AUSTRALIAN POWER GENERATION TECHNOLOGY REPORT

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Australian Government
Australian Renewable Energy Agency
Australian Government
Department of Industry and Science
Office of the Chief Economist
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EXECUTIVE SUMMARY

This report provides a sound foundation for evaluating our electricity future.

It is critical for policymakers, power industry professionals and the energy sector more broadly to have a high-quality, up-to-date dataset on power generation technologies in order to make informed decisions about Australia's electricity sector.

This report provides an unbiased, technology-neutral review of a broad range of generation technologies, their capabilities and their costs for 2015 and out to 2030. Rather than making predictions about which generation sources will contribute to Australian electricity grids in future, it instead provides the information needed to understand what they could look like and how much they might cost.

This is the most in-depth study of its kind to date. The project consulted leaders from industry, government, consumer groups and industry associations and worked closely with consultants, modellers and developers.

The report provides all the building blocks needed to accurately and quantitatively explore and evaluate a range of possible technological futures. These datasets will underpin most power industry modelling studies in Australia over the next few years, help investors make important decisions and assist policymakers to guide Australia towards reliable and sustainable electricity supply.

The datasets are backed up and elucidated by a broad range of supporting information, including information on:

- how Australia's electricity grids operate
- the status of carbon dioxide (CO_2) capture, transport and storage
- the role and development of energy storage systems
- an in-depth assessment of the Callide oxyfuel technology demonstration project in Queensland.

An industry-led project

This report resulted from the combined efforts of a broad cross-section of industry participants, including project developers, technology experts and international consultants. This includes international industry leader Electric Power Research Institute (EPRI), which led the technology and current costs review; CSIRO, which developed projections of future capital costs; leading consultants; and government, academic and industry experts on a range of topics. The Australian Power Generation Technology Assessment Reference Group, a diverse group made up of 45 organisations, participated and contributed markedly to this study.

To help determine current capital and operating costs, developers and operators shared confidential data about their costs of project development. Building on that information, this report provides robust figures for the costs of constructing and operating new power plants in Australia.

The focus of this report

This Australian cost of electricity study provides credible technology cost and performance data for 2015 to 2030. It contains data 'building blocks' for policymakers, power professionals and the energy sector to use for policy and investment decisions and for further modelling of Australian electricity generation options. For a wide range of technologies, the study includes current and projected capital costs, operation and maintenance costs, and detailed performance data.

The study did not attempt to forecast the likely future make-up of the generation suite used in Australia in 2030 scenarios. This report is not designed to be used for choosing a 'winning' technology, but as a source of data as an input to further modelling and assessment work.

The future of Australia's electricity grids

The role of Australia's various electricity grids is to deliver safe, environmentally acceptable and reliable power, at an acceptable cost.

When and how electricity is produced, transmitted and distributed to consumers and how it is consumed may be very different in the future, but will require a mix of generation technologies, each playing a different role. No single technology or class of technologies can efficiently and effectively supply 100% of our energy needs.

Australia's electricity grid is changing

Both the supply and the demand side of Australia's electricity sector are undergoing significant transformation. Australia has a broad range of new technologies that can supply our future electricity generation needs, ranging from low- to zero-emissions fossil-fuel generators through to the use of CCS and to utility-scale renewable generation. Many consumers can already choose self-generation (particularly rooftop solar PV), and with rapidly developing energy storage technologies will be able to shift their electricity demand to more opportune times throughout the day. The global push for lower emissions to address climate change will continue to accelerate both the introduction of new technologies and advances in existing technologies.

Operating the grid is complex

Electricity grids are complex systems, and the largest machines ever developed by humans. Grid operators must constantly balance supply and demand by rapidly and flexibly adjusting the output of power stations, by electricity demand-management techniques, by using energy storage to smooth demand, or any combination of the three. They must also ensure that the failure of any one component (a power station or power line) does not disrupt the rest of the network. In Australia, this places constraints on the generation mix and supporting technologies.

No single technology can supply all our energy needs

Transforming Australian electricity grids is not simply a matter of choosing one technology and using it to replace our entire existing supply. As with our current grid, we need combinations of technologies that can allow supply to match demand or shift demand to times when it can be met.

Intermittent renewables do not necessarily follow changes in load (demand) across the day, as their output depends on local weather patterns, but traditional coal- and gas-fired baseload (continuously operating) generators are also being challenged to operate more flexibly. Some technologies, such as peaking generators, will continue be used infrequently, as they are now, and provide significant value despite their high LCOEs.

Electricity market design in Australia is intended to motivate generators to deliver electricity at the lowest possible prices, reflecting their actual cost of production. Future generation combinations can thus be determined by evaluating prices across the day and year, and then investigating different combinations of supply to determine the lowest cost technology mix that still manages other constraints (such as the reliability of supply and environmental considerations). Australian electricity markets will continue to provide ongoing opportunities to invest in advanced new-generation technologies to replace or displace current-generation power plants.

Not all Australian grids are the same

In addition to different demand and supply profiles, which drive different combinations of technologies, different grids in Australia have specific requirements. For example, in smaller grids such as the Northern Territory's, flexible generation is highly valuable because it can respond quickly to changes in load or the failure of a generator, potentially avoiding the need to shed load. Larger interconnected grids, such as the National Electricity Market in eastern Australia and the Wholesale Electricity Market in Western Australia, are more resilient because of their larger volume and diversity of generation and load, but will need continued careful management to respond to an increasingly diverse generation mix.

Grid planners need to continue to ensure the availability of sufficient capacity for year-round supply, the flexibility needed to meet both surges in demand and unexpected outages of generation, redundancy in both power stations and the transmission and distribution grids, and the availability of the frequency control and network support services that are needed for a functioning grid. Failure to address these requirements increases the risk that a single outage will lead to a cascade of failures and widespread blackouts.

Future electricity grids worldwide will be more diverse than in the past, as the large base of generation and major industrial demand connected to high-voltage networks becomes increasingly integrated with small embedded generators and customer loads in low-voltage distribution networks (Figure E1).

Figure E1: A highly integrated future grid. Source: EPRI, The integrated grid: realising the value of central and distributed energy resources, EPRI product ID 3002004103.

Comparing our technology options

This report presents a set of important 'building blocks' that enable different generation technologies to be compared on a common basis. It provides industry, government and consumers with the tools needed to evaluate all relevant factors related to cost (both capital and operating costs) and performance (including carbon emissions, water usage and capacity factors).

Figure E2 shows the *levelised cost of electricity* (LCOE) for a range of technologies if they were to be built in Australia today, under today's conditions. The LCOE captures the average cost of producing electricity from a technology over its entire life, given assumptions about how the generator will operate. It allows the comparison of technologies with very different cost profiles, such as solar photovoltaic (PV) (high upfront cost, but very low running costs) and gas-fired generators (moderate upfront cost, but ongoing fuel and operation costs).

THE COST OF GENERATION IN 2015

No single technology is optimal across all metrics, so the ideal grid should include a mix of technologies.

Of the renewable technologies, wind power has the lowest LCOE in 2015.

Of the fossil-fuel technologies, natural gas combined cycle and supercritical coal-fired generation have the lowest LCOEs.

All new technologies have significantly higher LCOEs than the current Australian grid average wholesale price.

A levelised cost does not capture the total cost of operating an electricity grid. For that reason, the LCOE and current electricity pool prices are not comparable, as LCOE covers long-run costs but pool prices often do not.

The LCOE of a technology is the average cost of producing electricity from that technology over its entire life, given assumptions about how the power station will operate; it is the cost of power as delivered to the plant boundary. Table E1 shows typical inputs to LCOEs for a range of generation technologies used in Australia.

A levelised cost does not capture the total cost of operating an electricity grid. For that reason, the LCOE and current electricity pool prices are not comparable, as LCOE covers long-run costs but pool prices often do not.

Recognising the limits of the current LCOE methodology, CSIRO has begun research to develop an extended methodology so that technologies can be compared on a more 'like for like' basis. The initial focus of the research is to determine how to take into account the costs of integrating intermittent renewables into the electricity system.

However, LCOEs allow comparisons of technologies with very different cost profiles, such as solar PV versus gas- or coal-fired generation.

Table E1: LCOE input values

Financial assumptions	Values
Nominal cost of equity (% p.a.)	11.5
Nominal cost of debt (% p.a.)	8.0
Percentage debt (%)	70.0
Inflation (% p.a.)	2.5
Company tax rate (% p.a.)	30
Property tax / insurance (% p.a.)	2.0
Analysis year	2015
Currency	$A
Asset book life (years)	30
Asset book life—wind only (years)	20
Fuel costs	
Brown coal ($/GJ)	1–1.75
Black coal ($/GJ)	2–4
Natural gas ($/GJ)	5–8
Diesel ($/GJ)	20–22

Straight-line tax life depreciation was assumed for this Australian study. The tax life for fossil fuel, nuclear and solar plants was assumed to be 30 years, and for a wind plant 20 years. These tax lives are consistent with the depreciation guidelines from the Australian Taxation Office.[1]

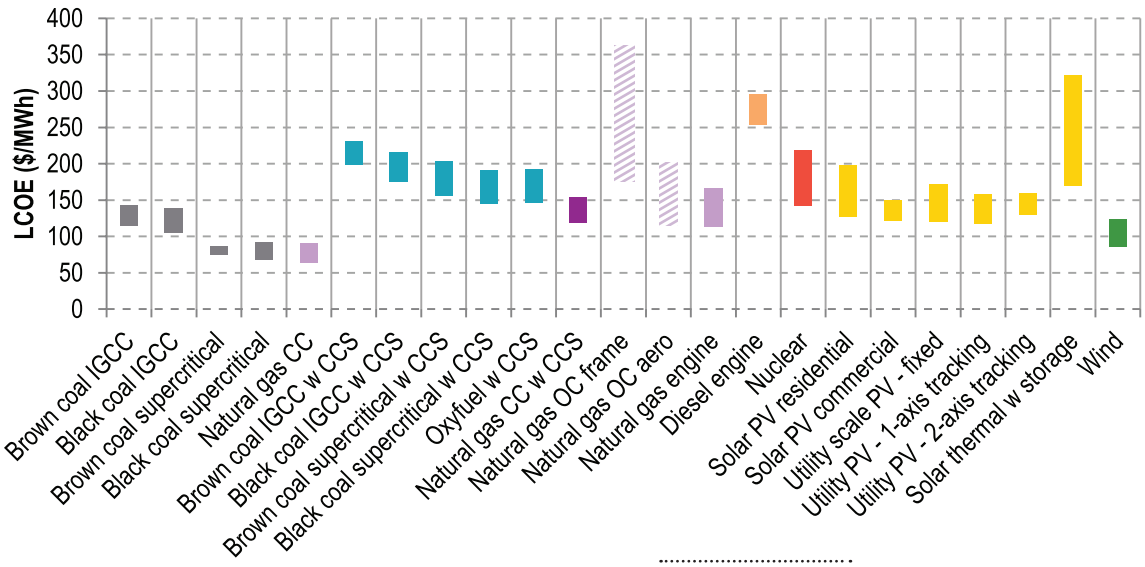


Figure E2: 2015 Levelised cost of electricity ($/MWh)

1 Taxation ruling TR 2015/2, https://www.ato.gov.au/law/view/document?LocID=%22ITD%2FEF20151%22&PiT=99991231235958

The spread of costs for each technology reflects a range of project-specific factors that can affect the costs. This includes the cost of bringing fuel to the plant, the local wind or solar resource levels, and site-specific factors that affect construction costs. The cost of new hydropower generation was not assessed, as it is unlikely that new large-scale hydropower projects will be deployed in Australia.[2]

Key trends in 2015

Wind power

Wind generation is the lowest cost renewable low-emissions technology currently available.

Commercial and utility-scale solar PV

For utility-scale solar PV, the lowest LCOE can be obtained from using single-axis tracking (panels that track the sun from east to west on a single pivot point), although this is site-specific.

Commercial rooftop PV systems have an LCOE comparable to those of utility-scale PV systems.

Residential solar PV

Residential solar PV systems, backed by various incentives, are already price competitive, as they compete at the retail level. This sector is expected to continue growing in market share beyond 2030.

Lowest cost traditional baseload technologies

Natural gas combined cycle and supercritical pulverised coal (both black and brown) plants have the lowest LCOEs of the technologies covered in the study.

Combined cycle gas with CCS

Natural gas combined cycle with CCS is the lowest cost baseload low-emissions fossil-fuel technology. While CCS technologies are not very mature, coal with CCS is more slightly mature than gas with CCS.

Retrofitting coal plants with CCS

It is technically feasible to retrofit post-combustion carbon capture (PCC) to wet- or dry-cooled black coal power plants. The LCOE for a PCC-retrofitted plant is less than for a new dry-cooled black coal supercritical plant with PCC.

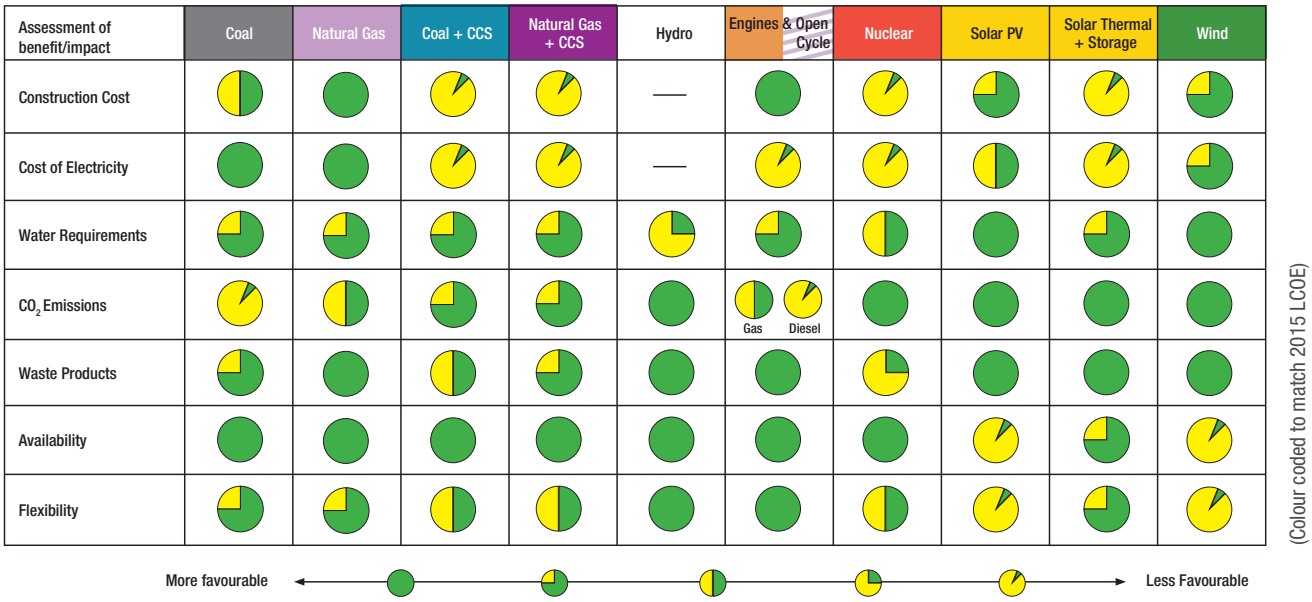
Nuclear power

Nuclear power costs are comparable to those of coal with CCS, but the costs are predicated on the development of a mature nuclear industry in Australia. The *Environment Protection and Biodiversity Conservation Act 1999* currently prohibits the development of nuclear power in Australia.

The advantages and disadvantages of each technology

Beyond the range of costs considered above, each technology has operational advantages and limitations that must be considered. Designers of reliable power systems must take all the attributes listed in Table E2 into account, as well as the integration of combinations of low-cost generation and flexible generation and emissions reduction obligations.

Table E2: Electricity technology comparisons



[2] The focus of current hydropower investment in Australia is on the refurbishment and modernisation of existing assets and in some cases the addition of mini- and micro-hydro units to waterways. The costs of refurbishments and small hydro are too site-specific for inclusion in this study.

FUTURE COST REDUCTIONS BY 2030

All new low- and zero-emissions technologies are projected to reduce in cost by 2030. In general, the more mature the technology, the less opportunity for further cost reductions.

The scope of cost reduction for a given technology depends heavily on the global take-up of that technology, along with learning-by-doing in local projects.

The overall ranking of LCOEs for technologies in 2030 is not projected to change from 2015, but there is likely to be convergence in LCOEs across most technologies.

Just as critical as assessing the current market is understanding of technology costs and capabilities are likely to go in the future. The scope and rate of technology improvements, whether incremental or breakthrough, depend on how much of each technology is deployed—which itself depends on the technology cost—so iterative modelling is needed.

Because all technologies used in Australia are also deployed globally, it is the global deployment levels that will drive technology and manufacturing cost breakthroughs. To capture these learning-by-doing effects, this study used GALLM, a global and local model from the CSIRO, informed by data from EPRI and industry partners (Figure E3). GALLM considers learning curves for each technology in a global context and projects future costs under various scenarios. A key input is the current development status of the technology: more mature technologies are less likely to experience future cost reductions.

EPRI has also conducted a separate assessment of each technology to identify explicit cost reductions achievable through focused R&D for each component. Both approaches have merit: the component-based approach identifies readily achievable cost savings, while the learning curve approach captures the more significant cost reductions that have been observed historically for many emerging technologies.

This study's findings on costs to 2030 include the following.

Solar PV

Solar PV capital costs are projected to reduce by 35–50%. As more solar PV plants are built, the cost of PV modules will continue to decline due to mass production. Other system costs and inverter costs are also expected to decrease over time. In laboratories, researchers are continuing to develop new PV configurations that promise to increase cell and module efficiency.

Solar thermal

Solar thermal capital costs may halve, depending on the volume of global installations.

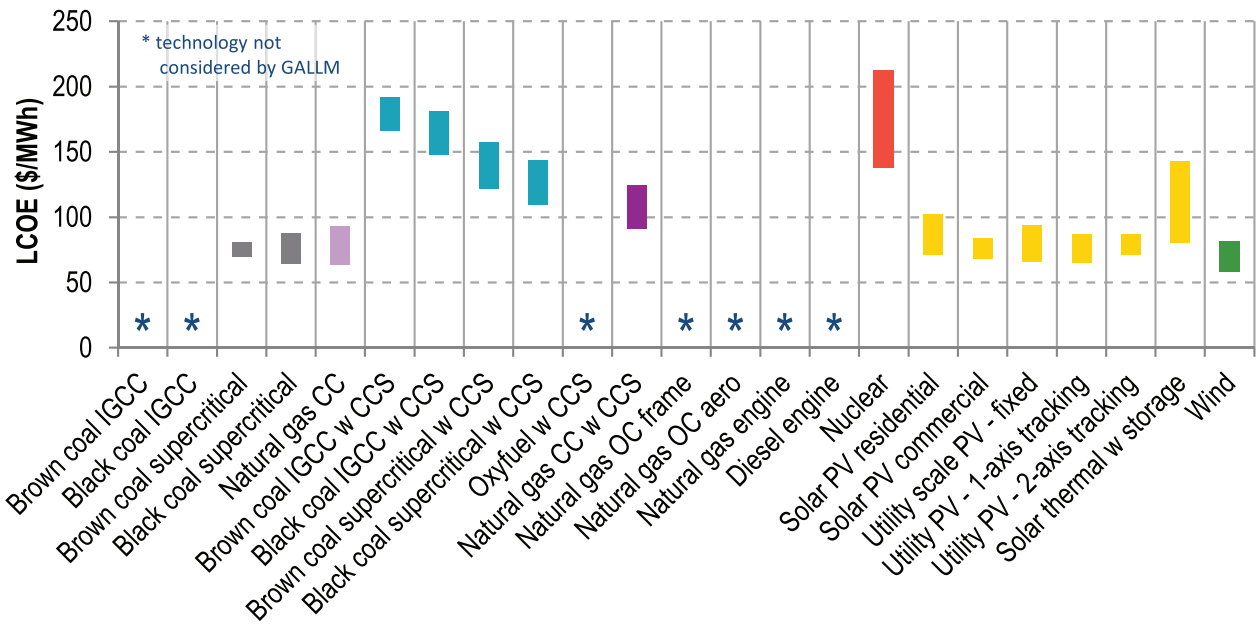


Figure E3: 2030 Levelised cost of electricity ($/MWh)

Note: LCOE assumptions are as in Table E2, except for natural gas pricing, which is $6–10/GJ.

CCS plant

CCS plant capital costs are projected to reduce by 30–50%, which translates into a reduction in levelised cost of 10–25% when operating costs are taken into account. There are likely to be improvements in both base plant efficiency and capture technology. However, if there is a lack of deployment at the global level this may inhibit learning by doing and therefore not lead to reductions in costs for CCS.

Combined cycle gas

Combined cycle gas generation is projected to become the cheapest fossil-fuel traditional baseload technology. Natural gas combined cycle plants are likely to benefit from higher firing temperatures, leading to increased efficiencies and reduced capital costs. It is projected that these developments will be used to reduce the cost and improve the performance of integrated gasification combined cycle units.

Changes to LCOE rankings caused by pricing carbon emissions

To examine the effect of pricing carbon emissions on the LCOE ranking, the study applied a carbon price to 2015 LCOEs.

In the base case studied in this report, fossil-fuel technologies are the lowest cost generators, being lower than wind and significantly lower than solar PV. In order to alter the LCOE ranking of carbon-emitting technologies, a sensitivity analysis on pricing carbon emissions was conducted (Figure E4).

The sensitivity cases showed that a high carbon price is currently required to significantly change the ranking of low-emissions generation technologies:

- Wind is competitive with supercritical coal with a \$30/t$CO_{2\text{-}e}$ price on CO_2 emissions.
- Solar PV is competitive with supercritical coal with a \$70/t$CO_{2\text{-}e}$ price.
- Supercritical coal with and without CCS are equivalent with a \$130/ t$CO_{2\text{-}e}$ price.

This situation is likely to change by 2030.

Supporting technologies

In addition to the generation technologies, a range of supporting technologies may create new opportunities to deliver an even more efficient and lower emissions grid. The costs and capabilities of this infrastructure should be considered when designing an integrated grid.

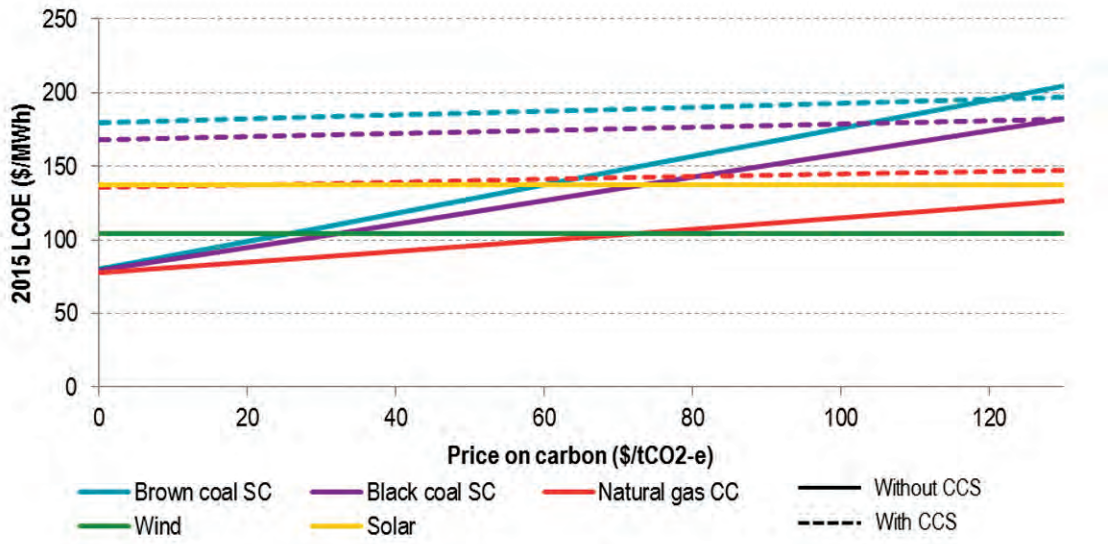
ENERGY STORAGE

Energy storage systems allow better matching between load and generation. Storage can act:

- as an alternative to peaking generation, by providing energy into the grid at peak times
- to support traditional baseload generators, by smoothing demand across the day
- to support variable renewables, by shifting production to match the system load.

The initial adoption of energy storage is likely to provide multiple benefits to the grid, such as peak shaving, the deferral of capital expenditure, provision of frequency control and network support, and energy trading in 'behind the meter' applications.

Figure E4: LCOE sensitivity to emissions pricing



Energy storage systems can be used to reduce peak demand and hence network expenditure, manage demand to shift load to more opportune times, and provide flexibility to grid operators. In many cases, storage can provide more than one service, increasing its potential value and hence its economic viability.

There is currently significant investment in a range of storage technologies, particularly battery technologies, which have already seen significant cost reductions over recent years. Recent modelling from the CSIRO using the GALLM learning curve model suggests that battery costs could halve again by 2030, leading to new market opportunities, particularly in behind-the-meter residential and commercial applications and in network support roles.

However, due to unavoidable inefficiencies in charging and discharging storage systems, a high take-up of such systems would increase the total consumption of energy in the system. When evaluating potential future systems, these costs need to be considered as part of the total cost of operating a grid.

TRANSMISSION AND DISTRIBUTION NETWORKS

The distribution and transmission network is the backbone that enables generators and consumers of power to trade with each other, even over long distances.

The various Australian grids have been developed over decades, and new grid developments are only undertaken if the benefits are demonstrated. The opportunity to expand a grid is further limited by regulatory constraints on the system.

The LCOEs for all technologies are calculated at the generator's boundary, with no allowances for the cost of connection to the grid. Larger projects (above about 100 MW) typically connect to high-voltage transmission grids; smaller projects (under 100 MW) typically connect to low-voltage distribution systems.

The cost and practicalities of connecting to a grid play an important role in determining which projects, and technologies, will be built. New power lines cost from about $0.4 million/km for distribution lines capable of connecting 10–100 MW projects to upwards of $1 million/km for transmission lines capable of supporting projects above 100 MW. While siting new power stations close to the existing grid reduces connection costs, it potentially reduces technology options.

To use the full output of low-utilisation generators (such as intermittent renewables or peaking gas plants), network connections must be built to the peak capacity, even though they might be used for only 20–40% of the time on average. Because connection costs have to be paid by the developer, this precludes all but short lines connecting to the existing grid without increasing an installed project's LCOE. Traditional baseload generators may justify longer connections to the grid.

CARBON DIOXIDE TRANSPORT AND STORAGE

To facilitate the implementation of CCS in Australia, one or more CO_2 transport and storage networks need to be developed.

The cost for transport and storage of CO_2 (excluding owner's and risk-adjusted costs) from power plants in Australia is likely to vary from $5–14/t CO_2 to almost $70/t CO_2. Variations in factors such as operating conditions, engineering assumptions, material costs, topography and geological characteristics may lead to different costs. The integrated design of capture systems, transport routes, operating conditions and injection strategies may lead to lower costs.

CCS is an enabling technology for reducing emissions from large stationary sources of CO_2, such as power plants and other industrial plants. The implementation of CCS requires a CO_2 transport and storage network involving pipelines, booster pumps, wells, storage site facilities and storage site monitoring. Such a network does not currently exist in Australia.

The lowest projected cost for transport and storage from power plants in Australia ($5–14/t CO_2) is for cases involving a short transport distance to sites with good storage characteristics. The highest projected cost (up to $70/t CO_2) is for cases involving transport over long distances to storage formations with poorer characteristics.

Variations in industry activity, exchange rates, macroeconomic cycles and owner's costs all have a significant effect on estimated CCS costs. Other major factors affecting the costs are related to variability in storage site characteristics (especially for larger and longer term injection of CO_2) and the incorporation of trade-offs in pipeline network design and storage site design. In a dynamic operating environment in which the amount of CO_2 for injection increases over time, accounting for these trade-offs becomes even more critical.

AUSTRALIAN OXYFUEL TECHNOLOGY DEMONSTRATION

The Callide Oxyfuel Project demonstrated the feasibility of oxyfuel combustion for over 10,000 hours in Australia's largest low-emissions coal plant demonstration.

Oxyfuel technology is one of the prospective technologies applicable for CCS. It involves turning air into oxygen before combustion in boilers that use pulverised coal. This facilitates the removal of CO_2 from the boiler after combustion.

- Key highlights from the project included the following:
- The project demonstrated ramp-rates under oxyfuel conditions that are equivalent to those for air-fired operations.
- It achieved a 50% load factor turndown, demonstrating the operational flexibility of an oxyfuel boiler.
- A CO_2 purity offtake of greater than 99.9% was achieved.
- The project also achieved the nearly complete capture of sulphur dioxide, nitrogen oxides, trace metals and particulates.

CONTENTS

1 INTRODUCTION

Introduction—key messages:

- This Australian cost of electricity study provides credible technology cost and performance data for 2015 to 2030. It contains data building blocks for policymakers, power professionals and the energy sector more broadly.
- It is expected that the data will form the basis for other Australian energy studies.
- The report represents the combined efforts of a broad cross-section of industry participants, including project developers, technology experts and international consultants. This includes international industry leader Electric Power Research Institute (EPRI) (which led the technology and current cost review), CSIRO (which developed projections of future costs), leading consultants, and government, academic and industry experts from a range of fields.

1.1 Introduction

Policymakers, power professionals and the energy sector more broadly need current and high-quality data on power generation technologies in order to understand and make informed decisions about Australia's electricity sector.

This Australian cost of electricity study provides credible technology cost and performance data for 2015 to 2030. It contains data building blocks for policymakers, power professionals and the energy sector more broadly. It is expected that the data will form the basis for other Australian energy studies.

1.2 Objectives

The objectives of this report are:

- to provide Australian governments, power professionals and the energy sector with a credible independent study on the current power generation technology cost and performance data in Australia
- to establish an up-to-date capital cost and technology performance database agreed by Australian stakeholders in the Australian context
- to provide a levelised cost of electricity analysis and an analysis of the capital costs of a basket of technologies for 2015 and 2030.

1.3 Study scope

To meet the objectives of this study, it was necessary to engage with government-funded institutions, companies and industry associations to determine the costs and performance of power generation options in Australia. This included engagement with Australian projects to gain an understanding of current and projected costs.

Specific topics beyond the basket of generation technologies to be examined included:

- a review the status of energy storage and how it may operate as part of a grid
- a review of post-combustion retrofit technologies and their application in an Australian context
- a review of the Callide Oxyfuel Project
- a review of carbon dioxide (CO_2) transport and storage opportunities
- a review of grid transmission and grid connection issues
- a review of how 'modularisation' may affect the capital costs of a power plant
- a 'cost walk-through', from a conceptual screening study to a fully engineered project, using ZeroGen as a case study.

The technologies covered in this report are summarised in Table 1 through Table 3. The reference group for this study determined that the size of the generation units was to be under 450 MW, with the exception of large-scale nuclear and ultra-supercritical coal technologies, both of which have efficiency penalties at small scales. Technologies are either covered for cost and performance (C&P), cost and discussion (C&D) or for discussion only (D).

Table 1: Renewable technologies

Technology type	Size (MW_e, sent-out basis)	Level of detail
Solar thermal		
Central receiver with 6 hours storage	125	C&P
Parabolic trough with 6 hours storage	–	D
Solar photovoltaic (PV)		
Utility-scale PV, fixed flat plate	10 / 50	C&P
Utility-scale PV, single-axis tracking	10 / 50	C&P
Utility-scale PV, two-axis tracking	10 / 50	C&P
Commercial-scale PV	100 kW	C&P
Residential-scale PV	5 kW	C&P
Wind		
Onshore wind	50 / 200	C&P
Offshore wind	–	D
Ocean		
Wave energy conversion	–	D
Tidal in-stream energy conversion	–	D
Ocean	–	D
Geothermal		
Hot rock	–	D
Hot saline aquifer	–	D
Hydroelectric		
Reservoir	–	D
Run of river	–	D
Biomass		
Biomass co-fired with coal, PC boiler	–	D

C&P = cost and performance, D = discussion only

Table 2: Fossil-fuel technologies

Technology type	Size (MW_e, sent-out basis)	Level of detail
Pulverised coal		
Supercritical	350 / 375	C&P
Ultra-supercritical	650	C&P
Post-combustion capture	260 / 270	C&P
Oxyfuel	375	C&P
Advanced ultra-supercritical	–	D
Integrated gasification combined cycle (IGCC)		
IGCC	350 / 380	C&P
IGCC with carbon capture and storage (CCS)	275 / 310	C&P
Combined cycle gas turbine (CCGT)		
CCGT	440	C&P
CCGT with CCS	375	C&P
Open cycle gas turbine		
Frame turbine	275	C&P
Aeroderivative	100	C&P
Engines		
Compression ignition engine	–	C&D
Spark or pilot injection ignition engine	–	C&D
Direct injection carbon engine	–	D

Note: C&P = Cost and performance; C&D = Cost and discussion; D = Discussion only.

Table 3: Nuclear technologies

Technology type	Size (MW_e, sent-out basis)	Level of detail
Nuclear		
Generation III/III+ (with seawater cooling)	1,100	C&P
Small modular reactor	–	D

Note: C&P = Cost and performance, D = Discussion only

2 AUSTRALIAN GRIDS AND ENERGY MARKETS

Australian grids and energy market—highlights:

- A strong governance mechanism encompassing regulation, market rules and market operations provides oversight of the generation, transmission, distribution and retailing of electricity to industrial, commercial and residential customers.
- Safety, reliability, security and economics are the key factors dominating the development of Australian grids.
- The major markets of the National Energy Market (NEM) and Wholesale Energy Market (WEM) provide about 93% of electricity produced. The remaining 7% is delivered within the Northern Territory, mining areas, and remote settlements.
- The markets enable the unencumbered entry and exit of generation.
- Transmission and distribution grids are regulated monopolies.
- Renewable generation technologies, now interfaced with the grid mainly through electronic inverters, together with new enabling technologies such as battery storage, are accelerating the development of a more integrated grid.

2.1 Introduction

Technical, economic, market and environmental factors as well as the levelised cost of electricity (LCOE) affect the choice of new generation in all grids, including those in Australia. This chapter discusses these factors and the functioning of integrated grids in Australia, incorporating generation, transmission and distribution networks.

2.2 Summary of influencing factors

The factors of most significance in relation to each Australian grid are itemised in Table 4 and discussed in subsequent chapter sections.

Table 4: Factors influencing the Australian grid

Technical	
Demand and energy have to be supplied reliably.	In combination, the following key technical factors influence the reliability of supply in all grids: • installed reserve plant margin relative to peak demand • size of largest generating unit relative to peak demand • generator availability • transmission and distribution network availability • system load factor and load shape.
Ancillary services provided by generators enable power to be delivered to all points in the grid and maintain grid stability.	Ancillary services include: • frequency control – frequency regulation – contingency reserves • voltage and volt amp reactive control.
Economic	
A mix of generation traditionally provides the most competitive wholesale price or cost outcome for all customers.	Most grids are a combination of the following generator types, which have the characteristics listed: • Baseload generation – high capital cost – low fuel cost – slow to start • Peaking generation – low capital cost – high fuel cost – fast to start • Mid-merit generation – mid-range fuel cost – efficient fuel usage – frequent starts, with daily or weekly cycling – flexibility for ramping up or down • Intermittent renewable generation – zero fuel cost
Market regulations must enable new generation to integrate with existing generation.	• The NEM provides open access to any type of generator subject to an agreed connection arrangement to the grid. Generators are dispatched in merit order based on bids. • The WEM is presently a firm access market, with a balancing market cleared on short run marginal cost based bids.
Existing network	The connection of new generation depends on resource location: • Fossil fuel is transportable. • Renewable generation is at source. • The shared transmission and distribution system costs are paid for by consumers. • Generators pay for connection assets to the shared network, shallow or deep. • New transmission must meet the regulatory investment test criteria for transmission or distribution.

Market	
Market rules	Market rules influence new generation entry in various ways, including: • the degree of vertical integration of the market • the gross pool or net pool market • energy only or capacity payments • bid-based or cost-based dispatch • open access or firm access networks.
Environmental	
Emissions limitations	Emissions limitations may include CO_2-e related regulations, such as: • renewable energy targets, such as the RET • aggregate emissions caps over time • plant-specific caps. Environmental limits include those on water consumption and discharge, particulates, SO_X, NO_X and other waste products.

2.3 Australian grids

2.3.1 Comparison of Australian and international grids

Australian grids are similar in technical respects to other grids worldwide, consisting of a network of power lines and switching stations joining power stations to end users. The combination of energy resources and the size of the demand for electricity are the dominant factors affecting the choice of generation technologies in each country. In Australia, the available energy resources have been dominated by black and brown coal, hydroelectricity, natural gas and biomass since large high-voltage grids began to be developed in the 1950s. In the past decade, wind power and solar power have expanded from negligible levels to form significant parts of the energy mix.

Alternating current (AC) grids in Australia generate alternating current at 50 Hz, as do the grids in the United Kingdom and Europe, while the US and Canada have adopted 60 Hz. All other countries have adopted one or both of these frequencies as the standard. The AC frequency is produced by the synchronous generators in the grid (traditionally thermal and hydroelectric), and all customers in the same AC grid receive power simultaneously at the same frequency. The generators are referred to as operating ‘in synchronism’. The rotating magnetic field created by each spinning thermal and hydroelectric turbine produces the AC power. Each generator is fitted with a governor to keep the frequency stable and ensure that all generators share any changes in power demand in proportion to their capacity.

The economic benefits of power trading across long distances between diverse resources have meant that grids have expanded to cover whole continents. After the start of the National Electricity Market (NEM) in Australia in 1998, Queensland was integrated with New South Wales, Victoria and South Australia, extending the AC grid from North Queensland to South Australia. In 2005, Tasmania was connected to the NEM by the 370 km Basslink direct current (DC) undersea cable. By connecting via a DC cable, Tasmanian hydroelectric generators are not synchronised to the mainland generators, as synchronism is not feasible for cable distances of more than about 100 km, but Tasmania is able to trade power with mainland Australia.[1]

The various Australian grids are shown in Figure 1.

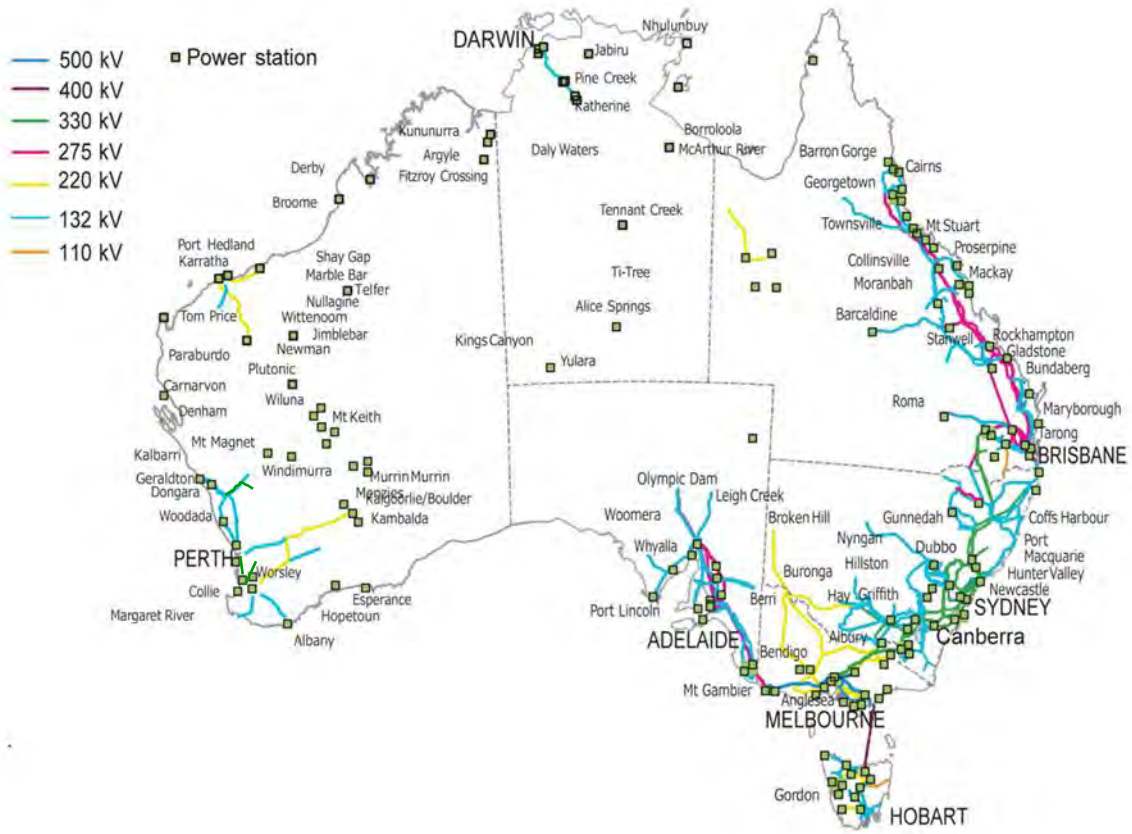


Figure 1: Australian grids and transmission systems

Source: Energia (2013), *Energy efficiency opportunities in electricity networks*, May, ISBN 978-1-922106-84-1.

[1] The need for reactive power support from intermediate substation systems, particularly undersea or underground cables, sets a limit on AC cable lengths. Cables (AC or DC) are much more costly than overhead lines, which further limits their application in situations where lines are not an alternative.

The NEM has approximately 45,000 MW installed generation capacity (including about 4,000 MW intermittent renewable generation and excluding capacity to be withdrawn from the market) and around 33,000 MW annual half-hourly peak demand.[2] It supplies about 85% of the national electricity consumption. The Western Australian Wholesale Electricity Market (WEM), also known as the South West Interconnected System (SWIS) surrounding Perth, has approximately 6,000 MW installed capacity and 3,900 MW peak demand and supplies around 8% of the national electricity consumption. The remaining 7% of Australian electricity production is widely spread among smaller grids and microgrids. Both the NEM and the WEM are mainly dependent on coal and gas generation. However, the NEM has major hydroelectric generating capacity, particularly in the Snowy Mountains. Tasmania is almost entirely powered by hydroelectricity, except for bilateral trading over the Basslink interconnector. Substantial wind resources have been developed throughout the NEM and WEM. Solar generation is, to date, mainly domestic rooftop, but large high-voltage grid-connected solar farms are now operating or under development. Both wind and solar developments have been incentivised by government policies supporting the further development of renewables, which also include hydroelectric, biomass, geothermal, wave, tidal and other energy sources.

North American[3] and European grids are composed of interconnected energy pools that are each around two to ten times the capacity of the NEM. This is due to their much higher population bases and higher population densities. These energy pools have approached the limit of technical and geographical size for AC grids. Hence, the North American and European energy pools are now further expanding by DC interconnections to maintain stability while enabling power trading. These include DC lines, undersea cables and back-to-back DC interties. One example is the Texas grid, ERCOT,[4] which has approximately 90,000 MW installed capacity and 67,000 MW peak demand and has DC ties with the other large systems in the US. The United Kingdom,[5] with approximately 70,000 MW installed capacity and 54,000 MW peak demand, has undersea DC ties with France, the Netherlands and Ireland.

The other isolated Australian grids include the Darwin Katherine Interconnected System (DKIS) in the Northern Territory, the collection of grids known as the North West Interconnected System (NWIS) in the Pilbara region of Western Australia, and the Mount Isa grid in north-west Queensland. These grids, each of several hundred to 1,000 MW, have been developed by power users to underpin the major expansion of liquefied natural gas, iron ore and minerals production since the minerals boom commenced around 2000. Each has characteristics particular to the grid ownership structure, fuel sources and growth rates that apply.

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[2] www.aemo.com.au/Electricity/Planning/Related-Information/Generation-Information (modified) (accessed November 2015).
[3] http://energy.gov/oe/services/electricity-policy-coordination-and-implementation/transmission-planning/recovery-act-0 (accessed November 2015).
[4] www.potomaceconomics.com/uploads/ercot_documents/2014_ERCOT_State_of_the_Market_Report.pdf (accessed November 2015).
[5] http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/FES/Winter-Outlook/ (accessed November 2015).

The DKIS, NWIS and Mount Isa grids are all dominated by gas-fuelled generation, although the NWIS and Mount Isa grids include coal-fired generators converted to operate on pipeline gas. The NWIS has no single dispatch protocol to manage operation, and the parts owned by Horizon Power (a government-owned corporation), Rio Tinto and BHP Billiton are operated largely or fully autonomously to suit the individual owners' commercial objectives. The Mount Isa system has recently developed a protocol enabling the private and government-owned generators to share access to the existing grid to supply their individual customer bases.

There are several hundred other isolated grids and microgrids servicing the needs of industries and residents in more remote locations. Electricity transmission from the major grids is not an economically viable option to supply these locations. The small grids include those in the East Kimberley and West Kimberley, Alice Springs and the Bass Strait islands. The remaining microgrids supply communities and mines throughout isolated areas of Western Australia, western Queensland, western New South Wales, northern South Australia and many islands. The small networks mainly rely on diesel fuel, but also on trucked liquefied natural gas (West Kimberley), Ord River hydro (East Kimberley) and hybrid renewable grids with diesel, solar and wind sources and battery storage. There is only one operational geothermal site using artesian water at present. Owing to the cost of diesel fuel, integration with solar and wind resources is emerging in many locations.

