative LCOE estimates in Table 22 indicate:

- The costs of global scale solar PV and wind are generally lower than the cost of coal plants with CCS.
- The least expensive zero or low emissions option is wind.
- This is followed by large scale solar field PV with costs no greater than and in some estimates, significantly less than coal with CCS.
- Both wind and solar are proven technologies, reducing financing and technology risks, whereas the uncertainties and risks with CCS technologies applied at scale to coal (given the limited global deployment to date) would make financing major new power station +CCS investments in Australia problematic.

Table 22: Current estimates of LCOEs of low emissions and renewable power generation ($/MWh)

Study	AEMO (ex Worley Parsons) 2012	BREE 2012/13	Lazard 2013	BNEF 2013	WEC 2013	EIA 2014
IGCC Black C +CCS	150+(20–50) =170–200	242+(20–50) =262–292	154+(20–50) =174–204	-	-	147
SC Black C +CCS	191+(20–50) =211–241	196+(20–50) =216–246	145+(20–50) =165–195	-	-	-
IGCC Brown C +CCS	-	199+(10–15) =209–214	-	-	-	-
SC Brown C +CCS	-	192+(10–15) =202–217	-	-	-	-
SC Black C w/o CCS	-	84	65	93–139	93–126	96
CCGT +CCS	128–140 +(10–50) =138–190	162+(10–50) =172–212	-	-		91 (*)
CCGT w/o CCS	91–101	75–105	-	97–116	92–108	66 (*)
Solar Therm PBT + 6hrs storage	302	250–410	-	360	156–469	243
Solar Tower + 6hrs storage	277	220–370	164	204	105–317	243
PV Field	224	160–270	104	157–236	127–191	130
Wind	99	90–130	45–95	80–113	71–99	80

Source: AEMO (2014a), Bureau of Resources & Energy Economics (2012, 2013a), Lazard (2013), Bloomberg New Energy Finance (2013a), World Energy Council (2013), USEIA (2014)

Notes:

Base LCOE numbers exclude the cost of transporting and sequestering CO_2. This conservatively adds $20—$50/MWh to the base numbers for black coal CCS cases (reflective of Queensland or NSW costs), and $10–$15/MWh (reflective of Latrobe Valley brown coal costs).

Costs for solar PV are for large field based systems. Recent field PV system costs for 50MW and 100MW installations have been tendered as low as US$50/MWh (US$80/MWh without production tax credit) (PV Magazine 2014). While residential systems are more expensive as the scale is very much smaller, these are consumer purchases and the traditional power industry economic LCOE comparisons do not apply. Consumers choose to install solar PV based on other economic and other criteria, and, to the extent there is a cost comparison, it should be with the retail cost of electricity delivered to the premises.

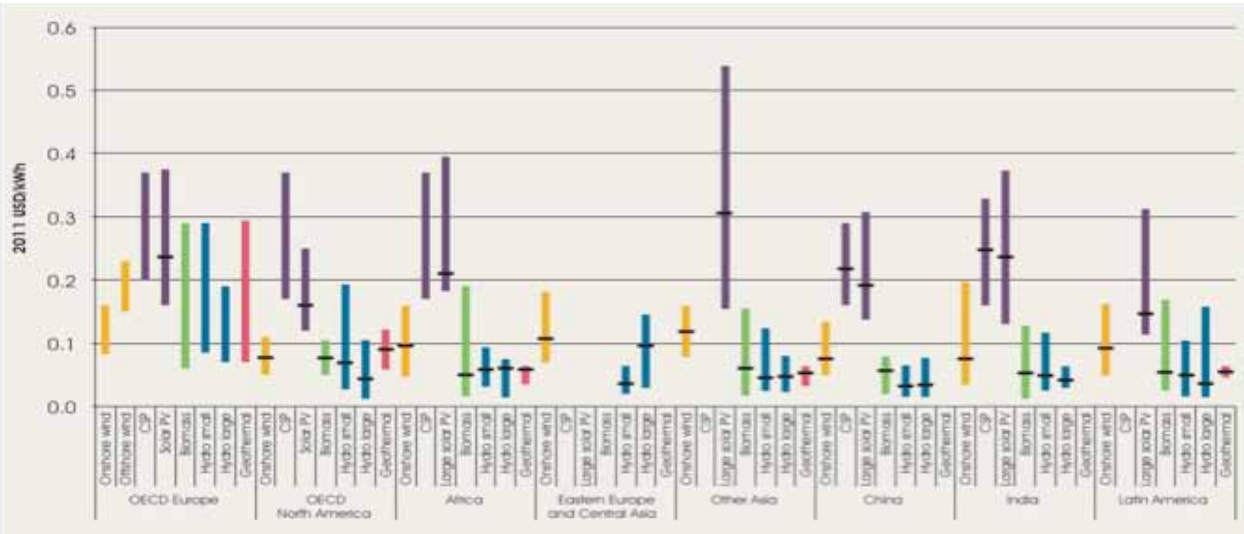
* EIA costs for US market with lower gas input costs reflective of US conditions