2.3.2 Security

Cascading failures in grids may occur when a single failure overloads remaining generation or transmission equipment and causes a collapse of the grid. This has occurred several times in North America, Europe and other advanced regions and has led to the concept of maintaining a technical envelope for security against generation or transmission contingencies, including in the Australian National Electricity Rules.[6] The Australian grid is therefore operated in an '$n - 1$' state, in which the tripping of any single generator or line will not cause loss of load and will not rely on intervention by the Australian Energy Market Operator (AEMO) before the next market dispatch interval, which occurs every 5 minutes in the NEM.

Within each 5-minute dispatch interval, the grid relies on automatic controls connected to each generator and transmission line to keep frequency and voltage stable throughout the grid. The generator governors, which operate in concert to maintain frequency, and the generator excitation systems, which operate in concert to maintain voltage, are the primary control systems for the successful functioning of the synchronous grid. Transformer tap changers and reactive power management devices, including static var compensators, STATCOMs capacitors and reactors, maintain the voltage profiles throughout the grid under AEMO management.

[6] National Electricity Rules, v. 75, 5 November 2015, Cl4.2.5 (a), www.aemc.gov.au/energy-rules/national-electricity-rules/current-rules (accessed November 2015).

The AEMO control centres monitor the performance of the grid at 4-second intervals through the supervisory control and data acquisition (SCADA) system and send out commands to manage the set points of governors, excitation systems, transformer tap changers and other controllable devices. The AEMO, aside from overseeing system security, computes the target dispatch levels for each generator based on their price bids submitted electronically each 5 minutes. The AEMO determines the NEM market price from the offers by generators to supply electricity to the market at particular volumes and prices.[7]

In critical load centres, particularly large cities, the grid may be operated with a higher standard of security, whereby no demand will be shed for the loss of two critical pieces of infrastructure ($n - 2$) at the same time. This applies when the risks of operating under $n - 1$ conditions outweigh the costs of maintaining a higher level of security. The AEMO may also declare, based on heightened risk at times, for example from bushfires, lightning and other weather-related events, that security should be increased. By declaring two or more possible contingencies a 'credible' contingency, the AEMO will dispatch the grid to be able to cope with such an event for the period of heightened risk. With the recognition of higher risk comes the acceptance of higher cost, so these periods are kept to a minimum.

The management of grid security involves a combination of sophisticated algorithms to analyse the grid, extensive measurement across the entire grid, much computer processing in real time and highly trained operating staff working around the clock. The AEMO operates two control centres in different states simultaneously, maintaining fully redundant backup systems in case one control centre becomes unavailable.[7]

2.3.3 Redundancy in generation and transmission capacity

Large numbers of generators operate in parallel in a coordinated manner to supply large grids, such as the NEM, which has about 200 generating units each larger than 30 MW capacity. However, all generators are subject to random forced outages due to a variety of different factors. For grid reliability assessments, these generators are defined by their statistical properties of mean time to fail (MTTF) and mean time to repair (MTTR). The AEMO periodically collects and collates these data on behalf of the electricity industry, while ensuring that individual generator confidentiality is preserved, to enable the integrated performance of the grid to be predicted.

Redundancy is carried on the grid in the form of reserve plant at all times, mainly through the mechanism of maintaining security against contingencies. When a contingency does occur, the AEMO is obligated by the market rules to restore system security within 30 minutes.[8] The minimum level of redundancy needed in the grid is thus related to having sufficient generation capacity either synchronised or offline but available to cope with multiple single contingencies within a defined period. The assessment of the level of redundancy needed to ensure reliability to customers is complex, and related to the factors listed in Table 4.

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[7] AEMO, *Fact sheet: the national electricity market*, http://www.aemo.com.au/~/media/Files/Other/corporate/AEMO_16839_Fact_Sheet_National_Electricity_Market_D4.ashx (accessed November 2015).

[8] National Electricity Rules, v. 75, 5 November 2015, Cl4.2.6 (b), www.aemc.gov.au/energy-rules/national-electricity-rules/current-rules (accessed November 2015).

In the NEM, a minimum level of responsive reserve is needed to avoid involuntary load shedding following a contingency and this level is specified at particular intervals during the post contingency period. This responsive reserve, or regulation frequency control service, is provided by generators on Automatic Generation Control (AGC). The AGC system allows the AEMO to continually monitor the system frequency and to send control signals out to generators providing regulation in such a manner that maintains the frequency within the normal operating band of 49.9Hz to 50.1Hz. Under the NEM frequency standards the AEMO must ensure that, following a single contingency event, the frequency deviation remains within the single contingency band and is returned to the normal operating band within 5 minutes. To meet this, the AEMO procures Frequency Control Ancillary Services (FCAS) through the market processes. These FCAS services are 6 second services to manage maximum frequency deviation, 60 second services to manage initial recovery and 5 minute services to restore NEM frequency back to normal operating band. All categories of reserve are supplied competitively based on generator bids to supply FCAS. The energy and FCAS markets are co-optimised to deliver supply at minimum cost.

The NEM is operated with enough reserve so that a single generator trip will not cause automatic underfrequency load shedding, even for the loss of the largest generating unit, which is currently 750 MW. The inherent level of rotating inertia provided by between 20,000 MW and 40,000 MW of online generation, together with additional inertia from the large amount of motor load being supplied at any time, slows down the frequency fall sufficiently for the reserves to respond before automatic underfrequency load shedding is triggered. In all systems, including the NEM and WEM, following a contingency, a further factor known as ‘load frequency relief’, which is inherent in motor loads and causes power demand to reduce as frequency falls, helps to alleviate the shortfall of generation experienced when a generator trips, ‘buying’ further time for reserves to respond.

The WEM experiences a level of load relief during contingency events in proportion to that in the NEM. In the WEM, the largest generating unit is 340 MW, and the loss of that unit will cause load shedding unless there is sufficient spinning reserve to replace 70% of lost output within 6 seconds, with the remainder being supplied by fast interruptible loads and load relief.

In Figure 2, an example of a simulated loss of generation in the NEM is shown under conditions that could be experienced by around 2030. This case has 25,000 MW demand, 15,000 MW supplied by synchronously rotating generation and 10,000 MW supplied by zero-inertia renewables. Of the 15,000 MW, 7000 MW of generation is enabled to respond to frequency changes, and partially loaded, providing a 1200 MW responsive reserve.

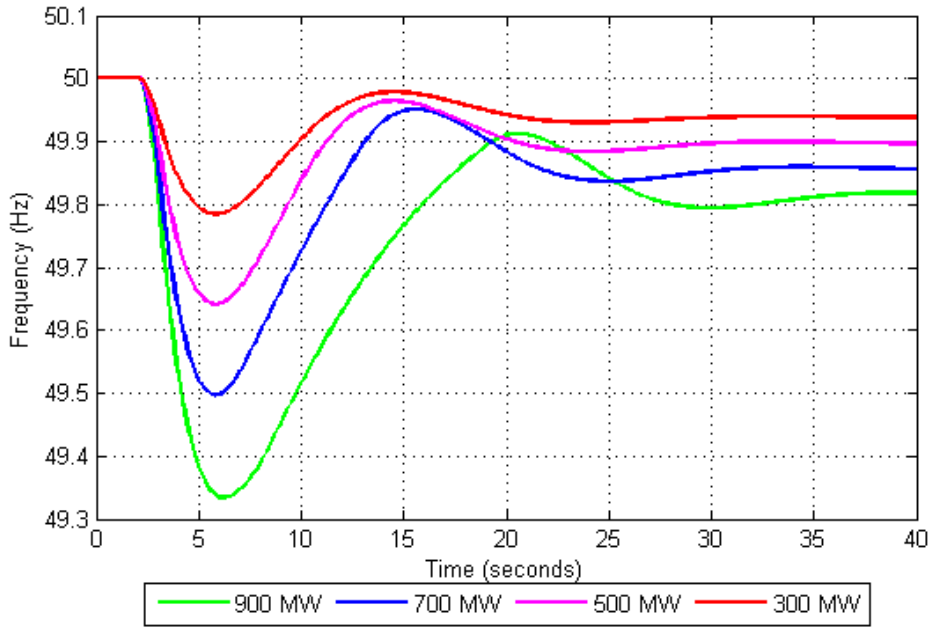

Figure 2: Effect of contingency size on frequency response

As shown in Figure 2, for these simulated NEM conditions, the loss of a 750 MW unit would not cause instantaneous load shedding at 49.5 Hz, whereas the loss of a hypothetical 900 MW unit would cause the frequency to fall to 49.3 Hz, which may result in underfrequency shedding, depending on the settings adopted in the NEM at the time.

This analysis has been extended to assess the broader relationship between inertia, spinning reserve and size of the largest unit. Figure 3 shows the combination of system inertia and responsive reserve needed to avoid load shedding for contingencies of various sizes. The 'X' marks the conditions shown in Figure 2. This model is broadly applicable to other regions, such as the WEM. For the WEM, the lower levels of inertia and the need to carry responsive reserve have been a major factor in setting the largest unit size of 340 MW.

For a given contingency size, there is a level of system inertia below which the responsive reserve needed to contain the frequency excursion following a contingency begins to escalate. For a 700 MW contingency, this is in the 50,000–60,000 MW seconds range, whereas for a 500 MW contingency it is in the 10,000 MW seconds range, although these values are indicative and would have to be verified for specific conditions.

Thus, there is a relationship between contingency size and the amount of response reserve and system inertia that form the technical envelope defined in the market rules. The AEMO is responsible for detailed assessments to ensure system security. It states in the 2015 National Transmission Network Development Plan that 'As more thermal synchronous generators withdraw from the NEM, there is a risk that there may be insufficient inertia and network support services available to be shared across all regions.'[9] As the system evolves, the network will continue to be evaluated by the AEMO and other agencies to meet security and reliability standards.

[9] AEMO (2015), National Transmission Network Development Plan for the National Electricity Market, November.

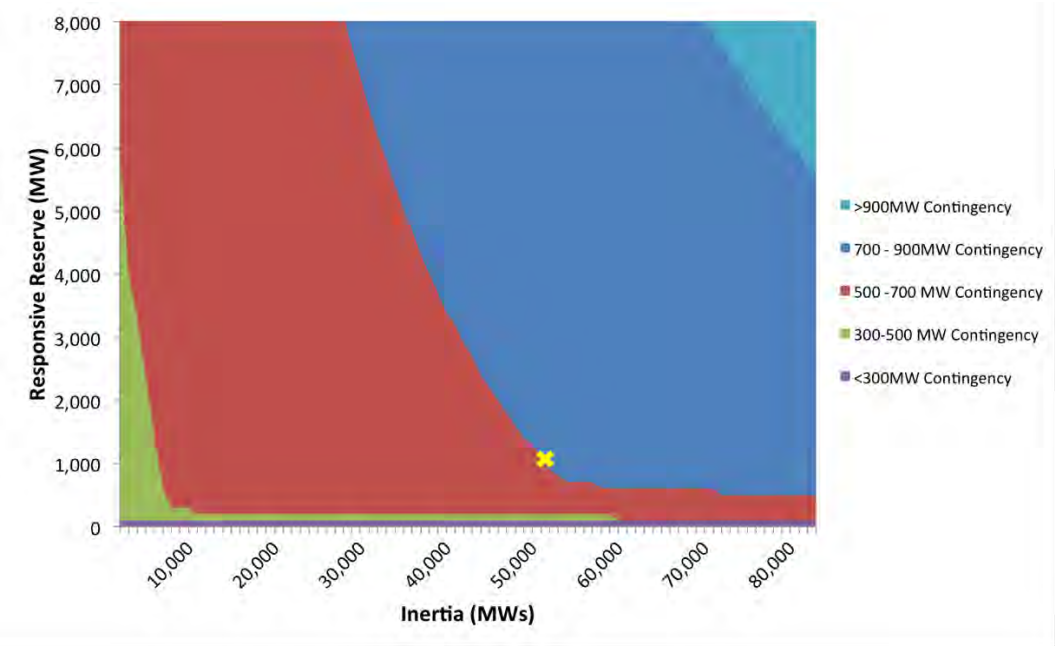

Figure 3: Acceptable contingency size as a function of responsive reserve and inertia

The United States, Europe and other jurisdictions follow an approach to grid operations similar to Australia's. However, owing to their much larger grid capacities, and hence larger grid inertia, the North American and European grids can accommodate larger individual generating units without underfrequency load shedding in a single contingency than is currently justifiable in the NEM and WEM. They have a larger buffer to cope with reductions of inertia associated with replacing rotating synchronous machines by generation without any inertia. A recent study by the National Renewable Energy Laboratory in the United States states that 'loss of system inertia associated with increased wind and solar generation is of little consequence for up to at least 50% levels of instantaneous penetration for the Western Interconnection as long as adequately fast primary frequency-responsive resources are maintained.'[10]

2.3.4 Reliability

The high reliability of electricity supply in advanced countries such as Australia is a key differentiator of Australian grids from those in developing countries, which often experience lengthy daily load shedding as the only means to match demand and supply.

The NEM and WEM have specified annual reliability targets. The NEM reliability standard is set by the Reliability Panel of the Australian Electricity Market Commission (AEMC). The panel is made up of appointees from industry, government and the community, who decide on the appropriate balance between reliability and cost of supply at the wholesale level through appropriate standards and settings. The wholesale reliability of supply is defined in Australia in accordance with the international definition of 'unserved energy', or USE. The USE is defined as the proportion of total grid energy demand that is unable to be delivered in

[10] NW Miller, M Shao, S Pajic, R D'Aquila (2014), *Western Wind and Solar Integration Study Phase 3: frequency response and transient stability*, National Renewable Energy Laboratory, December, http://www.nrel.gov/docs/fy15osti/62906-ES.pdf (accessed November 2015).

a specified time frame (in Australia's case, a year). This is done by estimating the unsupplied energy for each load shed event in retrospect.

In Australia, the reliability standard is a composite standard encompassing generation and transmission. It is measured at the bulk supply points where the distribution companies take the power to supply end users. It is thus the input standard for supply to the distribution network. The USE is specified not to exceed 0.002% in any given year. In the NEM, the standard is achieved by market forces using the mechanism of setting the market price cap (MPC) at a level sufficient to incentivise generators to meet the standard. This setting is related to the price that a peaking generator needs to obtain in only a specified number of hours of operation per year to operate and thus avoid load shedding due to lack of system capacity. The cost of generation, particularly peaking generation, is an input to the calculation of the MPC and is updated every four years and indexed annually.

The calculation of the MPC takes into account the four factors listed in the first box of Table 4: reserve plant margin, size of largest unit, availability and system load factor. The standard has been met in most years, with some exceptions mainly due to weather conditions more extreme than planned for. This is generally due to prolonged periods of extreme heat (or extreme cold), as happened in Victoria and South Australia in January 2009. These events were assessed as having a 1 in 20 year return period, while the grid is currently planned to meet the reliability standard for 1 in 10 year events.

In the NEM, with approximately 180,000 GWh/year of energy production, less than 4 GWh/year of customer demand is permitted to be unserved. This is equivalent to 10.5 minutes of customer average demand per year. Unserved load generally results from automatic underfrequency load shedding caused by generation or transmission protection trips due to malfunctions. In principle, operator-initiated rotational load shedding may be initiated for an impending shortfall, but only as a last resort requiring AEMO directions to the market.

Following rare events such as multiple generation trips, automatic underfrequency load shedding restores frequency. Then, offline generation will start automatically (or manually) to restore the generation shortfall and recover lost load. Load shedding applies automatically when the frequency drops below a set value within the 49.0–49.5 Hz range. All parts of the grid experience the same frequency drop almost instantly, so a loss of generation in one state may cause load shedding in that or another state, depending on the relevant underfrequency set points at substations. Load shed underfrequency settings are varied from time to time among most grid substations, except at critical facilities such as hospitals, which are spared from rotational load shedding; the converse applies for some industrial loads, which are first to be shed under interruptibility agreements.

The grid is therefore operated according to high and quantifiable standards of reliability through the setting of reliability standards, market incentives for generators to meet peak demands, operator oversight, comprehensive measurement systems and extensive modelling of the range of contingency situations. Actual events are investigated to avoid recurrences by changing designs or making improvements to operating practices and market rules. The market rules allow the AEMO to direct changes to maintenance plans if necessary to ensure that adequate generation is available to meet reliability targets. Training on power system simulators and on generation and transmission sites is undertaken regularly to ensure the timely restoration of power following widespread blackouts.

The WEM has comparable reliability standards to the NEM, incorporating a 0.002% annual USE standard. The AEMO has now been appointed to take over the operation of the WEM. However, there is no firm plan for the grids to be connected, owing to the separation of more than 2,000 km between them.

2.3.5 Intermittent generation

Intermittent generation, in particular wind and solar, is subject to uncertainty in resource availability as well as forced and planned outages. The electricity sector already has long experience with weather variability on the demand and supply sides. Forecasting demand based on weather is provided within control centres for the duration of available weather forecasts (currently 7 days ahead). On the supply side, the impact of temperature and humidity on the capability of thermal generation is also accounted for. For intermittent renewables, therefore, including forecasts of variability of wind and solar intermittent generation over the entire grid has been a natural extension of existing techniques. Clearly, with an extensive grid such as the NEM, extending some 4,000 km linearly throughout the eastern states and South Australia, the benefits of diversity in renewable production are greater than for the relatively compact SWIS. Diversity in renewable resources is beneficial in managing intermittency, as all generation in the NEM is 'pooled' for supply to consumers, as it is in the WEM.

2.3.6 Performance of the distribution network

While the combined generation and transmission system is planned and developed to meet the 0.002% reliability standard, and operated so as to deliver the standard, it would be uneconomic to develop the distribution system to match that standard.

While 0.002% USE equates to around 10 minutes/year of unsupplied energy to each consumer in the grid on average, the distribution system is planned to achieve around 20 times that level, or 200 minutes/year[11] on average. In practice, this varies widely, with consumers in cities having a fraction of that level and regional consumers up to several times that level. This is an outcome of the costs of providing redundancy at the distribution level, together with the tendency for more extreme events, such as trees falling and lightning strikes, to be both more prevalent and subject to longer exposure distances in rural compared with urban areas.

It has been accepted for decades that reliability at the bulk power transfer level provided by bulk generation and transmission facilities should be higher than that at distribution level because of the propensity for contingencies at higher power levels to be of much wider scale than those of individual feeders at the distribution level. This is a function of the consequences of large-scale supply failures being more severe. These fundamentals may change in the future, as embedded generation, with or without grid connection, has a potential to increase the reliability of electricity supply to consumers that is not economically feasible with the current mix of overhead and underground distribution technologies.[12]

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[11] Australian Energy Regulator, *State of the energy market 2014*, Figure 2.9.
[12] EPRI, *The integrated grid: realising the value of central and distributed energy resources*, product ID 3002004103.

2.4 The integrated grid

Australian power grids are undergoing significant changes in load and generation mix,[13] influenced by changing fuel and technology costs and the drive towards lower emissions systems. This primarily involves an increase in non-traditional renewable generation sources. Non-traditional renewable generation operates very differently from traditional sources.

The most technologically and economically accessible low-emissions technologies in Australia are currently wind and solar photovoltaic (PV) power. These are different from traditional generators in several important ways:

- *Size:* Non-traditional generators are typically much smaller units.
- *Operation:* The wind and solar resource is intermittent, so the operation of these generators cannot be completely controlled.
- *Electricity creation:* Power electronics are now used to feed the power into the grid, using inverters to synchronise with the grid.

As shown in Figure 4, traditional generators are those that use steam or gas turbines to create electricity, and are synchronised to the frequency of the network through those turbines. This includes coal, gas, geothermal, biomass and solar thermal power, among others. Hydro operates very similarly, although there are small differences due to using water directly in the turbine instead of a gas.

Figure 4: Traditional power generation

Non-traditional generators are those that are synchronised to the frequency of the grid but their waveform is synthesised to match the AC grid waveform as their electricity is produced through electronic components. This includes solar PV, wind and batteries.

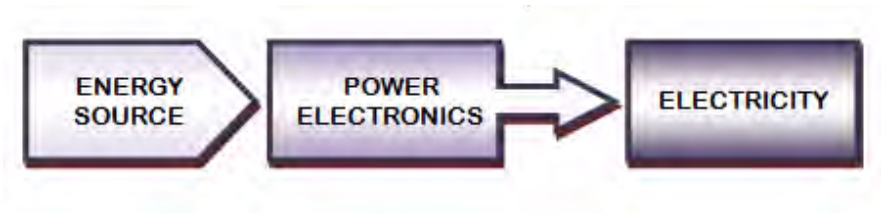


Figure 5: Intermittent renewable generation

Modern power electronics ensure that the intermittent renewable generators operate within the system's technical rules and limits. However, unlike traditional synchronous generation, there is not an inherent mechanism to help maintain the system frequency during disturbances. Specifically, there is no mechanical rotating machine that provides inertia, as there is with existing synchronous generators. Increasing amounts of wind and solar PV power generation, and correspondingly smaller amounts from traditional rotating machines,

[13] AEMO (2015), National Transmission Network Development Plan for the National Electricity Market, November.

may therefore negatively affect the operation of the power system, driving the inertia to lower values, which may reduce the ability to cope with generation contingencies. Furthermore, renewable generators do not provide reserve unless operated with spare capacity, which may affect their economic viability.

Inertia is a potential limiting factor on the percentage of non-traditional generation allowable while maintaining the security and reliability of the grid. All methods of creating inertia, whether retaining traditional generation, converting retired generators to synchronous compensation, using technologies such as flywheels or creating synthetic inertia from wind turbines, will increasingly be deployed based on economic rationales. As the proportion of non-traditional generation increases, the challenges of reduced inertia and the need for increased reserves may become greater, depending on our ability to incorporate advanced grid management technologies.[14]

2.5 Microgrids

Microgrids are isolated grids with their own frequency and voltage control systems, which enable them to function in an equivalent way to much larger grids in that they deliver AC power to consumers at standard frequency and voltage. There are several hundred microgrids operating in Australia. Traditionally, microgrids have been powered by diesel engines with governors and voltage control to enable the output to be matched to the demand at all times. Now, microgrids can also rely on inverters with controls to manage frequency and voltage.

Inverters convert the DC power supplied by solar PV, wind generators and batteries into AC. All inverters for wind, solar and batteries are essentially the same, converting DC to AC by using solid-state devices such as insulated-gate bipolar transistors, producing a synthetic AC waveform. Because the AC waveform of inverters is synthetic, and is controlled fully electronically, inverters can support the microgrid in a variety of ways by changing the phase angle of the AC waveform to generate or absorb reactive power at the same time as they deliver real power, thus holding voltage levels steady.

Microgrids consisting only of intermittent renewable sources will not function as stand-alone systems because they cannot maintain a balance between supply and demand:

- If the generation side is in excess, the output of the generation can be adjusted to match the demand.
- If the generation side is in shortfall, demand has to be switched off to match generation, which is especially problematic if the generation falls to zero.

The solution for microgrids is to add modules of battery storage, such that the essential demand can be supplied by the batteries and the renewables can charge the batteries. Batteries supply their power through inverters and so can deliver power, frequency and voltage control through those inverters. Sufficient battery storage is expensive, so it is not likely to be economically justifiable to rely on batteries alone.

The economic optimum currently is to have some rotating plant (typically diesel engines) to provide part of the supply and also provide frequency and voltage control. The AC waveform produced by inverters is compatible with the AC waveform produced by rotating generators.

[14] Synchrophasors are already installed in grids, including the NEM, for system support, and their role could be expanded.

For grid-based inverters, there is less need for frequency and voltage control systems to be fitted, as the inverters lock onto the existing AC waveform and thus do not need frequency control (although German systems are now specifying frequency control). Inverters can provide voltage control if they are fitted with control systems to adjust the phase angle of the power being supplied to the system.

There is an increasing trend for the demarcation between grids and microgrids to become blurred as inverters are increasingly deployed in both to allow renewables and batteries to gain a greater share of the generation market.

2.6 Summary

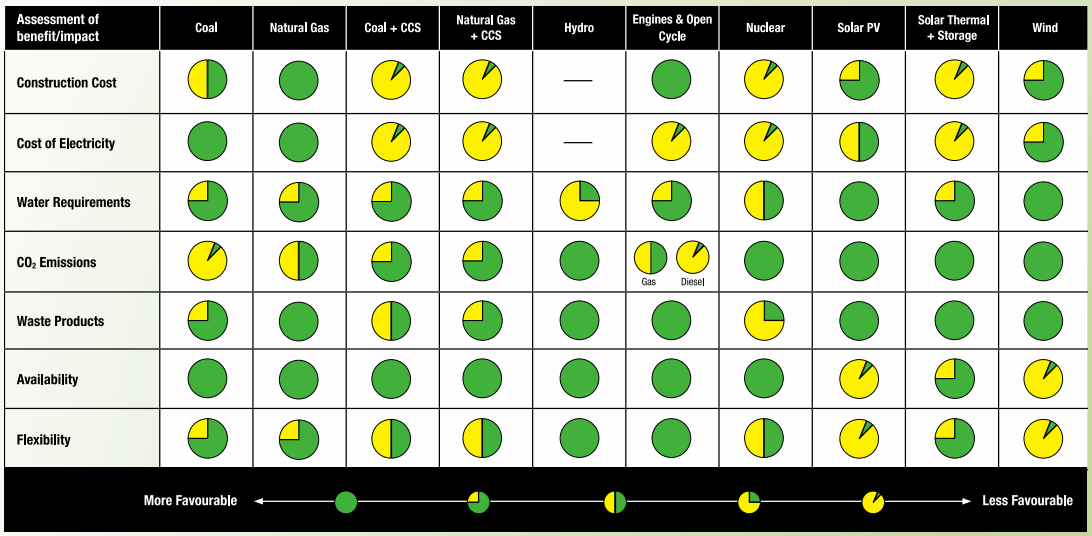
Large power systems, including the NEM, are experiencing significant penetration by wind and solar generators. Intermittent renewable generation, including renewables, particularly rooftop solar PV, and larger solar and wind projects are forecast to expand in capacity for the foreseeable future. However, the security of all power systems remains reliant on the inherent magnetic coupling of synchronous generators to keep frequency constant throughout the grid. Inertia and spinning reserve provided by traditional generators maintains a stable frequency during steady-state and dynamic events.

In contrast, non-traditional wind and solar generation, while synchronising with traditional generation, does not help to support the AC frequency, except synthetically in the case of wind. There are various enabling technologies, including batteries, synchronous condensers, flywheels and pumped storage, that will continue to develop and expand in capacity to support the changing generation mix. The evolving generation mix in the Australian grids will be dependent on the incorporation of a wide range of technical and economic factors within a market framework.

3 POWER GENERATION TECHNOLOGY

Technology—highlights:

- All electricity generation technologies have advantages and disadvantages. Renewable technologies such as solar and wind have no energy costs and do not produce greenhouse gases, but are not always available. Technologies such as pulverised coal produce electricity in large quantities reliably around the clock, but result in significant greenhouse gases.
- The generation mix that supplies grid power must both take advantage of the positive attributes of the various technologies and ensure that any shortcomings are covered.



This chapter covers, for each technology area:

- a brief description of the technology
- a survey of the technology's development status
- major technical issues and future development directions or trends
- expected improvements in the technology by 2030.

Note that the cost and performance estimates in this report are deliberately idealised for representative generating units and provide representative efficiencies (heat rates) and costs for the particular technology areas. The cost and performance estimates are not intended to apply to specific technologies at specific sites, since site-specific and company-specific conditions can vary substantially.

3.1 High-level technology comparison

All electricity generation technologies have advantages and disadvantages (see Figure 6). Renewable technologies such as solar and wind have no fuel costs and do not produce

greenhouse gases, but are not always available. Technologies such as coal and nuclear produce electricity in large quantities reliably around the clock, but result in significant greenhouse gases (in the case of pulverised coal) and long-term waste disposal considerations (in the case of nuclear).

The high-level comparison covers the following factors:

- *Construction cost:* This is based on the data collected for this study and is on a $/kW basis.
- *Electricity cost:* This is based on the base case levelised cost of electricity (LCOE) determined in this study.
- *Land use:* This is defined as the area needed to support fuel supply and electricity generation.
- *Water requirements:* This compares volumes of water needed for electricity production. Except for nuclear, all cooling is dry cooling. Hydroelectric water requirements are assessed on other factors, including evaporation from reservoirs.
- *CO_2 emissions:* This compares CO_2 emissions in tonnes/MWh, but does not include a life-cycle assessment of greenhouse gas emissions.
- *Waste products:* This compares the volumes, toxicity, or both of wastes from power plant operations.
- *Availability:* This compares generation technologies' ability to generate electricity when needed. Rankings are based on the fraction of time over a year that a given technology would be likely to be available to operate.
- *Flexibility:* This compares the flexibility of generating plants to increase or decrease output to meet changes in demand, to respond to changing output from other plants, and to respond to changing grid conditions. It also includes load-following, peaking, ancillary services and 'black-start' capability.

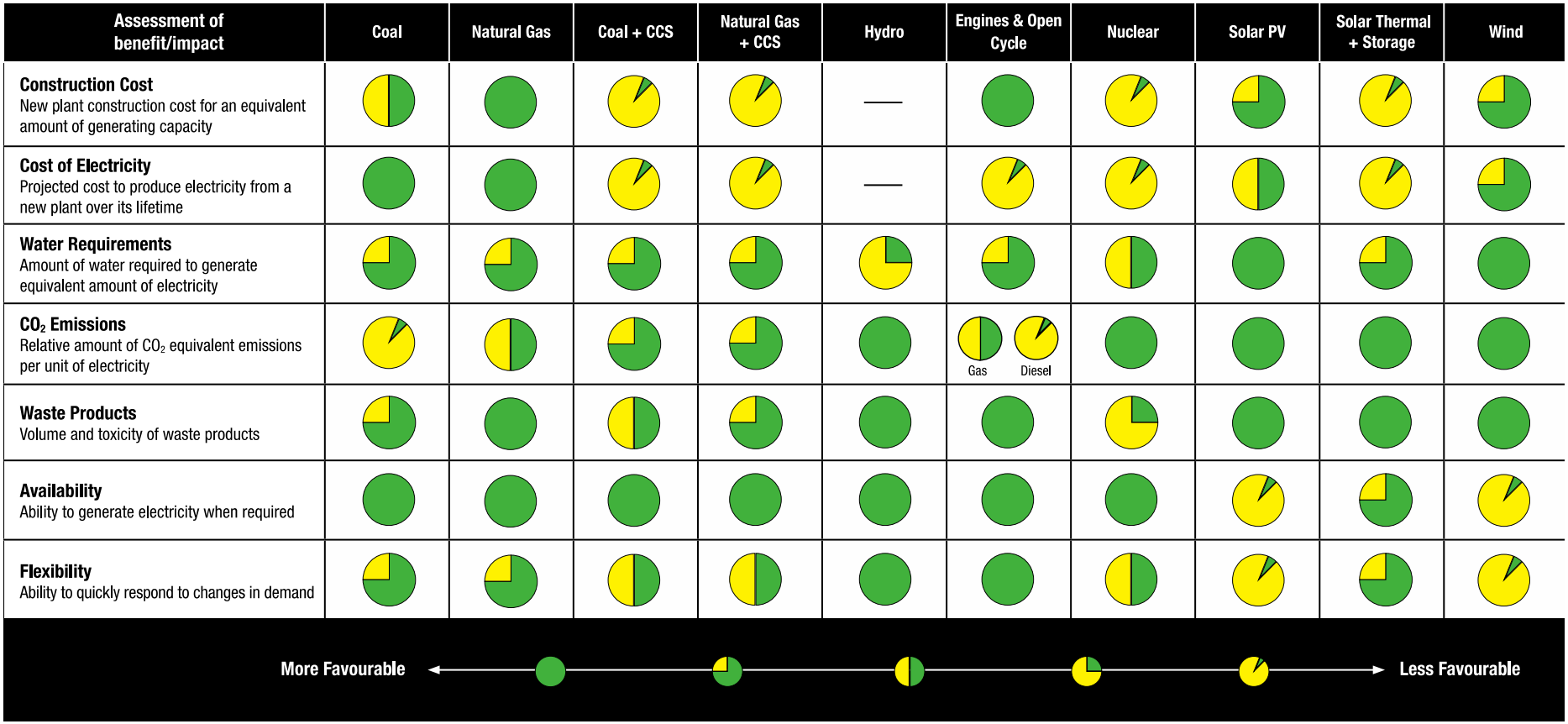


Figure 6: High-level technology comparison

3.2 Renewable technologies

The renewable technologies covered here are:

- solar technologies
  - solar thermal technologies (power towers, parabolic troughs, linear Fresnel receivers)
  - solar PV technologies (fixed, single-axis tracking, double-axis tracking)
- wind technologies
  - onshore
  - offshore
- ocean energy technologies
  - wave energy
  - tidal in-stream energy
  - ocean current technologies
- geothermal technologies
  - enhanced geothermal (hot rocks)
- biomass technologies
- hydroelectric technologies.

3.2.1 Solar thermal

Brief description of the technologies

Concentrating solar thermal power technologies use direct sunlight to heat a heat transfer medium and then use that medium to drive a power generation system. The sun's energy can be concentrated up to 1,000 times by using mirrors (also known as heliostats). The concentrated sunlight is then focused onto a receiver containing a gas or liquid heat transfer medium that is heated to high temperatures and transfers heat to a power generation system.

The three common concentrating solar thermal power technologies are:[1]

- power towers
- parabolic troughs
- linear Fresnel reflectors.

They are based on concentrating direct normal irradiation or insolation (DNI) to produce steam used in electricity-generating steam turbine cycles (see also Figure 7 for classification nomenclature). These systems use mirrors that continuously track the position of the sun and reflect solar radiation energy onto a heat transfer medium.

The solar energy can be harnessed and transferred in two ways: indirectly or directly. The indirect method uses a heat transfer fluid or solid medium that absorbs solar radiation energy and transfers the heat to water via a series of steam generator heat exchangers, thus indirectly producing steam. The direct method circulates water directly through the concentrated solar radiation path, thus directly producing steam. Both approaches use the steam in a steam turbine generator to produce power.

[1] A fourth and early-development technology, dish / dish Stirling engines, is not covered in this report.

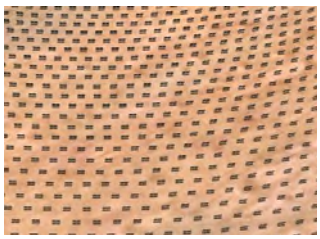
	Line focus	Point focus
Fixed receivers—in which the concentration system is independent from the receiver and energy conversion system		
Tracking receivers—in which the receiver and energy conversion system move together		

Figure 7: Concentrating solar classification system

Source: http://www.powerfactbook.com (accessed October 2015—subscription required).

Power tower / central receiver

A power tower system (also known as a central receiver system) uses heliostats (two-axis tracking mirrors) to concentrate DNI on a receiver at the top of a tower (**Error! Reference source not found.**). Typically, a molten nitrate salt heat transfer medium is used. It is heated to approximately 290ºC and then pumped out of the 'cold' tank, through the receiver, and into the 'hot' tank at 565ºC. The hot tank delivers the molten salt to a steam generator, where superheated steam is produced and expanded through a conventional steam turbine, producing electricity. Molten nitrate salt has been used as the common heat transfer medium because of its superior heat transfer and energy storage capabilities.

Figure 8: Brightsource Energy's LPT 550 system—the Ivanpah Station

Source: http://www.powerfactbook.com (accessed October 2015—subscription required).

The ability of a molten salt heat transfer medium to be heated to 565ºC and generate steam at 540ºC results in higher cycle efficiencies than are achievable with the lower temperature steam of the typical synthetic oil parabolic trough plant (see below). The elimination of oil also reduces environmental risks due to leaks and reduces consumables costs because salt is typically significantly cheaper than synthetic oil. However, molten salt has a relatively high freezing point at 220ºC. To maintain salt in the liquid state, a significant electrical freeze protection system or natural gas auxiliary boiler must be employed. Another disadvantage of this technology is that each mirror must have its own dual-axis tracking control; as a result, tower plants also have larger parasitic loads associated with mirror tracking relative to parabolic trough systems.

Recent build

Ivanpah is a concentrated solar thermal plant in the Mojave Desert in California.
It has 392 MW gross capacity.
It deploys 173,500 heliostats for three centralised solar power towers and operates with a molten salt heat transfer medium.

Unlike the synthetic oil heat transfer fluid in a parabolic trough system, power tower technology using molten salt allows for direct thermal energy storage (that is, the heat transfer medium is the same fluid as the storage medium) to be integrated into the system. This allows for a substantial cost advantage for the thermal energy storage system compared to an indirect thermal energy storage system because oil-to-salt heat exchangers are eliminated. Higher operating temperatures require much smaller storage tanks for a given amount of energy compared to parabolic trough plants, resulting in an additional cost reduction. Figure 9 shows a schematic diagram of the primary flow paths in a molten salt solar power tower plant with an integrated two-tank thermal energy storage system.

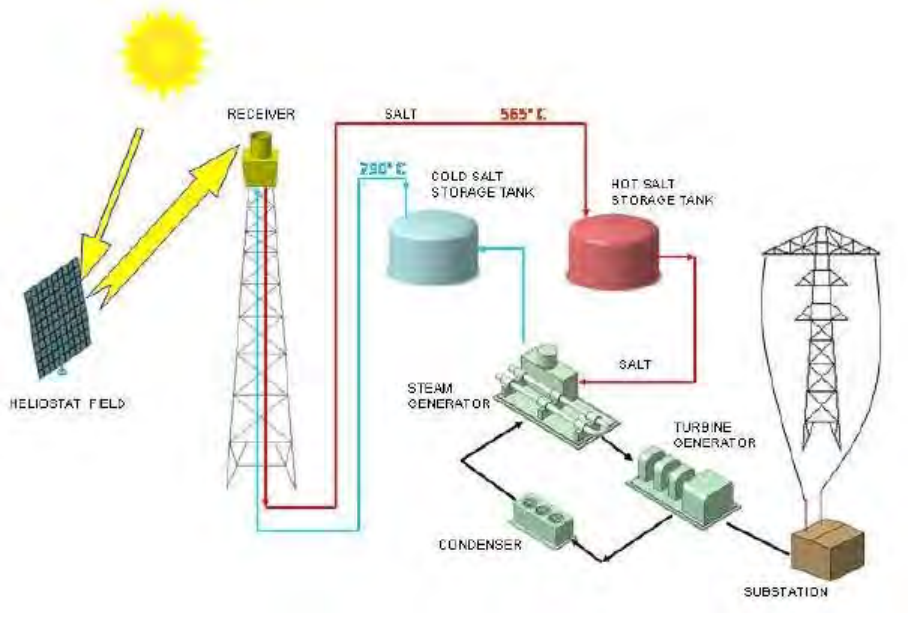


Figure 9: Schematic of molten salt power tower system

For a given power tower design with a fixed number of heliostats (solar field size) and a fixed tower height, the plant design variables are the steam turbine/power block and storage capacities. More specifically, with a larger turbine plant, output is higher at peak solar insolation periods, but less energy is available for storage; a smaller turbine allows for more stored energy, and thus a higher capacity factor, but less peak output to the grid. The optimal balance is highly dependent on the planned dispatch profile.

Some important site requirements include having a level land area (Table 5); however, in principle the requirements are less stringent than for a parabolic trough design, because of two-axis mirror tracking and not having to pump the heat transfer fluid through receiver tubes. Having a continuous parcel of land able to accommodate an oval-shaped footprint is also a valuable feature. The footprint of a tower system is relatively larger than that of a parabolic trough system.

Table 5: Direct land usage by concentrating solar thermal power technology

Technology	Direct area			
	Projects	Capacity (MW_{ac})	Capacity weighted area (hectares/MW_{ac})	Generation weighted area (hectares/MW_{ac})
All	17	2,216	3.1	1.1
Trough	7	851	2.5	1.0
Tower	9	1,358	3.6	1.1
Linear Fresnel	1	8	0.8	0.7

Source: Based on National Renewable Energy Laboratory (2013), *Land-use requirement for solar power plants in the United States*.

Many efforts are underway to develop power towers with higher efficiencies and lower capital costs. Examples of concepts in various stages of development include supercritical CO_2 power cycles, solid particle receivers and storage systems, and air Brayton cycles.

Parabolic trough

Parabolic trough systems use banks of trough-shaped mirrors with a parabolic cross-section to focus sunlight onto high-absorbing, low-emitting receiver tubes located at the focal line of the parabolic surface (**Error! Reference source not found.**). A high-temperature heat transfer fluid such as synthetic oil absorbs the thermal energy as it flows through the receiver tube and is pumped through a series of heat exchangers to produce superheated steam at approximately 390°C, which expands through a conventional steam turbine to generate electricity.

The solar field consists of several hundred to several thousand parabolic trough solar collectors, known as solar collector assemblies (SCAs). Rows of SCAs are aligned on a north–south axis, allowing the single-axis troughs to track the sun from east to west during the day. It is important for a parabolic trough system to have a large contiguous square- or rectangular-shaped land area, allowing for north–south SCA row arrangement with a slope between 1% and 3% to minimise the trough tilt angle and heat transfer medium pumping load. The solar collector assembly can move from about –30° below the sunrise position to +2° above the sunset horizon. The normal stow position is 30° to minimise wind loads. During peak winds, the stow position is face down. Overall positioning accuracy is approximately ±0.1°.

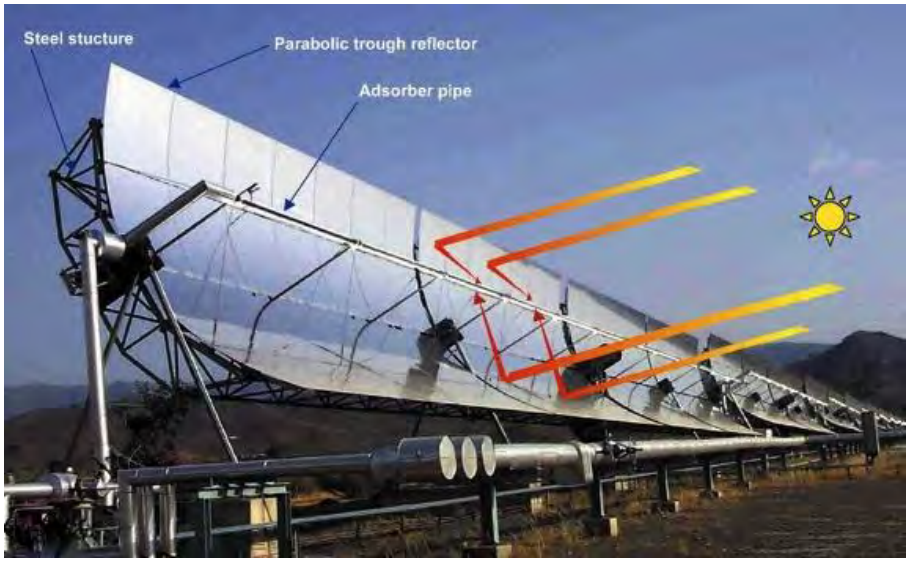


Figure 10: Typical parabolic trough structure

Note: The focus method is highlighted.

The primary efficiency limiter in conventional parabolic trough plants is the degradation temperature of the traditional synthetic oil heat transfer fluid, which limits the operating temperature to approximately 390°C. The synthetic oil heat transfer fluids are typically a mixture of 73% diphenyl oxide and 27% biphenyl, such as DowTherm A or Therminol VP-1.

An alternative to using heat transfer media of any sort coupled with a solar steam heat exchanger that is currently being developed is known as direct steam generation. Here, water is used as the working fluid in the solar field, generating steam directly and omitting the liquid-to-water heat transfer process, allowing for potentially higher steam temperatures and thus improving thermodynamic efficiency. Furthermore, replacing heat transfer oil with water significantly reduces consumables costs, environmental hazards and operating and maintenance (O&M) costs. Nevertheless, directly generating steam in the solar field introduces the instability of two-phase flow in the receiver tubes and the risks associated with temperature gradients in the tubes. Cost and performance issues will need to be addressed due to the high vapour pressure of water, which will require thicker heat collector element system components compared to systems using synthetic oil heat transfer fluids. For reference, the vapour pressure of water at 343ºC is about 15 MPa versus 0.5 MPa for typical synthetic oils.

Using molten salt as the heat transfer medium, as opposed to synthetic oil, has the potential of obtaining steam above 565ºC without the cost and performance issues associated with using water as the heat transfer fluid described above. However, significant engineering and O&M issues arise due to the high freezing temperature of molten salts.

Figure 11: Parabolic trough (north-south axis view)

Parabolic trough systems can be coupled with thermal energy storage to enable solar thermal power plants to be dispatchable. The most commercially viable thermal energy storage technology is the indirect molten salt two-tank system. In this system, some or all of the hot heat transfer fluid from the solar field may be diverted from the solar steam generator and pumped through heat exchangers to heat a molten salt fluid as it passes from a cold storage tank to a hot storage tank. When power is needed at a later time, the flow is reversed and the molten salt is used to heat the heat transfer fluid so that it may then generate steam.

Recent build

Abengoa's 100-MW KaXu Solar One parabolic trough plant in South Africa is an example of a solar thermal plant that includes a molten salt two-tank system. It began operating in early 2015 with a 3-hour thermal storage capacity.

Linear Fresnel reflector

The linear Fresnel reflector (LFR) system uses multiple parallel mirrors to focus DNI onto a single elevated receiver. The mirrors are flat or elastically curved reflectors that are mounted on a sun tracker. In essence, the mirrors are a 'digitised' approximation of a parabolic surface. Similarly to the parabolic trough plant, rows of reflectors are typically placed on a north–south axis, allowing the single-axis mirrors to track the sun from east to west during the day (**Error! Reference source not found.**). However, while a conventional parabolic trough solar thermal system has one curved reflector for each receiver line, the linear Fresnel reflector system typically has 10. Each individual mirrored reflector has the option of directing reflected solar radiation to at least two different receivers. This minimises shading losses, allows arrays to be much more densely packed, and permits the receiver tubes to be lower than would otherwise be possible.