Importantly, the estimates in the Tables 20 and 22 reflect costs broadly as they exist in 2012/13. Actual costs for renewable projects appear to be coming in at or below desktop estimates. Solar thermal projects with 6–8 hours storage or gas boosting approximate to fossil fuelled plants with CCS in that they both provide near base load power delivery with low emissions. While the costs of the two technology types are not dissimilar at a desktop level, the higher capital costs for the two actual fossil fuelled CCS power projects suggest that these may be more expensive to deliver abatement with firm capacity than renewable solar thermal projects with storage.

The ranges of LCOEs for actual projects cover a range of outcomes, depending on location (Figure 22).

These costs just reflect today's costs. Costs for some renewables are coming down rapidly with industrial learning. Solar PV and, to a lesser extent, wind,

Figure 22: Typical LCOE ranges and weighted averages for renewable power generation technologies by region, 2012.



Source: IRENA 2013

Note: The bars represent the typical LCOE range and the black horizontal bars the weighted average LCOE if enough individual project data are available. Figures assume a 10% cost of capital and biomass costs of between USD 1.3 and USD 2.5/GJ in non-OECD countries and between USD 1.3 and USD 9/GJ in OECD countries.

costs are coming down quickly—potentially 20%lower by 2020 for wind, and up to 60% lower for solar PV by then. Cost reductions are predictable for solar PV and wind by 2020, and further reductions are forecast for the 2020's decade as well. Existing coal technologies without CCS are mature, therefore, little, if any, cost reductions are likely. Adding CCS to coal plants adds complexity and reduces efficiency, increasing costs substantially. So does long-distance transportation of CO_2 to reservoir sites. Given the very limited numbers of new or retrofit coal CCS projects being constructed globally, it is doubtful that material cost reductions will be achieved in the decade ahead for this technology, increasing the cost advantage of renewables.

HOW SRMC DETERMINES WHICH COAL OR GAS PLANTS ARE CALLED ON TO PRODUCE POWER

Renewables such as wind and solar have the lowest SRMC—close to zero. Coal and gas have higher SRMCs, and their relative position depends on the costs of fuel, power station efficiencies and emissions costs. This means existing renewables power plants will almost always outcompete fossil fuelled plants on short run costs.

The SRMC for a modern natural gas fuelled combined cycle plant with no CCS approximates to:

> SRMC ($/MWh) = Natural Gas cost ($/GJ) x Heat Rate (6.5 to 7.0) + $3–5 (GE 2009).

For example, if gas was $10/GJ, the gas plant would cost $68—75/MWh to run. If emissions were priced at say $25/tonne CO_2, that would increase the cost of operating to $80 to $85/MWh, as it produces 0.4 to 0.5 tonnes of CO_2 per MWh. This short run cost for gas fired plant excludes other costs such as operating labour and allows for no interest, tax or profit. The short term costs of running gas power are approaching the current long run costs (i.e. including all costs including capital return and profit) for wind projects today in Australia.

For an existing coal fired plant, a similar calculation will apply. Cheaper coal prices mean the SRMC for coal is significantly less than for gas fuelled plants, even though the efficiency of conversion of coal to electricity is around 30–50% less than in a modern gas CCGT and emissions for coal are much higher per MWh.

In periods when gas prices are very low, gas plants will tend to have lower SRMCs than coal fuelled plants, a trend which will be enhanced if GHG emissions are priced for both. On the other hand, if gas prices are relatively high—such as the situation that now exists in Australia with gas approaching or above world parity LNG prices—gas will have a higher SRMC than coal even if emissions are priced.

Emissions pricing increases the SRMC of coal more than for gas, as coal plants are more carbon intensive and less efficient than gas plants. However, with gas prices currently at internationally high levels, emissions pricing needs to be at much higher levels than the current Carbon Tax, or higher than levels prevailing internationally, to achieve fuel switching from coal to gas. In the absence of emissions pricing and with high current and projected gas prices, coal will outbid gas into the market as it will have lower SRMCs. This may well occur in Australia in coming years, increasing emissions from the power sector.

THE MERIT ORDER EFFECT—HOW RENEWABLES LOWER WHOLESALE ELECTRICITY PRICES

On any given day, renewables generators will almost always be dispatched first into a pool market for electricity as they have the lowest SRMCs. The fossil fuel generators usually set the prices for most of the time as they are typically the last unit of power called on by the market operator for dispatch, but it will be the lower priced bands that will be called on, and so overall pool prices will tend to be lower. This situation will continue while coal and gas plants remain a significant part of the Australia's generation fleet.