Figure 12: Concentrating linear Fresnel reflector at Liddell Power Station, NSW

LFR technology uses water as the heat transfer fluid, thus employing a direct steam generation process. The concentrated heat boils water within a receiver composed of specially coated steel tubes in an insulated cavity, producing saturated or superheated steam that is then delivered to a conventional steam turbine or alternative user. The in-field piping and components need to be thicker than those in a parabolic trough plant due to the higher vapour pressure of water compared to synthetic oil, and this is a significant consideration when the solar arrays are located remotely from the power block. LFR technology may also use biphenyl/diphenyl oxide (oil) as an alternative to water.

Australian test facility

The Macquarie Generation has installed a 9MW$_t$ CLFR solar field into the existing 2000 MW coal-fired Liddell Power Station in New South Wales.
The field, which consists of two concentrating LFR solar steam generators, became operational in 2008.
The Fresnel reflectors focus the sun's energy onto overhead water-filled tubes, where the water is heated to produce saturated steam. They are interconnected to the top feedwater heater of one of the four 500 MW

This technology is designed to reduce capital costs compared to parabolic trough and central receiver systems. The unresolved question is whether the capital cost is low enough to compensate for the lower performance of LFR systems.

Error! Reference source not found. shows a typical LFR configuration. The system is modular, and a large-scale system will consist of multiple arrays of mirrors and receivers. Land requirements are less demanding than for parabolic trough and power tower plants for a given field MW$_{th}$ output (see Table 5 for detailed information). The dual-axis tracking necessary for peak performance in the power tower design equates to greater land demands in comparison to the LFR plant design.

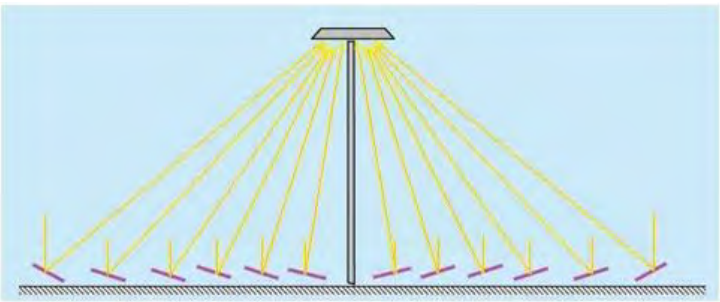


Figure 13: Schematic of a linear Fresnel reflector mirror-to-receiver energy path

Solar technology development status

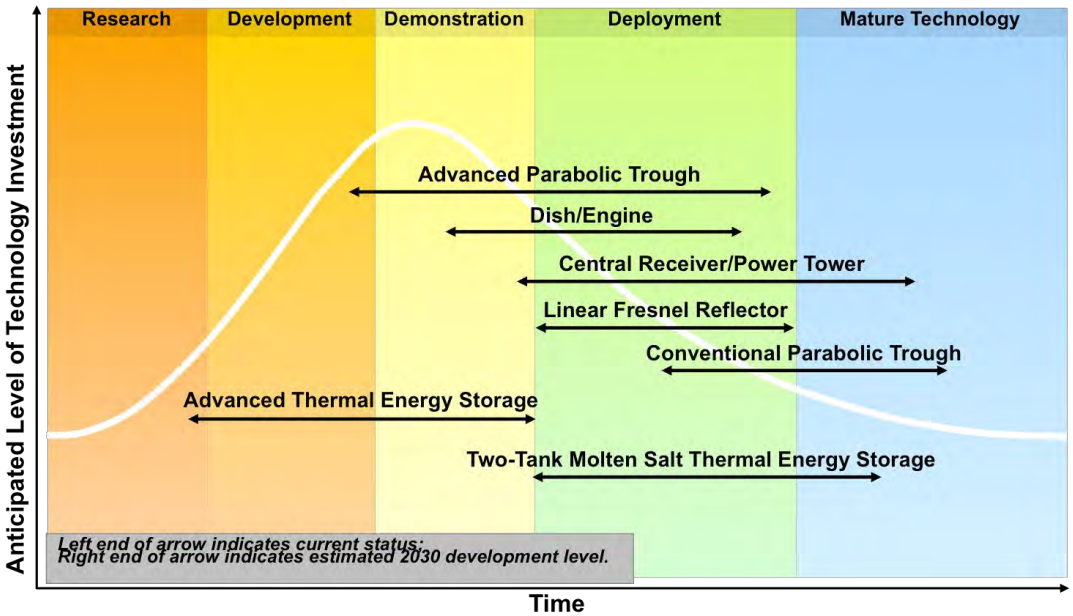


Figure 14: Solar thermal technology development curve

Some solar thermal technologies are earlier in technology development. For example, the Ivanpah solar power tower is considered 'first of a kind' in the United States, while the dish-engine and LFR designs have even fewer deployments. However, conventional parabolic trough technologies and some power tower designs are globally commercialised. Considerable research is underway, and improved technologies and material selections are expected to advance solar market penetration.

Conventional parabolic trough plants are the most mature of the solar thermal technologies. They accounted for more than 46% of 2014 global installed capacity, while tower plants accounted for more than 41% of global installed capacity in the same year. In 2014, 1,066 MW of concentrating solar power was installed globally, which was less than 1% of globally installed renewable generation capacity.[2]

Demonstration and commercial-sized plants are being built for all of these technologies, all of which are forecast to mature by 2030 to late-deployment or early-mature stages. Advanced parabolic trough plants that are under development use molten salt or direct steam heat transfer fluids, removing some of the operating temperature limitations imposed by using synthetic oil. It is estimated that these plants will also progress considerably between now and 2030.

Future development directions/trends

One technical issue associated with solar power technology is the need to increase the annual capacity factor. One advantage of concentrating solar thermal plants is their potential for storing solar thermal energy to use during sunless periods and to dispatch power when it is needed most. As a result, thermal energy storage allows parabolic trough power plants to

[2] Market Size Power Generation Database, Bloomberg New Energy Finance, 3Q 2015.

achieve higher annual capacity factors—from 20% without thermal storage to 40% or more with it, depending on the amount of storage incorporated.

As shown in Figure 15, the solar field is sized to allow for both direct power generation and the storage of energy during daytime hours. The stored energy is used to continue power generation after the sun goes down. Two-tank molten salt thermal energy storage is currently in the early stages of deployment, but is forecast to become a mature technology by 2030 due to the high interest in thermal energy storage for smoothing solar electricity production and the ability to perform load following if desired. Advanced thermal energy storage technologies, such as thermoclines, concrete or graphite storage, phase change materials, and thermochemical storage, are currently under R&D, and at least some of those technologies are expected to move through demonstration and begin deploying by 2030.

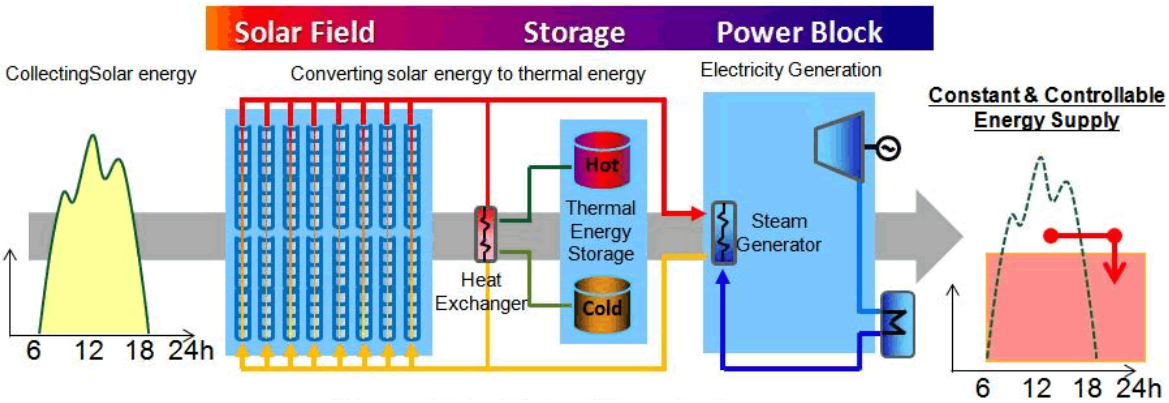


Figure 15: Concentrating solar thermal with storage and storage dispatch

Source: http://www.chiyoda-corp.co`m/technology/en/green_energy/solar_energy.html (accessed October 2015).

In addition to technical issues, land and water use are also key factors.

Solar thermal plants without storage require 2–4 hectares/MW of peak capacity in good solar-resource locales (over 2,200 kWh/m^2/year). However, plants that incorporate some storage may require three to ten times more land per peak megawatt, and their generating units will typically not be designed to use the entire peak thermal output of the collector field. Therefore, a more meaningful metric of land use would be the area required per MWh/year of output, which would range from about 0.2–1.6 × 10^{-3} hectares/MWh/year. (Note that, although conceptually distinct, these two quantities have the same fundamental units of area/power).

Anticipated improvements by 2030

As concentrating solar power plants gain footing in the utility market and their installed capacity expands, their cost is expected to continue to decrease due to the higher production volume of key equipment (receiver tubes, power towers, and so on) and the greater experience of the manufacturers and engineers who are planning and building plants. In addition, it is expected that cheaper heat transfer fluids will become available or that fluids that can handle higher temperatures, and therefore enable higher power cycle efficiency, will be used. The cost of storage systems is also expected to be reduced. Furthermore, improvements are expected in receiver tube absorption and steam turbine efficiencies that would increase the capacity factor for these plants. The combination of a decrease in capital cost and an increase in plant output will lead to a lower cost of electricity (Table 6).

Table 6: Concentrating solar thermal power—power tower with storage cost and performance improvements

	Current technology	2030 technology average		
		GALLM scenario		Road map
		450 ppm	550 ppm	
Capital cost (relative to current technology)	1.00	0.46	0.46	0.80
Thermal efficiency	Base			+5 pts

Note: Refer to Chapter 16 and Section 15.14 for details on the capital cost estimation methodology.

Development and commercialisation timeline

Each of the solar thermal technologies is at a different stage of development. To better understand the development of solar thermal, it is helpful to consider the global installed capacity of concentrating solar thermal power (CSP) compared to solar PV. Bloomberg New Energy Finance indicates that there is around 4.3 GW of CSP generation installed around the globe, which is about 2.5% of the approximately 175 GW solar PV installed.[3] Just from that standpoint, many governments, including the Australian and United States governments, have invested money in assessing CSP potential and the R&D needs to increase the deployment of CSP technologies. The most mature technology is the parabolic trough, with about 3 GW of installed capacity at the end of 2014. Power towers are relatively new in comparison, with only close to 700 MW of installed capacity.

LFR is much earlier in development: close to 200 MW is installed, with the largest project (100 MW) being commissioned in November 2014 in India. Before that, most LFR projects were pilots. There is some concern with its trajectory since Areva exited the solar business after suffering financial loses after acquiring Australian-founded start-up Ausra. The 44 MW Kogan Creek Solar Boost project has had significant delays due to a combination of factors, including scheduling and technical issues—pushing back commissioning from 2013 to late 2016.[4]

Using molten salt as a heat transfer medium, as opposed to synthetic oil, has the potential of obtaining 565°C+ steam without the cost and performance issues associated with using water as the heat transfer fluid described above. However, significant engineering and O&M issues arise from the high freezing temperature of molten salts. R&D using molten salts in parabolic trough systems is ongoing and has the potential to reduce the LCOE over power from plants using synthetic oil.

[3] IRENA (2015), *Renewable energy capacity statistics*.
[4] S Vorrath (2014), *Areva exits solar, mothballs Aust-made CSP technology*, www.reneweconomy.com.au.

3.2.2 Solar photovoltaic

Brief description of the technology

Solar PV technology converts light directly into energy via the photoelectric effect, which is the process in which light (photons) excites electrons into a higher energy state. This creates an electron flow—electricity.

Because of the extreme modularity of PV systems, they have been used for small-scale residential, commercial and industrial applications and for large-scale utility applications.

Solar PV technologies

A solar PV cell is a solid-state device and can be categorised as a:

- crystalline silicon cell
- thin film
- multi-junction cell
- single-junction cell.

The two main types are crystalline silicon and thin film.

Within the solar cell, the junction between two thin layers of dissimilar semiconductor material provides an electron flow when the cell is exposed to light, producing electricity.

Semiconductor materials used for PV cells are typically silicon doped with other elements that have either one more or one less valence electron to alter the conductivity of the silicon. For example, if the silicon is doped with an element having one more valence electron, such as phosphorus, the resulting material will have an extra electron available for conduction. This material is called an n-type semiconductor. Conversely, when the silicon is doped with an element having one less valence electron, such as boron, the p-type semiconductor that is produced has an electron vacancy, or hole. When adjacent layers of n-type and p-type materials are illuminated, a voltage develops between them, which can cause a DC electric current to flow in an external circuit.

A typical silicon solar cell today is about 100 cm^2 in area and produces about 3 amps at 0.5 volts. Individual cells are connected in series and parallel as modules to provide higher voltage and current levels. The active areas of the modules range from 0.1 m^2 to 2 m^2, and the modules are typically connected together into arrays (Figure 16).

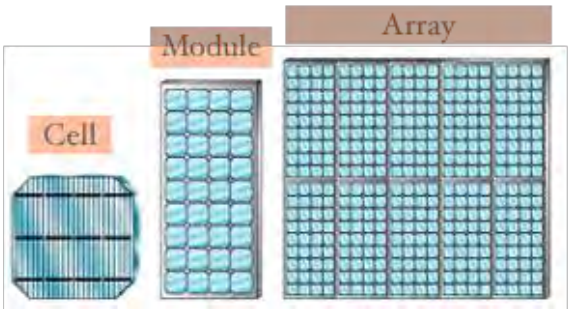


Figure 16: Scalable solar PV—cell, module and array

Source: http://www.powerfactbook.com (accessed October 2015—subscription required).

Crystalline silicon technologies

Most currently produced cells use wafer-based crystalline silicon technology, which is fairly well understood. Crystalline silicon can be grown in two main forms: monocrystalline and polycrystalline. Monocrystalline silicon has an ordered crystalline structure, with atoms arranged in a regular pattern. These cells have a slightly higher efficiency and a better temperature coefficient (the power output is less affected by increases in temperature) than polycrystalline cells. However, monocrystalline silicon is more expensive than polycrystalline silicon because of the high processing control required and high energy consumption during its manufacturing. Sensitivity to silicon costs and the sophistication of cell fabrication are key factors with this technology.

Thin film technologies

In thin film PV, which uses thin films of amorphous silicon, copper indium diselenide, cadmium telluride, copper indium gallium selenide or other novel semiconductors are deposited on a low-cost substrate, such as plastic, glass or metal foil. Thin films typically use about 1–5% of the semiconductor material used in crystalline silicon modules. Thin-film modules accounted for more than 10% of the market early this decade, but due to the sharp drop in silicon prices in recent years, production has dropped closer to 5% of overall PV production.

Currently available commercial modules for first-generation wafer-based crystalline silicon technology have efficiencies in the range of 14–21%. Today's second-generation thin film technologies have lower efficiencies in the 7–14% range. Both crystalline silicon and thin film technologies have a similar upper efficiency limit (known as the Shockley–Queisser limit), and the efficiency gap in current modules is an artefact of imperfect manufacturing processes. Advances in thin film efficiencies are expected to outpace those accruing to crystalline silicon modules and narrow the performance gap between the two technology types over time.

Array configurations

Four types of mounting system are used in solar PV systems:

- flat plate
- fixed tilt
- single-axis tracking
  - dual-axis tracking

Recent Australian solar install

The Moree Solar Farm will have a capacity of 56 MWac. The panel technology is polycrystalline modules with horizontal tracking.
The project is the first large-scale facility in Australia to use a tracking system. The tracker is attached to piles, and a drive mechanism is used to orient the panels towards the sun, moving from east to west throughout the day. 2,800 trackers are required, with each tracker supporting 80 PV modules.

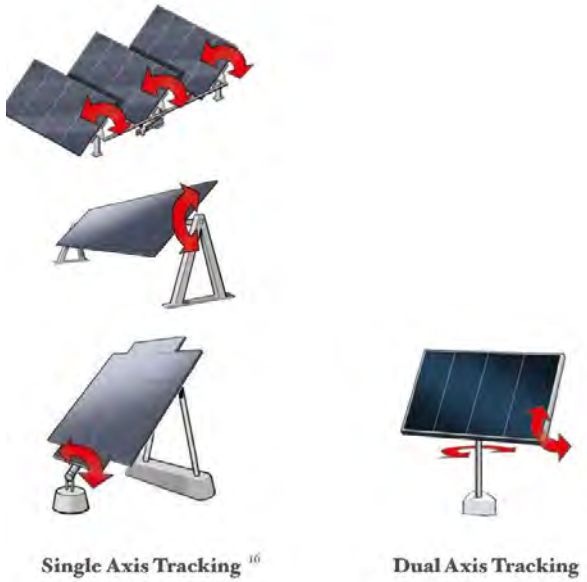


Figure 17: Solar PV tracking alternatives

Source: http://www.powerfactbook.com (accessed October 2015—subscription required).

Single-axis tracking systems, which follow the sun from east to west throughout the day, produce more energy than the same panels installed on fixed racks. Single-axis tracking systems that track the sun from north to south throughout the seasons may be useful, depending on the latitude of the system. Dual-axis tracking, which uses both east–west and north–south tracking, provides the optimal tracking solution.

DC to AC conversion

The ratio between the DC power capacity of a solar array and the AC inverter is the inverter load ratio (ILR). Solar PV systems are optimally designed to maximise the energy production from each solar panel in the array; the key metric is the specific yield, or kWh of energy production per kW of installed capacity. The optimal array-to-inverter ratio greater than 1, taking into account that the DC rating of the array is measured under ideal conditions that most often are not experienced in the field because of cloud cover. When the power output from a solar PV array is greater than the rating of the inverter, the inverter limits the power from the array to the inverter's maximum nameplate power. The inverter's power limiting is known as 'clipping'. Traditionally, the DC power output of the solar array is fairly close to the AC inverter's nameplate power; solar array designers have targeted an ILR of 1.00–1.25. For example, a solar array that produces a maximum DC capacity of 1.2 MW would be matched with a 1.0 MW AC inverter, yielding an ILR of 1.2.

However, developers have recently began a new trend of increasing the ILR (by oversizing the DC output of the solar PV array) to maximise energy production during peak times of the day when the energy is most valued. This has mainly been driven by the decrease in solar PV panel pricing and by increased revenue that can be gleaned in the power market by providing power during high-demand periods. Figure 18 highlights the potential benefits of oversizing the solar PV array. In the figure, the yellow curve represents a system that is right-sized based on traditional thinking. Its ILR is 1.2. The green curve represents a system that is oversized, meaning the inverter has been undersized compared to the DC output of the solar PV system. In the figure, the oversized system has an ILR of 1.5.[5]

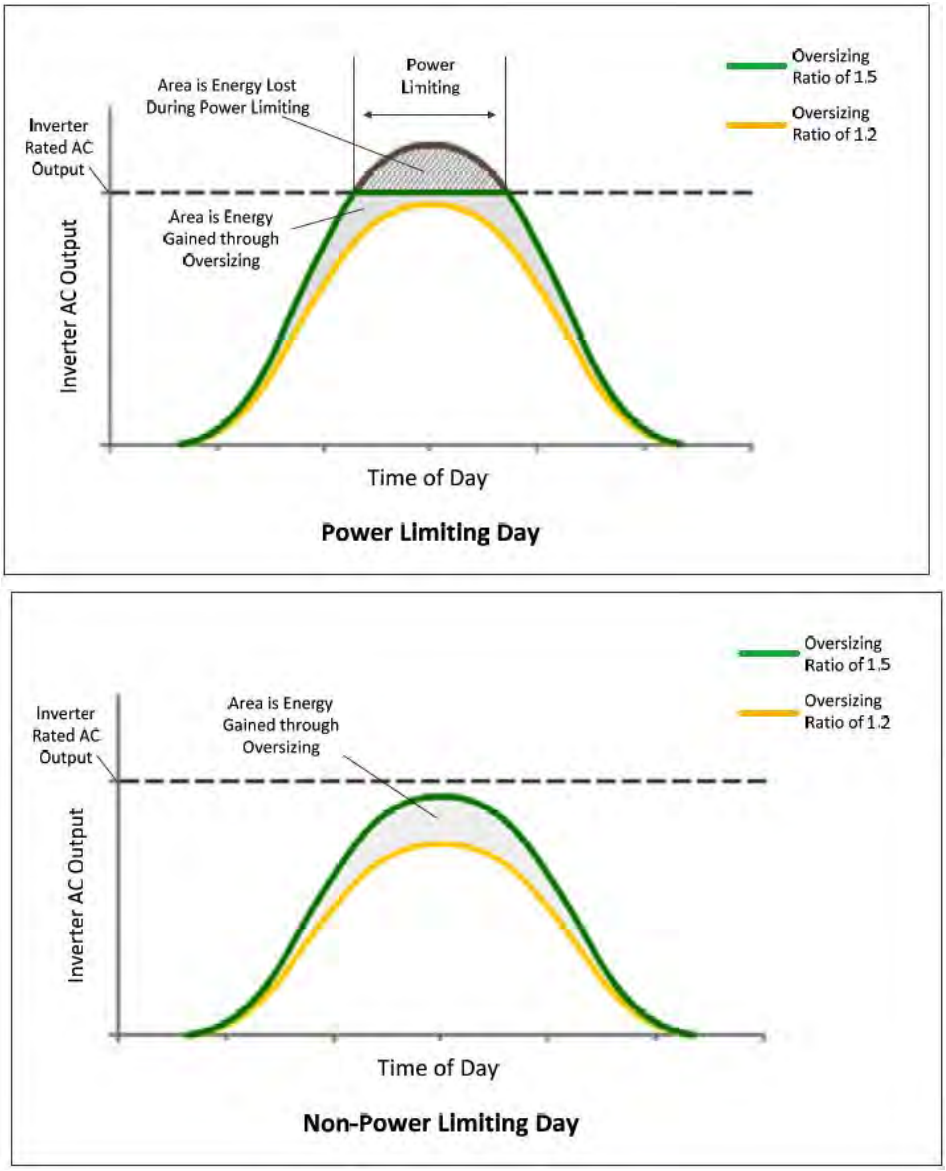


Figure 18: Solar PV daily energy production profiles with inverter load ratio values of 1.2 and 1.5

[5] Jon Fiorelli, Michael Zuercher-Martinson (2013), 'Supersize it: how oversizing your array-to-inverter ratio can improve solar-power system performance', *Solar Power World*. July.

Source: J Fiorelli, M Zuercher-Martinson. 'Supersize it: how oversizing your array-to-inverter ratio can improve solar-power system performance', *Solar Power World*. July 2013.

The solar PV installation question is now focused on optimising design; that is, on manipulating the ILR to yield the most economic value from the system. In general, a higher ILR works well for systems that may not experience peak power output (those in hot climates or cloudy areas).[6]

Inverter manufacturers caution against too much oversizing, noting that oversizing inverters leads to them operating at high power for longer periods, reducing the life of the components. Operating at higher power outputs increases inverter heating, possibly leading to overheating. Warranty concerns may become an issue for owners of systems that operate outside the manufacturer's intended parameters.[7] There is a limit to permissible overloading based on calculations using the United States National Electrical Code (NEC 690.8(A)(2)), which is set by the maximum array short circuit current of the inverter. The exact limit depends on the system design.[8]

Technology development status

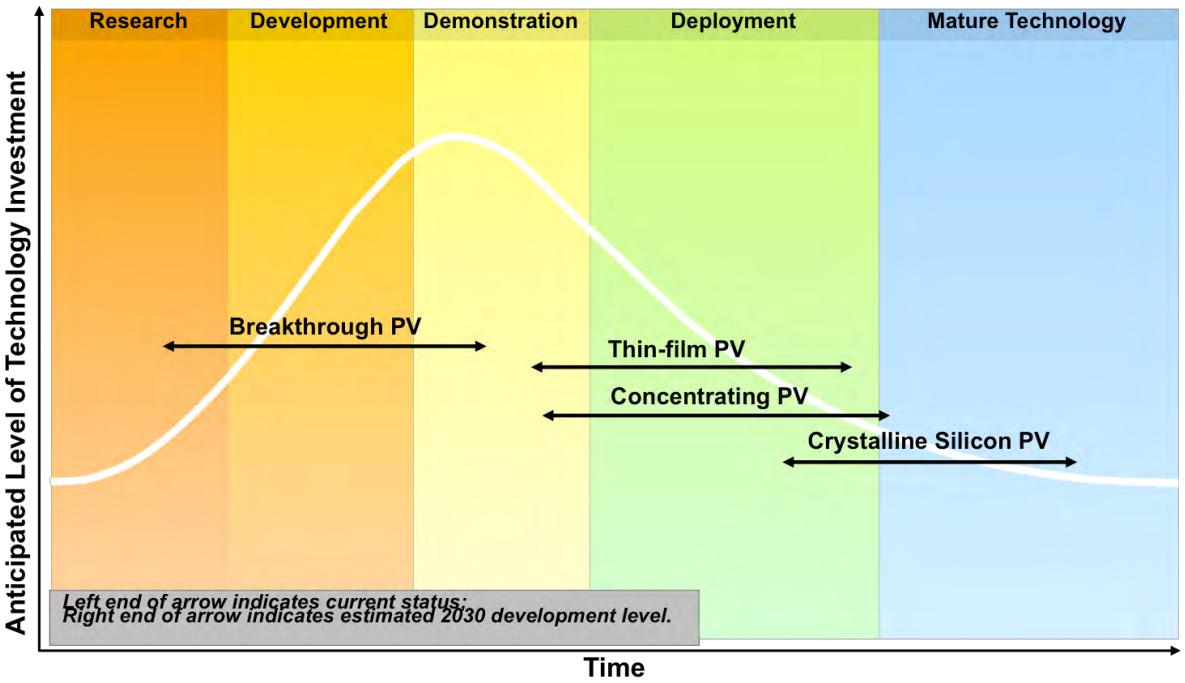


Figure 19: Solar PV technology development curve

PV technology is still evolving (Figure 19). Installations of solar PV have increased dramatically over recent years. In 2014, 768 MW of PV systems were installed in the Australia. At the end of that year, the total solar PV capacity in Australia was about 4 GW, a 25% increase from 2013.[9] Worldwide, there have been large increases in installations and capacities: about 45 GW was installed in 2014, bringing total worldwide capacity close to

[6] *DC loading of PV powered inverters*, Advanced Energy application note, 2012.
[7] *Oversizing of SolarEdge inverters: technical note,* November 2014.
[8] *DC loading of PV powered inverters*, Advanced Energy application note, 2012.
[9] Market Size Power Generation Database, Bloomberg New Energy Finance, 3Q, 2015.

186 GW. This growth continues to occur in residential, commercial and utility markets. Meanwhile, costs continue to decrease.

Concentrated photovoltaic (see below) is just starting to be built in increased capacities (cumulative installed capacity is at 357 MW).[10]

As efficiencies improve and costs continue to decrease, it is estimated that by 2030 crystalline silicon PV will be a mature technology, and thin-film PV and concentrated PV will be near maturity. At the same time, breakthrough PV technologies, such as hot carrier, Perovskite, and multi-exciton PV cells, which are currently in the research phase, are likely to progress through development and into demonstration by 2030. The development of these truly novel 'breakthrough' technologies will depend on progress in research and funding for technology development from governments, venture capital, and strategic investors looking to ultimately manufacturer and compete on a global scale. Worldwide deployment of these innovative technologies on the scale of 5–10 MW could occur in the 2025–2030 timeframe, driving the next generation of solar PV installations.

Major technical issues and future development directions/trends

Including tracking in solar PV installations has historically been cost-prohibitive for most project owners. The increased energy production did not justify the increase in capital expenditures and O&M costs. As a result, relatively few single-axis tracking (SAT) and dual-axis tracking PV plants have been installed. However, this appears to be changing, particularly for SAT systems.

In the past few years, there has been a notable uptick in the number of PV plants that are using SAT. Moreover, given a generally improving cost–benefit calculus, some of the more recently commissioned plants are incorporating thin-film module technologies, which typically do not lend themselves to tracking because of their larger area requirements compared with crystalline silicon panels as a consequence of their lower conversion efficiencies. Figure 20 shows two modules with the same power rating. With a higher efficiency, the smaller module requires a smaller area to achieve the same power output as the larger, less efficient module. Thus, for a given plant size, less efficient modules will result in more surface area needed for conversion, and consequently add costs due to the need for more land area, as well as steel, copper and concrete for the racking and support structure, including tracking hardware. With this overarching shift in market mindset, analysts project year-on-year growth in SAT system adoption out to 2020.

[10] GlobalData (2014), *Concentrated photovoltaics (CPV): update 2014—global market size, competitive landscape, and key country analysis to 2020*, GlobalData.

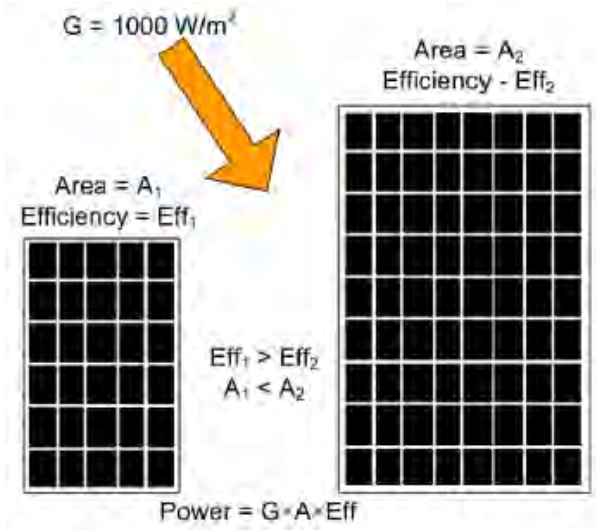


Figure 20: Comparison of PV modules with differing conversion efficiencies and power densities

Source: EPRI (2004), *Solar energy technology guide*, product ID 3002003681.

Adding tracking to a PV system increases the energy yield by allowing the modules to follow the sun from east to west in single-axis applications and both daily and seasonally in dual-axis applications. In addition to generating more energy each year than plants using fixed flat plates of the same capacity, tracking PV systems alter the shape of the daily output profile, in effect modifying PV resource availability. SAT systems use north–south rows. Typically, the axis of rotation is horizontal, but in some cases the axis is tilted so that the modules are more south facing (in the Northern Hemisphere). Tilting results in increased energy production, frequently at a higher capital cost for the mounting structure. Figure 21 shows an example.

Figure 21: 250 MW Silver State solar project, which includes one of the world's largest SAT systems

Source: EPRI (2014), *Solar energy technology guide*, product ID 3002003681.

Two-axis tracking results in the highest annual energy production, but at a higher capital cost. Concentrating PV (CPV) systems, for example, require either one-axis or two-axis tracking, depending on whether the system is line focus or point focus. Some low-concentration CPV systems use a line focus single-axis tracking configuration in which the sun is focused on a line of PV materials, in much the same way that the sun is focused on receiver tubes in parabolic trough concentrating solar thermal power systems. Low-concentration CPV line focus systems have not proven commercially successful to date, largely because of their marginal benefits relative to alternative plant configurations, such as non-concentrating single axis tracking or high-concentration PV dual-axis systems. High-concentration CPV systems use dual-axis tracking and create a 'point' focus on individual small PV cells by pointing directly at the sun and using lenses to focus the sun on the cells.

Solar PV systems using different mounting configurations produce different hourly energy generation curves. Figure 22 shows typical daily generation profiles for various PV plant configurations; the profiles have broader 'shoulders' for the tracking systems because of those systems' orientation towards the sun during the early morning and late afternoon compared to fixed-tilt systems. Tracking the sun also results in a flatter midday output profile. These generation profiles have implications for how well solar energy production matches daily system demand.

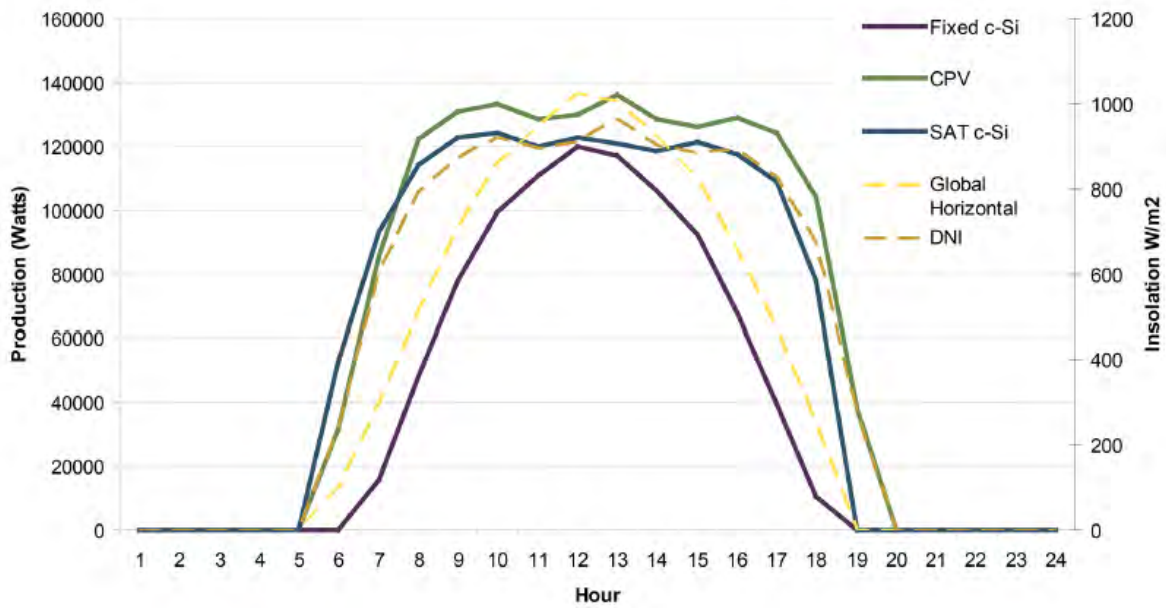


Figure 22: Comparison of output profiles for various PV plant configurations

Figure 23 highlights the impacts of tracking on energy production and capital costs. The addition of tracking can increase energy production by over 30% relative to a horizontal, fixed PV system. However, it is best to compare incremental tracking gains to a fixed flat-plate PV system at latitude tilt, because that is more typical of utility-scale ground-mounted plants. This approach reveals a more modest energy advantage—perhaps an increase of around 7%—that is offset by an additional ~5% in capital costs. System performance improvements with trackers are most pronounced at sites with high-quality solar resources (such as those in arid deserts) and can, in turn, have a greater impact in reducing a PV plant's LCOE. SAT plants typically require ~2.8 hectares/MW, while fixed-tilt systems often require ~5 hectares/MW, although these rule-of-thumb measurements vary according to site conditions.

				
	Horizontal	**Fixed Tilt**	**Single-Axis Tracking**	**Two-Axis Tracking**
Indicative Energy Boost Relative to Fixed Horizontal System	0%	15%	22%	32%
Increased Capital Cost per m^2 of Panel Relative to Fixed Horizontal System	0%	10%	15%	20%

Figure 23: Effects of tracking on annual energy production and capital

Source: EPRI (2014), *Solar energy technology guide*, product ID 3002003681.

According to GTM Research, tracking adds an estimated ~$0.20–$0.25/W to the capital cost of projects, though those premiums may be smaller for very large projects. Meanwhile, O&M expenses associated with tracking have diminished as engineering, procurement and construction providers and developers accrue greater experience in managing SAT plants. As more SAT plants have been installed, O&M costs have become better understood, thus reducing the perceived risk of projects with tracking.[11]

Much R&D effort has been directed at reducing solar PV module costs. As module prices have significantly decreased, attention is now being directed at power electronics, including inverters. Inverter reliability has been an issue for grid-connected PV systems, making inverter replacement or repair a leading O&M cost component. Power electronics account for 8–12% of lifetime PV costs. Figure 24 highlights the magnitude of challenges stemming from the inverter. The data is based on operating data from SunEdison in Belmont, California.

[11] EPRI (2015), *Solar PV market update*, 2015, product ID 3002005776.

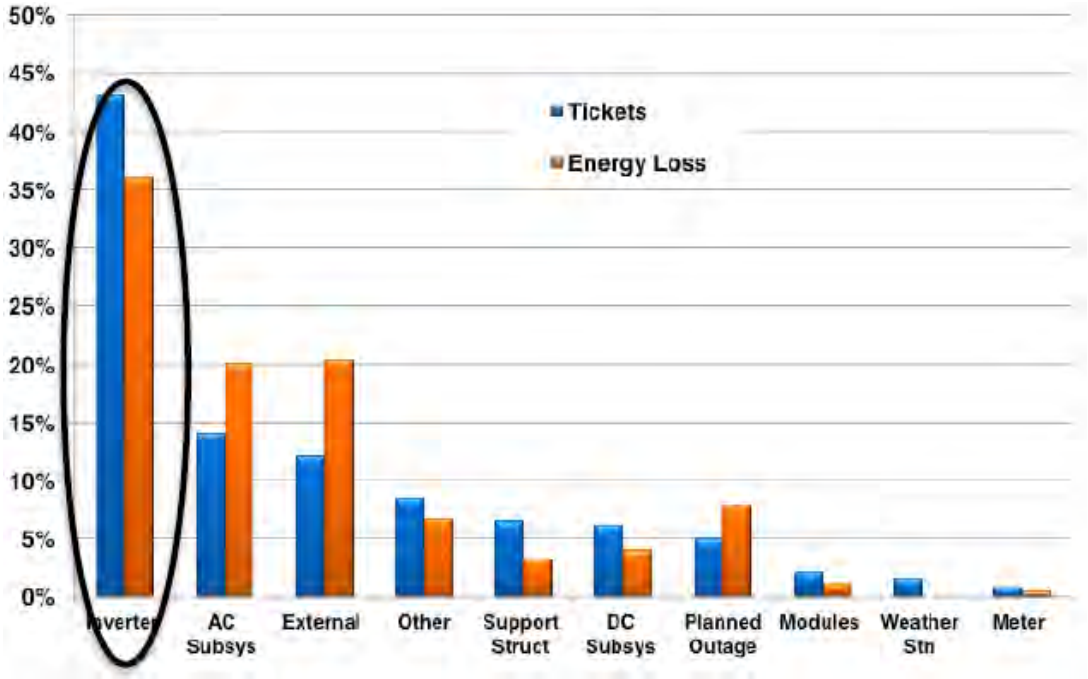


Figure 24: Solar PV component-level reliability

Source: J Flicker (2014), *PV inverter performance and component-level reliability*, Sandia National Laboratories, August.

Figure 24 shows that 36% of energy loss incidents are due to the inverter, while 43% of the work tickets received during the analysis period were related to the inverter. This situation has been improving. EPRI, along with Sandia National Laboratory, is working to collect and compare solar PV O&M data to gain a more accurate understanding of O&M practices and develop improvements to those practices that result in greater reliability and lower installation and operational costs for solar PV systems.[12]

Anticipated improvements by 2030

The cost of electricity from photovoltaic plants has decreased rapidly in recent years and is expected to continue to decline into the future. This is due both to expected reductions in solar panel costs and increased efficiency. As more solar PV plants are built, the cost of solar modules continues to decrease due to mass production. The balance of system and inverter costs is also expected to change over time. Researchers have continued to develop new PV configurations, such as multi-junction concentrators, that promise to increase cell and module efficiency. While the efficiencies seen in a commercial solar field typically lag the record efficiencies seen in laboratories by 15–20 years, these improvements can be expected by 2030. Figure 25 shows the growth in module efficiencies; there is still room for improvement through developments in promising technologies such as perovskites,[13] which have a cell efficiency limit of 31%, based on detailed balance analysis.[14] Higher efficiencies can also contribute to lower capital costs and lower O&M costs, as less surface area is needed to produce a given amount of power (Table 7).

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[12] EPRI, *Photovoltaic Reliability Operations and Maintenance (PVROM) Database Initiative: 2014 progress report*, 2014, product ID 3002003735.
[13] *The future of solar energy: an interdisciplinary MIT study led by the MIT Energy Initiative*, May 2015.
[14] Wei EI Sha, Xingang Ren, Luzhou Chen, Wallace CH Choy (2015), 'The efficiency limit of $CH_3NH_3PbI_3$ perovskite solar cells', *Applied Physics Letters*, 106(22)221104.

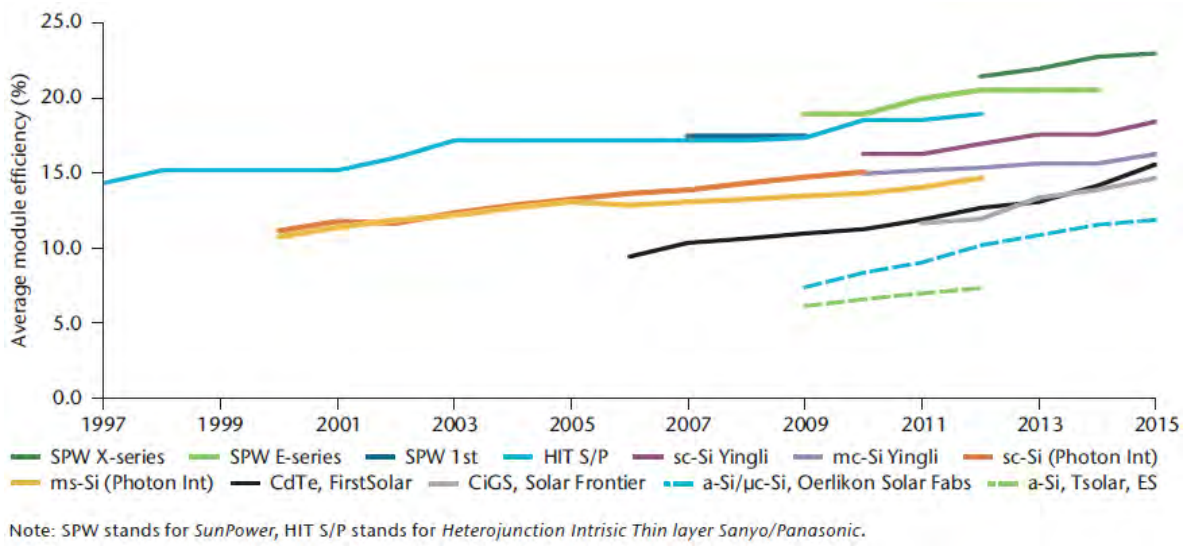


Figure 25: Commercial 1-Sun module efficiencies

Source: International Energy Agency (IEA) (2014), *Technology roadmap: solar photovoltaic energy*, IEA.

Table 7: Anticipated cost and performance evolution for PV

	Current technology	2030 technology average		
		GALLM scenario		Road map
		450 ppm	550 ppm	
Capital cost (relative to current technology)	1.00	0.48	0.49	0.50
Solar to electricity efficiency	Base			+7 pts

Refer to Chapter 16 and Section 15.14 for details on the capital cost estimation methodology.

Development and commercialisation timeline

New materials and manufacturing techniques have been sought throughout the history of PV development to increase efficiency and lower costs. Overall, those efforts have been very successful, and new materials and techniques continue to promise significant further improvements. The key to reducing the cost of crystalline silicon cells has been improved manufacturing techniques to speed mass production while also reducing material consumption and improving efficiency.

R&D in thin-film PV cells is also producing promising improvements in performance in laboratory tests and strong interest from venture capitalists. Again, the ability to manufacture large quantities cost-effectively, along with improved efficiency, will help bring down the costs for thin-film PV and support greater market acceptance.

Single-axis tracking technologies are already moving towards greater deployment (Table 8).

Table 8: Global ground mount installed PV capacity forecast

Global ground mount forecast (MW_{dc})	Actual	Estimate				
	2013	**2014**	**2015**	**2016**	**2017**	**2020**
Fixed tilt	22,728	21,005	26,159	28,251	29,039	44,558
Tracking	2,110	3,814	6,653	8,519	5,971	14,738
Total	**24,838**	**24,819**	**32,812**	**36,770**	**35,010**	**59,296**
Tracking penetration	8.5%	15.4%	20.3%	23.2%	17.1%	24.9%

3.2.3 Wind energy

Brief description of the technology

A wind turbine is a device that converts kinetic energy from the wind into electricity. The energy extracted from the wind turns blades around a rotor. The rotor, which is connected to a shaft, spins a generator to create electricity.

Onshore wind

Many wind turbine design configurations have been proposed and tested during the past 20 years of development, including vertical and horizontal axes, upwind and downwind rotors, two and three blades, direct and gearbox-drive trains, and fixed-speed, two-speed and variable-speed generators. Today, the most common configuration used on shore is the three-blade, upwind, horizontal-axis design with a three-speed gearbox, variable-speed generator and power electronics to generate 50 Hz or 60 Hz power.

The main components of an onshore wind turbine include the tower and foundation, the rotor, the nacelle and drive train, and the electrical controls, all of which are described in more detail below. Figure 26 shows a typical wind turbine.