Studies have shown that in markets where there are higher levels of renewables, the wholesale power prices are often lower. This is called the "merit order" effect. One example is in South Australia, where the historical record of power prices has shown that as the level of renewables has increased over the years in this state, the wholesale power prices have not increased—In fact, they have reduced in real terms. The table below summarises the last decade of outcomes for average wholesale power prices in South Australia, as the share contributed by wind power has increased.

Table 23: Impact of wind penetration on South Australian average annual wholesale prices.

Financial Year	Average Annual Price $/MWh—nominal*	Wind Share of SA Generation %
99/00	59.27	-
00/01	56.39	-
01/02	31.61	-
02/03	30.11	-
03/04	34.86	-
04/05	36.07	-
05/06	37.76	6.9
06/07	51.61	6.7
07/08	73.50	9.3
08/09	50.98	14.2
09/10	55.31	17.5
10/11	32.58	21.9
11/12	30.28	27.6
12/13 *	69.75**	27.9

Source: AEMO, Windlab 2013

* Prices are in actual $ of the year

** Includes impact of carbon price applied to electricity generation

Overseas and domestic studies have shown that this South Australian price outcome is not unique. The very low SRMCs of renewables like wind and solar mean that they get dispatched ahead of fossil fuel generators and tend to lower the marginal price at which the last increments of fossil capacity get accepted by the system operator for dispatch.

Overseas studies have looked into this effect. Studies of German, Texas, New York and Mid-West USA markets have all shown that increasing levels of renewables reduce wholesale market prices (Sinclair Knight Merz 2013). The impact of renewables in lowering wholesale prices can be relatively low at times of low demand when fossil generators are bidding low prices just to stay online and receive some income. On the other hand, when demand is high, such as at times of peak demand, renewables, particularly solar, will displace relatively high cost generators, called peaking plants, for much of that time. At peak times, renewables can have a significant lowering effect on wholesale prices. Not just for the time interval concerned, but also for the overall year as these high priced volatile periods impact on the time weighted average prices over the year. These lower average spot market prices will then flow onto forward contract prices.

Two studies have been undertaken to assess the impact of low SRMC renewables on wholesale power costs across the NEM. The first study looked at the impact on wholesale prices in NEM states over the decade to 2025 (Sinclair Knight Merz 2013). It found that without a price on carbon, the RET would reduce wholesale prices by between $6 to $25/MWh in NEM states, with the biggest reductions in South Australia and Victoria, the states likely to have most wind power constructed under the RET. It concluded wholesale prices in these two states could range from $16 to $25/MWh lower over the decade 2016 to 2025 (Sinclair Knight Merz 2013). Depending on how much retail customers share in these wholesale price reductions, the savings are offset in part by the costs of the RET scheme which are also passed on to retail customers. The study concluded that retail customers could expect to see their net prices lowered by $7 to $9/MWh (Sinclair Knight Merz 2013).

A second study (Sinclair Knight Merz 2014) looked at a very hot period in summer January 2014 to determine the impact of wind on wholesale prices. It concluded that wind had a large lowering impact on wholesale prices on several of the hottest days, reducing wholesale prices in South Australia and Victoria by around $300/MWh over 24 hour periods on three of the hottest days (Sinclair Knight Merz 2014). Over the seven-day period, the study concluded that wholesale prices were at least 40% lower than they would have been without the contribution of wind (Sinclair Knight Merz 2014).

REDUCING ELECTRICITY SECTOR EMISSIONS COMES AT A COST– WHETHER THROUGH RENEWABLES OR FOSSIL FUELS WITH CARBON CAPTURE AND STORAGE

Some would argue that renewables increase the cost of retail power in Australia, as the cost of the Renewable Energy Certificates (RECs) which support the rollout of zero emissions renewable power are passed on by retailers to consumers. These RECs are essentially a mechanism to offset the somewhat higher capital cost of the zero emission renewable power plants being built. Studies of capital costs and LCOEs show low or zero emissions power plants (irrespective of whether they are fossil fuelled or renewable based), are more expensive to build than conventional fossil fuelled power plants. Domestic and international experience demonstrates that renewable plants are significantly (one half to two-thirds) cheaper to build today than low emissions coal or gas plants with CCS. Fossil fuelled power with CCS carries higher construction and financing risks. Contrast only two commercial scale coal CCS power plants under construction through to 2020, with over 70,000 MW of wind and solar now constructed annually.

Building renewables is a lower cost pathway for making deep cuts to electricity sector emissions as they are cheaper and lower risk than the fossil fuelled alternatives available today. Wind and solar PV costs are less than the costs of retrofitting CCS onto existing coal plants. Transporting and injecting the CO_2 alone will cost at least $10–50/tonne of CO_2. (Producing a MWh from coal with CCS will require capturing around a tonne of CO_2.) This is roughly equivalent to the current REC pricing levels of $20 to $40/MWh. The additional substantial costs of retrofitting the power plant itself to capture the CO_2 also would need to be covered. And CCS plants only capture and sequester some 50–85% of total emissions produced, while renewables produce no emissions when generating.

The costs of wind and solar PV renewables continue dramatic reductions. These trends, expected to continue until 2020 and beyond, further increase the cost advantages of scale renewables over fossil fuelled plants with CCS.

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Higher levels of wind and solar penetration do reduce wholesale prices by more than the support cost (RET) that consumers of power are asked to pay, bringing down electricity costs to consumers and doing so while also reducing power sector GHG emissions.

Without a scheme to price the GHG captured and stored, thereby supporting CCS on the construction of new low or zero emissions power plants, and replacing or retrofitting existing emissions intensive plant, no new plant will be built. The existing plant will continue to operate, getting older and less and less competitive.

FUTURE COSTS FOR LOW EMISSIONS AND RENEWABLE POWER

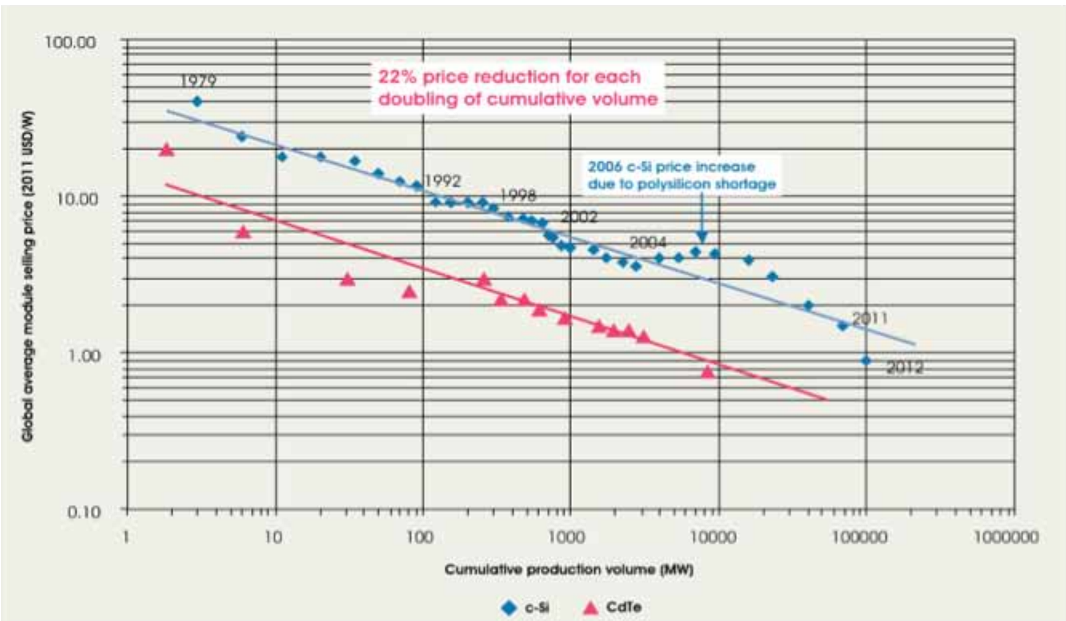
Today, the cost differentials between renewables and fossil fuelled power with CCS, and conventional fossil fuelled electricity generation without CCS, mean that the production of electricity without emissions is somewhat more expensive. But what situation is to be expected in coming years?

Assessments have been made of the projections for these costs into the future. The assessments rely on the concept of costs reducing as a result of learning which takes place as industrial products are manufactured in increasingly greater scale. This concept is best illustrated through reflection on how products like automobiles, televisions, computers and mobile phones have advanced in product offering whilst costs have reduced substantially over the years. With more mature products like cars with internal combustion engines, the cost reductions are lower, while with relatively new products like liquid-crystal display televisions, cost reductions and performance improvements have advanced rapidly.

These same trends are taking place with PV and wind, as the volumes deployed globally grow dramatically. Industrial learning typically shows a reduction in cost of a relatively constant percentage for each doubling of global installed capacity. For products early in their life cycle, relatively small cumulatively increases in annual quantity deployed can quickly double the cumulative capacity installed as growth accelerates. On the other hand, with mature products that have been in the market for 50 years or more, the rate of increase in global deployment relative to the capacity already installed is typically much less. Thus, the relatively more recently deployed gas turbine technologies have seen product improvements at a faster rate than steam turbines, which have been in power plants for over a century.