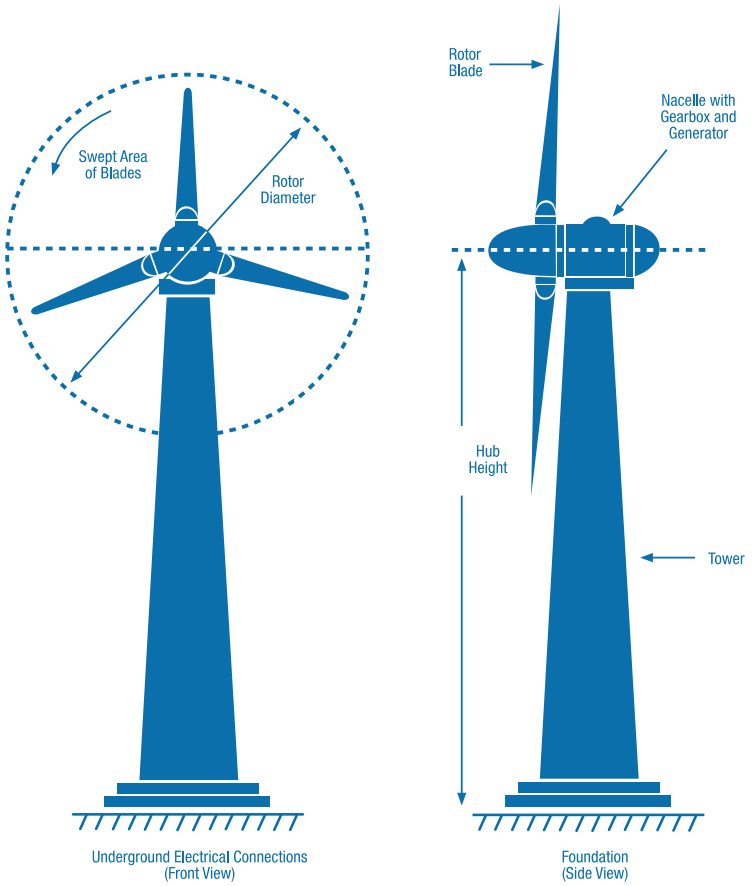


Figure 26: Wind turbine (front and side view)

The tower is the base that holds the nacelle and the rotor. Typically, turbine towers are constructed from steel. To support the tower, the rotor and the nacelle, as well as the dynamic structural loads created by the rotating turbine, a large steel-reinforced concrete foundation is required; the amount of material needed for the foundation depends on the site and soil conditions.

For large-scale electricity production, multiple wind turbines are typically arranged in single or multiple rows, which are oriented to maximise generation when the wind is from the prevailing direction. In Australia, turbines have been installed following hilly topography rather than in rows on large open plains.

Wind turbines must be arranged to minimise the impact of wake turbulence on other downwind turbines. To do this, they are often separated by 5–15 rotor diameters downwind and 3–5 rotor diameters in the direction perpendicular to the wind. Because each turbine needs only a small area for its foundation, only 5–10% of the land covered by a wind farm is used for the turbines; the remaining area is available for crop production, grazing livestock or other uses.

At the top of the tower, the rotor blades capture the wind and transfer its power to the rotor hub, which is attached to the low-speed drive shaft. In modern wind turbines, the pitch of the rotor blades is controlled by individual mechanisms that rotate the blade about its long axis to control the wind load on the turbine in high winds. The rotor also helps to maintain a constant power output and limit drive train overload.

The rotor blades are conventionally fabricated from fibreglass composites. However, the wind industry seems to be moving towards carbon composite blades, which have a much higher length-to-weight ratio, allowing longer blades to be used as rated capacity increases without making the dynamic loads at the top of the tower proportionately bigger. The rotor blades are attached to the hub, which is typically made from cast iron or steel.

As the rotor blades capture the wind, they rotate the hub and the low-speed shaft of the turbine. Some turbine designs use direct-drive multiple-pole generators, and most use a three-stage gearbox to increase the rotation speed and drive the generator to produce electricity. Contrary to typical electrical generators, the rotor, gearbox and generator are designed to efficiently capture wind energy at both low and high wind speeds. Efficiency is less important at wind speeds higher than the rated wind speed, when the blade pitch is adjusted to spill some of the wind in order to maintain the rated power. The nacelle serves as the housing for the gearbox and the electrical generator and is typically fabricated using fibreglass composites.

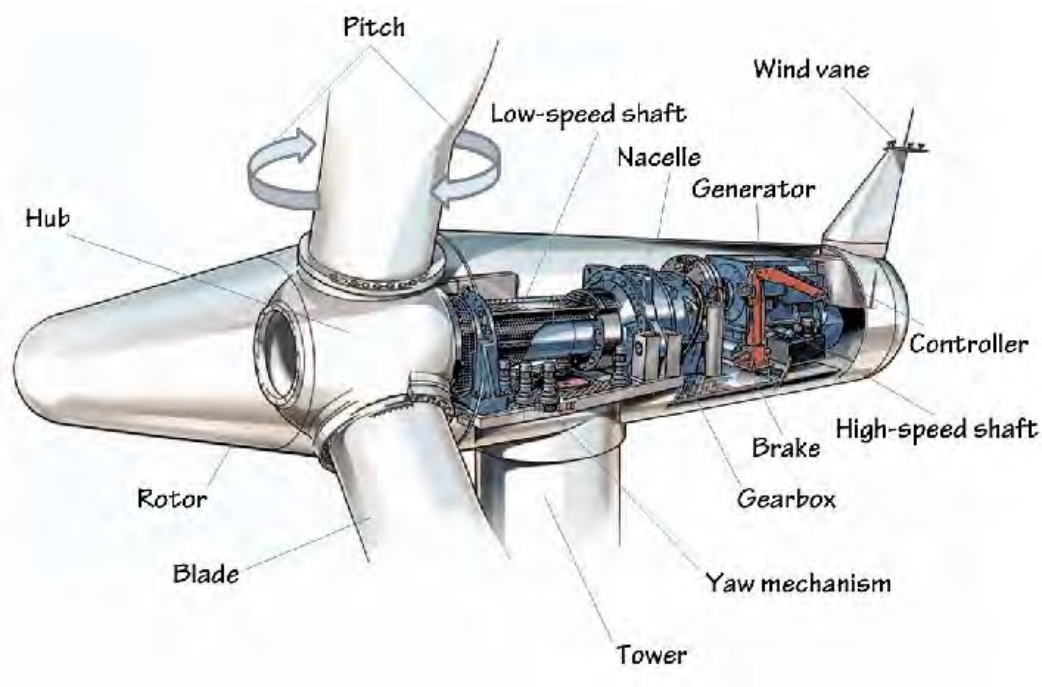


Figure 27: Components of a typical wind turbine

Source: Center on Globalisation Governance and Competitiveness (2009), *Wind power: generating electricity and employment*, Duke University.

The electronic controller monitors the wind turbine's condition. It controls the yaw mechanism, which uses an electric motor to rotate the hub and rotor blades so that the turbine is facing optimally into the wind. It also starts and stops the turbine based on wind speed and shuts down the turbine if there is a malfunction.

Wind turbines are designed to operate within a wind speed window, which is bound by a 'cut-in' speed and a 'cut-out' speed. When the wind is below the cut-in speed, the energy in the wind is too low to use. When the wind reaches the turbine's cut-in speed, the turbine begins to operate and produce electricity. As the wind gets stronger, the power output of the turbine increases until it reaches its rated power. After that, the blade pitch is controlled to maintain the rated power output, even as the wind speed increases, until the wind reaches its cut-out speed. At the cut-out speed, the turbine is shut down to prevent mechanical damage.

Wind plants are typically monitored and controlled by a supervisory control and data acquisition (SCADA) system. Using on-board computers, the turbine starts up when the wind reaches its cut-in speed and shuts down when the wind exceeds its cut-out speed or drops back below the cut-in speed. The system is also designed to shut down the turbine if any mechanical or electrical failures are detected, and to notify maintenance crews.

Offshore wind

The main differences between offshore and onshore wind turbines are their size and foundation requirements. Due to the high cost of offshore wind turbine foundations and undersea electric cables, offshore wind turbines are typically larger than their onshore counterparts (in the order of 3.5–5 MW) in order to take advantage of economies of scale. In addition to the difference in size, offshore wind turbines have been modified in a number of ways to withstand the corrosive marine environment. For example, they have fully sealed or positive-pressure nacelles to prevent corrosive saline air from coming into contact with critical electrical components, structural upgrades to the tower to withstand wave loading, and enhanced condition monitoring and controls to minimise service trips.

Offshore foundations must be taller to extend above the highest waves, must withstand the impact of the waves in addition to wind loading, and must withstand harsher conditions than onshore foundations. Different foundation types are used, depending on the water depth. Currently, commercial offshore wind farms are installed in depths of up to 30 m with foundations fixed to the seabed. The most common foundation type for shallow depths is the steel monopole foundation, which is drilled or driven 25–30 m into the seabed. Other types of fixed foundations include steel or concrete gravity bases, which rest on top of the seabed and rely on the weight of the structure to provide stability. Bucket foundations are large-diameter hollow steel structures that are partially driven into the seabed by suction and filled with soil and rock to stabilise them. Future developments in offshore wind turbine foundation technology include fixed turbine foundations for transitional depths of 30–60 m and floating turbine foundations for deepwater sites of 60–200 m depth.

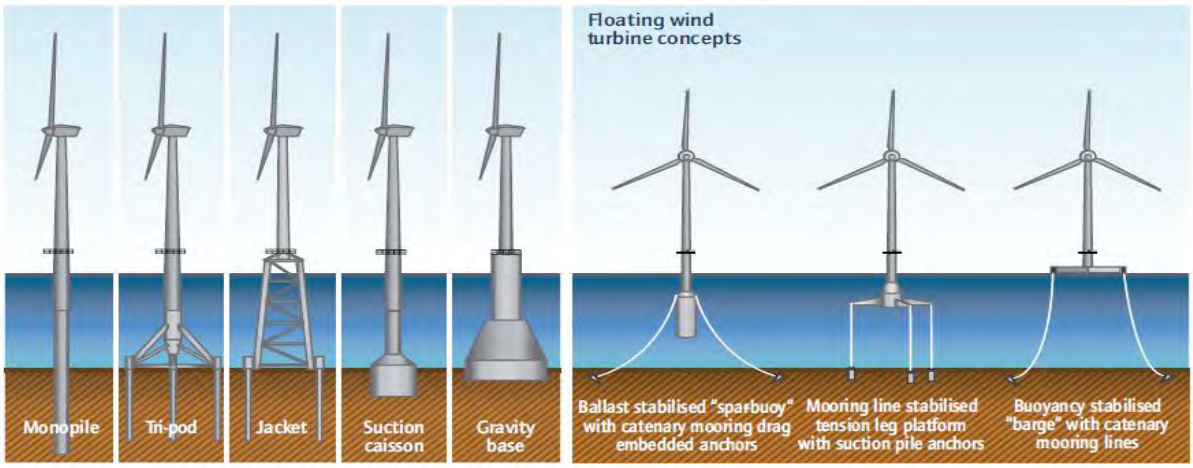


Figure 28: Offshore wind turbine foundation types

Source: IEA (2013), *Technology roadmap: wind energy*.

Currently, offshore wind farms are installed at distances from shore ranging from 0.8 km to 20 km in shallow water. Undersea cables connect the turbines within a project to an offshore substation and from the substation to the mainland. Most offshore wind farms use high-voltage AC transmission lines to transmit power from the offshore substation to the mainland. High-voltage DC transmission is a new technology that experiences lower electrical line losses than high-voltage AC. However, rectifier and inverter losses occur when converting from AC to DC at the offshore substation and from DC back to AC at the onshore grid connection point. The lower line losses are expected to outweigh the additional electrical conversion losses and cost differential only for projects a significant distance from shore.

Technology development status

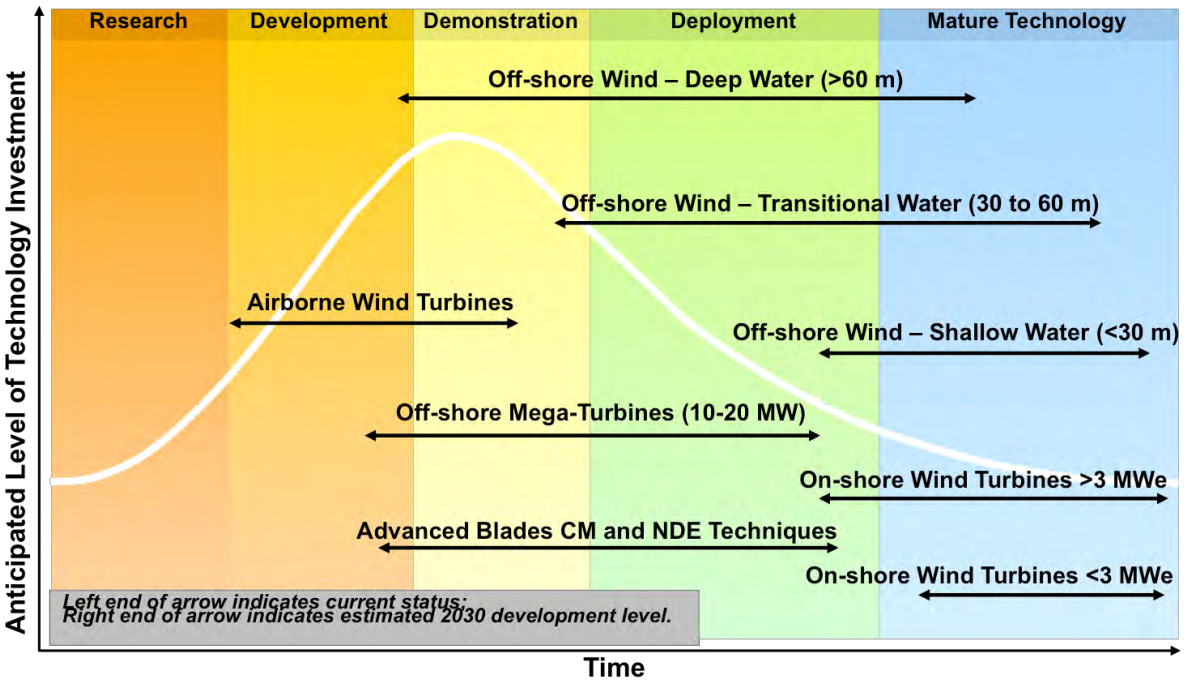


Figure 29: Wind technology development curve

With over 350 GW[15] of globally installed capacity at the end of 2014, onshore wind turbines are considered to be a mature technology. However, the average size of onshore wind turbines being installed continues to increase and advances continue to be made in turbine components, such as condition monitoring and non-destructive evaluation techniques, to help maintain turbine equipment, minimise plant downtime and maximise energy generation.

There are close to 8 GW[15] of offshore wind turbines installed around the globe. As offshore wind power continues to develop, it will move into deeper water, where the resource is even better and the potential capacity is higher. This requires the further development of new foundation types, including floating foundations for deepwater turbines. Offshore turbines are also expected to continue to increase in size. Vestas recently debuted its 8 MW offshore turbine design, the Vestas V164. GE is partnering with Oak Ridge National Laboratory to develop a 10–15 MW generator for wind turbines, and megaturbines in the 10–20 MW range are expected to be entering deployment by 2030.

[15] Market Size Power Generation Database, Bloomberg New Energy Finance, 3Q 2015.

The global wind industry is trending towards larger turbines to achieve greater economies of scale. Industry observers expect to see taller towers for access to greater wind speeds, larger rotors for lower wind speed locations, and improved reliability and efficiency to help reduce the cost of wind-generated electricity. Original equipment manufacturers have engaged in a race to deploy larger turbines. While the current average market offering is 3.5 MW for onshore turbines, one manufacturer, Enercon, has an onshore model with a 7.5 MW capacity.

Taller towers are an apparent trend in the European market, and more of them are expected the United States as well. A recent report by the United States Department of Energy estimated that by using turbine towers with hub heights of 110 m, the available project sites based on wind resources increase by 54% compared to using towers with hub heights of 80 m—the current average hub height in the United States. There are transportation and logistics challenges, such as cranes to lift the nacelle to the appropriate height, that will need to be overcome. Some of the highest hub heights are intended for offshore installation. In Germany, the average turbine height has exceeded 100 m since 2009, and by 2014 was 116 m (Figure 30).

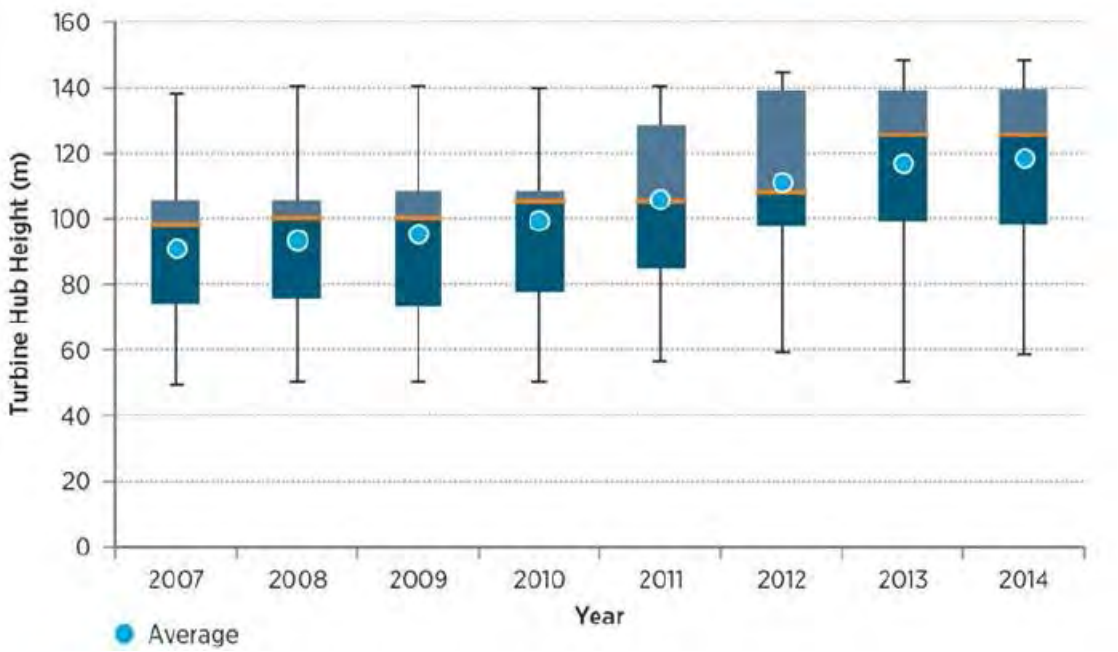


Figure 30: Wind turbine hub height trends, Germany, 2007 to 2014

Source: US Department of Energy (2015), *Enabling wind power nationwide*, May.

In addition to increasing the number of potential project sites, taller towers capture greater wind speeds, leading to higher capacity factors and more stable wind conditions that can improve turbine operations. One of the world's tallest installations is in Bavaria, Germany. The turbine, commissioned by REpower Systems SE, is rated 3.2 MW and has a rotor diameter of 114 m and a hub height of 128 m.[16]

[16] https://www.senvion.com/global/en/press-media/press-releases/detail/repower-commissions-its-tallest-wind-turbine-1/ (accessed October 2015).

Another major trend is the deployment of longer blade rotors for higher production at low-speed sites. Several manufacturers have launched turbines for low wind speeds, including Siemens, which announced a 75 m-long blade. The average land-based rotor diameter in the United States has increased from 50 m in 1998 to 97 m in 2014. In 2014, around 75% of onshore installations included rotor diameters greater than 100 m.[17] The average nameplate capacity of wind turbine generators in the United States was a little less than 2.0 MW (Figure 31).

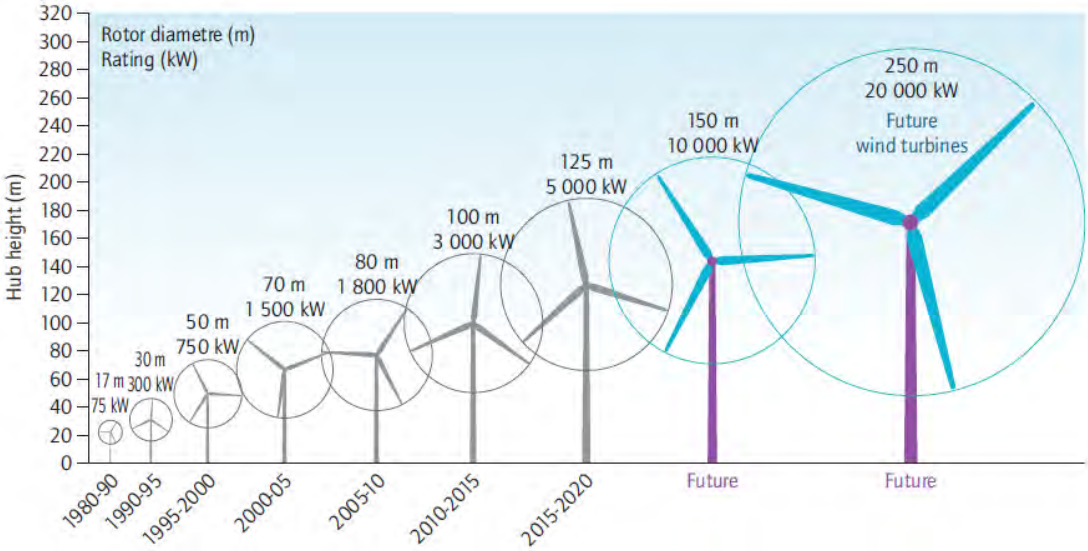


Figure 31: Growth in size and power of wind turbines since 1980

Source: IEA (2013), *Technology roadmap: wind energy*.

The wind industry continues to aim to improve reliability by better understanding gearbox malfunctions, introducing torsional limiting control devices and torque monitoring systems to extend the life and reliability of gearboxes, and to increase market share for direct-drive turbines. Larger wind turbine units for offshore deployment will use permanent magnet direct-drive generators.

Another unique idea that is being developed by GE—the digital wind farm—will change the future operation of wind farms. The idea is based on treating a wind farm as a unit instead of as many individual turbines. Based on GE's claims, this could lead to an additional 20% in energy production from greater efficiencies. The concept uses integrated controls and sensors to optimise wind farm production (for example, by using slow upwind turbines to increase the production of turbines downwind). The digital wind farm is built on PREDIX, software that GE developed specifically for the industrial internet. GE claims that the system can accommodate any number of apps designed for specific wind farm tasks (energy demand, prediction of output, noise reduction and so on). The system is now in the demonstration stage.[18]

[17] US Department of Energy, August 2015, *2014 wind technologies market report*.
[18] https://renewables.gepower.com/wind-energy/overview/digital-wind-farm.html (accessed November 2015).

Finally, there is a trend towards improving forecasting methods. Better forecasting now allows wind-farm operators and power purchasers to be able to plan several days ahead so that utilities can power down their variable-load generators and let wind power deliver the difference.

Major technical issues and future development directions/trends

As for many other renewable technologies, intermittency can be an issue for wind power development. As the integration of wind generation with the electricity grid increases, the intermittency of wind can become more of a problem. Forecasting systems have been improving over the years to allow system operators to schedule a wind plant's capacity and energy with some accuracy, effectively avoiding reliability problems.

As briefly mentioned above, recent developments in the offshore wind industry include ventures in deeper waters, further from the shore and with increased total capacities per project, leading to greater interest in floating platforms. As offshore projects increase in installation capacity, greater competition for manufacturing capacity and installation resources are driving vertical integration and consolidation in the supply chain, including of installation vessels. Several project developers are buying vessels and some are funding new ones.

Anticipated Improvements by 2030

Developments in the operation and efficiency of wind turbine technology are expected to be the main driver in the decrease in wind-power costs in the future. Taller towers (up to 140+ m) are increasingly being installed to access greater wind generation at lower wind speed locations. In addition, manufacturers are increasing the energy captured by turbines by increasing the swept rotor area. This is accomplished by increasing the blade length. As larger turbines with larger rotors and higher hub heights are used, the power output of a single turbine will increase. Improvements in the power electronics and drive systems will also improve the performance of the turbines. In addition, wind-sensing equipment continues to improve, allowing for more optimised use and operation of wind farms, resulting in increased power production for the same sized wind farm.

Wind turbines are currently certified for nominal 20-year design lives, but many industry stakeholders are extending the operating life of projects by 5 or even 10+ years. Life extension—the operation of an asset beyond the normal design life—is just one option to maximise the financial return from wind assets. Others include repowering, upgrading or uprating turbines. To make informed decisions about life extension, wind project owners and operators need to demonstrate to lenders, insurers, utilities and the public that these machines can be reliably and safely operated past their 20-year design life. Life extension up to 30 years will be typical by 2030, contributing to a substantial reduction in the levelised cost of electricity produced.

Optimised wind turbine controls and strategies will be available by 2030 to facilitate integration into the electric power system of high levels of wind power by providing balancing services, such as regulation and voltage control.

Airborne wind turbines are one concept that is in early development and is likely to be entering the demonstration phase in 2030. In this design concept, the turbines are supported in the air without a tower, relying on either aerodynamic lift or buoyancy to keep them aloft, allowing them to take advantage of more constant wind at higher altitudes. It is believed that airborne wind turbines could generate electricity at a much lower price than conventional turbines.

Table 9: Anticipated cost and performance evolution for onshore wind turbines

	Current technology	2030 technology average		
		GALLM scenario		Road map
		450 ppm	550 ppm	
Capital cost (relative to current technology)	1.00	0.78	0.76	0.80
Average capacity factor	Base			+7 pts

Note: Refer to Chapter 16 and Section 15.14 for details on the capital cost estimation methodology.

Development and commercialisation timeline

Onshore and offshore wind farms are continuing to be installed worldwide. Onshore turbines are expected to continue to increase in size for the near future, although it is expected that there will ultimately be a limit on their rotor diameter, probably at a generating capacity of 3–5 MW onshore, because of logistical and construction requirements.

As offshore wind farms become more prolific, the size of their turbines will also be likely to increase (up to 10+ MW). Improvements will be made to their design and maintenance regimes as operational experience is gained.

3.2.4 Ocean energy

Brief description of the technologies

Technologies for generating electricity from the ocean include wave power, tidal power, ocean currents, ocean thermal energy conversion, ocean winds and salinity gradients.

The two most developed technologies are wave energy conversion and tidal conversion.

Wave energy conversion technology

Wave energy is the capacity of waves to do work. Ocean waves are generated by the influence of the wind on the ocean surface, which at first causes ripples. As the wind continues to blow, the ripples become chop, then fully developed seas and finally swells. In deep water, the energy in waves can travel for thousands of miles until it is finally dissipated on distant shores.

With the right technology, the energy in waves can be captured to generate electricity. Figure 32 is a diagram of the type of technology used in the Perth Wave Energy Project, which became operational in its first phase in February 2015.[19]

[19] Carnegie Wave Energy Limited. (n.d.), *CETO 2D schematic*, http://www.power-technology.com/projects/perth-wave-energy-project/perth-wave-energy-project1.html (accessed October 2015).

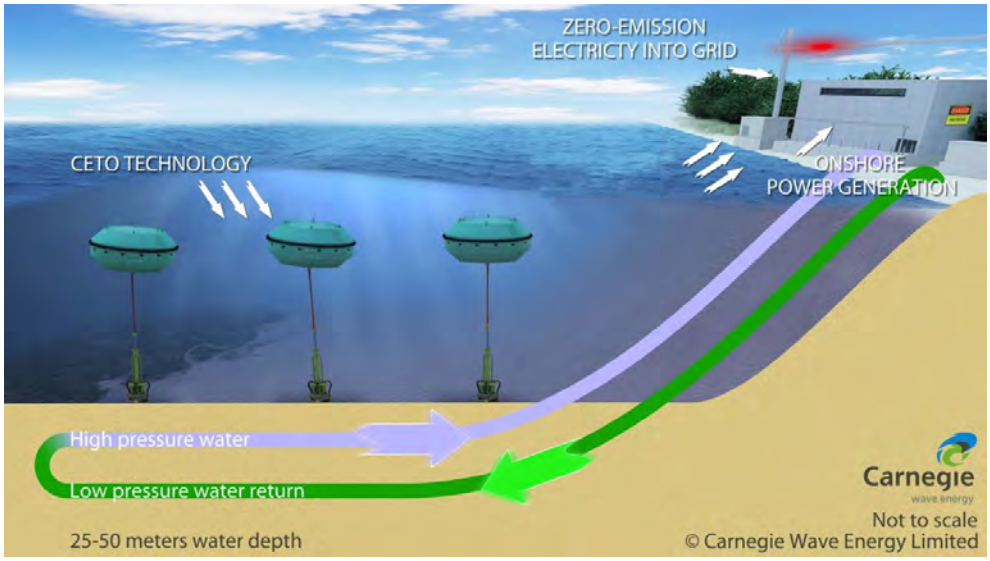


Figure 32: The Perth Wave Energy Project

Wave energy technologies are composed of four major components:

- The structure and the prime mover collect the wave energy.
- The foundation or mooring anchors the structure and prime mover.
- The power take-off system transforms mechanical energy into electrical energy.
- The control system protects and enhances the operations.

Wave energy extraction is complex, and many designs have been proposed. Six well-known device concepts are shown in schematics in Figure 33.[20] Wave energy plants are categorised by the method of energy extraction—different technologies are preferred for significantly different locations.

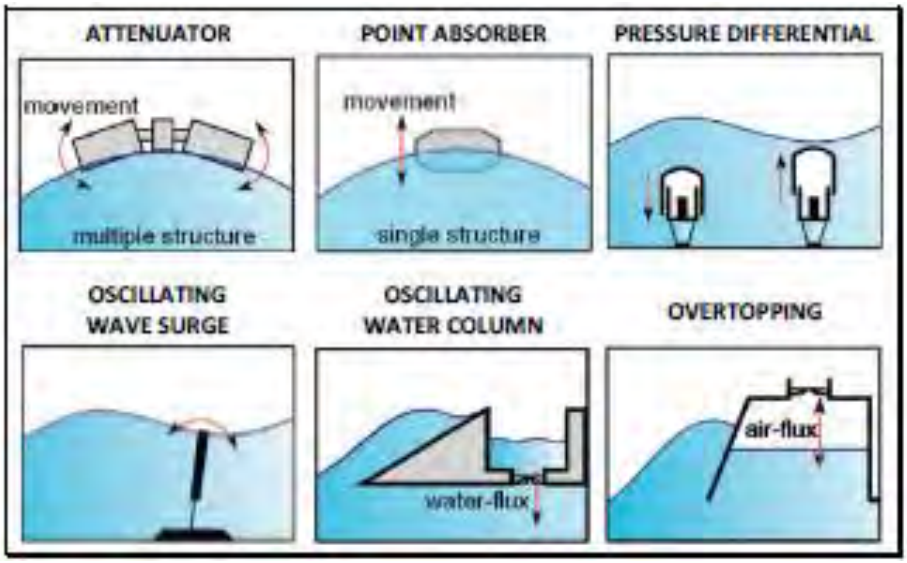


Figure 33: Schematics of various wave energy conversion configurations

[20] International Review of Electrical Engineering (IREE) (2015). *An up-to-date technologies review and evaluation of wave energy converters,* https://hal.archives-ouvertes.fr/hal-01153767/document (accessed October 2015).

Tidal in-stream energy conversion technology

Ocean tides are caused by the gravitational forces of the sun and the moon, and centrifugal and inertial forces, acting on the Earth's waters. Because of its nearness to the Earth, the moon exerts roughly twice the tide-raising force of the sun. The gravitational forces of the sun and moon and the centrifugal and inertial forces caused by the rotation of the Earth around the centre of mass of the Earth–moon system create two 'bulges' in the earth's oceans: one closest to the moon and the other on the opposite side of the globe.

A tidal energy conversion technology can be classified as one of the following three types:

- *Axial flow:* The axis of rotation is parallel to the direction of water flow.
- *Cross-flow:* The axis of rotation is perpendicular to the water stream and may be oriented at any angle, from horizontal to vertical, to the water surface.
- *Non-turbine:* The energy is captured using an oscillatory hydrofoil, vortex induced motion or a hydro Venturi device.

Figure 34 illustrates axial and cross-flow types of turbines.

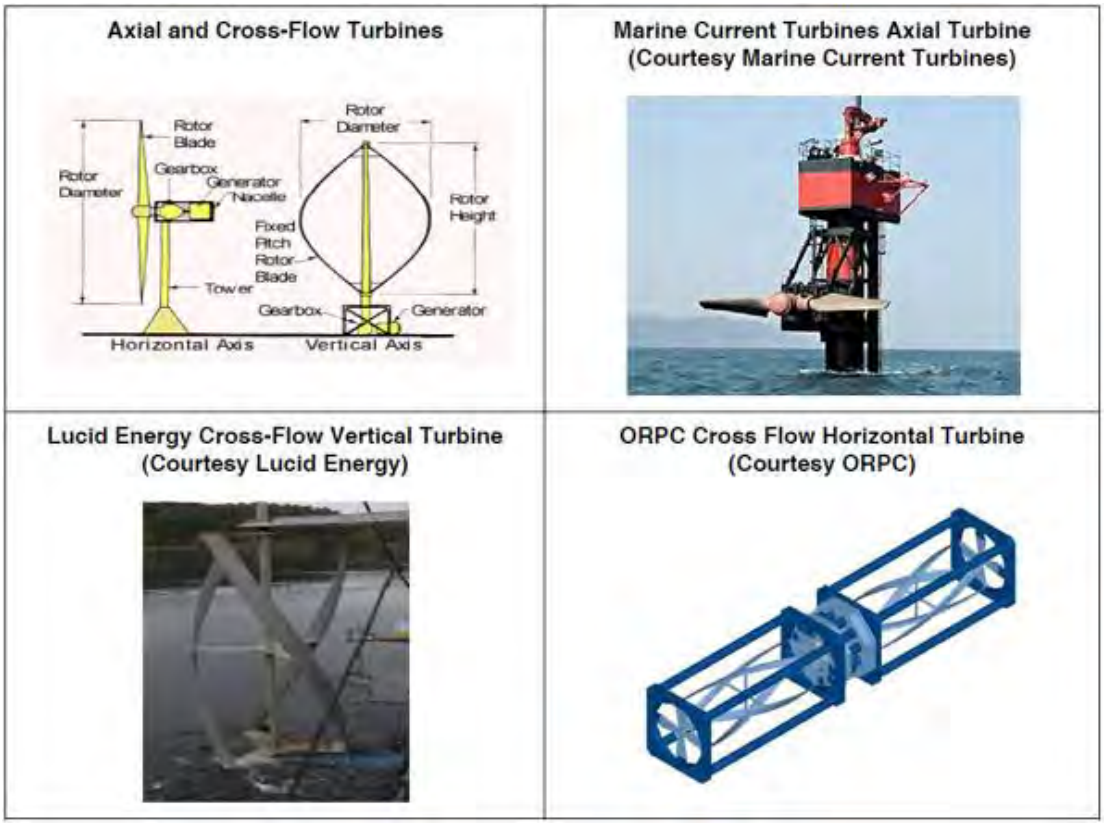


Figure 34: Tidal in-stream energy conversion configurations and example machines

The subsystems for hydrokinetic turbines typically include:

- a blade or rotor, which converts the energy in the water to rotational energy in a shaft
- a drive train, which usually comprises a gearbox and a generator
- a support structure for the rotor and drive train
- other equipment, including controls, electrical cables and interconnection equipment.

The extraction of kinetic power from tidal streams alters the tidal regime in an estuary by reducing flow volumes, constricting the tidal range and altering the timing of tidal events.

However, the magnitude of those impacts depends strongly on the level of power extraction, estuary geometry, the nonlinear dynamics of in-stream turbines, and the natural tidal regime. An understanding of the various fluidic effects of large-scale kinetic power extraction is an essential first step in a more detailed investigation of ecosystem impacts.

Ocean current technology

Currents in the open ocean are relatively steady flows of water moving in a constant direction, driven by wind and the rotation of the Earth. Ocean current technology is in the very early stages of development, so there are few detailed specifications for appropriate generator designs.

The general concept is to use submerged turbines, much like wind turbines, to harness the hydrokinetic energy of currents. Although the speed of ocean currents is much lower than the wind speeds required for wind farms, the density of the water makes up for this, resulting in far less velocity being needed to exert the same force on the turbine. While the turbine would be near the surface of the ocean, it would be likely to be tethered to the ocean floor far below.

Technology development status and future development directions/trends

Wave energy conversion technology

Wave energy conversion technology is a developing technology.

Wave energy conversion is typically more spatially concentrated than wind and solar, which makes it an attractive option. However, its transition from concept to commercialisation remains slow and relatively expensive, as pilot or demonstration plants tend to have to be large systems even in the concept stage.[21]

For wave energy conversion to become a mature technology, researchers and engineers will have to:

- build offshore generators that can better tolerate rough seas
- improved mooring designs to withstand waves, currents and winds
- overcome structural fatigue
- reduce O&M costs
- handle marine growth and corrosion.

Understanding the long-term performance of wave energy conversion technologies, optimising the technologies in a trade-off between cost and the longevity of equipment, and converging on a standard design will also be important.

Tidal in-stream energy conversion technology

Tidal in-stream energy conversion is a developing energy technology. The global installed capacity of the technology is about 6 MW. While most of these devices are prototypes, MW-scale demonstration and early commercial projects have been announced.

One new trend is the development of dynamic tidal energy, which can generate electricity even in regions with poor tides. In the longer term, tidal energy and offshore wind energy could combine to provide hybrid energy systems. However, the technologies will have to

[21] https://hal.archives-ouvertes.fr/hal-01153767/document (accessed October 2015).

overcome rough marine conditions, low capacity factors and high costs. R&D will need to focus on material strength, performance, maintenance and lifespan.

With proper care in site planning, tidal in-stream power should pose minimal environmental problems and not cause any permanent damage to the environment. As with wave energy conversion technologies, early demonstration and commercial tidal in-stream power plants include rigorous monitoring to record environmental impacts as well as impacts at nearby undeveloped sites.

Several numerical modelling, laboratory flume and field monitoring studies have been performed to determine the environmental impacts of tidal power devices. Preliminary results indicate that they have minimal environmental impact. Many temporary testing activities in the United States, Canada, the United Kingdom and other countries have not observed any harm to aquatic life. The blades of tidal in-stream energy conversion devices rotate very slowly (around 10 rpm for an 18 metre diameter rotor), and the speed at the tip of the blade is about 10–12 m/second. The devices are self-limiting, as any faster speed results in cavitation, which slows the blade.

Ocean current technology

Ocean current technology is in the early stages of development. No prototype devices have been tested in a relevant environment, and most commercial efforts are either in the design, proof-of-concept or small-scale demonstration phase.

Because of its very early developmental status, a lot of research must take place to develop this technology. Technical research will be needed to investigate appropriate materials for ocean conditions, conduct life-cycle analysis, and test installation and maintenance procedures. Some of this work may be able to use developments in other ocean energy technologies as a baseline. The impact of ocean current technologies on ocean life, current flow and other environmental concerns must also be investigated through long-term testing. The effects of future farms on shipping routes and recreational uses of the water must be considered.

Development and commercialisation timeline

Demonstration projects and early commercialisation wave energy conversion projects, including multi-MW ‘wave farms’ are expected to be developed over the next decade in Europe, South America and Australia. For tidal in-stream energy conversion devices, major players in the wind and conventional hydropower industries are acquiring significant stakes in hydrokinetic device development and manufacturing companies. The technical and business experience they bring to hydrokinetic generation may accelerate the development of the tidal generation industry.

3.2.5 Geothermal energy

Geothermal energy is energy in the form of heat within the Earth. Because that heat is constantly flowing outward from the Earth’s centre, temperature increases with depth everywhere on the planet. However, in some places temperatures increase at a greater rate than average with depth, either because molten rock (magma) is present very close to, or at, the surface, or because rocks buried at shallow depths contain higher than average concentrations of radiogenic elements that give off heat as they undergo radioactive decay.

Geothermal resources can be classified in three categories (see also Figure 35):

- conventional hydrothermal systems (volcanogenic or magmatic)[22]
- unconventional hydrothermal systems (hot sedimentary aquifers, amagmatic)
- enhanced geothermal systems ('hot rocks').

In Australia, the only available resources are hot sedimentary aquifers and enhanced geothermal systems.

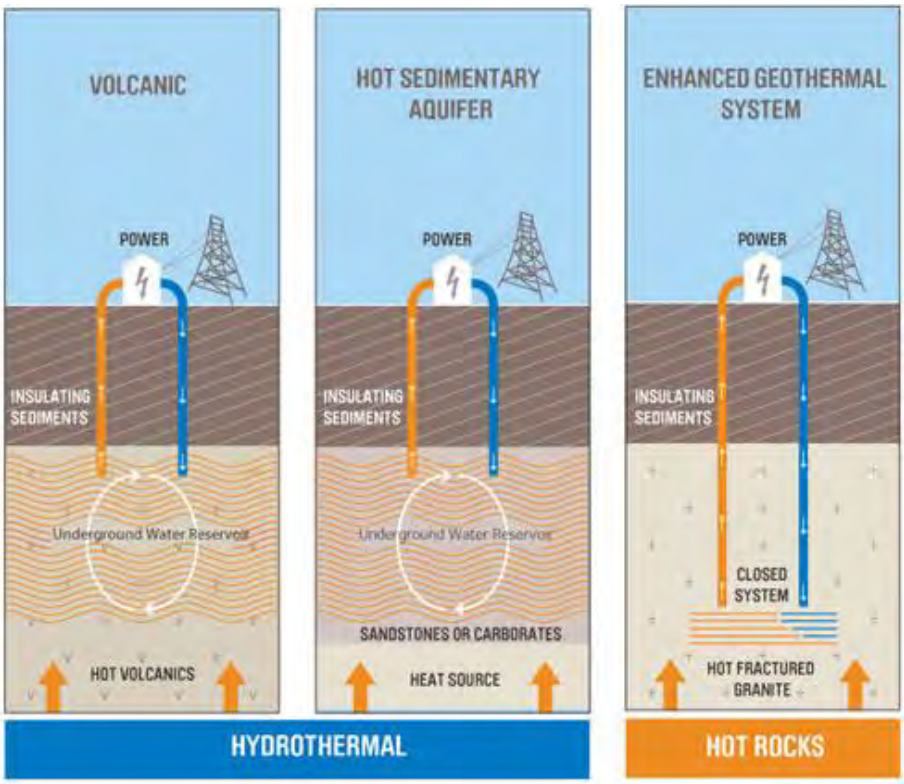


Figure 35: Geothermal energy system categories

Brief description of the power generation technology

Geothermal power generation systems (the above-ground equipment) can be classified in three categories:

- back-pressure
- hydrothermal flash steam
- binary cycle.

Back-pressure conversion

Back-pressure geothermal power plant systems are simple and low cost, but have the lowest thermal efficiency compared to the other types of geothermal power plants. A back-pressure turbine without a condenser might convert around half as much energy in steam to electricity compared to a condensing turbine. Back-pressure systems can operate on a range of inlet

[22] Volcanic resource descriptions are not covered in this report because they have little relevance to Australia.

pressures and non-condensable gases, since there is no gas removal equipment required, making them well suited to proving a new field.

Hydrothermal flash steam conversion

Flash steam hydrothermal plants are suited for high-enthalpy geothermal resources where the flash steam and reservoir temperatures are hotter than 180°C. Hot water is removed from the production well and flashed in a separator, where the drop in pressure causes part of the water to turn to steam. Liquid from the first flash is sometimes sent to a second-stage separator ('dual flash') to produce lower pressure steam (see Figure 36).

The flashed steam flow is typically 15–25% of the mass of the fluid from the reservoir and is sent to the high-pressure and low-pressure inlets (if multiple flash) of a steam turbine generator. The steam is then routed through the generator while the separated water ('brine') is reinjected into the hydrothermal reservoir. After the steam passes through the turbine, it is condensed and also returned to the reservoir to be reheated.

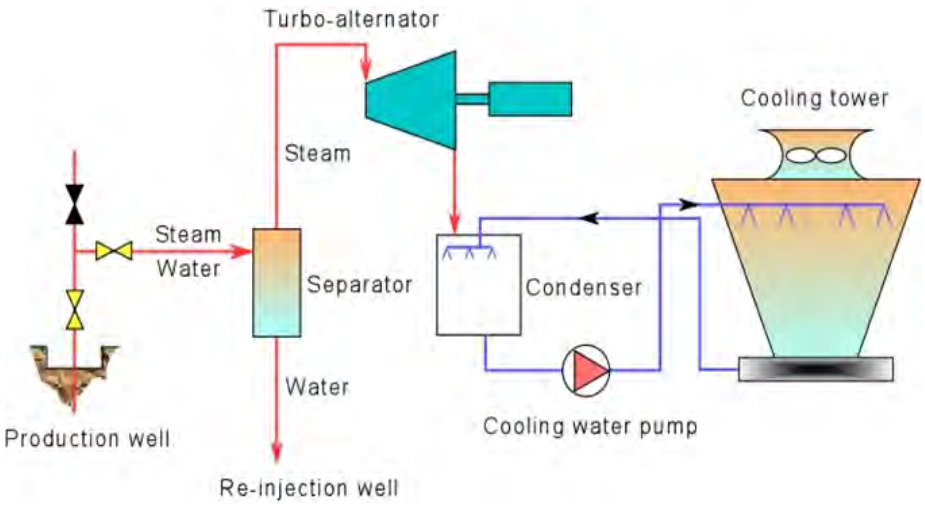


Figure 36: Flash steam hydrothermal plant

Binary cycle conversion

Binary cycle hydrothermal plants are best suited to moderate- to low-enthalpy geothermal resources.