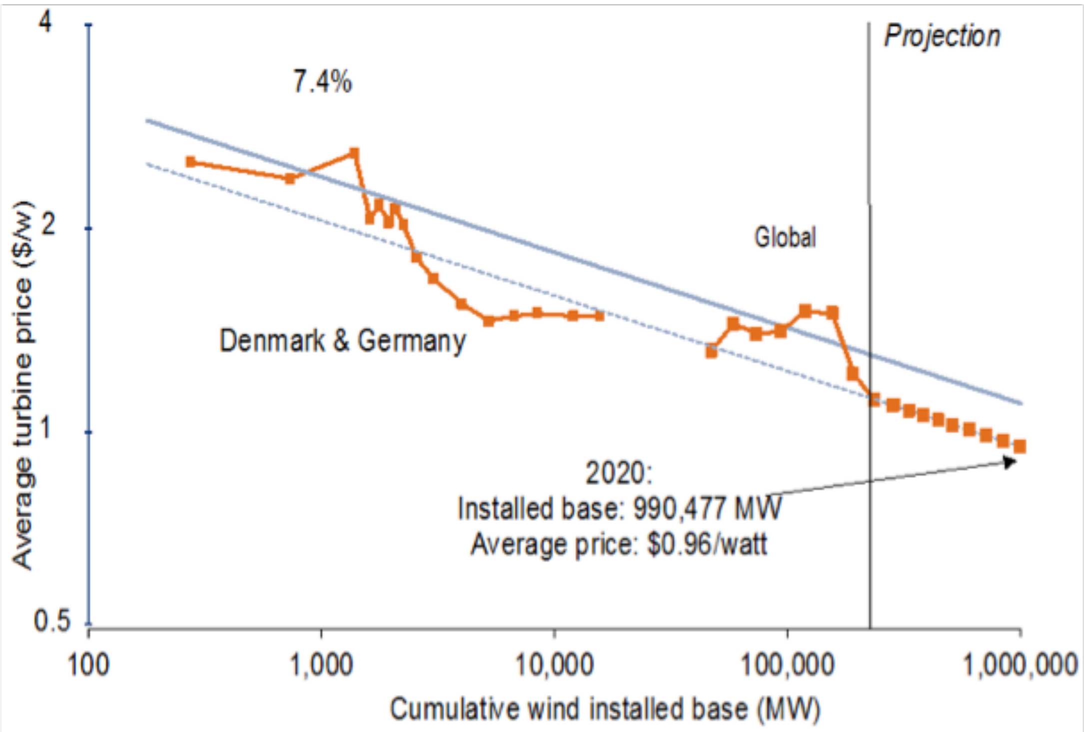
Actual historical data for the costs and deployment of renewables like wind and solar PV have been analysed and charted by various studies. Solar PV has demonstrated a rate of learning of around 18–20%, that is, for every doubling of global cumulative capacity, costs have come down around 20%. Wind has demonstrated a similar curve, though with a somewhat lower slope of around 7.5% (Citigroup 2013). The historical price trends for both are shown in the curves below.

Figure 23: Solar PV module cost learning curve for crystalline silicon and thin-film.



Source: IRENA 2013, based on data from EPIA and Photovoltaic technology platform 2011; Liebreich 2011; Sologico 2012

Figure 24: Forecast for average wind turbine costs.



Source: Citigroup 2013, from Bloomberg New Energy Finance, Citi Research

Installed cumulative capacity of wind turbines globally is nearly three times that of solar PV, so it is perhaps not surprising that the rate of cost reduction in onshore wind in coming years is not forecast to be as high as solar PV. Nevertheless, there are several studies concluding that wind power will continue to see improvements in capacity factor and cost reduction, which will see ongoing unit cost reductions in the range of 10–20% by 2020, and 20–30% by 2030. Noting the LCOE estimates reported earlier, reductions of this order would make wind competitive with new gas or coal fossil fuelled stations (without CCS) at around $60–70/MWh.

Table 24: Cost reduction potential for onshore wind systems.

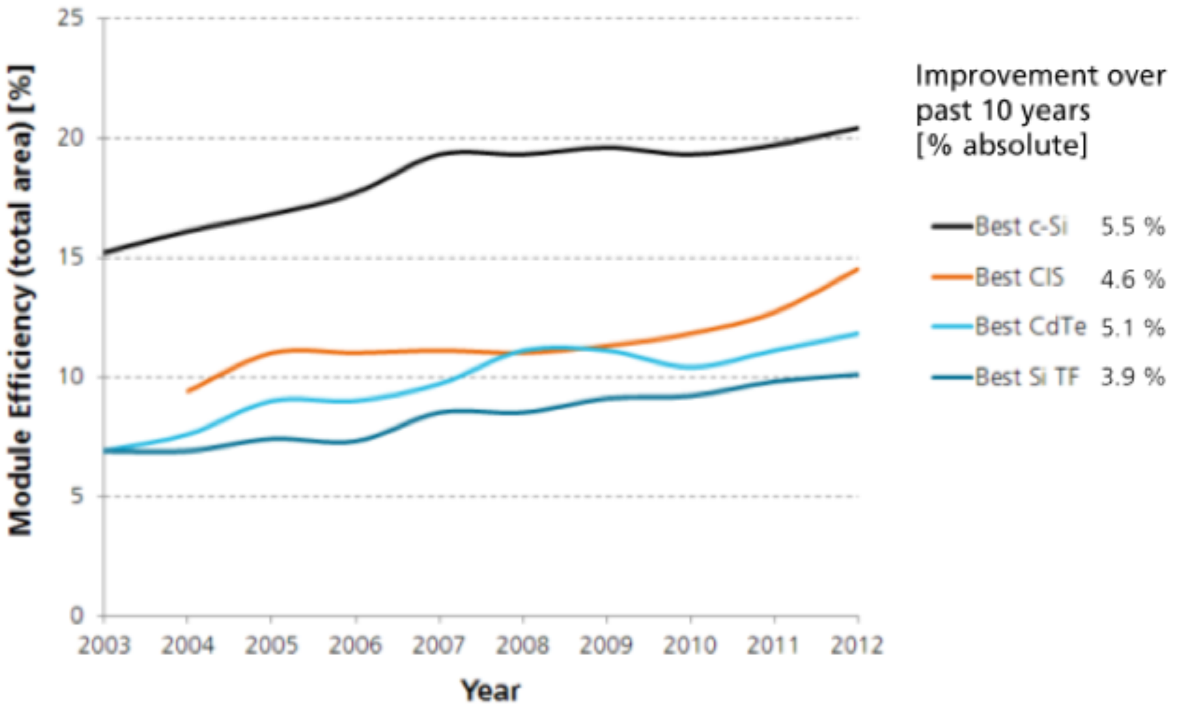
Study	Cost Reduction Potential % Reduction	Timeframe
IEA	18	2010–2030
EWEA	22/29	2010–2020/ 2010–2030
GWEC	12/18	2010–2020/ 2010–2030
Mott McDonald	12	2010–2020
McKinsey	30	2010–2025

Source: IRENA 2012b.

In the case of PV, there is potentially an additional learning effect coming into play. This relates to the semiconductor nature of the materials involved in converting sunlight to electricity. Development of semiconductor technology in computing has a demonstrated track record of getting more computing power out of increasingly smaller silicon chips.

In a similar manner, developments of semiconductors in PV products have shown the capacity to achieve higher conversion efficiencies out of the same or lesser amounts of material. Figure 25 tracks how modules using the various semiconductor photovoltaic technologies have been improved over the years.

Figure 25: Industrial PV Module Efficiency (%)—best modules.



Source: Fraunhofer ISE 2013

By coupling solar cells with higher conversion efficiencies to the balance of system costs (glass, metal, inverters etc.), it is possible to increase the amount of power produced for given areas and materials, thus further lowering the unit costs of producing electricity. Various estimates have been made of the expected cost reductions for solar PV in coming years, some of which are summarised in the Table 25.

Solar PV systems have considerable flexibility, able to be installed in relatively small unit sizes in residential areas, medium scaled installations in commercial premises, and field scale power projects of multi tens of MW sizes. Noting the LCOE estimates earlier in

Table 25: Cost reduction potential for PV modules and systems

Study	Cost Reduction Potential % Reduction	Module/System Timeframe
IRENA 2012c	51	Module 2010–2015
EPIA 2011	36–51	System 2010–2020
McKinsey & Co 2012	55	System 2010–2020
NREL 2012	60	System 2010–2020
First Solar 2014a	40	System 2012–2017

this report for solar PV systems installed at scale, it is reasonable to conclude that by 2020, the LCOE for large scale solar PV systems will be in the same range, or lower than onshore wind, at or below the cost of new coal and gas fuelled stations without CCS, and below the marginal cost of existing gas fired stations (excluding CCS) if gas is priced at LNG export netback parity. With these trends exhibited internationally, it is not an exaggeration to observe that the potential growth of this industry will be astronomical in years to come.

At the residential level, when installed "behind the meter", solar PV competes with electricity supplied from central generating plants delivered to households through the transmission and distribution networks, "the grid". Under current pricing arrangements, most of the costs and profits of delivering power for retail consumers around the world are recovered through unit charges for each kWh of electricity consumed. These charges are set by regulators or market forces, depending on the jurisdiction. Initially in several markets, incentives were also provided to encourage the uptake of solar PV by retail customers, either through up front capital support payments, or through "feed in" tariffs which allowed surplus electricity generated by PV to be repurchased at a premium over the life of the installation.

As centrally delivered electricity is fully costed and as PV system costs continue to reduce, the number of retail residential markets where PV becomes competitive in its own right, increases, thereby increasing the total capacity installed globally, and also in each country or regional market, and thus reducing costs over the medium term. At some point, PV becomes the preferred economic choice for consumers in selecting how to source the majority of their power. Whilst customers remain connected to the grid, a large share of their consumption is sourced from renewable PV. This has implications for grid owners, power retailers and generators. Grid owners lose potential throughput, undermining profitability, retailers lose sales volume, again undermining profitability (as they typically make a margin on every kWh they sell), and generators lose volume and pricing power at the times of peak summer demand, when PV generates power largely coincident with the summer peak air conditioning demand.