For moderate-enthalpy systems, brine is removed from the production well and passed through a heat exchanger, where it transfers heat to a second (binary) liquid, the working fluid. The working fluid then boils to vapour and expands through a turbine, generating electricity. The working fluid is then condensed to a liquid to begin the cycle again, while the geothermal water is returned to the reservoir via a reinjection well to be reheated (Figure 37).

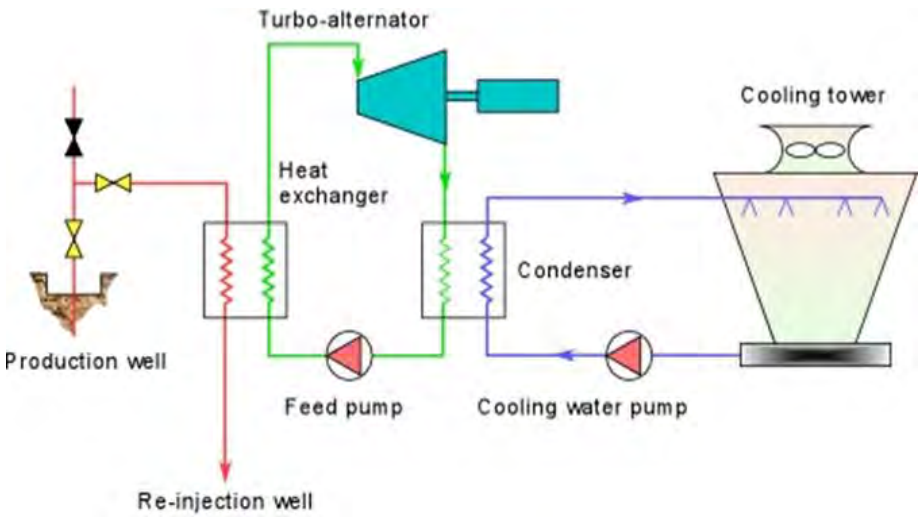


Figure 37: Binary cycle hydrothermal plant

For low-enthalpy geothermal resources, a cycle based on reverse cycle air-conditioning components can be used. The cycle uses a single-stage centrifugal compressor, which runs in reverse as a radial inflow turbine, and a heat exchanger transfers heat from the geothermal resource to the working fluid (such as R-134a working fluid). In general, this technology can reduce the minimum temperature at which power can be produced from shallow, lower temperature hot spring systems from 105°C to around 80°C.

Enhanced geothermal system / hot rock resources

Potential enhanced geothermal systems or 'hot rock' resources are relatively deep masses of rock that contain little or no steam or water and are not very permeable. In principle, enhanced geothermal power systems could be constructed anywhere, but economics dictates that wells must be cost-effective, and access to demand is needed. Conventional hydrothermal systems rarely require drilling deeper than 3 km, while the technical limit for current drilling technology is to depths greater than 12 km.

Soultz-sous-Forêts: an enhanced geothermal system demonstration

This pilot project comprises an initial 1.5 MW_e module developed at Alsace, France. It has been in production since 2010 and draws on heat sources (up to 200°C) 4,500–5,000 m deep. It operates an organic Rankine cycle to produce power.

The first phase involves drilling an exploratory well to understand the geology and characterise the resource. After initial stimulation and mapping of the fractures, another well is drilled such that a permeable reservoir is present between the two or between sets of two wells. The operating phase involves bringing the geothermal brine from the reservoir to the surface. At a high enough temperature, the water can be flashed to steam and used to generate power. Alternatively, the brine can be held at high enough pressure to maintain it in liquid form for use in a binary or a flash/binary hybrid cycle. The brine is then reinjected to be reheated.

The technical challenges lie not in the power cycle, but rather the subsurface elements of the system, and are notably related to deep drilling and in situ fracturing.[23] Figure 38 illustrates the enhanced geothermal production process.

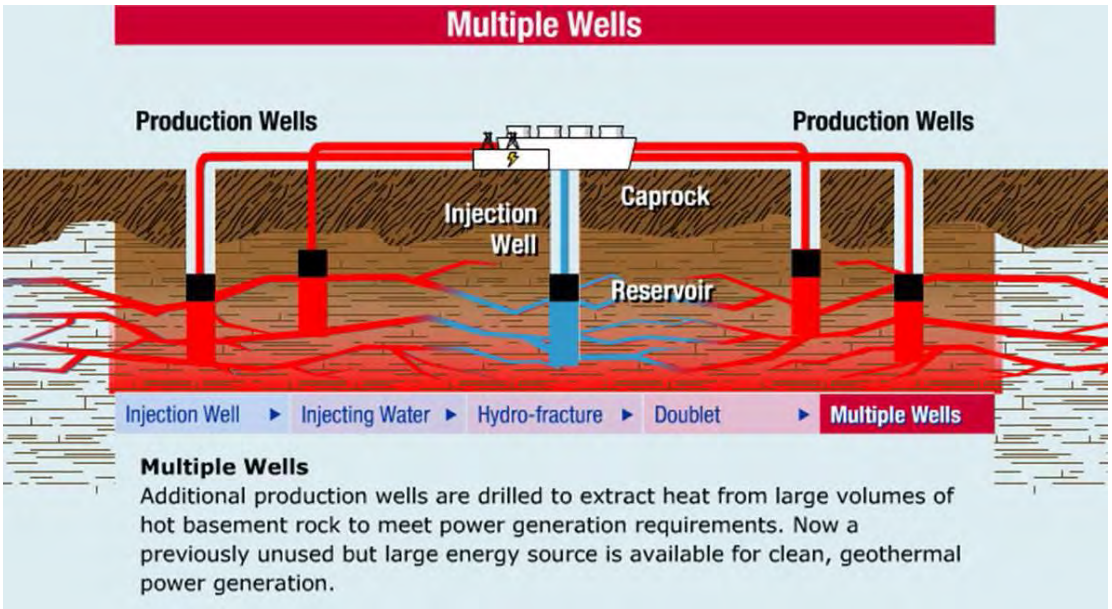


Figure 38: Enhanced geothermal system production process

Source: http://energy.gov/eere/geothermal/animations (accessed October 2015).

Hot sedimentary aquifer resources

Hot sedimentary aquifers are reservoirs in which groundwater within the rocks is heated by burial to significant depths or by the flow of heat from deeper underlying heat sources. The water is present in porous rocks contained between two impermeable layers, creating an aquifer from which hot fluid can be extracted. Enhancements of a resource may be carried out to improve fluid flow using various drilling and fracturing techniques that are mature in other industries.

A hot sedimentary aquifer typically requires a binary cycle for electricity production due to the moderate temperature of the brine.

Sauerlach Geothermal CHP

The Sauerlach Geothermal CHP plant in Germany officially started operation in January 2014. The plant uses the roughly 140°C thermal water to both provide heat and produce electricity. It is a 5.1 MWe facility using an organic Rankine cycle to produce power; the plant also provides 4 MW_{th} for district heating.

[23] JW Tester, HJ Herzog (1990). *Economic predictions for heat mining: a review and analysis of hot dry rock (HDR) geothermal energy technology*, Massachusetts Institute of Technology; HCH Armstead, JW Tester (1987), *Heat mining: a new source of energy*, E&FN Spon Ltd, University Press, London.

Technology development status, major technical issues, and future development directions/trends

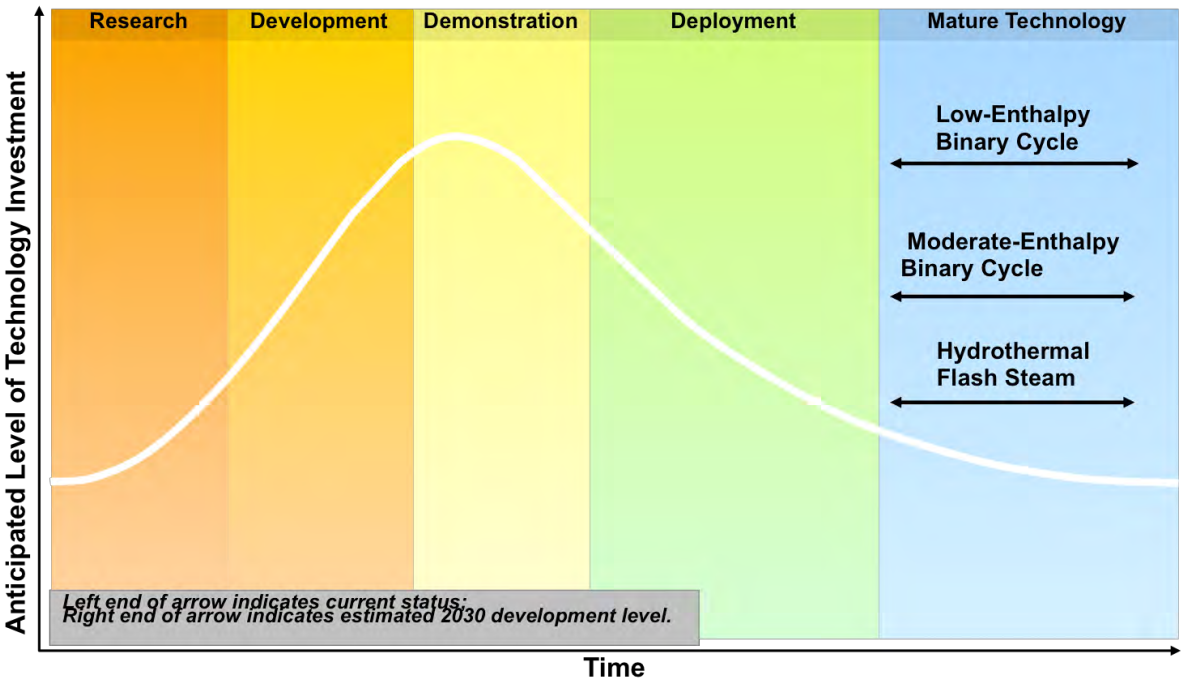


Figure 39: Geothermal power conversion technology development curve

Conventional hydrothermal technologies are considered more mature than the other geothermal energy technologies. Off-the-shelf power generation equipment is readily available for hydrothermal plants, and the drilling technology required for tapping the resource is now well established. Advances in scale inhibitor chemicals have helped to reduce problems with wellbore and equipment scale and reduced O&M costs. A better understanding of reservoir management, which will increase project lifespans and reduce long-term resource risks, continues to develop.

While risks remain with conventional hydrothermal power plants, they are typically relatively easy to manage. Risks include expensive exploration and drilling costs. There is also risk associated with reservoir cooling and managing the reservoir to maintain its output. Reservoir life depends on the success of reinjection into the reservoir, and supplemental injection may be needed to extend it.

Enhanced geothermal energy conversion is not yet a commercial technology, although small systems have been demonstrated overseas. Well costs increase exponentially with depth, and because enhanced geothermal resources are much deeper than more conventional hydrothermal resources they are much more expensive to develop. While the technical feasibility of creating enhanced reservoirs has been demonstrated, each site is very specific and requires extensive development.

Hot sedimentary aquifers are not yet commercially proven in Australia but are in production elsewhere. However, the opportunity for near-term geothermal development in Australia is often considered. Several potential sedimentary basins have been identified, which may further reduce exploration, drilling and reservoir risks.

Conversion technology

A recent trend is increasing interest in using the potential smaller scale 3–8 MW plants to exploit low-enthalpy geothermal resources at temperatures below 100°C. This would use organic Rankine cycle and radial outflow turbine technology with two pressure levels and a single expander.

This new binary plant configuration offers increased plant performance and economic feasibility for lower enthalpy resources.

Most other conversion systems are considered mature.

Geothermal resource development

Many aspects of geothermal resource technology continue to advance and evolve. In particular, advanced and innovative technologies under development in the oil and shale gas sectors will be directly transferable to geothermal applications. Concepts in well design, drilling methods and hydraulic stimulation have also rapidly progressed in the geothermal energy sector and are currently being trialled at geothermal projects in Europe and the United States.

However, the uniqueness of each geothermal resource's local geology, including rock types, depth, size, fluid characteristics, permeability and enthalpy, makes the generic application of technological advances difficult without a thorough characterisation of these location-specific parameters. This inevitably requires investment in initial reconnaissance and exploration drilling and research to define the local project-scale geological conditions before planning the implementation. Hence it is critical that local expertise is maintained in Australia and that the transfer of knowledge about evolving technologies from Europe and the United States be facilitated to support their future application in the Australian context.

3.2.6 Biomass co-firing

Biomass fuels (matter produced by living plants or animals) can be used to produce steam or heat, but mainly at relatively small scales and in niche applications. Such uses are out of scope for this study, which instead looks at the use of such fuels in co-firing.

Brief description of the technology

Co-firing is the practice of firing one or more biomass fuels as a supplement to coal in a pulverised coal electricity generation plant.

Biomass fuels have certain fundamental differences from fossil fuels. Typically, they are either gathered up or harvested from diffuse sources and concentrated at a given location, in contrast to coal, which is produced in fewer locations but in large volumes.

Biomass fuel

Fuels currently used as biomass fuels are typically residues from other processes. They may be wood-processing residues, such as bark, sawdust and spent pulping liquor. They may be agricultural and agribusiness residues, such as bagasse, or wastewater treatment gas or landfill gas. These are commodities that are currently outside the commercial mainstream but have potential material and energy value. Wood waste markets, for example, can include mulch for urban areas, bedding for livestock and poultry, feedstocks for materials such as particleboard, and feedstocks for niche chemical and related products. As a result, biomass fuel pricing is highly sensitive to locale and the competitive pressures of local and regional economies. However, in direct firing applications for power generation this dispersal may be beneficial.[24]

Biomass co-firing with pulverised coal

Co-firing systems are most readily adapted to electric power stations burning pulverised coal. Biomass can be integrated with the fuel supply to existing boilers designed to utility standards. The biomass can be used in large reheat boilers where steam is used most efficiently. If the biomass fuel is temporarily unavailable, the operation of the unit is not compromised. However, integrating biomass fuel into the coal stream involves complex issues of materials handling and control. Furthermore, co-firing does not contribute additional capacity; instead, it displaces coal fuel at the unit.

Co-firing in pulverised coal boilers can be accomplished either by blending biomass with coal on the main belt feeding the coal bunkers or by separately injecting biomass directly into the furnace, which is equipped with either modified burners or specially designed biomass burners. Blending on the belt is limited to woody biomass. Herbaceous biomass, such as switchgrass, causes significant problems in this application. Milling of the biomass for blending on the belt limits the amount of biomass that can be used to about 3–5% to minimise problems with the mills.

Major technical issues and future development directions/trends

Efficiency penalties due to co-firing biomass can vary depending upon system design and operation. Typically, biomass is introduced with ambient air. This reduces the combustion air passing through the air heater and raises the temperature of the gaseous combustion products exiting the air heater. Furthermore, moisture and hydrogen in the fuel exact a minor penalty in boiler efficiency.

Along with the diffuse nature of the biomass fuel source, another limitation results from typical biomass fuel characteristics: 240–320 kg/m^3 bulk density; 40–50% moisture; and 8–10 GJ/tonne as received, unless it is dried and the energy density is increased at the source by pelletisation or pyrolysis.

These factors combine to limit boiler and generating capacity. Given typical transportation distances for wood fuel of up to 80 km, wood-fired boilers have been limited to a nominal 100–125 t/hour firing rate (nominally 300 m^3/hour of fuel), or 50–70 MW depending on system design and operation. This capacity limitation has significant implications.

[24] Direct firing/conversion of biomass is not within the scope of this report.

Many wood wastes can contain trace minerals and chemicals drawn up by the plant, such as chlorine. They tend to concentrate in the leaves and twigs and can cause material corrosion under high firing temperatures. Australian eucalypts are a case in point. Leaching pre-treatment technology has the potential to remove most of the deleterious components causing slagging, fouling, the agglomeration of ashes and corrosion problems, enabling the use of eucalyptus waste in co-firing with coal in existing boilers.

3.2.7 Hydroelectric power

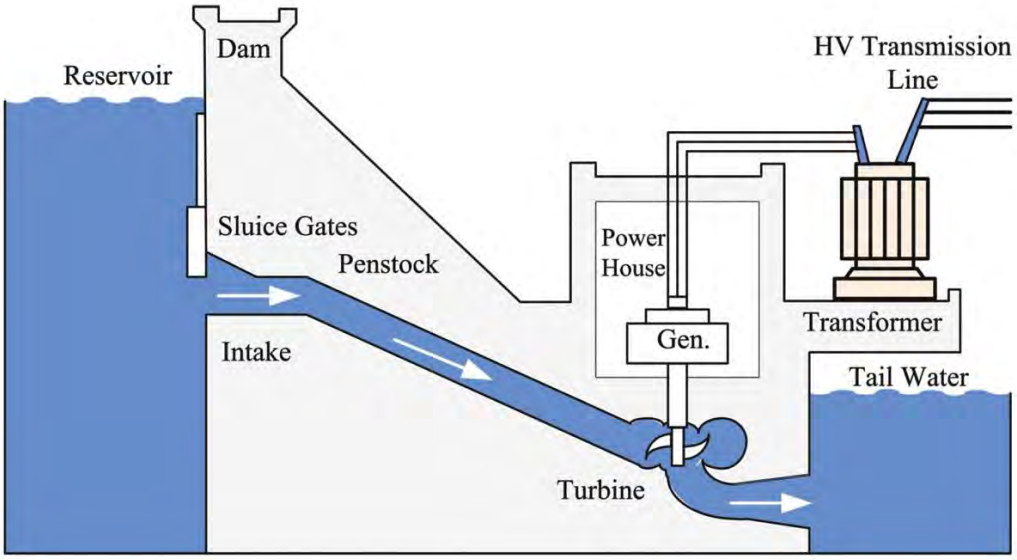
Brief description of the technology

Hydroelectric power is electricity created from the force of running water. This force can be the natural flow of rivers or waterfalls or the flow of water released from dams. The kinetic energy of the water is converted to electric energy as the water flows through turbines that are attached to generators. The cost of new hydropower generation was not assessed, as it is unlikely that new large-scale hydropower projects will be deployed in Australia.[25]

The most common hydroelectric power plant is the reservoir/dam-based configuration (Figure 40). The major components of a hydroelectric plant are:

- a reservoir
- a dam wall
- a sluice gate and penstock
- a turbine
- an alternator or generator
- a regulator.

Run-of-river plants, a type of mini hydro or micro hydro system, can function without having a large reservoir. A percentage of the water is diverted to a channel or pipeline that transports it to a waterwheel or turbine.



[25] The focus of current hydropower investment in Australia is on the refurbishment and modernisation of existing assets and in some cases the addition of mini- and micro-hydro units to waterways. The costs of refurbishments and small hydro are too site-specific for inclusion in this study.

Figure 40: Schematic of a reservoir-based hydroelectric power plant

Source: http://psapublishing.com/Hydroelectric.pdf (accessed October 2015).

The four components of a run-of-river plant are:

- a water conveyance system
- a turbine, pump or waterwheel
- an alternator or generator
- a regulator.

Major technical issues and future development directions/trends

Large hydroelectric power plants are a very mature technology. However, concerns have been raised in more recent years about the effect of hydroelectric dams on fish, other animals and plant life because of changes in water flow patterns, land use and water quality.

The large area of land that dams require also raises concerns. Any new hydroelectric power generation in Australia will be likely to come from much smaller new plants, such as micro (less than 500 kW) and mini hydro (less than 5 MW), and from the addition of generators to existing dams and structures.

3.3 Fossil-fuel technologies

The fossil-fuel technologies covered here are:

- pulverised coal
  - supercritical
  - ultra-supercritical
  - post-combustion capture
  - advanced ultra-supercritical
  - oxyfuel
- integrated gasification combined cycle
- gas combustion turbines
  - natural gas combined cycle
  - natural gas open cycle
- reciprocating internal combustion engine
  - compression ignition engine
  - spark or pilot injection ignition engine.

3.3.1 Pulverised coal

Brief description of the technology

The various pulverised coal power plants have a similar schematic, with the main difference being the boiler technologies they use. Coal is pulverised (milled) to a fine powder, which is fed into a boiler, where it combusts within seconds. The heat is absorbed by tubes in the boiler walls. The steam generated in the boiler tubes is used to turn a steam turbine and generator to create electricity. The pulverised coal type of boiler dominates the electric power industry, producing about 50% of the world's electricity supply.

Oxyfuel has an additional step in the process using an air separation unit to remove nitrogen from the inlet air to the boiler to create an oxygen-rich combustion environment.

The difference between subcritical, supercritical and ultra-supercritical boiler technologies is in the steam conditions created in the boiler (Table 10). Supercritical and ultra-supercritical technologies are also referred to as high-efficiency, low-emissions technologies.[26]

[26] IEA (2012), *Technology roadmap: high-efficiency, low-emissions coal-fired power generation*.

Table 10: Pulverised coal nomenclature / classification—Australia

Plant type	Steam conditions	Efficiency (% HHV)[a]	Typical CO_2 emissions (kg CO_2-e/MWh)
Subcritical	16.5 MPa. 565/565ºC	34–38	880
Supercritical	565/585ºC. >24.8 MPa	38–41	800
Ultra-supercritical[a]	>24.8 MPa. 593/621ºC and above	41–42	760
Advanced ultra-supercritical[b]	>34.5 MPa. 677ºC and above	> 42	< 750

HHV = higher heating value.
a: Efficiencies are based on black coal with dry cooling, and are on an HHV basis.
b: Not commercially available.
Note: This report uses the term 'ultra-supercritical' to allow comparisons with other studies. 'Ultra-supercritical' is not a definable steam temperature/pressure condition, but a conventional term to differentiate the performance of different power plants.

Supercritical pulverised coal plant

The major components of a supercritical pulverised coal-fired plant include:

- coal-handling equipment
- the steam generator island
- the turbine-generator island
- bottom and fly ash handling systems
- emissions control equipment.

The steam generator island includes coal pulverisers; burners; waterwall-lined furnaces; superheater, reheater and economiser heat transfer surfaces; soot blowers; air heaters; and forced-draft and induced-draft fans.

The turbine-generator island includes the steam turbine; the power generator; the main, reheater and extraction steam piping; feedwater heaters; boiler feedwater pumps; condensate pumps; and a system for condensing the low-pressure steam exiting the steam turbine.

A diagram of a pulverised coal supercritical power plant is shown in Figure 41. It is also shown with a post-combustion capture addition (indicated by the dashed lines). A typical boiler is shown in Figure 42.

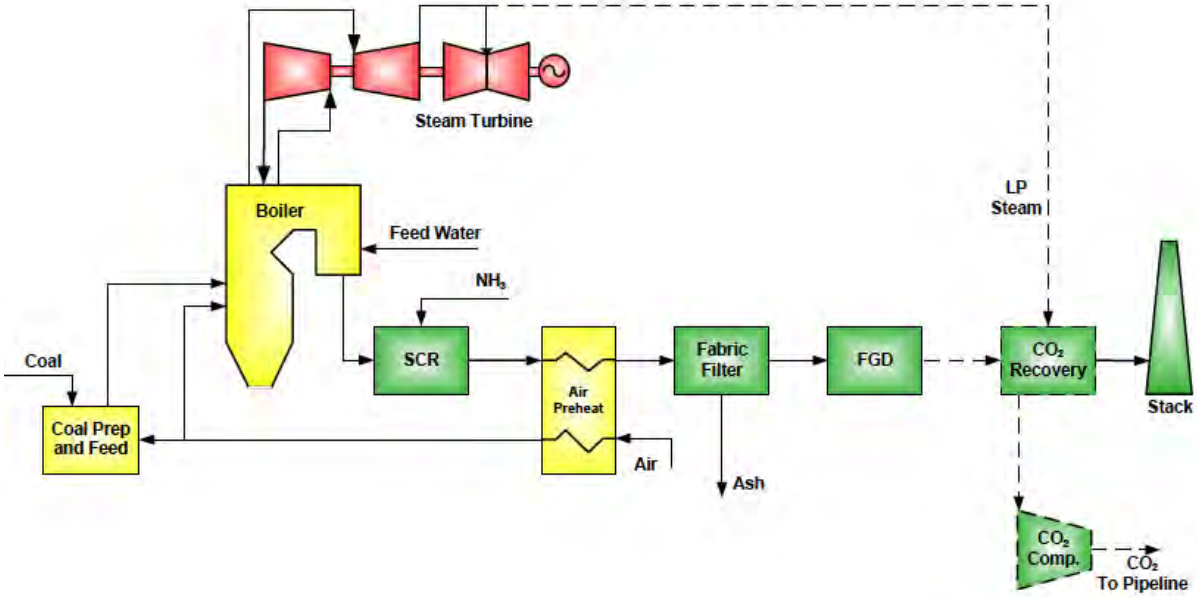


Figure 41: Schematic of a supercritical pulverised coal power plant (with CO_2 capture)

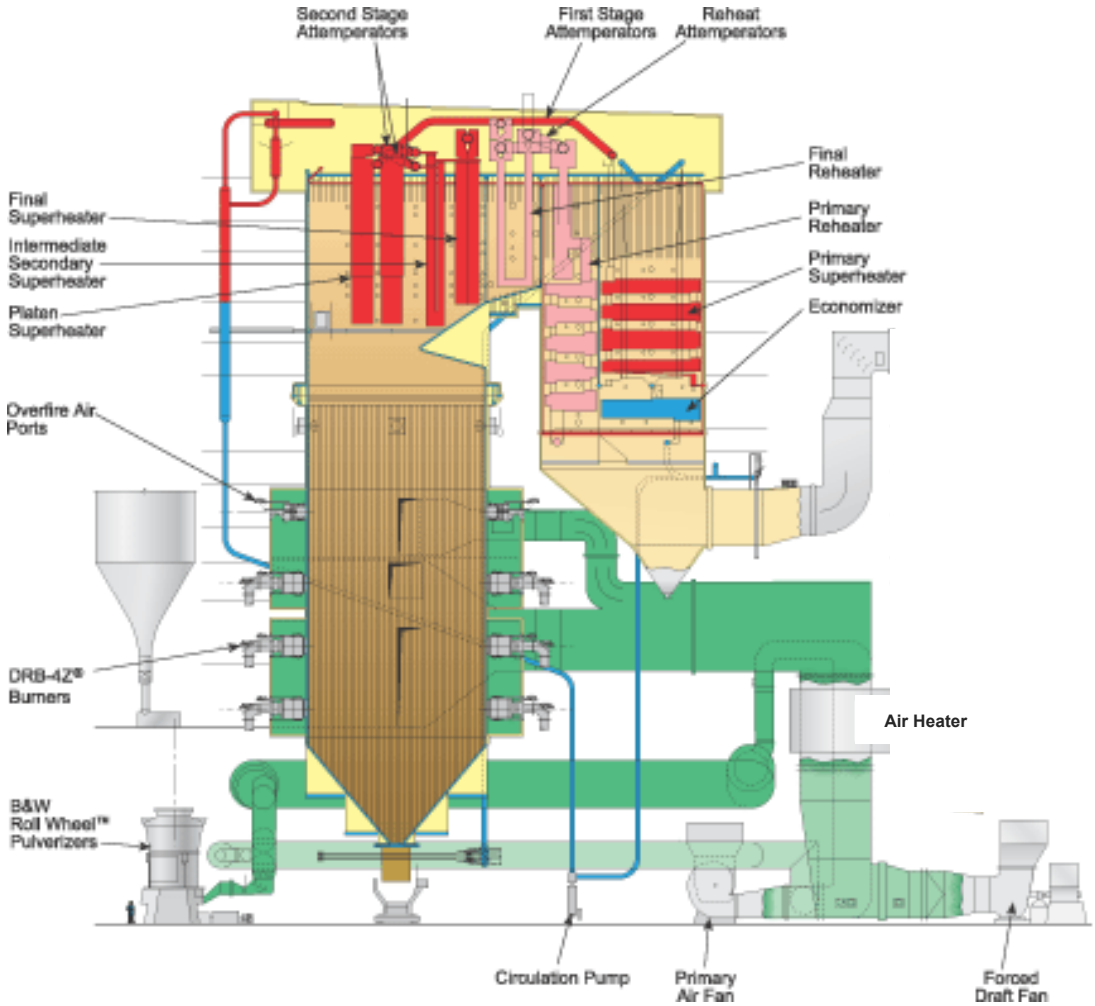


Figure 42: Vertical tube supercritical boiler layout

Ultra-supercritical pulverised coal plant

The main components of an ultra-supercritical pulverised coal-fired plant are the same as those of a supercritical plant.

Generating efficiency is increased by designing the unit for operation at higher steam temperature and pressure. This is a movement from subcritical to supercritical to ultra-supercritical steam parameters (Table 10) and has been made possible by the recent development of new materials with higher performance capabilities.[27] Operating steam cycle conditions above 593/621ºC and 28.4 MPa are referred to as ultra-supercritical.

Example plant

The 600 MW John W Turk Jr. Power Plant began operation in December 2012 as the first ultra-supercritical' unit in operation in the United States. It operates at a steam temperature of 593ºC.

Post-combustion capture

The post-combustion process separates CO_2 from combustion exhaust (flue gas) through either adsorption or absorption. The captured CO_2 is then recovered to form a high-purity steam, which is then sequestered.

The absorption solvents most frequently used are based on monoethanolamine (MEA), an amine solvent. The process principle is based on the thermally reversible reaction between components in the liquid absorbent and CO_2 present in the flue gas. A typical flow sheet of CO_2 recovery using chemical absorbents is shown in Figure 43.

Before amines are used to remove CO_2 from a flue gas, the gas is cooled and treated to reduce its levels of sulphur dioxide and particulates.[28] The sulphur dioxide is removed using a caustic scrubber, as low sulphur dioxide levels are needed to avoid poisoning of the amines. Subsequently, boosted by a fan to overcome pressure losses in the system, the flue gas is routed through an absorber. In the absorber, the gas interacts with a lean amine solution that flows countercurrently to the gas. This interaction absorbs the CO_2. The nearly CO_2-free flue gas continues to the plant stack. The amine solution, which is now rich in CO_2, is pumped into a stripper in order to separate the amine and the gas. Steam provides the energy needed to desorb the CO_2 from the solution. The CO_2-rich solution at the top of the stripper is condensed and the CO_2 phase is removed and sent off for drying and compression.

[27] The term 'ultra-supercritical' is used in this report to allow comparisons with other literature. It is not a definable steam temperature/pressure condition, but a convention used to differentiate the performance of different power plants.

[28] Some solvent technologies no longer require sulphur dioxide pre-removal, instead using the solvent to capture sulphur dioxide. However, sulphur removal systems are then needed to reduce the sulphur from the solvent.

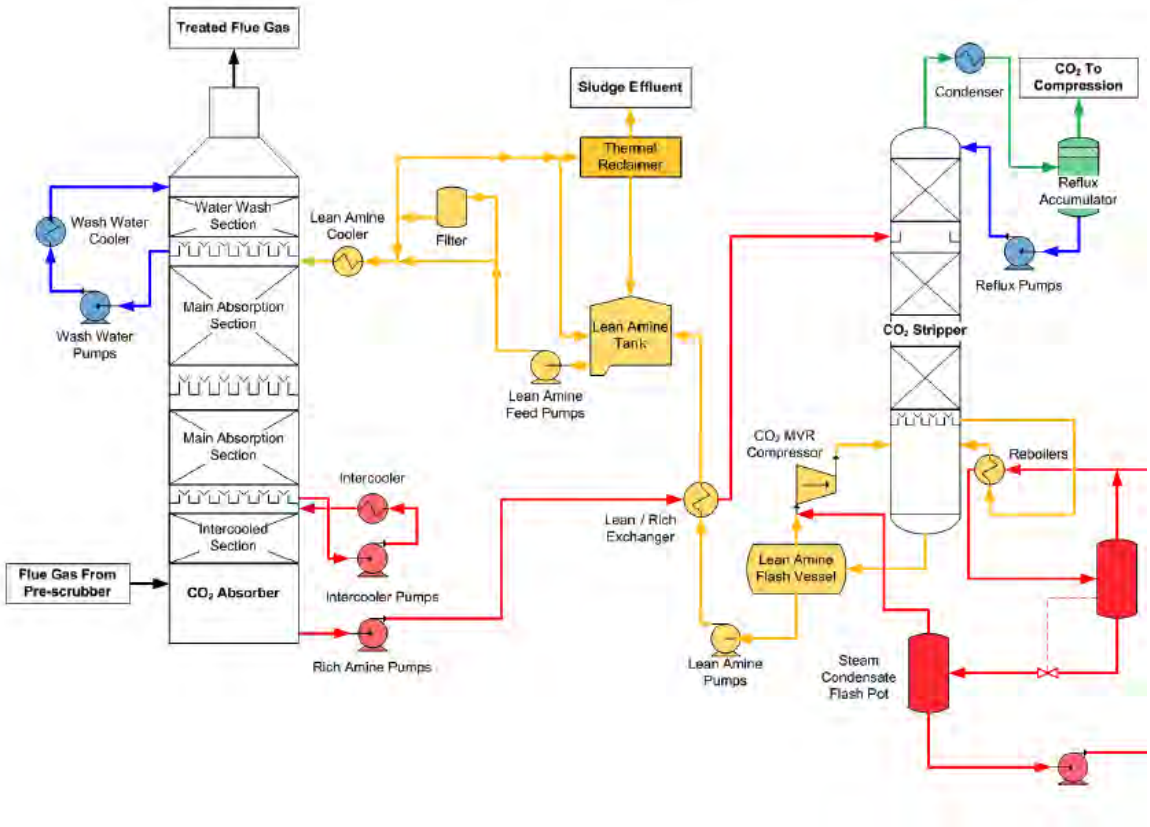


Figure 43: Schematic of a typical solvent configuration for CO_2 capture

Oxyfuel pulverised coal plant

Oxyfuel is the term given to a process that involves firing a conventional pulverised fuel coal boiler with oxygen and recycled exhaust gases instead of ordinary air (Figure 44). This produces a concentrated stream of CO_2 that can be captured and sequestered.

Firing coal with only high-purity oxygen would result in a flame temperature too high for existing furnace materials, so the oxygen is diluted by mixing it with a slipstream of recycled flue gas. The flue gas recycle loop may include dewatering and desulphurisation processes. As a result, the flue gas downstream of the recycle slipstream take-off consists primarily of CO_2 and water vapour (with small amounts of nitrogen, oxygen and criteria pollutants). After the water is condensed, the CO_2-rich gas is compressed and purified to remove contaminants and prepare the CO_2 for transportation and storage.

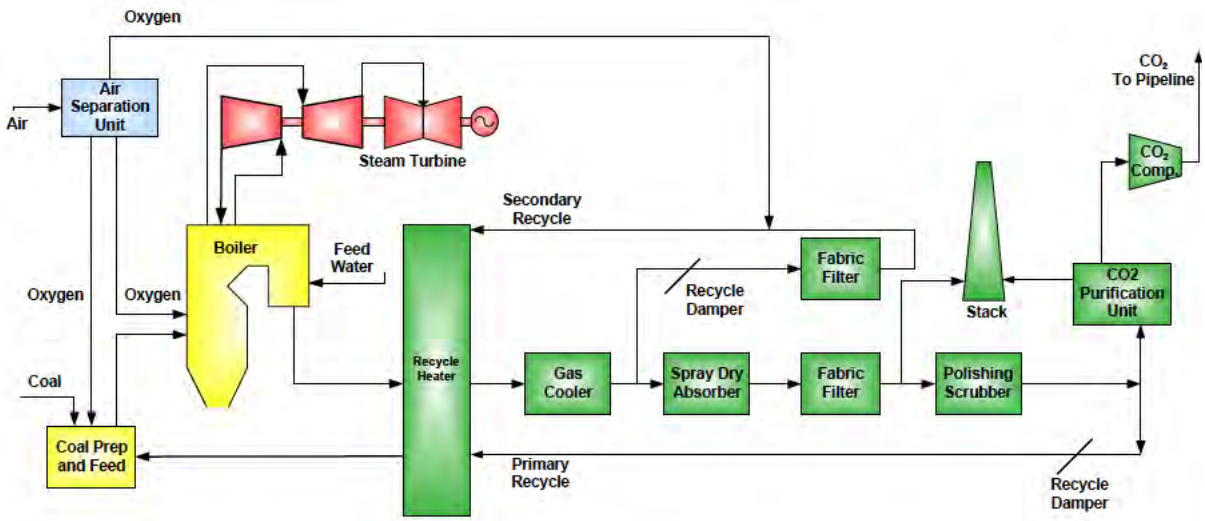


Figure 44: The oxyfuel process

Plants that are designed for oxyfuel combustion use large quantities of almost pure oxygen. Creating the oxygen stream is performed in an air separation unit (ASU). This is a large system that consumes a considerable amount of electricity. Oxyfuel power plants have additional flue gas treatment modules, several heat exchangers to extract low-grade heat, and fans and ducts for flue gas recirculation.

3.3.2 Integrated gasification combined cycle

Brief description of the technology

Gasification can be described as the thermal conversion of a coal feedstock to a synthesis gas (syngas) comprising mainly hydrogen, carbon monoxide, water, CO_2 and methane. Additional components, typically compounds of sulphur, nitrogen and other elements, may be present as contaminants depending on the feedstock. During the process, impurities from the raw syngas are removed before it is combusted.

The gasification process is quite complex and is accomplished through a series of physical transformations and chemical reactions within the gasifier. The coal undergoes several different reactions or processes including pyrolysis, combustion, gasification, water–gas shift and methanation.

Integrated gasification combined cycle (IGCC) technology is called ‘integrated’ because heat recovery in the gasification unit is integrated with the plant’s combined cycle. Additionally, the gas turbine compressor provides pressurised air used in the ASU that produces oxygen for the gasification process. The syngas produced is used as fuel in a gas turbine, which produces electrical power. To improve the overall process efficiency, heat is recovered from both the gasification process and the gas turbine exhaust in ‘waste heat’ boilers, producing steam. This steam is then used in steam turbines to produce additional electrical power.

A diagram of an IGCC power plant is shown in Figure 45. It is also shown with a pre-combustion CO_2 capture configuration (indicated by the dashed lines). It is the integration of the system components that brings the most important advantage of IGCC plants.

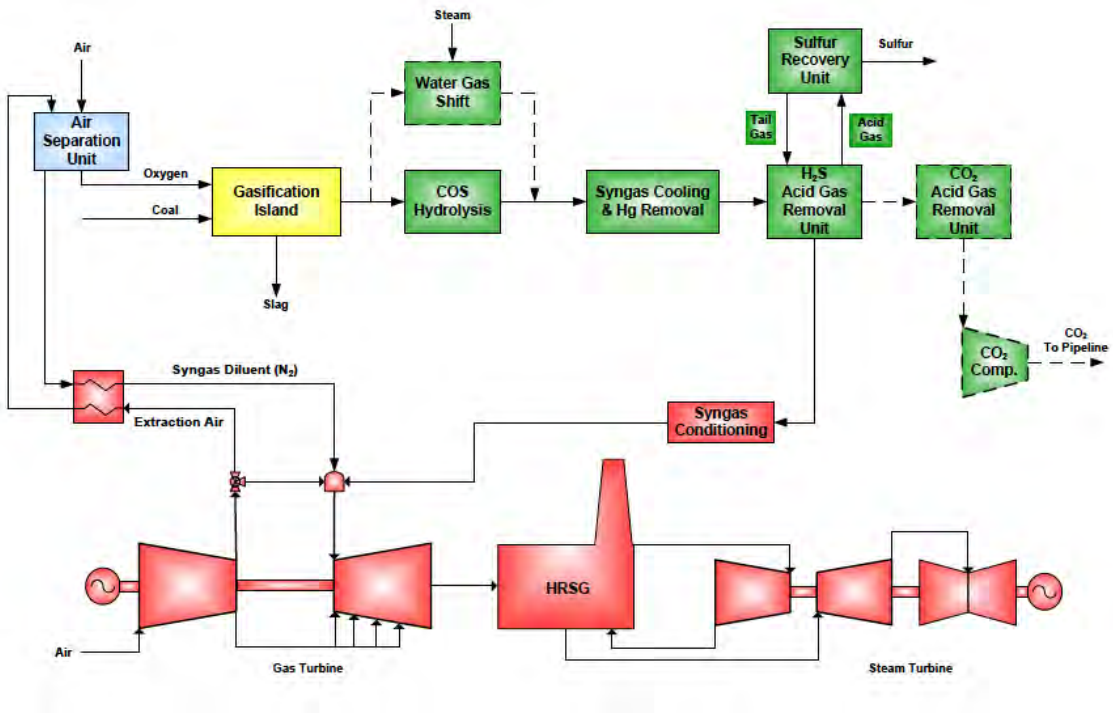
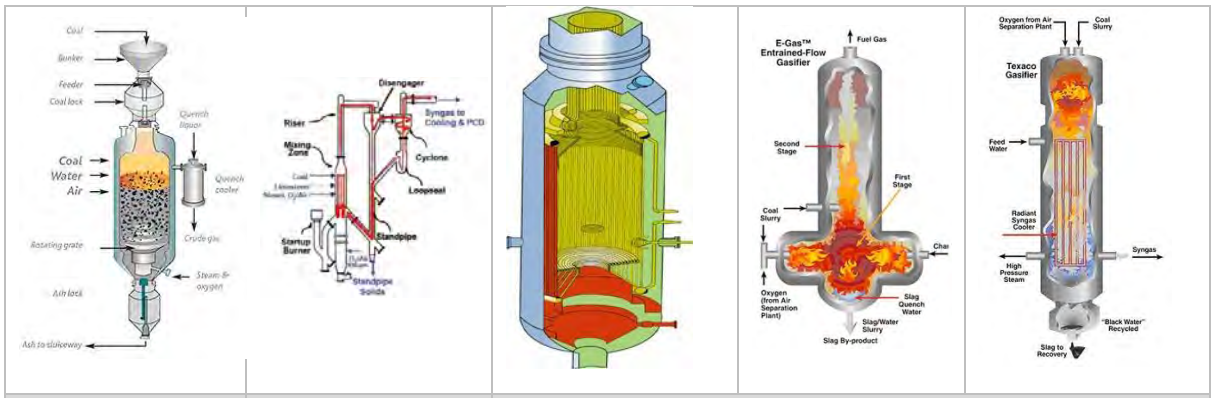


Figure 45: Schematic of an IGCC power plant (with CO_2 capture)

Gasification

There are three types of gasification technologies: fixed bed, fluidised bed and entrained flow (Figure 46). In addition, gasifiers are either air-blown or oxygen-blown. While most of the commercially available entrained-flow gasifiers are oxygen-blown, Mitsubishi Heavy Industries offers an enriched air-blown entrained-flow gasifier. KBR and Southern Company offer an air-blown transport gasifier (a fluidised bed) for use with lower rank coals.



Fixed bed	*Fluidised bed*	*Entrained flow*		
		Dry fed (down flow)	*Slurry fed (up flow)*	*Slurry fed (down flow)*

Figure 46: Three major gasification technology classes

Source: http://www.powerfactbook.com (accessed October 2015—subscription required).

Black coal gasification

The Shell entrained-flow oxygen-blown gasifier with dry coal feed was the representative gasifier chosen for this study on Hunter Valley black coal. The Shell gasification technology uses a dry-fed, single-stage, upflow gasifier. Figure 47 shows a cut-away schematic of the Shell gasifier, illustrating the membrane wall reactor within a pressure vessel.

Dry pulverised coal is mixed with oxygen and moderator steam in opposed burners located near the bottom of the reactor. Hot, raw gas and fly slag exit the top of the vessel, while liquid slag flows down the water-cooled membrane wall to a quench pool and discharge opening at the bottom of the vessel. Cooled, recycled gas is added at the top of the vessel to quench the hot raw product gas and to harden any entrained molten slag before the gas enters the syngas cooler. The firetube type syngas cooler generates steam at one or two pressures while recovering high-level heat from the quenched raw gas. Solids and condensed liquids are removed in a dry solids removal system comprising a cyclone and barrier filter and a wet scrubber using an acid gas clean-up stage for hydrogen sulphide.

For the gasifier to produce liquid slag, it must operate above the reducing fluid ash temperature. Fuels with high fluid ash temperatures may require fluxing to reduce it. Limestone is typically used as the fluxing agent.

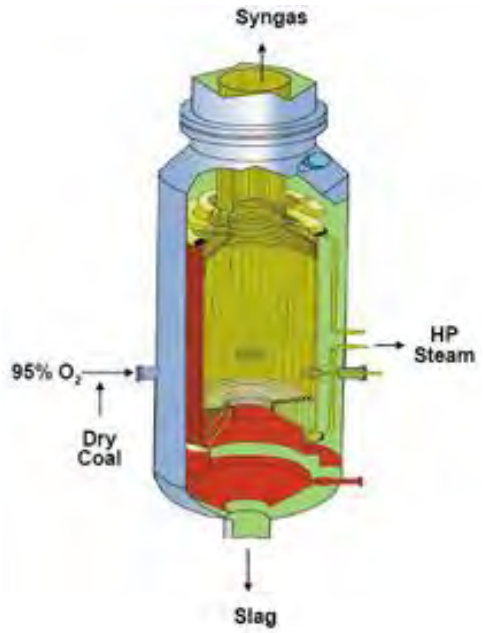


Figure 47: Cut-away view of the Shell gasifier

The gasifier operates at about 4 MPa and 1,540°C. The syngas leaves through the top of the gasifier and consists of mainly carbon monoxide, hydrogen, CO_2 and water. Before the syngas leaves the gasification island, it is quenched with recycled syngas, then passes through the syngas cooler, which uses feedwater from the combined cycle to generate medium-pressure and high-pressure steam. The syngas then passes through a candle filter and a fraction is recycled back to the gasifier for quenching. The remainder is further cooled in the syngas scrubber before being transported to the carbonyl sulphide hydrolysis unit.

In a non-carbon capture case, the scrubbed syngas is then sent through a single carbonyl sulphide hydrolysis reactor filled with catalyst to hydrolyse the carbonyl sulphide to hydrogen sulphide to help the downstream acid gas removal unit achieve the required total sulphur removal levels. The sour syngas is then cooled to about 38°C by heating the treated syngas exiting the unit and the humidification loop water required for combustion turbine syngas dilution. The cooled syngas is then passed through a mercury removal bed and then on to the acid gas removal unit, which is a methyl diethanolamine (MDEA) gas treating unit, for hydrogen sulphide removal. Hydrogen sulphide is removed from the syngas stream down to approximately 30 ppmv so that sulphuric acid does not condense out of the gas turbine exhaust downstream in the heat recovery steam generator (HRSG). In the MDEA unit, the sour gas enters the absorber at the bottom and flows countercurrently to the MDEA solution. The liquid entering the top is known as the 'lean' solution. As the solution passes down through the trays or packing, it absorbs hydrogen sulphide and CO_2 from the gas stream, producing sweet gas that exits the top. When the MDEA gets to the bottom of the tower, the stream is called the 'rich' solution (rich in acid gases). The rich MDEA must be regenerated by steam stripping for reuse in the closed system.

Brown coal gasification

The KBR Transport Integrated Gasification (TRIG) system with an air-blown configuration was chosen for the gasification of brown coal in this study. The TRIG system is an advanced pressurised circulating fluidised bed gasifier that operates at temperatures between 815°C and 1,065°C.

The mechanical design and operation of the gasifier are based on KBR's fluidised catalytic cracking technology, which has more than 60 years of commercial operating history. The TRIG gasifier is simple in design and has no internals, expansion joints, valves or other moving parts (Figure 48).

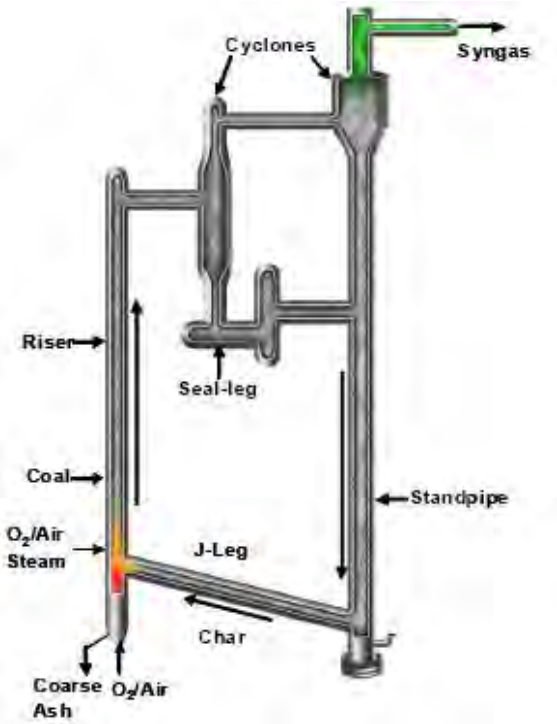


Figure 48: The TRIG system, an advanced pressurised circulating fluidised bed gasifier

The moderate temperatures employed in the non-slagging, air-blown TRIG gasifier, combined with the dry feed and dry ash handling systems, greatly improve gasification cold gas efficiency and reduce the specific oxygen demand when gasifying low-rank coals. In addition, the operating temperature range of the gasifier is sufficient to achieve high carbon conversions while mitigating the formation of tars and oils.

In particular, the gasifier's continuous dry ash handling system eliminates the technical difficulties associated with slag handling and removal faced by comparable slagging gasifiers. Slagging gasifiers generally require frequent refractory change-out due to the erosive nature of the high-temperature fluidic slag. This can escalate maintenance costs while reducing gasifier availability. In contrast, lower operating temperatures in the TRIG gasifier allow the installation of conventional, cost-effective alumina–silica type refractory that has a significantly longer life.

The coal preparation system for the TRIG gasifier is designed to transport coal from the coal pile to the crushed coal silos while the coal is crushed during transport.[29] The coal is then forwarded to the coal mills. The closed-loop milling system uses several fluidised nitrogen beds for milling and drying. The nitrogen is heated using low-pressure steam/condensate. The moisture of the brown coal is reduced to approximately 10% before the coal enters the gasification island.

Combined cycle

Combustion of the syngas is completed in the gas turbine, thus integrating high-efficiency combined cycle gas turbine technology with the gasification systems. The syngas is burned in the gas turbine combustors with high-pressure air, and the resulting combustion gases drive the turbine, which generates electric power. Nitrogen from the ASU can also be expanded through the gas turbine to increase power production and to reduce NO_X emissions. The steam generated in the gasification process is combined with the steam produced in the gas turbine heat recovery steam generator (HRSG) and fed to the steam turbine-generator (refer to the red process components in Figure 45).

Compressed air from the gas turbine can be channelled back to the gasifier or the ASU. In addition, exhaust heat from the gas turbine and heat recovered from the syngas clean-up cooling system are used to generate steam for a steam turbine-generator.

Power is produced from both the combustion and the steam turbines. The use of gas turbines and a steam turbine constitutes the 'combined cycle' aspect of IGCC and is one reason why gasification-based power systems can achieve high power-generation efficiencies. In a typical IGCC unit, about 60% of the sent-out power output is generated by gas turbines and about 40% by the steam turbine. Due to the relatively high efficiencies of modern combined cycle technology, the overall thermal efficiency of an IGCC plant is 38–41% HHV for Hunter Valley bituminous coal and 33–36% HHV for Victorian brown coal.

[29] This style of coal-drying unit is being commissioned at the Mississippi Power–Kemper County IGCC facility.

Syngas is a low-energy-density fuel with a heating value of about 9.3 MJ/m^3, or roughly one-quarter that of natural gas. As a result, the operation of gas turbines on syngas requires a higher volumetric flow through the gas turbine combustors to achieve the same turbine-section heat input as in operation on natural gas. Currently, operating advanced gas turbines on high hydrogen content syngas requires turbine inlet temperatures to be slightly lower than those used when firing natural gas because of differences in aerodynamics, heat transfer, and erosion issues.

Nonetheless, gas turbines have been designed to accommodate higher fuel mass flow and the lower flame temperatures associated with firing syngas. In many cases, despite the lower firing temperature, the higher mass flow allows an increase in the gas turbine power rating. Some turbine designs are modified with stronger drive shafts and larger generators to take advantage of this capacity. In addition, to control NO_X, syngas is diluted with nitrogen to lower the flame temperature. This provides additional mass and motive force to the gas turbine, increasing the MW output.

There are many variations on the basic IGCC scheme shown in Figure 45, especially in the degree of integration. All of the current coal-based plants integrate the steam systems of the gasification and power block sections. Typically, boiler feedwater is preheated in the HRSG and passed to the gasification section, where saturated steam is raised from the cooling of the raw syngas. The saturated steam passes to the HRSG for superheating and reheating before its introduction, with additional HRSG superheated steam, to the steam turbine for power production.

Syngas treatment and CO_2 capture

A major advantage of gasification-based energy systems compared with conventional coal combustion is that the CO_2 produced by the process is in a concentrated high-pressure gas stream. The partial pressure of CO_2 in the syngas, following the water–gas shift reaction step, is much higher than that in post-combustion flue gas. This is especially true for oxygen-blown gasifiers, although air-blown gasifiers also provide a higher partial pressure of CO_2 than in ambient-pressure flue gas. This higher pressure makes it easier and less expensive to separate and capture CO_2 from syngas than from flue gas. Once the CO_2 is captured, it can be sequestered.

The IGCC technology is able to achieve low air emissions through:

- removing the emissions-forming constituents from reduced syngas volumes under pressure before combustion to meet extremely stringent air emissions standards
- removing >99% sulphur
- achieving NO_X emissions at <20 ppmv at 15% O_2 in the gas turbine exhaust (these levels can probably be lowered with further combustor modifications; selective catalytic reduction can be used, but the economics are not yet established)
- achieving carbon monoxide emissions of 1–2 ppmv at 15% O_2
- ensuring that particulate emissions are at an undetectable level.

In this study, the IGCC plants without carbon capture use the MDEA process for sulphur removal with a Claus unit. IGCC plants with carbon capture use two-stage Selexol units from a water–gas shifted feed gas and a Claus unit for recovering sulphur. Figure 49 shows the hydrogen sulphide removal process, which may operate as a stand-alone configuration without the CO_2 removal process or in combination with CO_2 removal.

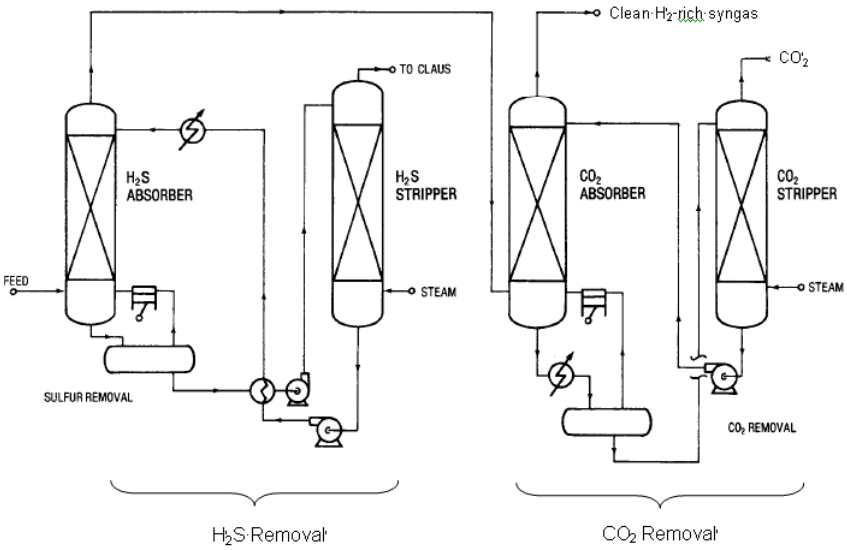


Figure 49: Typical IGCC acid gas recovery process arrangement

Under the reducing conditions of gasification, sulphur in the coal is converted mainly to hydrogen sulphide, with ~3–10% converting to carbonyl sulphide. This typically necessitates the use of a carbonyl sulphide hydrolysis reactor to convert it to hydrogen sulphide before hydrogen sulphide removal by an acid gas recovery (AGR) system.

The most common AGR processes use the chemical solvent methyldiethanolamine (MDEA) or a physical solvent such as Selexol, which is a mixture of dimethyl ethers of polyethylene glycol. The chemical solvent reacts with the acid gases and requires heat to reverse the reactions and release the gases. Physical absorbents dissolve acid gases and require pressure as the driving force for absorption and pressure release for regeneration.

CO_2 can be separated from syngas by AGR—the same process used to separate sulphur species. However, achieving higher levels of CO_2 capture requires adding a water–gas shift reactor before separation. This contains a catalyst that, in the presence of water, 'shifts' CO in the syngas to CO_2 and hydrogen:

$$CO + H_2O \rightarrow H_2 + CO_2 \qquad \text{Equation 1}$$

A single-stage shift reactor can achieve most of the carbon monoxide conversion (80–85%). To achieve additional carbon monoxide conversion requires additional shift reactors at increased capital cost. The CO_2 in the shifted syngas is removed via contact with the solvent in an absorber column, leaving a hydrogen-rich gas for combustion in the gas turbine.

The water–gas shift reaction releases heat, which decreases the chemical energy contained in the syngas. Consequently, in order to supply the same fuel energy to the gas turbine after passing the syngas through a water–gas shift reactor, 5–10% more syngas would have to be produced.

The heat released during the shift reaction is typically used to produce high- or intermediate-pressure steam.

The water–gas shift option increases the CO_2 concentration, which allows CO_2 capture to take place at the pre-combustion stage at elevated pressure, taking advantage of higher partial pressures, rather than at the atmospheric pressure of post-combustion flue gas, permitting capital savings through smaller equipment as well as lower operating costs.

The impact of current CO_2 removal processes on IGCC plant thermal efficiency, sent-out plant output and capital cost is significant. In particular, the water–gas shift reaction reduces the heating value of syngas to the turbine. Because the gasifier outlet ratios of carbon monoxide to methane to hydrogen are different for each gasifier technology, the relative impact of the water–gas shift reactor process also varies. In general, however, it can result in a fuel energy reduction of approximately 10% for full shift.

Heat regeneration of chemical (and sometimes physical) solvents reduces the steam available for power generation. In addition, solvents need to be depressurised to release captured CO_2 and must be repressurised for reuse. Cooling water consumption, or dry cooling load, increases for solvents that need cooling after regeneration and for pre-cooling and interstage cooling during the compression of separated CO_2.

3.3.3 Reciprocating internal combustion engines

Brief description of the technology

All reciprocating internal combustion engines have the same basic processes. A combustible mixture is first compressed between the head of a piston and its surrounding cylinder. The mixture is then ignited and the resulting high-pressure products of combustion push the piston down the cylinder. This movement is converted from linear to rotary motion by a crankshaft. In a 4-cycle variant, the piston returns, pushing out exhaust gases, and the cycle is repeated. In a 2-cycle variant, the exhaust gas is pushed out of holes in the bore by incoming fresh charge from an external air pump, such as a supercharger.

Reciprocating engine generators convert the energy in natural gas or diesel fuel into mechanical energy, which rotates a shaft to generate electricity (Figure 50). They are typically between 1 MW and 20 MW in capacity and are used for remote, on-site or backup power generation. Recent consideration has also been given to using them instead of battery storage at the ‘edge of the grid’.

Two ignition methods are used: compression ignition and spark or pilot injection ignition. Both of the ignition methods can be used in either the 4-cycle or 2-cycle configuration. These engines may also be configured for dual fuel use (being able to run on both natural gas and diesel fuel).

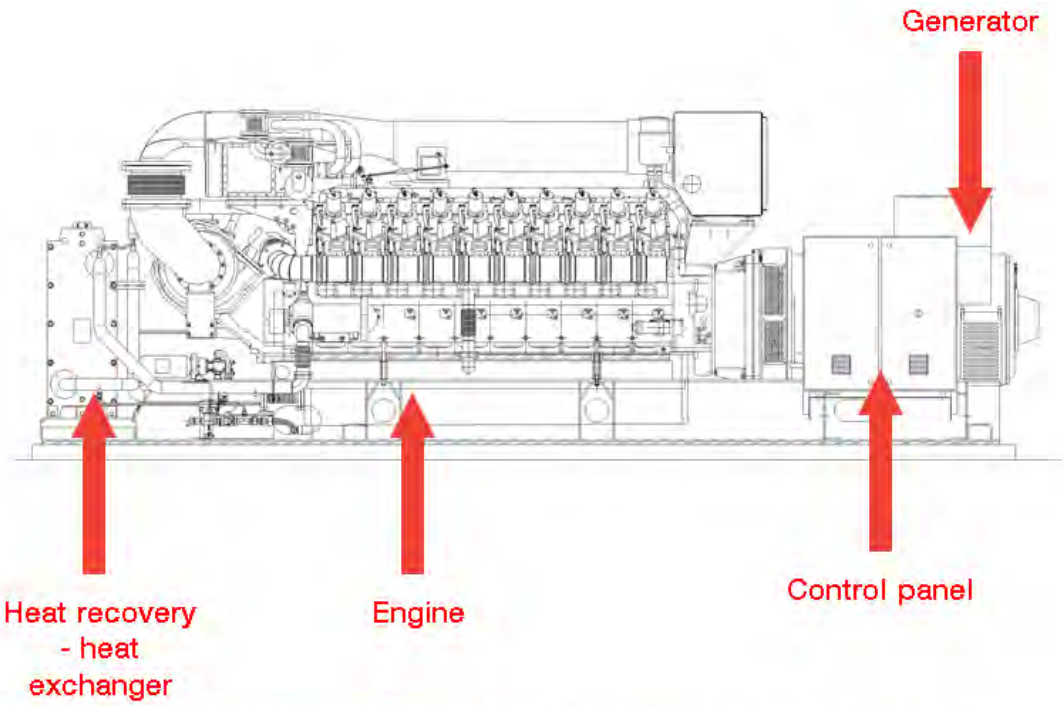


Figure 50: Typical configuration of a combustion engine

Source: http://www.powerfactbook.com (last accessed October 2015—subscription required).

Compression ignition combustion engines

The compression ignition combustion engine, commonly referred to as the diesel engine, differs from the spark ignition engine by using the high compression of an air and fuel mixture, rather than a spark plug, to ignite the fuel. Air is compressed adiabatically with a static compression ratio typically between 15:1 and 25:1. This compression raises the temperature to the ignition temperature of the fuel mixture, which is formed by injecting fuel once the air is compressed. Turbocharging or supercharging can be used to further increase the dynamic compression ratio.

Typical fuels for compression ignition engines include diesel and heavy fuel oil. Potential future fuels include micronised refined carbon, which is a finely ground coal–water slurry.

Spark ignition and pilot injection combustion engines

The spark ignition combustion engine is based on the Otto cycle and uses a spark plug to ignite an air–fuel mixture injected at the top of the cylinder. In the Otto cycle, the fuel mixture does not get hot enough to ignite without a spark or other ignition source, which differentiates it from the diesel combustion cycle. A high-voltage spark provides the ignition source in a spark ignition engine, while a very small amount of diesel injected at the desired ignition point provides the ignition source for pilot injection engines.

Typical fuels for these engines include gas (natural gas, liquefied natural gas, liquefied petroleum gas) and methanol (or similar alcohol variants from renewable sources). While each fuel has particular detailed requirements, spark or pilot ignition engines can be described generically by considering the natural gas variant.

Most natural gas engines are modified diesel-fired engines. They typically use the same block, crankshaft, main bearings, camshaft and connecting rods as their diesel-fired 'parent' engines. However, manifold-injected natural gas engines must operate at lower compression ratios to prevent uncontrolled auto-ignition and engine knock (thus requiring spark ignition). Due to the derating effects of the lower compression ratio and fuel gas aspiration, corresponding engine models produce only 60–80% of the power output of their diesel-fired counterparts. The slightly larger cylinder size of the natural gas engine provides only partial compensation for the derated output. More modern direct-injected natural gas engines do not require the same level of derating and can run at similar compression ratios to those of diesel compression ignition engines. These engines are typically ignited by a small pilot injection of diesel timed to suit the combustion of the gas.

One advantage of reciprocating engines is that their power output is less affected by increasing elevation and ambient temperature compared to gas turbines. Furthermore, a reciprocating engine plant comprising several small units can be more efficient in part-load operation than a single gas turbine plant of equivalent size because of the ability to shut down engine units and run the remaining units at higher load (nearer to peak efficiency).

3.3.4 Gas turbines

Brief description of the technology

A gas turbine (also known as a combustion turbine) includes an air compressor, a combustor and an expansion turbine. Gaseous or liquid fuels are burned under pressure in the combustor, producing hot gases that pass through the expansion turbine, driving the air compressor. The shaft of the gas turbine is also coupled to an electric generator so that mechanical energy produced by the gas turbine drives the generator.

Gas turbines can also be configured in conjunction with heat recovery steam generators (HRSGs) to produce steam. A turbine coupled with an HRSG used to produce steam for power generation and running on natural gas is called a natural gas combined cycle turbine.

Turbine size / classification

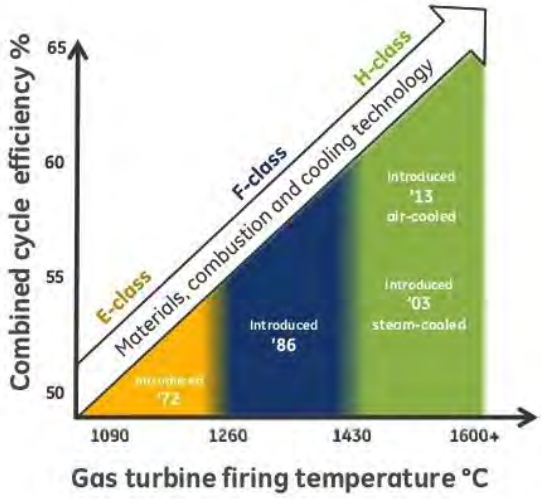
Gas turbines are categorised as aeroderivative or frame gas turbines, although a few turbines have recently adopted features of both design types.[30] In general, the differences between the aeroderivative and frame turbines are:[31]

- weight
- size
- combustor and turbine design
- bearing design
  - antifriction bearings for aeroderivative turbines
  - hydrodynamic ones for industrial turbines
- the lube oil system.

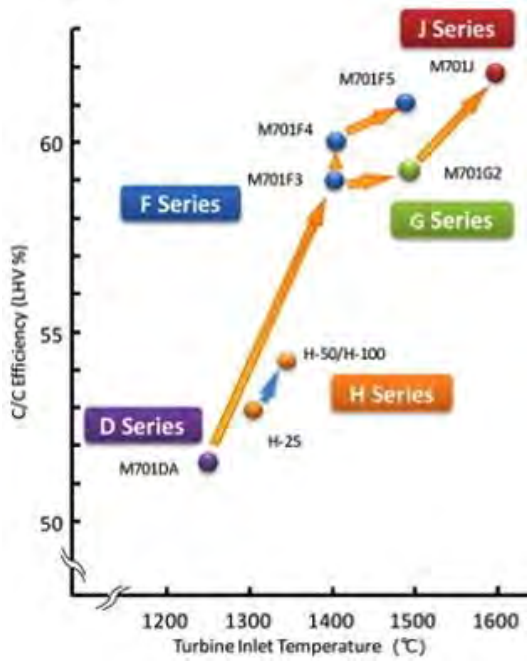
[30] General Electric's LMS100 is a recent hybrid. It has a Frame 6FA low-pressure compressor and a CF6-80C2 high-pressure compressor.
[31] www.powermag.com/selecting-your-next-combustion-turbine/?pagenum=1 (accessed October 2015).

Frame turbines are also field-erected and maintained in place, whereas aeroderivative turbine plants are designed for a quick replacement of the entire engine when maintenance is required.

Frame turbines are usually classified by firing temperature, although there is some variation in nomenclature between manufacturers. Figure 51 shows two temperature/efficiency curves for GE and MHI turbines. Note that the efficiencies are in ideal conditions and with the MHI on a low heating value.



GE frame turbines



MHI frame turbines

Figure 51: Frame turbine classification

Sources:
GE frame turbines, www.slideshare.net/GEKorea/ge-technologyupdates-leekyungjin (accessed October 2015); MHI frame turbines, www.mhps.com/en/products/thermal_power_plant/gas_turbin/mhps_gas_turbine/performance_evolution.html (accessed October 2015).

Aeroderivative gas turbines

Aeroderivative gas turbines are derived from turbofan aircraft engines and consequently have high pressure ratios. Because of the high pressure ratio, they typically have better simple cycle efficiency and lower exhaust gas temperatures than heavy-frame units of similar rating. However, heavy-frame units generally have better combined cycle efficiency, as their high exhaust temperatures permit an efficient steam cycle. The high pressure ratios of aeroderivatives require higher fuel gas pressure, so they are more likely to require fuel gas compression. Figure 52 shows a typical aeroderivative gas turbine.

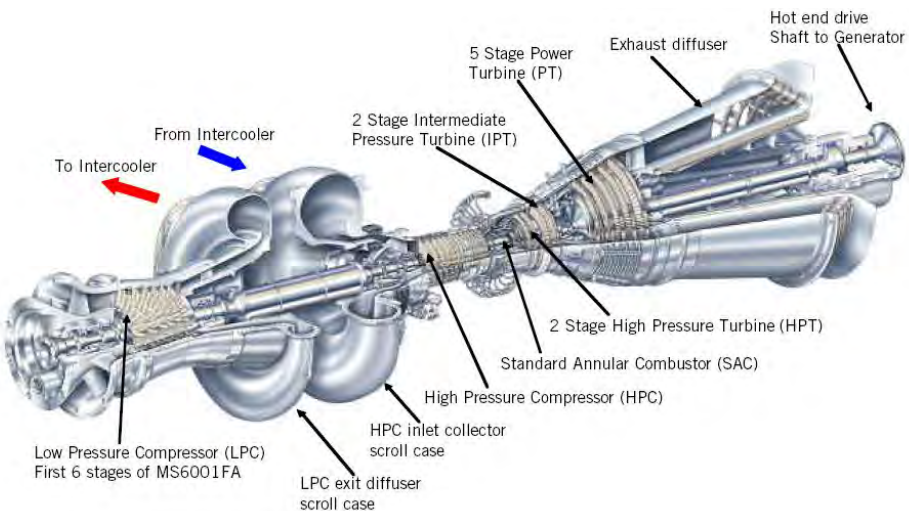


Figure 52: LMS100 aeroderivative gas turbine (cross-section)

Source: GEA13640, 3M, 11/03. Image courtesy of GE.

Since aeroderivatives are based on aircraft engine designs, their rotors and casings are lighter. One benefit of lighter weight components is that they are able to withstand cycling service with less thermal stress. Because of their better cycling characteristics and higher simple cycle efficiency, most aeroderivative units are in cycling service. Generally, maintenance intervals for aeroderivatives are not set by the number of start cycles, but instead are based on fired hours or the observed condition of the hot section. Consequently, aeroderivatives can be used for simple cycle peaking applications with little penalty from maintenance costs.

In summary, the general attributes of aeroderivative engines are:

- high simple cycle efficiency
- good start-up, shutdown and cycling performance
- higher fuel gas pressure requirements (they are more likely to require fuel gas compression)
- higher capital costs
- higher maintenance costs
- shorter maintenance outages, if a replacement engine is available.

Frame gas turbines

Frame gas turbines are usually larger, heavier, slower and narrower in their operating speed range than aeroderivative turbines. They also have higher air flow, are slower in start-up and need more time and spare parts for maintenance. Figure 53 shows a typical frame gas turbine.

Traditionally, the preference has been to place aeroderivative units in remotely located applications and to place frame turbine units in easily accessible applications.

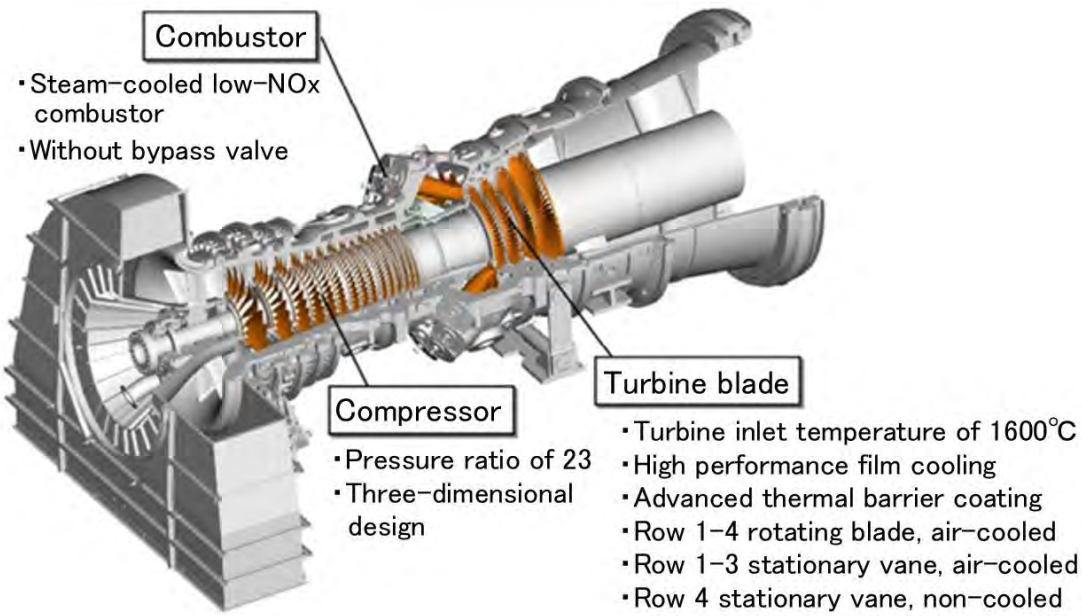


Figure 53: Frame gas turbine (MHI M501 J-type)

Source: Mitsubishi Heavy Industries (2013), *Mitsubishi Heavy Industries technical review*, 50(3), September.

Gas turbine performance factors

The performance of a gas turbine is affected by a number of factors, including:

- ambient temperature
- relative humidity
- fuel type
- inlet pressure drop
- outlet pressure drop
- site elevation.

Higher ambient temperatures result in less dense air, and lower ambient temperatures result in more dense air. Because the gas turbine is an ambient air breathing engine, its performance will be changed by anything affecting the mass flow from the air intake to the compressor. Figure 54 shows a typical open cycle compressor inlet temperature performance curve. It shows the correction factors for the open cycle gas turbine to be applied to generated output, heat rate, exhaust flow and heat consumption. An open cycle altitude correction curve (Figure 55) shows the effect of site elevation on gas turbine output and fuel consumption.

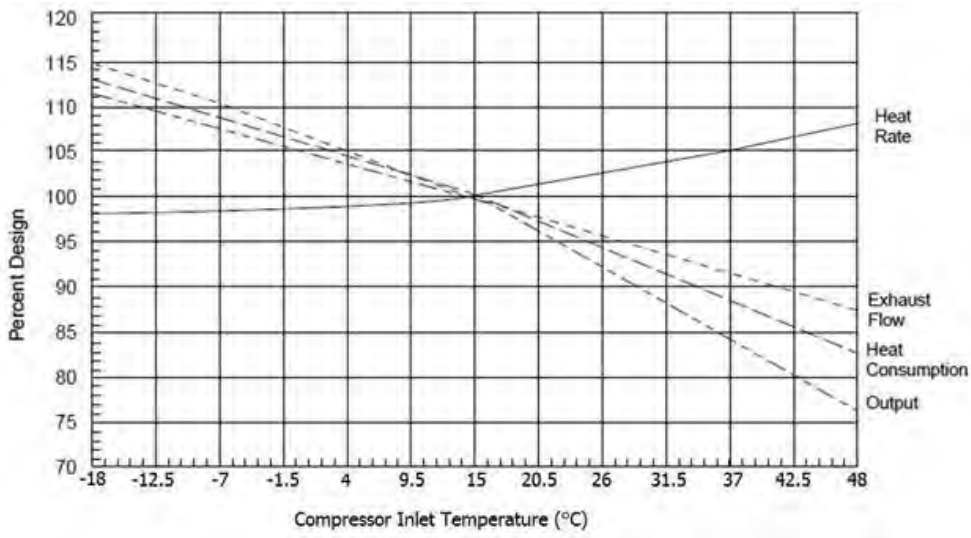


Figure 54: Open cycle compressor inlet temperature performance curve

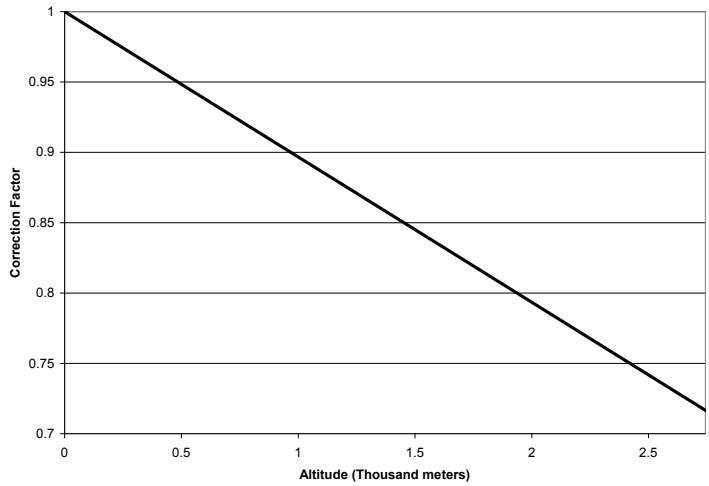


Figure 55: Open cycle altitude correction curve

Generally, it is not possible to control the factors that affect gas turbine performance. Most are determined by the site location and the plant configuration. However, if additional output is needed, there are several possibilities that may be considered to enhance performance:

- *Inlet cooling:* The compressor inlet temperature can be lowered by installing an evaporative cooler or inlet air chiller in the inlet ducting downstream of the inlet filters.
- *Steam or water injection:* Steam or water can be injected to augment power (and for NO_X control).
- I*ncreasing firing temperature for peaking operation:* With shorter operating hours, it is possible to increase the firing temperature to generate more output. The penalty for this type of operation is a requirement for shorter inspection intervals. However, running a gas turbine at peak firing temperature may be a cost-effective way to obtain more power without the need for additional peripheral equipment.

Natural gas combined cycle

When a gas turbine is combined with a Rankine steam cycle, significant improvements can be realised in both efficiency and electrical output. This configuration is called a ‘combined

cycle'. In a natural gas combined cycle turbine, the hot exhaust gas from the turbine passes through an HRSG, where it exchanges heat with water, producing steam and cooling the gas to between 110°C and 135°C. Initial designs for natural gas combined cycle plants had exhaust gases entering the HRSG at less than 530°C, while more recent designs incorporate exhaust gas hotter than 595°C.

If an open cycle plant's plot plan has allowed for expansion, the steam turbine bottoming cycle may be added to the plant. This second phase of construction results in a combined cycle plant.

Figure 56 shows a natural gas combined cycle with a post-combustion capture addition (indicated by the dashed lines).

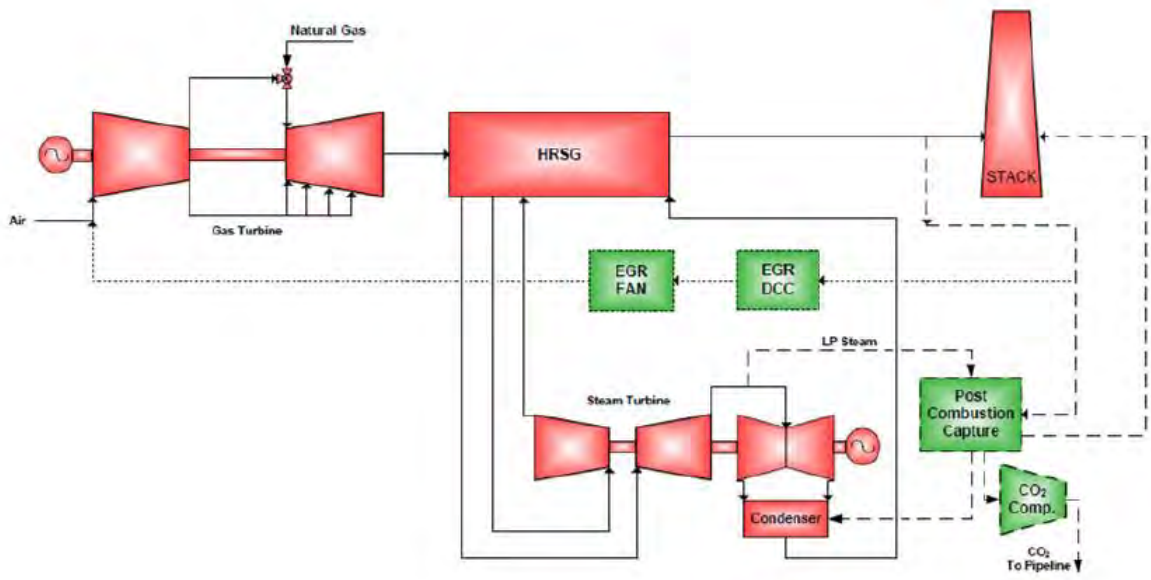


Figure 56: Schematic of combined cycle gas turbine with CCS

Depending on the gas turbine, the steam conditions from the HRSG range anywhere between 4.3 MPa and 17.2 MPa, with temperatures of 482–565°C. The steam produced in the HRSG is used to drive a steam turbine generator. Usually about two-thirds of the total power is produced from the gas turbines and one-third from the steam cycle. The steam from the steam turbine is condensed, and the condensate is returned to the HRSG by condensate pumps.

The condensate from the condenser is pumped to the low-pressure drum of the HRSG. Feedwater pumps then forward the feedwater to the steam drum/evaporator circuit through high-pressure economisers. The steam generated in the steam drum is superheated in the front section of the HRSG and routed to the inlet of the steam turbine. This basic cycle can have various additions or enhancements, depending on the gas turbine class, the size of the plant, operating flexibility requirements, emissions control requirements, and so on.

The combined cycle gas turbine can be built up from the particular sized gas turbine. The HRSG and steam turbine are scaled to the exhaust energy available from the gas turbine. There are various configurations of combined cycles with various HRSG pressure levels. The best heat rates are obtained in combined cycles in which the steam cycle requirements are matched by maximising the recoverable energy from the gas turbine exhaust. Therefore, various optimised combined cycles can be constructed from a combination of the basic components.

Combined cycle plants can be further characterised by:

- the steam cycle (reheat or non-reheat)
- HRSG pressure levels (single-pressure, two-pressure, three-pressure)
- the number of turbine generator shafts and their arrangement (such as single-shaft or multi-shaft).

Figure 57 shows arrangements of single-shaft and multi-shaft combined cycles.

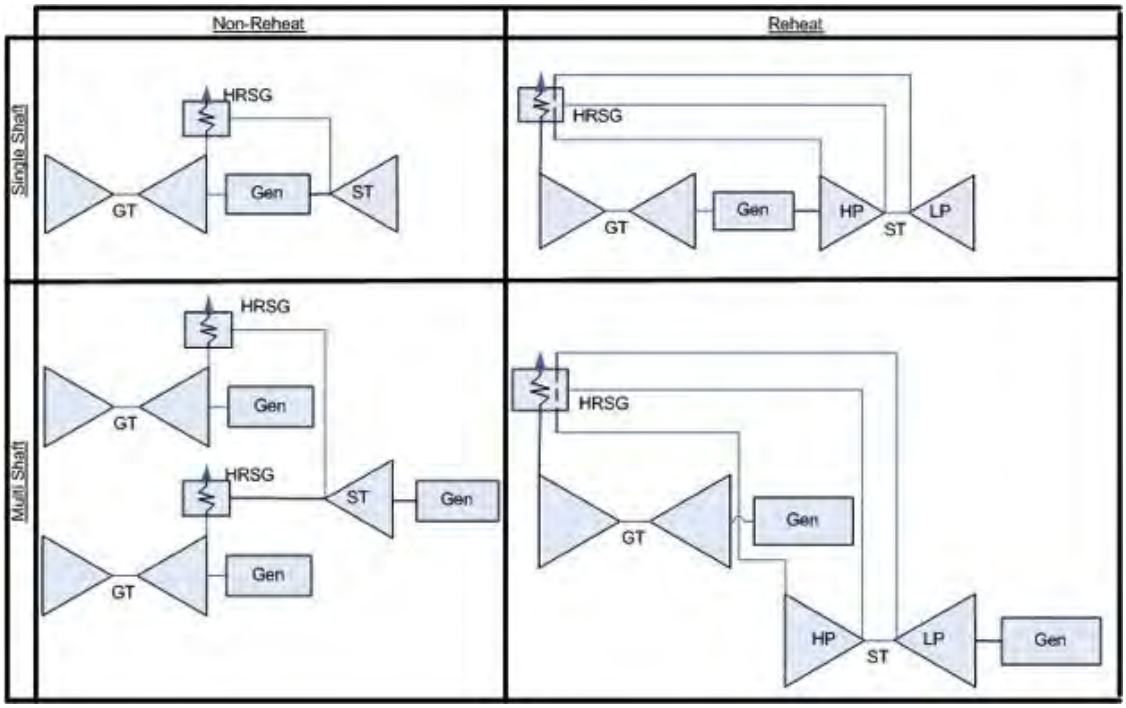


Figure 57: Schematic arrangements of single-shaft and multi-shaft combined cycles

A single-shaft design has several advantages, such as:

- one less generator, main transformer and associated auxiliaries (a simpler high-voltage system) and a smaller overall space requirement (a better fit for long, narrow sites)
- simpler steam piping (no HRSG cross-tie piping, intercept valves, superheater relief, main steam and reheat steam non-return valves)
- axial or side exhaust on the low-pressure steam turbine instead of downward exhaust (if the steam turbine is small enough)
- slightly higher efficiency at <50% load (assuming one train is completely shut down)
- the possibility of adding smaller increments of capacity with a standard design (quicker to build).

However, there are also disadvantages associated with a single-shaft design, such as:

- one additional steam turbine, condenser, circulating water system and associated auxiliaries
- lack of flexibility to operate the gas turbine without the steam turbine (unless a synchronising clutch is installed)
- slightly lower full-load efficiency (smaller, less efficient steam turbines, more lube oil and controls, partially offset if higher efficiency hydrogen-cooled generators are used instead of air-cooled generators)

- the long shaft length (if space is a constraint)
- possibly higher building costs (depending on preference for steam turbine in building vs gas turbine enclosure outdoors)
- slightly higher capital cost and maintenance cost (depends on plant specifics)
- steam turbine vendor typically must be the same as gas turbine vendor.

Additional features of a combined cycle plant can be the inclusion of supplementary firing in the HRSGs, which allows the plant to increase power output at a slight expense of cycle efficiency. Operating flexibility requirements may require a plant to include a gas turbine bypass stack (subject to regulatory approval) and a steam turbine bypass system.

Restrictions on water consumption and the discharge of cooling tower blowdown have led to the increased use of alternative designs, such as air-cooled condensers (Figure 58). For a unit with an air-cooling configuration, a large steam duct carries the steam turbine exhaust to the cooling system. The steam condenses in finned tubes that are cooled by fans. Once the steam is condensed, it drains into a condensate storage tank.

Combined cycle plants with air-cooled condensers require a steam turbine designed for high-backpressure operation. Such a design typically reduces plant output and efficiency compared to a conventional steam turbine design. An air-cooled condensing plant design can reduce plant gross output by as much as 1% compared to wet cooling.

Figure 58: Natural gas combined cycle power plant with air cooling

Open cycle gas turbine

An open cycle gas turbine is one in which the working fluid remains gaseous throughout the thermodynamic cycle (Brayton cycle). This cycle consists of adiabatic compression, isobaric heating, adiabatic expansion and isobaric cooling.

Figure 59 shows the schematic arrangement of a basic open cycle gas turbine. The gas turbine includes an air compressor, a combustor and an expansion turbine. Air is compressed and then mixed with natural gas to be burned under pressure in the combustor, producing hot

gases that pass through the expansion turbine. The shaft of the gas turbine is coupled to both the air compressor and an electric generator so that mechanical energy produced by the gas turbine drives the electric generator as well as the air compressor.

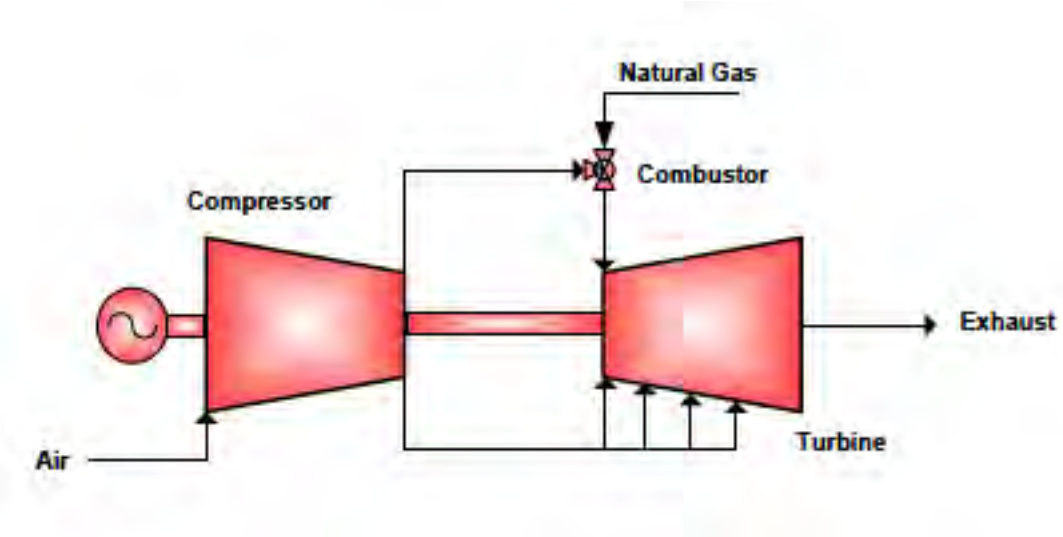


Figure 59: Schematic of an open cycle gas turbine

The major pollutant emissions from open cycle combustion turbines are nitrogen oxides (NO_X) and carbon monoxide. NO_X emissions can be controlled by injecting water or steam into the combustor. Several manufacturers offer dry low-NO_X or dry low-emissions combustors, in which low levels of NO_X are achieved without having to inject water or steam.

Fuel-efficient operation requires that part loads can be carried without significant loss in heat rate. Part-load operation may be achieved most efficiently by closing the inlet guide vanes at the compressor inlet. This method permits the maintenance of the full-load operation down to the limit of the inlet guide vanes. For most units, this will result in typically 70–80% of full load. At that point, the gas turbine heat rate climbs as shown in Figure 60.

Figure 60 shows the open cycle part-load performance curve under two conditions. In the first, the part load is achieved by reducing fuel input without closing the inlet guide vanes. In the second, the inlet guide vanes are closed and then the fuel input is reduced. Heat rate deteriorates as part-load output becomes lower.