Whilst these competitive dynamics were minimal when PV had a very small share of the residential market (around 5 years ago), the incumbent players largely ignored the threat PV posed to their business models and profits. However, as PV costs continue to reduce and penetration by PV of the residential market increases (for example, to levels of 22% of households in Queensland and 25% in South Australia today), the threat becomes increasingly real to the incumbents and their attempts to block or delay increased PV take up will intensify. This will manifest itself in all manner of activity—lobbying regulators to change network pricing structures, lobbying politicians to inhibit or lower the price for buyback of surplus PV power generated, lobbying through the media against renewables, and so forth. However, given that this is a global market for a global industry, the cost reduction forces are unstoppable as a virtuous cycle of ever lowering costs encouraging ever widening uptake continues to expand markets, add manufacturing capacity and cost reducing innovation and scale. Irrespective of the approaches taken in Australia, short of an outright ban on PV (which some state owned utilities have already tried), PV will continue to grow in displacing purchases of power off the grid. A related complementary technology will soon create a second powerful force linked to PV in further reducing grid power demand in residential areas—battery storage.

The capacity that residential PV has to mitigate peak demands on the grid is still actively debated, but recent analysis of the past summer in the South Australian market (where PV penetration is highest) is instructive as to the role PV can play. In January 2014, Victorian electricity consumption topped 10,300MW, with the highest level of electricity use occurring during the heatwave. Installation of 3 GW of solar power in Australia has assisted with meeting the demand—according to the Australian Renewable Energy Agency, solar PV contributed more than 11% of South Australia's power needs on some of the hottest days in the January 2014 event (SMH 18 January 2014).

Increasingly as solar PV deployment costs reduce, it will become attractive for commercial premises to install as well. These systems will likely be in the range of multi 10s to 100s of kW. Solar PV is generally a better match to the commercial load profile as commercial demand tends to peak during the afternoon when solar PV output is highest. Financial institutions will likely enter the market as well, offering lower cost financing ways to fund such installations. This is already happening in overseas markets.

Large scale PV systems supplying at the wholesale level are not yet competitive with wind, but given the cost reduction pathways projected for the remainder of this decade, it is likely that they will become increasingly competitive in coming years. Field scale solar PV has the advantage in Australia that it can be installed in western parts of the NEM interconnected grid (for example, on Eyre Peninsula in SA, and in western Queensland and NSW). Not only do these areas have excellent insolation (solar input), but they are typically 1–1.5 hours (in a sun sense) behind the operating time zones of the eastern states' main population centres. This would allow such large PV generating plants to better match the domestic summer demand peak that tends to fall late in the afternoon, as well as better matching peak on more normal demand days. It is of note that AGL Energy's two field scale projects are located in mid and western New South Wales, no doubt in part for these reasons.

6. WE NEED TO START PLANNING NOW FOR A LOW EMISSIONS ELECTRICITY FUTURE FOR AUSTRALIA

Historically, Australia's electricity system was characterised by long term centralised planning by state owned agencies. This was particularly the case in the 1970s and 1980s when new central electricity generators and related infrastructure needed to be built to meet rising demand for electricity. In the 1990s and 2000s, Australia's electricity markets were largely deregulated, allowing planning and installation of new electricity generators to be left up to the market, when pricing signals called for it. Post 2000, renewable energy technologies were slowly introduced by legislating the Renewable Energy Target (RET) and other incentives. This decade, electricity demand is contracting. Global growth in renewables is dramatically lowering costs, opening up a multitude of end consumer markets. Highly distributed renewables, storage and smart systems are now challenging the centralised power system dynamic on which the industry was built for the past century.

Today, Australia's electricity generation sector faces the following challenges:

1. **Australia's emissions from coal fuelled electricity generation place Australia in the top ten emitters worldwide, and the largest domestic emitter.**

2. **Deep cuts in emissions are essential and urgent by all nations to keep the global temperature increase at less than 2 °C by the end of the century.**

3. **Planning to replace Australia's ageing coal-fired power stations needs to start this decade, regardless of any wider global emissions reduction imperatives.**

   The majority of Australia's coal fired power stations are old, inefficient and unlikely to be able to be retrofitted with CCS technologies. Within a decade, around half of Australia's coal fuelled generation fleet will be over 40 years old, with some currently operating stations approaching 60 years, all using obsolete sub critical coal technology. These older plants will likely be too outdated, inefficient and carbon intensive to be candidates for retrofitting CCS technology.