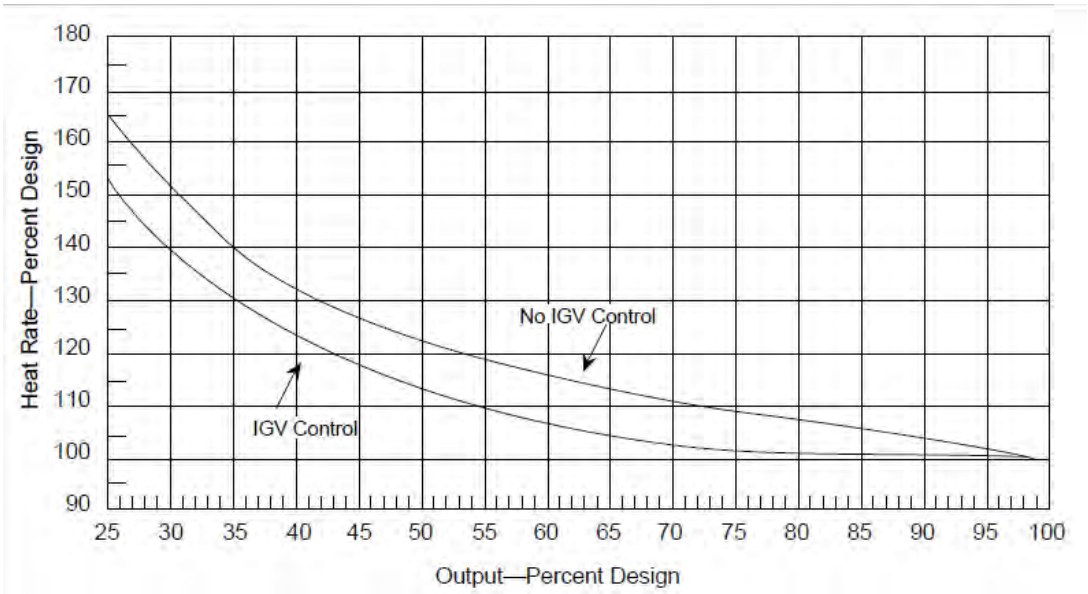


Figure 60: Open cycle part-load performance curve

IGV = inlet guide vane.

3.3.5 Fossil-fuel technology development status

The development status of technologies based on fossil fuels is shown in Figure 61.

Pulverised coal plants are typically characterised by their level of main steam temperature and pressure. Supercritical plants are mature technology, ultra-supercritical plants are now in the deployment phase, and advanced ultra-supercritical plants are still in the development phase.

IGCC plants can be characterised by the type of gas turbine used to fire the syngas. Current gas turbine-based IGCC plants are now in the deployment phase, while IGCC plants based on advanced, higher firing temperature gas turbines are still in the development phase.

Fossil power technologies with CO_2 capture include post-combustion capture for pulverised coal plants, IGCC with pre-combustion capture and oxy-combustion.

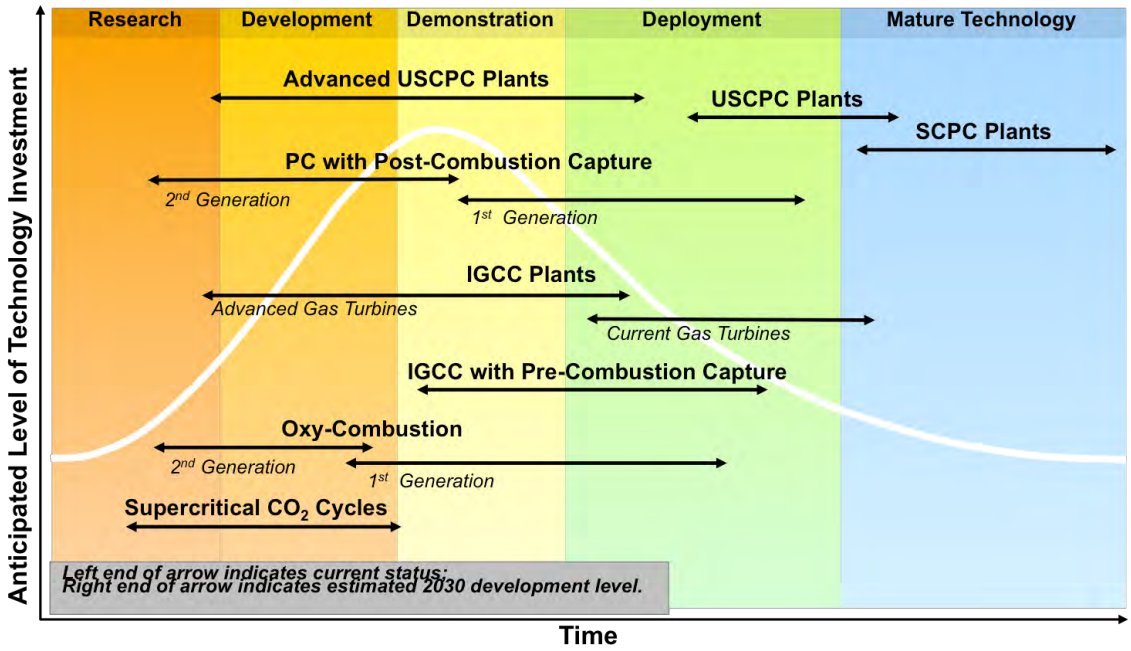


Figure 61: Technology development curve for coal-based technologies

Conventional pulverised coal plant

An advanced ultra-supercritical plant with steam pressures greater than 34.5 MPa and steam temperatures up to 760°C is expected to achieve efficiencies greater than 42% HHV, and would emit less CO_2 per MWh generated than an equivalent-sized supercritical pulverised coal unit. In the event that CO_2 capture is required, an advanced ultra-supercritical plant would have less flue gas to be treated and CO_2 to be captured per MWh than an equivalent-sized subcritical pulverised coal plant.

Major technical issues in advancing pulverised coal technology are mostly associated with new alloys, as well as operating flexibility. As the technology progresses further, new materials will be required for higher temperatures and pressures. This will necessitate the development of high-nickel alloys that can operate at temperatures above 700ºC for use in the boiler, steam piping and steam turbine.

Issues that need to be addressed to achieve improvements in performance include the following:

- *For OEM fabricators:* The process of code qualification (to meet ASME Boiler and Pressure Vessel Section I or equivalent) is rigorous and expensive.
- *For new materials:* Manufacturers need to devise the fabrication techniques and welding procedures to permit high-quality commercial fabrication.

In 2001, US Department of Energy's National Energy Technology Laboratory—in conjunction with the Ohio Coal Development Office, major boiler- and turbine-equipment manufacturers and other key groups,[32] including EPRI—launched a research program to develop and certify nickel alloys to achieve boiler and turbine steam conditions up to 760°C/35 MPa. Similar R&D programs are underway in Europe, Japan, China and India.

[32] ALSTOM Power, Babcock and Wilcox, Foster Wheeler, General Electric, Oak Ridge National Laboratory and Riley Power, Inc.

To date, significant worldwide progress has been made in identifying, evaluating and qualifying the alloys needed for the construction of the critical components of coal-fired boilers and steam turbines capable of operating at higher efficiencies than ultra-supercritical plants.

Main steam pressures greater than 34.5 MPa and steam temperatures up to 760°C in boilers and steam turbines are expected to be available in commercial-scale plants by 2030, and will increase thermal efficiency by at least 6 percentage points compared to typical supercritical plants.

Future units will most likely require a second reheat added to the steam cycle, along with sliding pressure design. Experience will need to be adopted from Japan and Europe.

The estimated performance and cost improvements are summarised in Table 11.

Table 11: Anticipated black and brown coal pulverised technology performance and cost improvements

	Current technology	2030 technology average		
		GALLM scenario		Road map
		450 ppm	550 ppm	
Capital cost (relative to current technology)	1.00	0.93	0.93	0.90
Thermal efficiency	Base			+3.5 pts

Note: Refer to Chapter 16 and Section 15.14 for details on the capital cost estimation methodology.

Oxyfuel pulverised coal plant

The oxyfuel process is applicable to virtually all fossil-fuelled boiler types and is a candidate for both retrofits and new power plants.

In 2030, pulverised coal plants using oxyfuel techniques will benefit from the same thermal efficiency gains from increasing Rankine cycle steam conditions and improving CO_2 compression systems as supercritical coal with post-combustion capture.

The production of oxygen with conventional cryogenic air separation plants adds a considerable parasitic load to the process. A potentially more efficient alternative being explored is to use innovations in ceramic membranes to separate oxygen from the air at elevated temperatures. Breakthroughs in oxygen production technology are expected by 2030, although there is currently less activity in that area than there is in post-combustion capture.

The capital cost of oxy-combustion pulverised coal plants could decrease by up to 20% due to both using less oxygen per MWh of electrical production (thanks to a higher efficiency steam cycle) and learning curve savings from novel ASU and CO_2 polishing and compression technology. The estimated performance and cost improvements are summarised in Table 12.

Table 12: Anticipated oxyfuel technology performance and cost improvements

	Current technology	2030 Technology average		
		GALLM scenario		Road map
		450 ppm	550 ppm	
Capital cost (relative to current technology)	1.00			0.80
Thermal efficiency	Base			+6 pts

Note: Refer to Chapter 16 and Section 15.14 for details on the capital cost estimation methodology.

Pulverised coal with post-combustion capture

Advances in pulverised coal efficiency do not directly affect post-combustion capture (PCC) processes, but do have an indirect beneficial impact. More efficient power plants produce less CO_2 per MWh generated, so a plant with a given MW output that has higher thermal efficiency will need smaller CO_2 capture systems. This decreases the capital cost of CO_2 capture on a $/kW basis and decreases the auxiliary power load of the capture system.

In addition to improved solvents, advances in CO_2 compression technology are also expected by 2030. They include more efficient compressors and intercooling designs that capture the heat of compression and either return it to the steam cycle or use it for solvent regeneration. Overall, the expected advances in solvents and compression systems could significantly decrease the overall loss in sent-out power production attributed to PCC.

While the nickel-based alloys that will be needed to achieve 760ºC steam conditions will increase the cost of the boiler and steam turbine equipment, higher thermal efficiency will reduce the size of the auxiliary equipment, including the PCC system. There will also be some additional capital cost savings in PCC simply from moving along the learning curve as more systems are deployed.

The cumulative impacts of the estimated performance and cost improvements are summarised in Table 13 and Table 14. The improvement in thermal efficiency is expressed in terms of a percentage points increase. In other words, an increase from 38.0% to 48.0% is an increase of 10 percentage points.

Table 13: Anticipated brown pulverised coal with PCC performance and cost improvements

	Current technology	2030 technology average		
		GALLM scenario		Road map
		450 ppm	550 ppm	
Capital cost (relative to current technology)	1.00	0.83	0.77	0.83
Thermal efficiency	Base			+11.5 pts

Note: Refer to Chapter 16 and Section 15.14 for details on the capital cost estimation methodology.

Table 14: Anticipated black pulverised coal with PCC performance and cost improvements

	Current technology	2030 technology average		
		GALLM scenario		Road map
		450 ppm	550 ppm	
Capital cost (relative to current technology)	1.00	0.81	0.71	0.81
Thermal efficiency	Base			+9.5 pts

Note: Refer to Chapter 16 and Section 15.14 for details on the capital cost estimation methodology.

Integrated gasification combined cycle

Although experience with gasification in coal-fired power plants is limited, it is supplemented by experience with over 2,500 MW of integrated gasification combined cycle (IGCC) plant used to gasify liquid petroleum residues in refineries and with multiple coal-based gasification units at chemical plants around the world. Those facilities have many years of experience in operating gasification and related gas clean-up processes. The most advanced of these chemical units are similar to the front end of a modern IGCC facility. Similarly, several decades of experience firing natural gas and petroleum distillate have made the basic combined cycle a mature generating technology.

A number of lessons have been learned from past research, development and demonstration of coal IGCC plant operations.

- Future advances in gas turbine technologies have the potential to improve efficiency and lower costs.
- Areas for improvement are carbon conversion, longer refractory life (although this is not an issue for membrane wall gasifiers), longer fuel injector tip life, and reduced syngas cooler fouling.
- The production of oxygen with cryogenic air separation plants adds a considerable parasitic load to the process. A potentially more efficient alternative being explored is to use innovations in ceramic membranes to separate oxygen from the air at higher temperatures.
- A high-temperature acid gas removal process will need to be developed.

In the near term, the major trends will be the development of standardised designs to reduce cost and construction time and improve reliability, and the development of designs for fuel flexibility.

In addition to ‘learning curve’ savings, there are also a number of potential technical improvements in IGCCs that could improve efficiency and reduce cost. One is using higher firing temperature gas turbines. The current IGCC plants are based on F class gas turbines, which have a firing temperature on syngas of around 1,300ºC. Natural gas fired gas turbines are now available in the G and H firing classes, and MHI is now offering its J class turbine. The H class turbines have a firing temperature around 120ºC hotter than F class machines. The higher firing temperature provides higher thermal efficiency, which means a smaller gasification system is needed to provide a given amount of power production. It is expected that H class or hotter firing temperatures will be available for IGCC plants in 2030, increasing thermal efficiency by 2.5–3.0 percentage points.

Advances in oxygen production will benefit IGCC plants just as they will oxy-combustion plants, although the impact will be smaller in IGCC plants because they use less oxygen per MWh than is used in oxy-combustion. Air Products and Chemicals, Inc. is nearing completion of an 11-year R&D program with the goal of reducing the cost of oxygen by one-third. It has compared its ion transport membrane against a state-of-the-art cryogenic ASU and predicts that the membrane would reduce the installed capital cost of air separation equipment by 35%. This translates to a 7% decrease in the installed capital cost of an IGCC plant and a 1% increase in efficiency.

A large potential advancement in IGCC technology that should be ready for commercial deployment in 2030 is so-called warm gas clean-up, which will allow the removal of sulphur compounds and CO_2 at temperatures well above ambient conditions. This will reduce the amount of heat exchange equipment needed in an IGCC plant and will also improve its thermodynamic efficiency. CO_2 separation via membranes will allow CO_2 to be produced at higher pressure, which will reduce the auxiliary power load of the CO_2 compression system, and the use of more efficient compressors will benefit IGCC plants in the same way that they will improve post-combustion and oxy-combustion capture economics. Taken together, these improvements in CO_2 capture and compression could increase IGCC plants' thermal efficiency by more than 3 percentage points while also reducing capital costs.

A final expected improvement is the use of liquid CO_2–coal slurry to feed an entrained flow gasifier rather than using a more expensive dry feed system. Liquid CO_2 has a much smaller heat of vaporisation than water, and it also has a lower viscosity. This means that more coal can be carried in the slurry and less oxygen is needed in the gasifier. If such a design were incorporated into a gasifier with a syngas water quench design, as opposed to the designs with syngas coolers assumed for the current technology cases, EPRI believes significant capital cost savings (around 10–12%) could be obtained without sacrificing thermal efficiency. Similar gains may come from dry solids pumping to remove the complexity of lock hoppers.

For brown coal applications, EPRI believes that advanced coal drying technologies will soon enable the use of low-level heat, such as that from the CO_2 compressor intercoolers, to dry coal, rather than burning syngas or hydrogen derived from the gasification system. This could significantly reduce the capital cost and improve the thermal efficiency of the process. An additional benefit of these drying processes is that they may facilitate the capture of the water driven off the coal so that it can be reused in the gasification process, for example as the raw water supply for the demineralised water production system.

The expected overall improvements in IGCC technology by 2030 are summarised in Tables 15–18.

Refer to Chapter 16 and Section 15.14 for details on capital cost estimation methodology.

Table: 15 Anticipated brown coal IGCC technology performance and cost improvements

	Current technology	2030 technology average		
		GALLM scenario		Road map
		450 ppm	550 ppm	
Capital cost (relative to current technology)	1.00			0.80
Thermal efficiency	Base			+5 pts

Table 16: Anticipated black coal IGCC technology performance and cost improvements

	Current technology	2030 technology average		
		GALLM scenario		Road map
		450 ppm	550 ppm	
Capital cost (relative to current technology)	1.00			0.80
Thermal efficiency	Base			+3.5 pts

Table 17: Anticipated brown coal IGCC+CCS technology performance and cost improvements

	Current technology	2030 technology average		
		GALLM scenario		Road map
		450 ppm	550 ppm	
Capital cost (relative to current technology)	1.00	0.83	0.77	0.61
Thermal efficiency	Base			+8 pts

Table 18: Anticipated black coal IGCC+CCS technology performance and cost improvements

	Current technology	2030 technology average		
		GALLM scenario		Road map
		450 ppm	550 ppm	
Capital cost (relative to current technology)	1.00	0.83	0.77	0.61
Thermal efficiency	Base			+6.5 pts

Direct injection carbon engines

The reciprocating internal combustion engine is a fully mature technology that continues to be improved in relatively small increments. Significant advances in the technology are not likely to come from engine development, but from alternative fuel sources.

The direct-injection carbon engine is a specially modified diesel engine that uses a micronised coal–water slurry as the fuel. The coal slurry combusts in a similar manner to heavy diesel fuel to produce intense temperature and pressure in the engine, which provides power to turn electrical generators. Both brown and black coals are likely to be suitable fuels.

The idea of using direct-injection carbon engines to generate power is not new and was successfully investigated in the United States in the 1980s and 1990s. Current investigations using modern micronising and mineral matter separation techniques combined with advances in injector and engine design are in the R&D phase.

Typical micronised coal slurry properties are as follows:

- 0.5–0.8% ash (wet)
- 55% coal by weight in the slurry
- 21 MJ/L (HHV)
- 15 mPa.s @ 90ºC
- stabiliser (trace additives).

Natural gas combined cycle

Combined cycle technology is a mature technology for power plants. Continuing manufacturer research and operator experience have resulted in reliable, highly efficient combined cycle plants that are, in many cases, the type of plant chosen to meet new intermediate or baseload needs.

Developments and enhancements to existing combined cycle gas turbines are ongoing processes. In today's market, the two main areas of interest to plant operators are achieving minimum load while meeting emissions limits and realising maximum output with minimum start-up time. Gas turbine manufacturers are currently adapting their combined cycle technologies to improve the cycling capability of the entire plant, not only individual components. This requires the optimisation of interactions between the main components (gas turbine, steam turbine, generator), most other plant equipment (such as HRSG, water and steam systems, and so on) and the control system. For example, Siemens has designed a new type of once-through HRSG that enables a higher number of fast starts. These efforts are in response to the growth in peaking and cycling power generation in recent years, which will continue through 2015 and beyond.

Operators of state-of-the-art heavy-duty gas turbines operating in combined cycles have accumulated significant experience. The F class machines are operating on natural gas at firing temperatures of 1,260°C and higher. They incorporate improved bucket cooling technologies and advanced coatings. This technology continues to improve and is expected to achieve greater than 1,315°C firing temperatures. It includes features developed from aeroderivative gas turbines. They will offer dry low-NO_X combustors and will have better cooling, improved bucket quality and durability.

Combined cycles in the future will be based on advanced heavy-duty gas turbines that will operate at even higher firing temperatures and high pressure ratios, and will include more aerodynamic features. New machines being offered by Siemens & MHI (H and J class technologies) are incorporating advanced air cooling and steam cooling technologies to allow turbine inlet temperatures well above 1,426°C (MHI claims that its J class technology operates at over 1,650°C turbine inlet temperature), which further increases efficiency. With these advanced gas turbines, a more efficient reheat steam turbine cycle can also be selected for higher efficiency for the bottoming cycle. With these newer machines and upgraded materials (new alloys for pressure parts in HRSGs), combined cycle efficiencies can approach about 60% HHV.

The potential impacts of including CO_2 capture in CCGTs must be considered, as this will significantly affect plant performance and total project cost. In addition, CO_2 from the natural gas-fired combined cycle flue gas poses another problem. The CO_2 concentration in a combined cycle plant's flue gas is only 4%, compared to 12–15% for a coal-fired plant. Furthermore, the flue gas flow in a natural gas fired plant is about 50% greater than in a coal-fired plant per MW of capacity because ambient air is used as the compressible medium by the gas turbine. Thus, the lower CO_2 concentration in exhaust gas combined with the higher flue gas flow rate could potentially double the cost per tonne of capturing carbon.

Natural gas fired combined cycles will benefit from many of the same technology advances that will improve coal-based power generation technology by 2030. The higher firing temperature gas turbines that improve IGCC thermal efficiency will also improve CCGT efficiency, and the more efficient post-combustion capture and CO_2 compression technologies expected for supercritical coal can also be used in CCGTs.

Combined cycles based on these advanced machines are making it possible to break the 60% combined cycle lower heating value efficiency barrier, and it is expected that by 2020–2030 all these technologies will be mature. The estimated performance and cost improvements are summarised in Table 20.

In comparison with today's technology, the thermal efficiency of a CCGT with post-combustion capture of CO_2 is expected to increase by at least 8 percentage points by 2030. The estimated performance and cost improvements are summarised in Table 20.

Refer to Chapter 16 and Section 15.14 for details on the capital cost estimation methodology.

Table 19: Anticipated CCGT technology performance and cost improvements

	Current technology	2030 technology average		
		GALLM scenario		Road map
		450 ppm	550 ppm	
Capital cost (relative to current technology)	1.00	0.97	0.97	0.90
Thermal efficiency	Base			+10 pts

Table 20: Anticipated CCGT+CCS technology performance and cost improvements

	Current technology	2030 technology average		
		GALLM scenario		Road map
		450 ppm	550 ppm	
Capital cost (relative to current technology)	1.00	0.65	0.49	0.82
Thermal efficiency	Base			+8 pts

Natural gas open cycle

Open cycle gas turbine plants are a mature generation technology. There are various types and categories of gas turbines available in the market today, including the state-of-the-art heavy-duty F, G, and H class turbine models and aeroderivative gas turbines.

Open cycle gas turbine efficiencies are strongly influenced by several factors, such as inlet mass flow, compression ratio and expansion turbine inlet temperature. The early heavy-duty gas turbines had maximum turbine inlet temperatures in the 800–1,100ºC range. More recent state-of-the-art models have turbine inlet temperatures as high as 1,300–1,375ºC. These turbines are designed with innovative hot gas path materials and coatings, advanced secondary air cooling systems and enhanced sealing techniques that enable higher compression ratios and turbine inlet temperatures. The advances made in the newer gas turbines by the manufacturers are generally down-flowed into earlier models for efficiency and power output improvements.

Aeroderivative gas turbines will have higher firing temperatures, with higher efficiencies and faster start times, compared to heavy frame gas turbines, and will be available with dry low-NO_X combustors. Some will be offered as quick-delivery pre-packaged units.

In comparison with today's technology, the thermal efficiency of an open cycle gas turbine is expected to increase by more than 6 percentage points by 2030. However, it is expected that a price premium will be associated with that level of performance, and the capital cost could increase by up to 10%. The estimated performance and cost changes are summarised in Table 21.

Table 21: Anticipated open cycle gas turbine technology performance and cost

improvements

	Current technology	2030 technology average		
		GALLM scenario		Road map
		450 ppm	550 ppm	
Capital cost (relative to current technology)	1.00			1.10
Thermal efficiency	Base			+7 pts

Note: Refer to Chapter 16 and Section 15.14 for details on the capital cost estimation methodology.

Coal drying

For brown coal power applications, it is expected that new coal drying technologies that use low-level heat from either low-pressure steam or the CO_2 compressor intercoolers will significantly improve performance and efficiency.

The brown coal based Coldry[33] process uses shearing and attrition as a means of reducing the coal's particle size and releasing water naturally held in the porous coal microstructure, forming a plastic mass. The plastic mass is then pelletised and dried. As the pellets shrink, the microstructure compacts significantly. This new structure reduces the coal's propensity to self-heat to that of a typical bituminous coal. The Coldry processing plant is shown in Figure 62, and the various process steps in Figure 63.

A key feature of the technology is its use of low-grade 'waste' heat from a co-located power station to provide the evaporative drying energy. The temperature range for the pellet drying is between 35°C and 45°C.

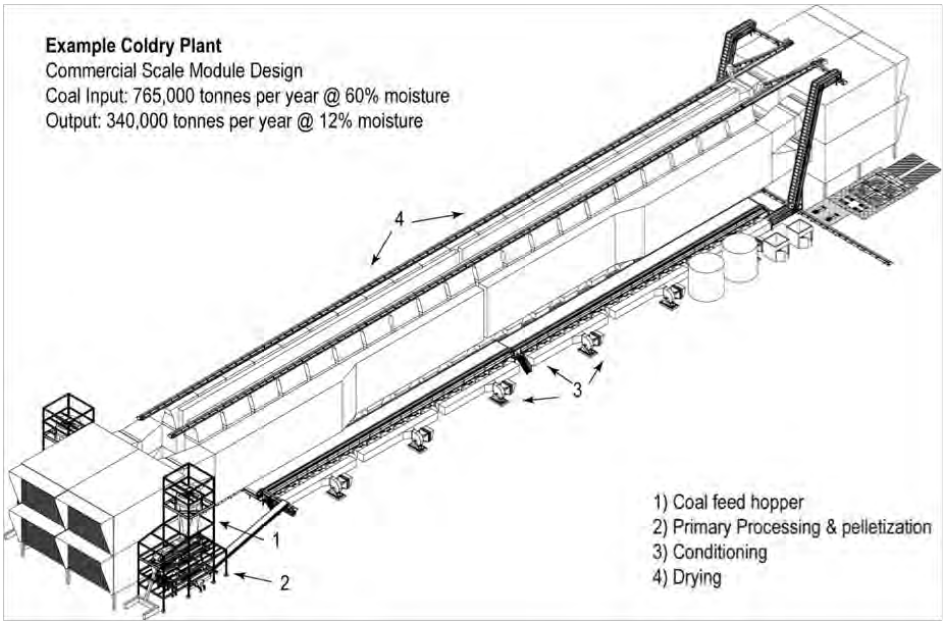


Figure 62: Coldry plant concept

[33] www.ectltd.com.au/coldry/coldry-overview/ (accessed November 2015).

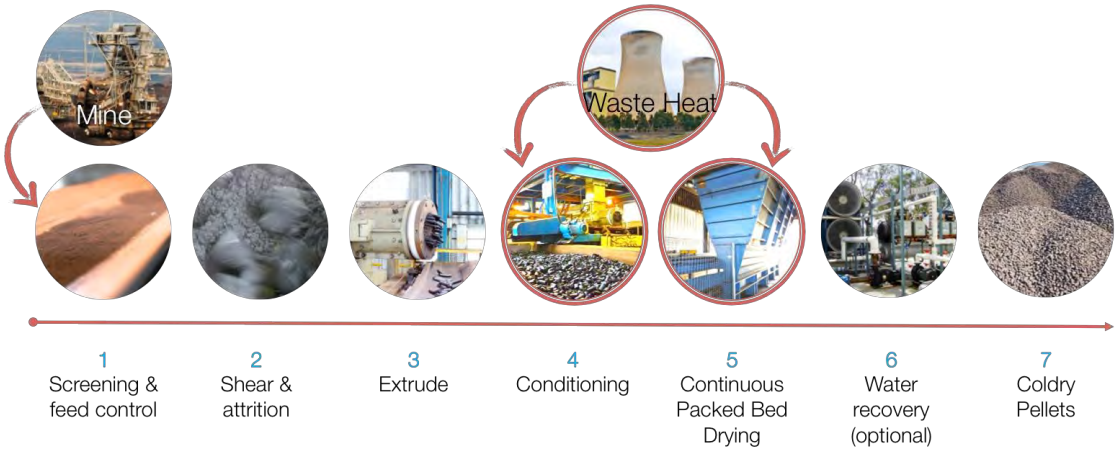


Figure 63: Coldry processing steps

RWE Rheinbraun has developed a pre-drying process, known as WTA.[34] As shown in Figure 64, brown coal (or lignite) is dried in a fluidised bed. The heat for drying is provided almost exclusively by the tubular heat exchanger immersed in the fluidised bed and only to a small extent by the fluidising media (coal moisture vapour). The heating steam in the heat exchanger can come either from an external source (open cycle), such as the bleed steam from the low-pressure steam turbine of the associated lignite unit, or from the recompressed vapour evaporated from the raw lignite (closed cycle). In the open cycle, the vapour coming out of the dryer may be condensed to preheat boiler feedwater or vented to the atmosphere as a low-cost option.[35]

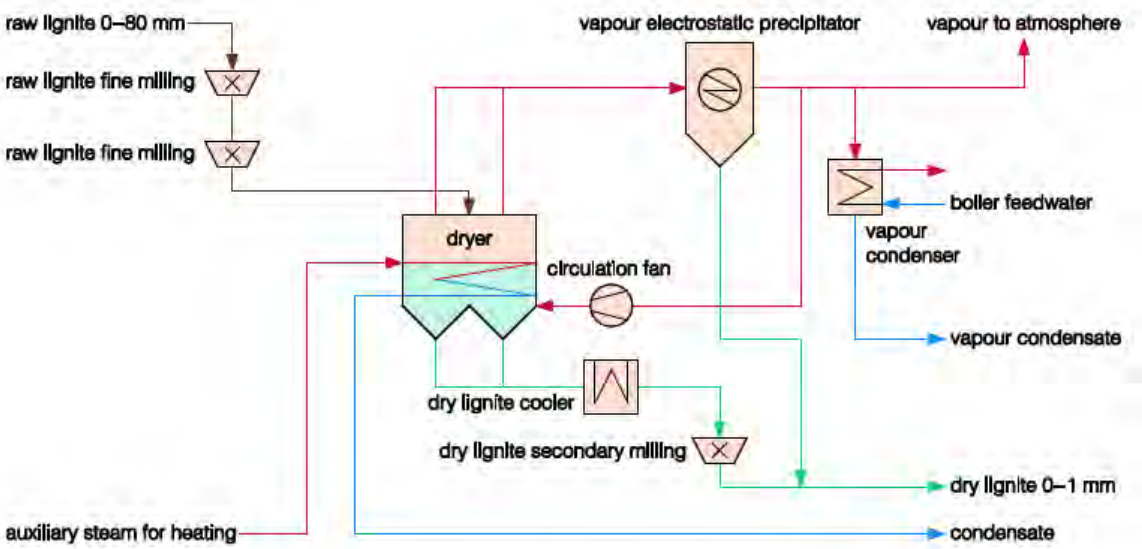


Figure 64: WTA process flow ('open cycle' with vapour recompression)

Source: N Dong (2014), *Techno-economics of modern pre-drying technologies for lignite-fired power plants*, IEA CCC/241' August.

[34] WTA stands for the German term Wirbelschicht-Trocknung mit interner Abwärmenutzung.
[35] N Dong (2014), *Techno-economics of modern pre-drying technologies for lignite-fired power plants*, IEA CCC/241.

Great River Energy has developed the DryFining coal treatment/drying process. Figure 65 shows a simplified schematic of the system currently operating at Coal Creek.[36] Wet coal transferred from the coal storage pile is crushed in the plant's coal crushers to the optimal size required by the fluidised bed dryer (typically <6 mm). The crushed coal travels through the fluidised bed dryers, where the moisture is evaporated by the hot fluidising air and heat exchangers embedded in the dryer. The dried coal is dropped onto conveyors that transfer it to a storage silo, where it is metered into a pulveriser by a coal feeder. The hot moist air leaving each dryer passes through a bag-house to remove any particulate matter from the dryer exhaust before venting to the atmosphere. Dry air is blended with wet air entering the bag-house to prevent bag-house caking and fouling.[37]

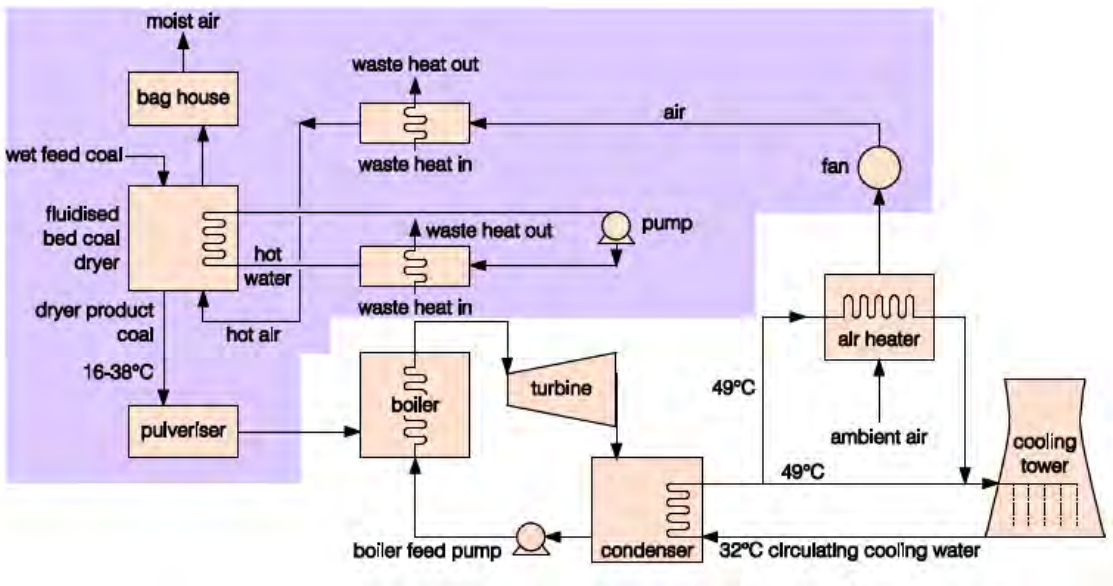


Figure 65: Schematic of integrated DryFining

Source: N Dong (2014), Techno-economics of modern pre-drying technologies for lignite-fired power plants, IEA CCC/241' August.

While it is estimated that such a system will add incremental cost, having drier coal will significantly reduce the amount of coal needed to produce a given amount of power, which should yield savings in the $/kW cost of the boiler and CO_2 capture systems, as well as providing a significant thermal efficiency boost (at least 3 percentage points).

[36] http://www.greatriverenergy.com/makingelectricity/coal/coalcreekstation.html (accessed October 2015).
[37] The DryFining™ process is commercially available, but has not been applied in Australia to higher moisture coals. It may be a retrofitting option or incorporated into a new power plant.

3.4 Nuclear technologies

3.4.1 Brief description of the technology

In a nuclear fission reaction, atomic mass is converted to energy. In a nuclear power reactor, the heat produced from controlled fission reactions in radioactive fuel is transferred via gas or liquid to produce steam, which is then converted to electricity via a steam turbine in a steam cycle similar to those used in conventional pulverised coal power plants.

The power output of a nuclear reactor is determined by the number of neutrons able to start more fission reactions. This is controlled by the use of moderators and control rods. A moderator is a material that slows down the neutrons produced in fission so that they can maintain a nuclear chain reaction. More neutron moderation means more power output from the reactors (although fast neutron reactors do not need moderators—see below). Control rods are used to reduce the number of neutrons available for fission and are made of material with high neutron absorption. Pushing control rods deeper into the reactor core reduces the reactor's power output; extracting them increases it.

Large-scale nuclear power plant technologies have continued to evolve since they were first used in commercial plants (Figure 66).

Nuclear power plants generate both high- and low-level nuclear waste. The wastes require safe storage and disposal, which may be accomplished through various means, including interim on-site and off-site storage and permanent geological disposal.

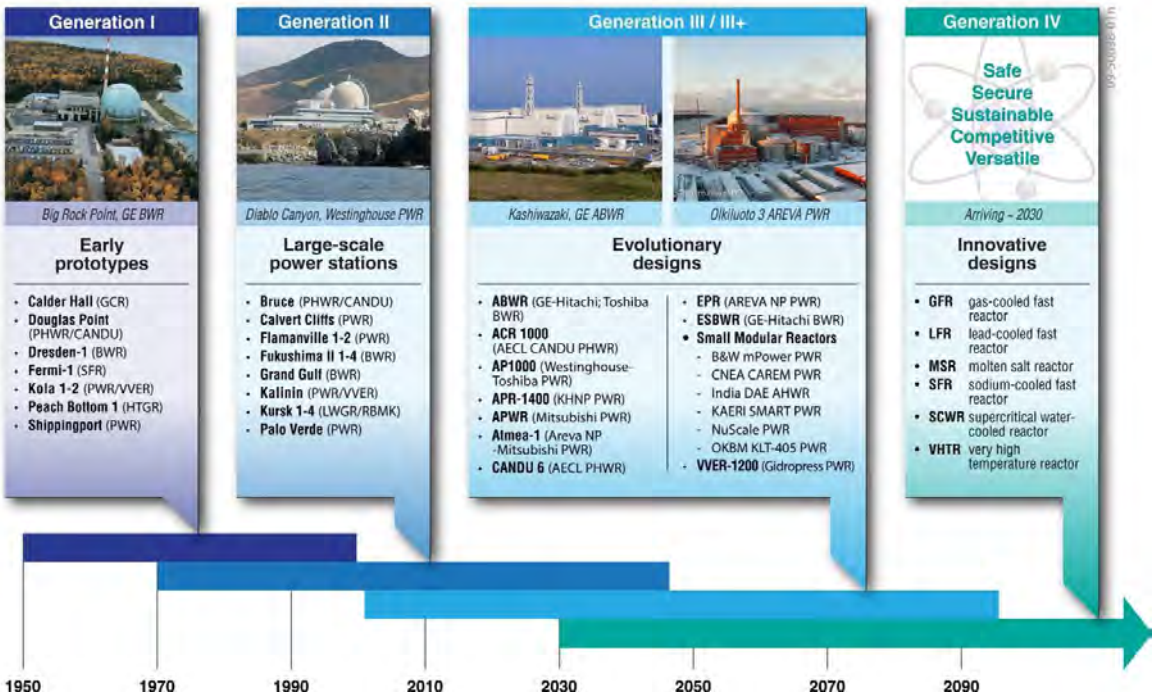


Figure 66: The evolution of large-scale nuclear reactors

Source: https://www.gen-4.org (accessed October 2015.

Large-scale nuclear power generation

Pressurised water reactors

Pressurised water reactors are the most common type of power reactor (more than 230 are in use). They originated as submarine power plants, and use ordinary water as both coolant and moderator. The design is distinguished by having a primary cooling circuit that flows through the core of the reactor under very high pressure and a secondary circuit in which steam is generated to drive the turbine (Figure 67).

Water in the reactor core reaches about 325°C, so it must be kept under about 150 times atmospheric pressure to prevent it boiling. Pressure is maintained by steam in a pressuriser. In the primary cooling circuit, the water is also the moderator, and if any of it turns to steam the fission reaction will slow down. This negative feedback effect is one of the safety features of the type. The secondary shutdown system involves adding boron to the primary circuit.

The secondary circuit is under less pressure. The water in the circuit boils in the heat exchangers, which are thus steam generators. The steam drives the turbine to produce electricity, and is then condensed and returned to the heat exchangers in contact with the primary circuit.

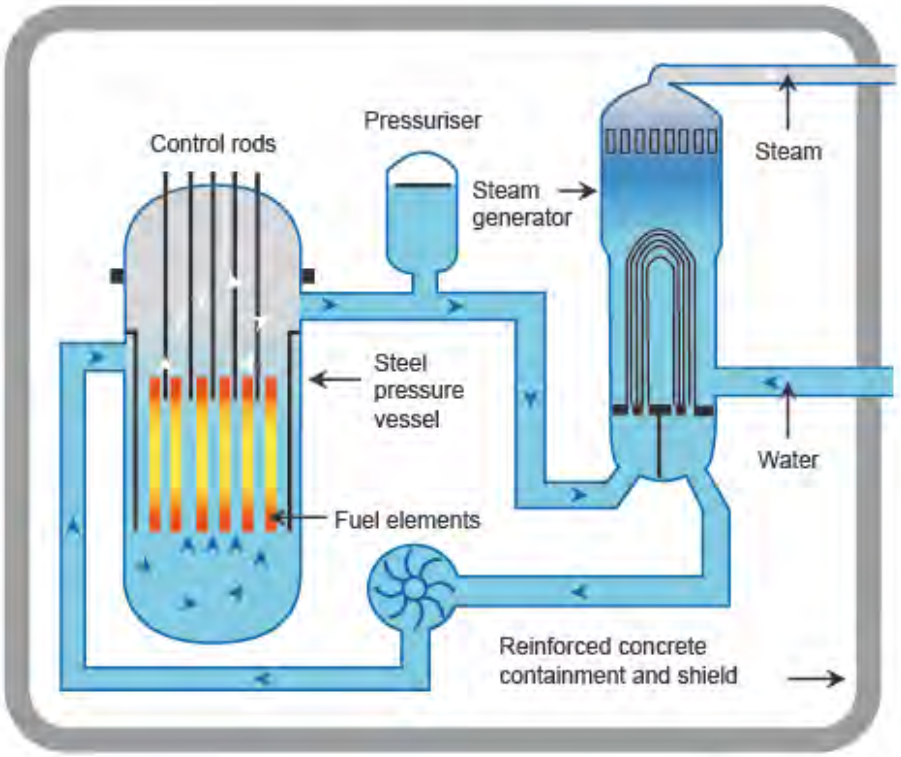


Figure 67: Schematic of a typical pressurised water nuclear reactor

Source: http://www.world-nuclear.org/info/Nuclear-Fuel-Cycle/Power-Reactors/Nuclear-Power-Reactors (accessed October 2015).

Boiling water reactors

A boiling water reactor has many similarities to a pressurised water reactor, except that there is only a single circuit in which the water is at lower pressure (about 75 times atmospheric pressure) so that it boils in the core at about 285°C (Figure 68). The reactor is designed to operate with 12–15% of the water in the top part of the core as steam, and hence with less moderating effect and thus efficiency.

The steam passes through dryer plates (steam separators) above the core and then directly to the turbines, which are thus part of the reactor circuit. Since the water around the core of the reactor is always contaminated with traces of radionuclides, the turbine must be shielded and radiological protection must be provided during maintenance. The cost of this tends to balance the savings due to the simpler design. Most of the radioactivity in the water is very short-lived, so the turbine hall can be entered soon after the reactor is shut down.

The secondary control system involves restricting water flow through the core so that more steam in the top part reduces moderation.

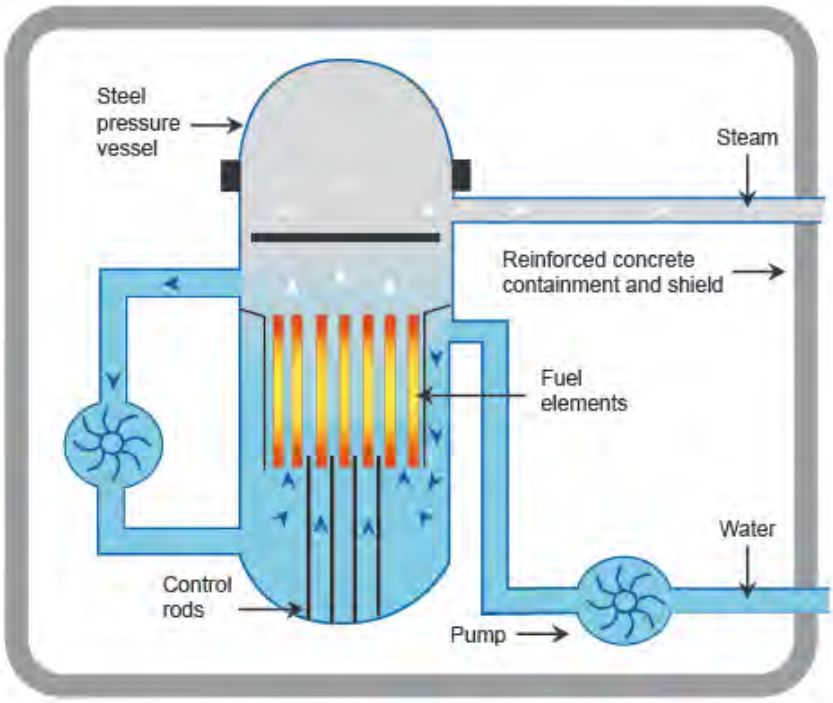


Figure 68: Schematic of a typical boiling water nuclear reactor

Source: http://www.world-nuclear.org/info/Nuclear-Fuel-Cycle/Power-Reactors/Nuclear-Power-Reactors (accessed October 2015)

Pressurised heavy water reactors

The pressurised heavy water reactor (PHWR) design (Figure 69) has been developed since the 1950s in Canada as the CANDU,[38] and more recently also in India. PHWRs generally use natural uranium oxide as fuel and so need a more efficient moderator, in this case heavy water (D_2O).[39] The PHWR produces more energy per kilogram of mined uranium than other designs, but also produces a much larger amount of used fuel per unit output.

The moderator is in a large tank, penetrated by several hundred horizontal pressure tubes that form channels for the fuel. The system is cooled by a flow of heavy water under high pressure in the primary cooling circuit, reaching 290°C. As in the pressurised water reactor, the primary coolant generates steam in a secondary circuit to drive the turbines. The pressure tube design means that the reactor can be refuelled progressively without shutting it down by isolating individual pressure tubes from the cooling circuit.