4. **A price on carbon will be needed to make retrofitting younger power plants with CCS technology economically viable.**

   CCS retrofits may be possible on some younger power plants using supercritical technology (in Queensland) located near possible CO_2 sequestration sites. To undertake such retrofits, state or private asset owners will need the credit capacity and balance sheet strength to fund the major multi billion dollar investments required. Unlike overseas, there are few if any opportunities in Australia to sell the recovered CO_2 for increasing oil recovery from large depleted oil fields (as in USA and Canada). A long term price on sequestered carbon will be essential (on top of electricity sales revenues) to ensure the huge investments required earn a return. Without a price and long term assurance of continuance, planning will stall, and investments, if made, will be stranded.

5. **Some key markets for traditional base-load power are now closing across Australia.**

   Major industrial loads such as aluminium smelters, car plants and oil refineries have announced they will be shutting down. Contributing to this trend, legacy low cost electricity contracts used two to three decades ago to secure remaining operating aluminium smelter projects are coming to an end. Kurri Kurri and Point Henry smelters, with an aggregate load of 660 MW, have already closed or announced closure. Existing contracts expire at other smelters this decade, increasing uncertainty around another 2,000MW of base load power.

6. **Australia's electricity demand is contracting, and becoming more volatile.**

   Australia is not unique. It has been happening in most developed western economies in recent years —USA, mainland Europe and the UK. Contraction in energy intensive heavy industries, energy efficient consumer appliances, and zero emission distributed power generated behind the consumer meter are all contributing.

7. **Planning and building new electricity generation capacity ready to meet demands for deep cuts in emissions by the 2030s will take at least a decade. The nation needs to start now.**

   Planning, designing, financing and building major new power infrastructure, such as transmission lines or large power stations, takes upwards of a decade. In order to have low or zero emissions assets in place by 2030 (to replace Australia's ageing and inefficient generators) to deliver deep emissions cuts for when the 2°C carbon budget is likely exhausted globally, Australia needs to be planning for that future now.

8. **The trend towards distributed power generation technologies like solar PV, wind and batteries is likely to accelerate due to continued decreasing cost.**

   The cost per MW of renewables is already lower today on a short and long run basis than newly built alternative fossil fuelled power generation with CCS, and the cost of renewables continues to reduce rapidly. Greater uptake and increasing global scale of deployment for wind, solar PV and batteries are driving faster industrial learning rates. Trends expected to continue for at least the coming decade based on relative forecasts of demand for these renewable technologies and CCS deployment. The economic drivers for renewables in preference to new coal and natural gas power stations with CCS will become compelling.

9. **Strategic transmission infrastructure investments (such as have been deployed to stimulate renewable development in Texas) would open up vast untapped Australian renewable resources, bolstering rural communities.**

   Australia is endowed with globally first class renewable resources across widely distributed regions. Much of these resources exist in rural areas of low population and marginal agricultural land. Investment in transmission lines is needed to connect these resources with markets.

It is worth reflecting that major transmission lines were built between the 1950s and 1970s to connect distant coal fuelled power stations to urban markets and major industrial loads.

Distributed wind energy deployment assists with supply variability. Large scale (multi MW) solar PV generators installed in the western regions of eastern seaboard states would help to align the time of maximum generation with maximum summer retail demand. A key transmission link that is needed is to join South Australia directly to NSW via Broken Hill. This would bring to the eastern electricity grid wind power from SA and western NSW, solar power from western NSW and South Australia, as well as a range of other benefits to grid operations.

10. **Australia's regulatory structures and network companies will need to adapt to these rapidly changing market dynamics.**

    Attempts to maintain the status quo in the face of increasing technological and social pressures for change may have short term appeal, but will ultimately fail.

    Regulatory structures should encourage the shift towards distributed, low emissions technologies by rewarding investments, whether it be smart grids to enable the best use of solar PV and batteries across distribution networks in our cities and suburbs, or major inter-regional transmission lines linking new untapped wind and solar PV resources to markets.

    Existing schemes which foster accelerated rollout of the lowest cost zero emissions electricity generation technologies should be maintained and expanded. For example, the existing fixed GWh RET for 2020 should remain, and be expanded to drive installation of lowest cost low emissions generation.

A vision, strategy and implementation plan for Australia's electricity generation sector is urgently needed to meet these challenges. Competitive low emissions electricity for modern Australia in the twenty-first century is fundamental to long term wealth creation. A strategic approach beyond short-termism fostered by player incumbency, politics and the 24 hour news cycle is imperative.

Before 2020, industry planning and construction horizons dictate that Australia has to start serious planning on how it will replace its ageing coal electricity generators post 2030. In doing so we have the opportunity adapt to the global forces now unleashed by technological change and emission reduction demands, shifting to a low emissions electricity future and participating in one of the greatest industrial and energy transformations since the industrial revolution.

Otherwise, Australia's electricity supply sector (and its economy which relies on it) risks being left behind, increasingly divorced from global realities, as the rest of the world moves towards low emissions electricity supply and smart demand usage.

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