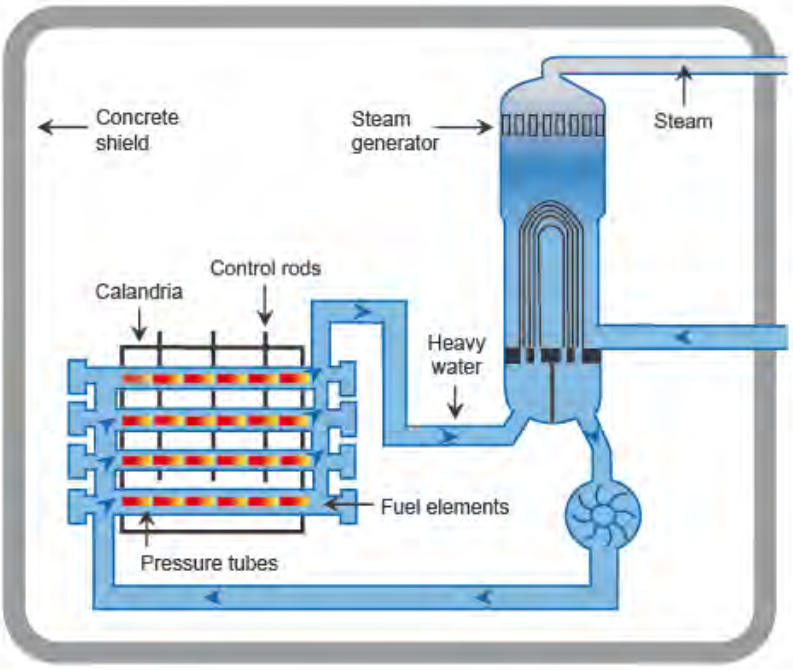


Figure 69: Schematic of a typical pressurised heavy water nuclear reactor

Source: http://www.world-nuclear.org/info/Nuclear-Fuel-Cycle/Power-Reactors/Nuclear-Power-Reactors (accessed October 2015)

Fast neutron reactors

Fast neutron reactors are a technological step beyond conventional power reactors, but are poised to become mainstream. Generation IV reactor designs are largely fast neutron reactors, and international collaboration on designs is proceeding with high priority.

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[38] A CANDU fuel assembly consists of a bundle of 37 half-metre long fuel rods plus a support structure, with 12 bundles lying end to end in a fuel channel. Control rods penetrate the calandria vertically, and a secondary shutdown system involves adding gadolinium to the moderator. The heavy water moderator circulating through the body of the calandria vessel also yields some heat (although this circuit is not shown in Figure 69).

[39] In the CANDU system, the moderator (water) rather than the fuel is enriched as a cost trade-off.

Several key features of fast neutron reactors make them particularly important for nuclear power generation. First, they offer the prospect of vastly more efficient use of uranium resources because they are able to use the abundant U-238 isotope (more than 99% of natural uranium consists of this isotope). The deployment of fast neutron reactors will therefore increase the available useful uranium resource by almost two orders of magnitude. Second, fast neutron reactors have the ability to burn actinides that are otherwise the long-lived component of high-level nuclear waste.

Currently, one commercial-scale fast neutron reactor is operating (an 800 MW BN-800 in the Russian Federation), and the construction of another is almost complete (a 500 MW prototype fast breeder reactor in India). Several other designs (mostly small-scale) are under development and considered to be deployable during the 2020s.

Small-scale nuclear power generation

Small modular reactors are defined as nuclear reactors with 300 MW_e equivalent output or less and designed with modular technology using factory fabrication in pursuit of economies of series production and short construction times.[40]

Fundamentally, small modular nuclear plants are not very different from large-scale reactors. As with larger reactors, a nuclear reaction takes place within the reactor and heat is transferred from the reaction to generate steam, which expands through a turbine and generates electricity.

Eight proven small modular designs are currently available for commercial deployment. They fall into the following technology categories:

- pressurised water reactor
- sodium-cooled faster reactor
- lead-bismuth-cooled fast reactor.

Light water reactors

Light water reactors are moderated and cooled by ordinary water and have the lowest technological risk, as they similar to most operating large-scale power plants and naval reactors. They mostly use fuel enriched to less than 5% U-235, have no more than a 6-year refuelling interval, and face fewer regulatory hurdles than other small reactors.[41]

New concepts are developing as alternatives to conventional land-based nuclear power plants:

- *Floating nuclear power plants:* Current work is focused on using a pair of pressurised water reactors derived from icebreakers.
- *Submerged Flexblue power plant:* Current work is focused on using a 50–250 MW_e reactor.

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[40] The World Nuclear Association, International Atomic Energy Agency and the US Nuclear Energy Institute all use a similar definition.

[41] www.world-nuclear.org/info/Nuclear-Fuel-Cycle/Power-Reactors/Small-Nuclear-Power-Reactors (accessed October 2015).

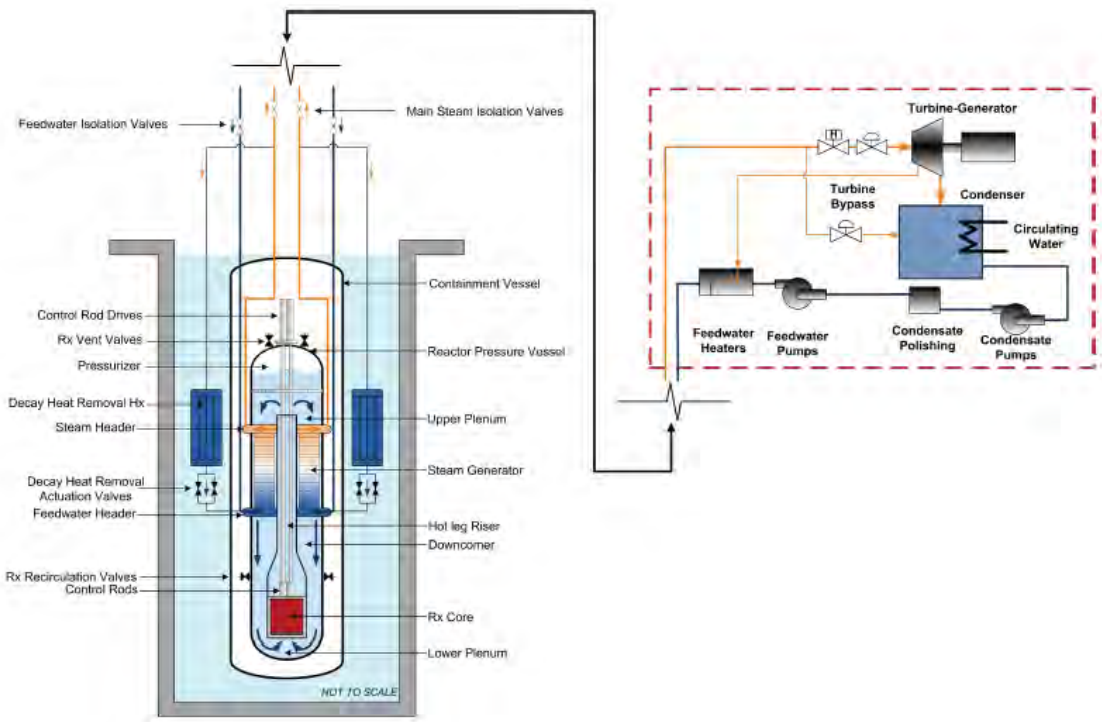


Figure 70: Schematic of a single NuScale unit

High-temperature gas-cooled reactors

High-temperature gas-cooled reactors (HTRs) use graphite as the moderator (unless they are of the fast neutron type) and helium, CO_2 or nitrogen as the primary coolant.

New HTR reactors are being developed that will be capable of delivering high-temperature helium (at 700–950ºC and eventually up to about 1,000°C), either for industrial application via a heat exchanger or to make steam to produce electricity. The steam is used conventionally in a secondary circuit via a steam generator, or directly to drive a Brayton cycle gas turbine, with almost 50% thermal efficiency (efficiency increases around 1.5% with each 50°C increment). Improved metallurgy and technology developed in the past decade make HTRs more practical than in the past, although the direct cycle means that there must be high integrity of fuel and reactor components. HTRs can potentially use thorium-based fuels, such as highly enriched or low-enriched uranium with thorium, uranium-233 with thorium, and plutonium with thorium.

HTRs have a negative temperature coefficient of reactivity (the fission reaction slows as temperature increases) and passive decay heat removal, so they are inherently safe and do not need a containment building. They are also small enough to allow factory fabrication, and will usually be installed below ground level.

The only HTR project currently proceeding is the Chinese HTR-PM (pebble-bed modular reactor) design (Figure 71).

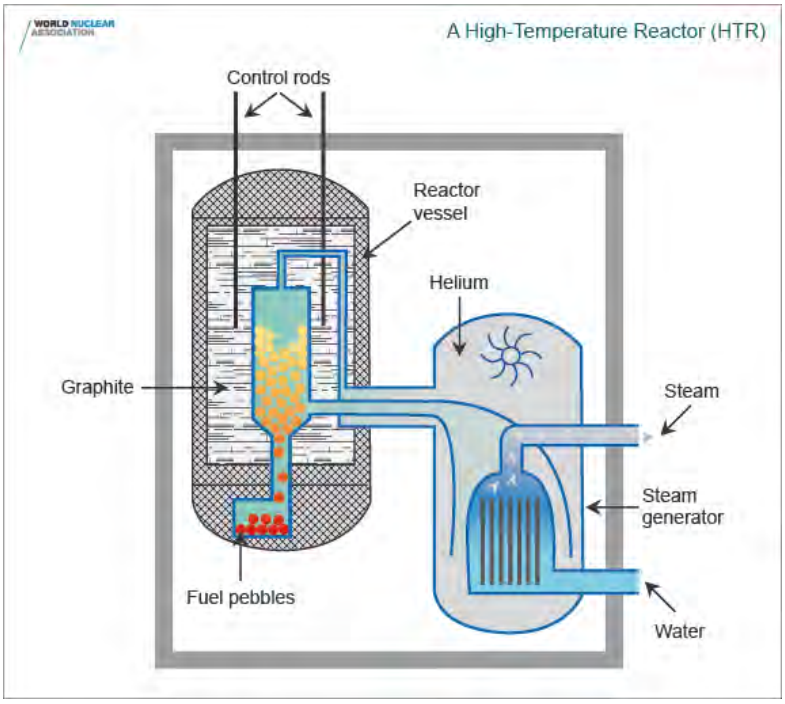


Figure 71: Chinese HTR-PM (pebble-bed modular reactor) design

3.4.2 Technology development status

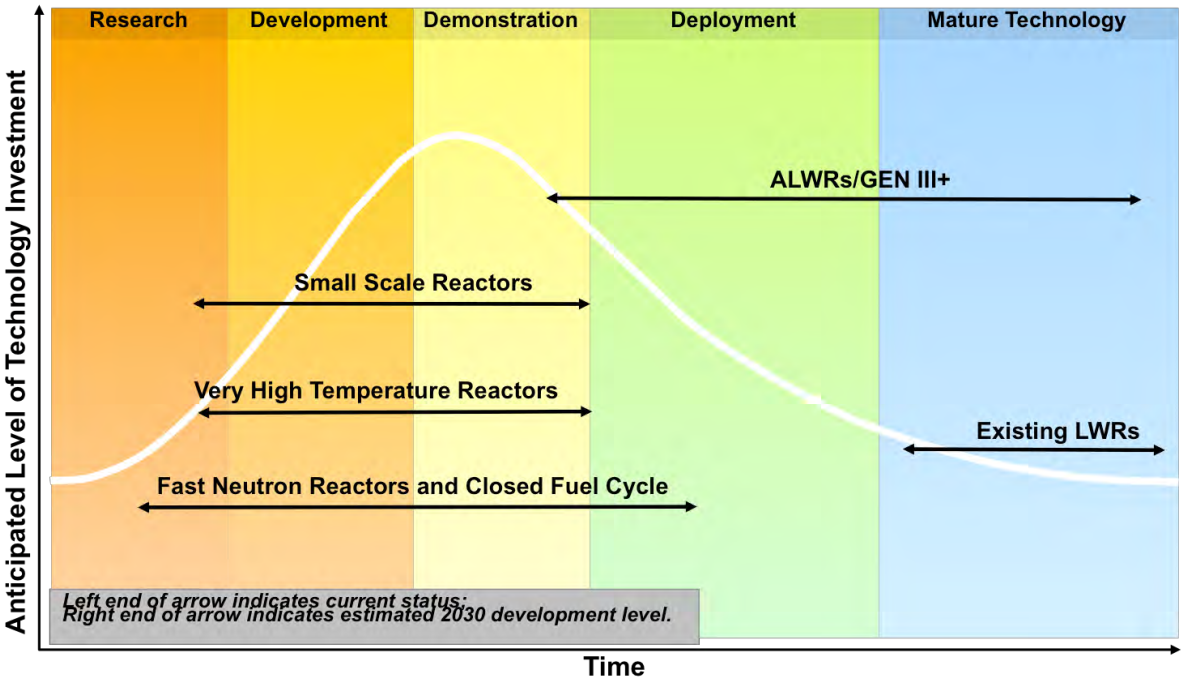


Figure 72: Nuclear technology development curve

Generation III and III+ reactors are being constructed and continue to undergo development. As reactor designs become more standardised, the hope is that the permitting and licensing period before construction can be reduced to help control capital costs. Research is underway for Generation IV reactors. This generation of reactor is expected to have increased burn-up rates to reduce nuclear waste and increase plant efficiency. Table 22 summarises the current development status of nuclear technologies and expected developments in the future.

Table 22: Nuclear technology development status

	Commercial power reactors (LWR/CANDU/AGR)	Gen. III/III+ advanced reactors (ABWR/EPR/ESBWR/ AP1000/VVER 1200 etc.)	Gen. IV fast and/or thermal reactors (GFR, LFR, MSR, SFR, SCWR, HTR, VHTR)
Major trends	Uprating of existing plants, increases in capacity factors by reducing the length of refuelling outages, extension and renewal of operating licences.	Move to Generation III/III+ designs with passive safety features, standardisation of designs.	Collaboration between and within industry and governments, standardisation of designs.
Changes to watch for	Not available	Development of smaller and medium-sized reactors (small modular reactors) ranging from 10 MW_e to 300 MW_e.	Additional fuel cycle development—increasing burn-up rates to reduce waste volumes and the development of new fast reactor fuels to reduce waste toxicity. Development of closed fuel cycle, incorporating both fast and slow (thermal) neutron reactors, with the fast reactors producing power and mixed oxide fuel for thermal neutron reactors.

GFR = gas-cooled fast reactor, LFR = lead-cooled fast reactor, MSR = molten salt reactor, SFR = sodium-cooled fast reactor, SCWR = supercritical water-cooled fast reactor, HTR = high-temperature reactor, VHTR = very high-temperature reactor.

While nuclear power plants do not release atmospheric emissions, they do produce nuclear waste. Reprocessing nuclear waste creates concerns about weapons proliferation, while disposing of it raises concerns about safety and longevity and where to store it. The unresolved issue of nuclear waste remains a contentious one in Australia and globally. The development of Generation IV reactors that have a higher burn-up rate and therefore reduce the amount of nuclear waste produced can help to relieve this problem.

Without the ability to use dry cooling methods, nuclear power plants also face water issues. Large volumes of water must be used for the cooling cycle, so droughts and other water restrictions can reduce production (this would be a particular problem in Australia). Water discharged to the environment can harm the biota if it changes the temperature of the receiving waters.

Nuclear plants are very capital intensive technology. While they remain less expensive to operate than typical fossil-fuel plants, the high upfront cost and financing risk remain barriers for many utilities. The extensive licensing process that is typically required before beginning construction on a nuclear plant also poses a challenge.

Generation IV designs may provide thermal efficiency improvements over Generation III/III+ designs, while fuel costs for nuclear plants are expected to remain low compared to fossil fuels. Some cost reductions in nuclear power technology are expected by 2030 due to the natural learning that will occur through the deployment of multiple Generation III+ and IV reactors.

Table 23: Anticipated cost and performance evolution for large-scale nuclear power

	Current technology	2030 technology average		
		GALLM scenario		Road map
		450 ppm	550 ppm	
Capital cost (relative to current technology)	1.00	0.97	0.97	0.85
Thermal efficiency	Base			+0 pts

Note: Refer to Chapter 16 and Section 15.14 for details on the capital cost estimation methodology.

4

RENEWABLE TECHNOLOGIES PERFORMANCE AND COST

This chapter reviews the performance and costs of three renewable energy technologies:

- concentrating solar thermal plants with central receivers
- solar PV plants
- wind turbine plants.

4.1 Concentrating solar plants with central receivers

The plant evaluated has 125 MW_e sent-out capacity and 6 hours of storage using a two-tank molten salt system. Including thermal energy storage allows the plant to provide power during times when sunlight is not available. The evaluation assumed that dry cooling is used for the power block steam cycle.

4.1.1 Performance

The performance of a central receiver strongly depends on the solar resource available at the plant site. The performance for the central receiver cases was evaluated for a 40–50% capacity factor range.

4.1.2 Emissions and water use

Since no fuel is burned in the generation of solar electric power, central receiver plants do not produce any emissions. The use of dry cooling greatly reduces the water requirements of the plant, where the main water use is for mirror washing. Approximately 38 litres of water is required per m^2 of mirror area each year, assuming the mirrors are washed once a week. A small amount of water is also required for power block make-up.

4.1.3 Cost estimates

Table 24 shows the total plant costs and operation and maintenance (O&M) costs for a central receiver plant with storage. All costs are shown in June 2015 Australian dollars.

Table 24: Total plant cost and O&M costs for central receiver plant cases

	Central receiver with 6 hours of thermal storage
Total plant cost (A$/kW sent-out)	8,500
Fixed O&M (A$/kW-year)	65
Variable O&M (A$/MWh)	4.0

Note: Shaded cells indicate EPRI data translated to Australian costs—see Chapter 15.

4.2 Photovoltaic plants

The PV systems analysed in this report were evaluated at both 5 MW and 50 MW utility scale. Three different photovoltaic systems are included in this analysis: fixed flat plate, single-axis tracking and two-axis tracking.

In addition, a 5 kW residential and a 100 kW commercial-scale case are included.

4.2.1 Performance

The performance of a photovoltaic system strongly depends on the solar resource available at the plant site and the mounting system. The performance for the PV cases was evaluated for a range of solar resource assumptions.

Table 25 shows the range of capacity factors for the three PV technologies analysed. The collection efficiency increases due to the increased exposure to the sun from the efficiency of the mounting system.

Table 25: Photovoltaic plant performance results

	Residential	**Commercial**	**Utility-scale**		
Size	5 kW	100 kW	10 / 50 MW		
Module mounting	Fixed	Fixed	Fixed	Single axis	Dual axis
Capacity factor (%)	14–20	17–20	19–22	25–28	30–32

4.2.2 Emissions and water use

Photovoltaic systems do not produce any emissions. The only water requirement is for occasionally washing the modules to prevent reduced collection efficiency. About 1.5 litres/m^2 of panel area is required, assuming they are washed four times a year.

4.2.3 Capital cost estimates

Table 26 shows the capital and O&M costs of the PV technologies evaluated in this study. All costs are shown in June 2015 Australian dollars.

Table 26: Photovoltaic plant capital and O&M costs estimate

Size	**5 kW**	**100 kW**	**10 MW**	**50 MW**	**10 MW**	**50 MW**	**10 MW**	**50 MW**
Module mounting	**Fixed**				**Single axis**		**Dual axis**	
Total plant cost (A$/kW sent-out)	2,100	1,950	2,400	2,300	2,850	2,700	3,600	3,400
Fixed O&M (A$/kW-year)	30	30	30	25	40	35	45	40

4.3 Wind turbine plants

Wind plants were analysed at two different sizes: 50 MW and 200 MW. Onshore wind turbines are considered a mature, commercial technology, although research continues into making the turbines larger and develop advanced controls.

4.3.1 Performance

The performance of the wind plant cases was evaluated for a 35–42% capacity factor range.

4.3.2 Emissions and water use

Wind plants do not produce any air emissions and do not have water requirements.

4.3.3 Capital cost and O&M cost estimates

Table 27 shows the total plant costs and O&M costs for the wind plant cases. All costs are shown in June 2015 Australian dollars.

Table 27: Total plant cost and O&M costs for wind plant cases

	50 MW	200 MW
Total plant cost (A$/kW sent-out)	2,550	2,450
Fixed O&M (A$/kW-year)	60	55

5 FOSSIL TECHNOLOGIES PERFORMANCE AND COST

Each of the selected fossil technologies has been evaluated at the ambient conditions defined in Section 14 and repeated below:

- Dry bulb temperature 25°C
- Wet bulb temperature 19.45°C
- Relative humidity 60%
- Atmospheric pressure 1.00 bar
- Equivalent altitude 111 m

In addition to the conditions above, since water supply is limited throughout Australia, all cases are based on the use of dry cooling equipment, such as air-cooled condensers and fin-fan coolers for auxiliary equipment. The Hunter Valley in New South Wales is the reference location for all of the fossil technologies except the brown coal cases, which are located in Victoria.

The technologies were evaluated based on the use of currently available equipment, systems and materials. Heat and material balances were developed for each case. The modelling employed Gatecycle™ 6.1.1, Thermo-Flow™ (v 22), ASPEN™ (v 7.1) and KBR proprietary software.

5.1 Pulverised coal-fired power plants

Power generation with pulverised coal combustion systems has been used by power utility companies around the world for over 75 years and is considered a very mature technology. Advances continue to be made to improve efficiency, reduce emissions and reduce costs.

The pulverised coal cases evaluated in this study include:

- supercritical steam cycles
- ultra-supercritical[1]
- oxy fuel.

5.1.1 Performance

The plant performance for each case evaluated was determined via process and heat and material balance calculations using information in the EPRI's subcontractor's technical databases. The calculated plant performance results for the base cases are shown in Table 28.

The calculated plant performance results comparing the small supercritical cases with the larger ultra-supercritical cases are shown in Table 29 for brown coal and Table 30 for black coal.

[1] Supercritical and ultra-supercritical technologies are also referred to as high-efficiency, low-emissions (HELE) technologies. IEA (2012), *Technology roadmap: high-efficiency, low-emissions coal-fired power generation*.

Table 28: Supercritical pulverised coal overall plant performance

	Brown coal		Black coal		
	No CCS	**With CCS**	**No CCS**	**With CCS**	**Oxyfuel**
Generated plant output (kW)					
Steam turbine	423,849	352,304	401,091	343,275	542,797
Total generated output	423,849	352,304	401,091	343,275	542,797
Aux. loads and losses (kW)					
Process plant	0	25,858	0	33,607	126,476
Power plant	47,578	66,586	24,888	38,021	39,690
Transformer losses	1,272	1,057	1,204	1,030	1,629
Total aux. loads and losses	48,850	93,501	26,091	72,658	167,795
Sent out output					
Plant power output (kW)	375,000	258,803	375,000	270,617	375,003
Plant efficiency (%—HHV)	36	25	40	29	30
Heat rate (kJ/kWh—HHV)	10,000	14,400	9,000	12,400	12,000

Table 29: Brown coal supercritical and ultra-supercritical pulverised coal comparison

	Without CCS		With CCS	
	Supercritical	**Ultra-supercritical**	**Supercritical**	**Ultra-supercritical**
Steam conditions				
Temperature (°C)	582/582	604/604	582/582	604/604
Pressure (MPa)	26.2	27.6	26.2	27.6
Generated plant output (kW)				
Steam turbine	423,849	734,673	352,304	610,662
Total generated output	423,849	734,673	352,304	610,662
Aux. loads and losses (kW)				
Process plant	0	0	25,858	51,716
Power plant	47,578	82,470	66,586	113,153
Transformer losses	1,272	2,204	1,057	1,832
Total aux. loads and losses	48,850	84,673	93,501	166,701
Sent out output				
Plant power output (kW)	375,000	650,000	258,803	443,960
Plant efficiency (%—HHV)	36	37	25	26
Heat rate (kJ/kWh—HHV)	10,000	9,700	14,400	13,800

Table 30: Black coal supercritical and ultra-supercritical pulverised coal comparison

	Without CCS		With CCS	
	Supercritical	**Ultra-supercritical**	**Supercritical**	**Ultra-supercritical**
Steam conditions				
Temperature (°C)	582/582	604/604	582/582	604/604
Pressure (MPa)	26.2	27.6	26.2	27.6
Generated plant output (kW)				
Steam turbine	401,091	695,225	343,275	595,010
Total generated output	401,091	695,225	343,275	595,010
Aux. loads and losses (kW)				
Process plant	0	0	33,607	67,214
Power plant	24,888	43,138	38,021	64,611
Transformer losses	1,204	2,087	1,030	1,785
Total aux. loads and losses	26,091	45,225	72,658	133,610
Sent out output				
Plant power output (kW)	375,000	650,000	270,617	461,400
Plant efficiency (%—HHV)	40	41	29	30
Heat rate (kJ/kWh—HHV)	9,000	8,800	12,400	12,000

5.1.2 Emissions and water use

The emissions of CO_2, SO_X and NO_X plus water consumption for each pulverised coal case are shown Table 31.

Table 31: Pulverised coal plant emissions and water consumption

	Brown coal				Black coal				
	Supercritical		Ultra-supercritical		Supercritical		Ultra-supercritical		
Emissions	**No CCS**	**With CCS**	**No CCS**	**With CCS**	**No CCS**	**With CCS**	**No CCS**	**With CCS**	**Oxy fuel**
SO_x emissions g/MW-hr-sent out	3,052	1	2,992	1	3.073	1	3,013	1	1
NO_x emissions g/MW-hr-sent out	2,529	3,680	2,479	3,608	2,267	3,120	2,223	3,109	1,226
CO_2 emissions kg/MW-hr-sent out	953	137	928	132	792	109	773	106	53
CO_2 captured kg/MW-hr-sent out	0	1,236	0	1,188	0	943	0	950	1,003
Water consumption litres/MWh	0	0	0	0	33	320	33	310	44

5.1.3 Capital cost estimates

The total plant costs for each of the pulverised coal cases were estimated using the procedures described in Section 15 of this report. The resulting estimates are summarised in Table 32. All costs are shown in June 2015 Australian dollars.

Table 32: Total plant cost for pulverised coal cases

	Brown coal				Black coal				
	Supercritical		Ultra-supercritical		Supercritical		Ultra-supercritical		
	No CCS	With CCS	No CCS	With CCS	No CCS	With CCS	No CCS	With CCS	Oxy-fuel
Equipment	1,161	2,673	1,200	2,747	920	1,954	943	2,027	2,413
Material cost	551	1,033	574	1,068	418	633	438	649	769
Direct labour	1,498	3,009	1,545	3,092	1,186	2,983	1,235	3,026	2,306
Bare erected cost	3,211	6,715	3,319	6,907	2,524	5,570	2,536	5,731	5,489
Engineering, home office fee	245	575	262	599	207	443	212	473	434
Contingency	394	960	415	994	269	738	271	726	828
Total plant cost (A$/kW sent out)	3,850	8,250	4,000	8,500	3,000	6,750	3,100	7,000	6,750

Note: Brown coal cases are based on a Victoria mine-mouth location; all others are in the Hunter Valley, NSW. Shaded cells indicate EPRI data translated to Australian costs—see Chapter 15.

5.1.4 Operating and maintenance cost estimates

The O&M costs for each of the pulverised coal cases evaluated were estimated using the procedures described in Section 15 of this report. The resulting estimates are summarised in Table 33. All costs are shown in June 2015 Australian dollars.

Table 33: Pulverised coal O&M costs

	Brown coal				Black coal				
	Supercritical		Ultra-supercritical		Supercritical		Ultra-supercritical		
	No CCS	With CCS	No CCS	With CCS	No CCS	With CCS	No CCS	With CCS	Oxy fuel
Fixed O&M (A$/kW-year)	55	65	55	65	45	55	45	55	55
Variable O&M (A$/MWh)	3.0	12	3.0	11	2.5	10	2.5	9	12

5.2 Integrated gasification combined cycle plants

The integrated gasification combined cycle cases evaluated in this study include:

- air-blown circulating fluidised bed gasifier (TRIG)—brown coal only
- oxygen-blown entrained flow gasifier (Shell)—black coal only.

5.2.1 Performance

The plant performance for each case evaluated was determined via process heat and material balance calculations using information in the EPRI subcontractor's technical databases. Some of the process information is considered proprietary by the process developer and therefore such additional data has not been included in the data summaries provided in this report. A summary of the overall plant performance for the brown and black coal IGCC cases is in Table 34.

Table 34: IGCC overall plant performance

	Brown coal		Black coal	
	No CCS	**With CCS**	**No CCS**	**With CCS**
Generated plant output (kW)				
Gas turbine	286,000	286,000	286,000	286,000
Steam turbine	173,842	167,480	188,683	162,391
Total generated output	459,842	453,480	474,683	448,391
Aux loads and losses (kW)				
Process plant	94,305	163,400	81,312	126,748
Power plant	10,797	12,104	10,338	11,534
Transformer losses	1,422	1,405	1,463	1,391
Total aux loads and losses	106,524	176,909	93,113	139,672
Sent out output				
Sent out plant power output (kW)	353,318	276,571	381,570	308,720
Sent out plant efficiency (%—HHV)	34	24	40	29
Sent out heat rate (kJ/kWh—HHV)	10,600	15,000	9,000	12,400

5.2.2 Emissions and water use

The emissions of CO_2, SO_X and NO_X plus water consumption for each IGCC case are shown in Table 35. Compared to the pulverised coal cases, the IGCC plant has lower emissions of SO_X and NO_X due to the process emissions reduction systems included; however, the CO_2 emissions and water consumption rates are higher for the black coal IGCC cases than the pulverised coal cases.

Table 35: IGCC emissions and water consumption

	Brown coal		Black coal	
	No CCS	With CCS	No CCS	With CCS
SO_x emissions g/MW-hr-sent out	129	6	55	8
NOx emissions g/MW-hr-sent out	188	214	158	176
CO_2 emissions kg/MW-hr-sent out	1,009	286	792	109
CO_2 captured kg/MW-hr-sent out	0	1,144	0	983
Water consumption litres/MWh	0	0	257	1,027

5.2.3 Capital cost estimates

The total plant costs for each of the IGCC cases were estimated using the procedures described in Section 15 of this report. The resulting estimates are summarised Table 36. All costs are shown in June 2015 Australian dollars.

Table 36: Total plant cost for IGCC cases

	Brown coal		Black coal	
	No CCS	With CCS	No CCS	With CCS
Equipment	1,856	2,911	1,630	2,451
Material cost	792	1,224	611	1,064
Direct labour	2,404	3,653	1,880	2,920
Bare erected cost	5,052	7,788	4,120	6,435
Engineering, home office fee	423	649	341	540
Contingency	675	1,014	539	825
Total plant cost (A$/kW sent out)	6,150	9,450	5,000	7,800

Note: Brown coal cases are based on a Victoria mine-mouth location; all others are in the Hunter Valley, NSW. Shaded cells indicate EPRI data translated to Australian costs—see Chapter 15.

5.2.4 Operating and maintenance cost estimates

The O&M costs for each of the IGCC cases evaluated were estimated using the procedures described in Section 15 of this report. The resulting estimates are summarised Table 37. All costs are shown in June 2015 Australian dollars.

Table 37: IGCC O&M costs

	Brown coal		Black coal	
	No CCS	With CCS	No CCS	With CCS
Fixed O&M (A$/kW-year)	55	65	50	60
Variable O&M (A$/MWh)	8.0	12	8.0	10

5.3 Natural gas turbine plants

The combined cycle system uses a conventional, subcritical steam cycle with a three-pressure heat recovery steam generator located after the gas turbine exhaust to recover energy as steam for feeding to the steam turbine. For the combined cycle case with CCS, a portion of the steam before the low-pressure steam turbine is extracted as needed for the CO_2 capture process; hence, the megawatts generated in the steam turbine are lower for that case.

Since turbines operating in open cycle configurations have higher heat rates than combined cycle plants, they are typically used to support electric power peaking load conditions. This results in low operating capacity factors, and for this case an average capacity factor of 7.5% for frame turbines and 20% for aeroderivative turbines was defined.

5.3.1 Performance

The plant performance for each case evaluated was determined via process and heat and material balance calculations using GT Pro software and information within the EPRI subcontractor's technical databases.

The calculated plant performance results for each case are shown in Table 38.

Table 38: Natural gas turbine plant performance

	Open cycle		Combined cycle	
	Frame	**Aero**	**No CCS**	**With CCS**
Generated plant output (kW)				
Gas turbine	280,989		309,061	309.061
Steam turbine	0	0	142,407	108,246
Total generated output	280,989		451,468	417,307
Aux. loads and losses (kW)				
Process plant	0	0	0	39,990
Power plant	1,765		8,055	7,085
Transformer losses	928		1,412	1,318
Total aux. loads and losses	2,693		9,467	48,393
Sent out output				
Sent out plant power output (kW)	278,296		442,002	368,915
Sent out plant efficiency (%—HHV)	34	39	50	42
Sent out heat rate (kJ/kWh—HHV)	10,600	9,200	7,200	8,600

5.3.2 Emissions and water use

Due to the use of natural gas fuel in the gas turbines, very little emissions control is needed to maintain low stack emissions levels. The gas turbines are equipped with dry low-NO_X combustors. No SO_X or particulate controls are needed to clean up the flue gases. The emissions values and water consumption values are shown in Table 39.

Table 39: Natural gas turbine emissions and water use

	Open cycle		Combined cycle	
	Frame	**Aero**	**No CCS**	**With CCS**
SO_x emissions g/MW-hr-sent out	0.2		0.1	0.001
NOx emissions g/MW-hr-sent out	170	396	112	133
CO_2 emissions kg/MW-hr-sent out	548	478	373	89
CO_2 captured kg/MW-hr-sent out	0	0	0	355
Water consumption litres/MWh	0	0	20	30

5.3.3 Capital cost estimates

The design, equipment and labour costs for each of the natural gas turbine cases were estimated using the procedures described in Section 15 of this report. The resulting estimates are summarised Table 40. All costs are shown in June 2015 Australian dollars.

Table 40: Total plant cost for natural gas turbine cases

	Open cycle		Combined cycle	
	Frame	**Aero**	**No CCS**	**With CCS**
Equipment	564		701	1,479
Material cost	91		156	290
Direct labour	193		460	803
Bare erected cost	848		1,317	2,571
Engineering, home office fee	39		65	152
Contingency	113		68	478
Total plant cost (A$/kW sent out)	1,000	1,200	1,450	3,050

Note: Shaded cells indicate EPRI data translated to Australian costs—see Chapter 15.

5.3.4 Operating and maintenance cost estimates

The O&M costs for each of the natural gas turbine cases evaluated were estimated using the procedures described in Section 15 of this report. The resulting estimates are summarised in Table 37. All costs are shown in June 2015 Australian dollars.

Table 41: Natural gas turbine O&M costs

	Open cycle		Combined cycle	
	Frame	**Aero**	**No CCS**	**With CCS**
Fixed O&M (A$/kW-year)	8.0	10	20	35
Variable O&M (A$/MWh)	12	15	1.5	12

6 NUCLEAR TECHNOLOGY PERFORMANCE AND COST

A general description of the nuclear reactor technologies in Section 3.4 of this report provides information on the technology status and systems used in nuclear power stations.

Since water supply in Australia is limited, the steam condenser and process auxiliary systems requiring cooling have been configured with direct seawater cooling, based on the plant being at a coastal location.

6.1 Performance

The nuclear plant performance was determined using information from EPRI's technical databases. A summary of overall plant performance for the nuclear case is in Table 42.

Table 42: Nuclear overall plant performance

	Large-scale nuclear
Sent out plant power output (MW)	1,100
Sent out plant efficiency (%—HHV)	33
Sent out plant heat rate (kJ/kWh—HHV)	10,900

Note: Shaded cells indicate EPRI data translated to Australian costs—see Chapter 15.

6.2 Emissions and water use

There are no CO_2 emissions from nuclear power plants. The cooling is provided by a once-through system using seawater. This cooling system uses approximately 6,800 L/MWh, and the water is returned to the ocean after use. The make-up water necessary for the steam cycle is approximately 40 L/MWh.

6.3 Capital and O&M cost estimates

Table 43 shows the total plant costs and O&M costs for the nuclear plant case. All costs are shown in June 2015 Australian dollars.

Table 43: Total plant cost and O&M costs for the nuclear plant case

	1100 MW
Total plant cost (A$/kW sent-out)	9,000
Fixed O&M (A$/kW-year)	100
Variable O&M (A$/MWh)	2.0

The O&M costs developed for nuclear plants for this study do not include additional costs for nuclear waste disposal or additional insurance costs beyond those assumed for the fossil-fuel technology calculations.

7 COST OF ELECTRICITY ANALYSIS AND SENSITIVITIES

Levelised cost of electricity analysis—highlights:

- Wind has the lowest levelised cost of electricity of the current renewable technologies in Australia.
- Natural gas combined cycle and supercritical coal have the lowest levelised costs of electricity of all the current new build technologies.
- All new technologies have significantly higher levelised costs of electricity than the Australian grid average.
- All technologies show improvement in 2030 from the 2015 levelised costs of electricity; however, significant uncertainties remain about future capital costs.

7.1 Introduction

The levelised cost of electricity (LCOE) analysis presented in this report represents two time frames—2015 and 2030. The 2015 costs represent a plant built 'overnight' and its operation in the first half of 2015. Technologies on the steep portion of the cost improvement pathway will see relatively rapid improvements on the 2015 LCOE presented in this report within a short period.

7.2 Levelised cost of electricity analysis

The LCOE was calculated for all of the technologies included in this study. Economic assumptions used for these calculations are set out in Section 17 and summarised in Table 44.

Single point averages of the total plant cost for the technologies are presented in Section 4, 5 and 6.

All of the LCOEs in this section are in constant June 2015 Australian dollars. Assumed fuel prices are shown in Table 45. LCOEs are summarised in Tables 46–54. In all these tables, 'T&S' stands for 'transportation and sequestration'.

Table 44: Economic assumptions summary

Factor	Value
Nominal cost of equity (% p.a.)	11.5
Nominal cost of debt (% p.a.)	8.0
Percentage debt (%)	70
Inflation (% p.a.)	2.5
Company tax rate (% p.a.)	30
Property tax / insurance (% p.a.)	2.0
Analysis year	2015
Currency	A$
Asset tax life (y)	30
Asset tax life—wind (y)	20

Note: Used to calculate LCOE in constant dollars—June 2015.

Table 45: Fuel assumptions

	Cost (A$/GJ)	
Fuel type	**2015**	**2030**
Black coal	2.0–4.0	2.0–4.0
Brown coal	1.0–1.75	1.0–1.75
Natural gas	5.0–8.0	6.0–10.0
Diesel	20–22	28–30
Uranium	1.0–2.0	1.0–2.0

Table 46: Supercritical pulverised coal levelised cost of electricity

	Brown coal		Black coal		
	No CCS	**With CCS**	**No CCS**	**With CCS**	**Oxyfuel**
Finance charges	56	120	44	98	98
Fixed O&M	7	9	6	7	7
Variable O&M	3	12	3	10	12
Fuel costs	14	20	27	37	36
Cost of CO_2 T&S	0	19	0	15	15
Cost of carbon	0	0	0	0	0
Average LCOE ($/MWh)	**80**	**179**	**79**	**168**	**169**

Table 47: Ultra-supercritical pulverised coal levelised cost of electricity

	Brown coal		Black coal	
	No CCS	**With CCS**	**No CCS**	**With CCS**
Finance charges	58	124	45	102
Fixed O&M	7	9	6	7
Variable O&M	3	11	3	9
Fuel costs	13	19	26	36
Cost of CO_2 T&S	0	18	0	14
Cost of carbon	0	0	0	0
Average LCOE ($/MWh)	**82**	**180**	**80**	**169**

Table 48: IGCC levelised cost of electricity

	Brown coal		Black coal	
	No CCS	**With CCS**	**No CCS**	**With CCS**
Finance charges	98	156	80	125
Fixed O&M	8	9	7	9
Variable O&M	8	12	8	10
Fuel costs	15	21	27	37
Cost of CO_2 T&S	0	17	0	15
Cost of carbon	0	0	0	0
Average LCOE ($/MWh)	**128**	**215**	**122**	**195**

Table 49: Natural gas turbine levelised cost of electricity

	Open cycle		Combined cycle	
	Frame	**Aero**	**No CCS**	**With CCS**
Finance charges	175	77	26	57
Fixed O&M	14	6	4	6
Variable O&M	12	15	2	12
Fuel costs	69	60	47	56
Cost of CO_2 T&S	0	0	0	5
Cost of carbon	0	0	0	0
Average LCOE ($/MWh)	**269**	**158**	**78**	**136**

Table 50: Engine levelised cost of electricity

	Engine	
	Gas	**Diesel**
Finance charges	38	29
Fixed O&M	2	0
Variable O&M	40	30
Fuel costs	60	216
Cost of CO_2 T&S	0	0
Cost of carbon	0	0
Average LCOE ($/MWh)	**140**	**275**

Table 51: Central receiver with storage levelised cost of electricity

	Central receiver with 6 h storage
Finance charges	226
Fixed O&M	16
Variable O&M	4
Average LCOE ($/MWh)	**246**

Table 52: Solar PV levelised cost of electricity

	Residential	**Commercial**	**Utility-scale**					
	Fixed	**Fixed**	**Fixed**		**Single axis**		**Dual axis**	
	5 kW	100 kW	10 MW	50 MW	10 MW	50 MW	10 MW	50 MW
Finance charges	141	118	133	128	122	119	131	128
Fixed O&M	21	19	17	14	17	15	17	15
Average LCOE ($/MWh)	**162**	**136**	**150**	**142**	**139**	**134**	**148**	**143**

Table 53: Wind power levelised cost of electricity

	50 MW	**200 MW**
Finance charges	87	87
Fixed O&M	18	16
Average LCOE ($/MWh)	**105**	**103**

Table 54: Nuclear power levelised cost of electricity

	Large-scale nuclear
Finance charges	148
Fixed O&M	13
Variable O&M	2
Fuel costs	16
Cost of CO_2 T&S	0
Cost of carbon	0
Average LCOE ($/MWh)	**180**

Note: Does not additional insurance and waste disposal costs.

7.3 Nuclear insurance and waste disposal cost sensitivity

Nuclear O&M costs and LCOE calculations for this study do not include additional costs for nuclear waste disposal or additional insurance costs beyond those assumed for the fossil-fuel technology calculations.

For every $0.10/GJ added to the fuel cost to account for additional nuclear waste disposal, the LCOE would increase by $1.10/MWh. For every 1% increase in the assumed insurance percentage, the LCOE would increase by approximately 6%.

7.4 Fuel cost sensitivity

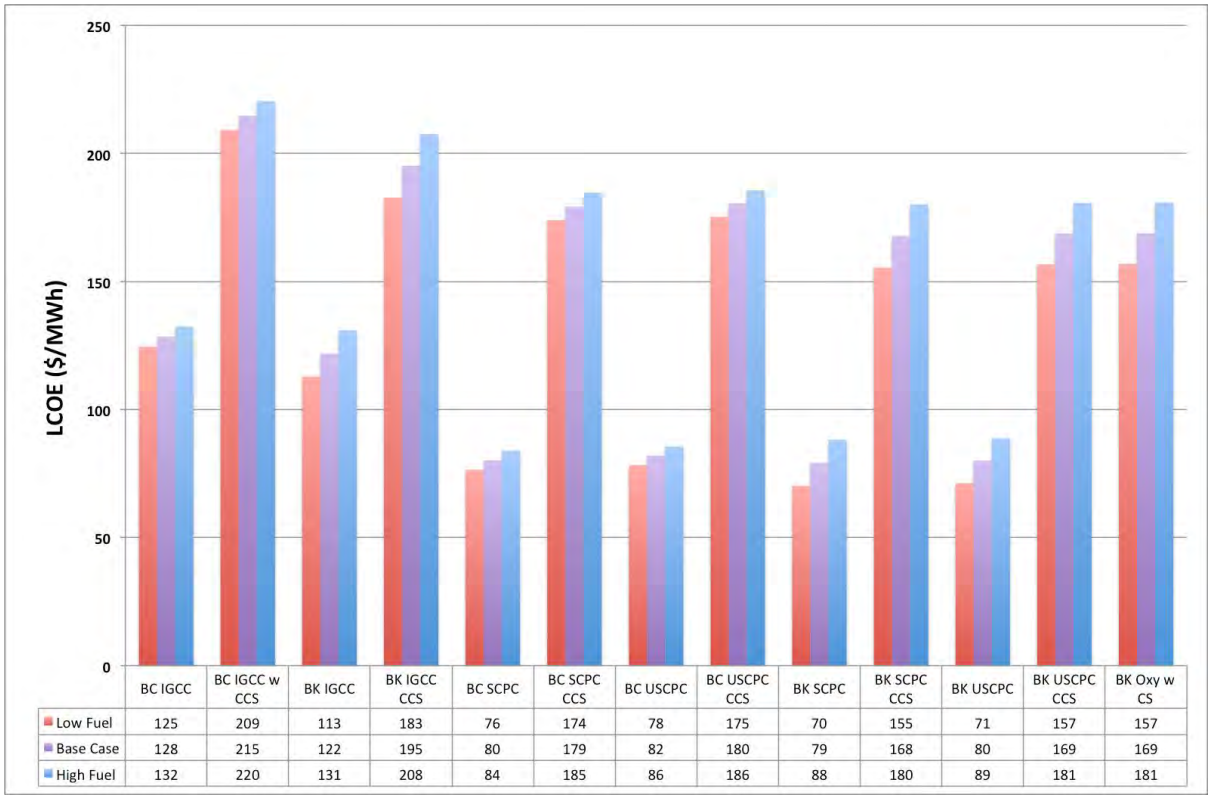
The cost of fuel can have a significant effect on the LCOE of fossil-fuel technologies. A sensitivity analysis was conducted for the fossil fuel cases to look at the effect of fuel costs on their LCOEs. The fuel price range is given in Table 45 and the fuel price sensitivities are given in Figure 73 and in Table 55 and Table 56 for diesel and nuclear power plants.

Table 55: Diesel fuel cost sensitivity of LCOE ($/MWh)

	Engine diesel
Low fuel	264
Average fuel	275
high fuel	285

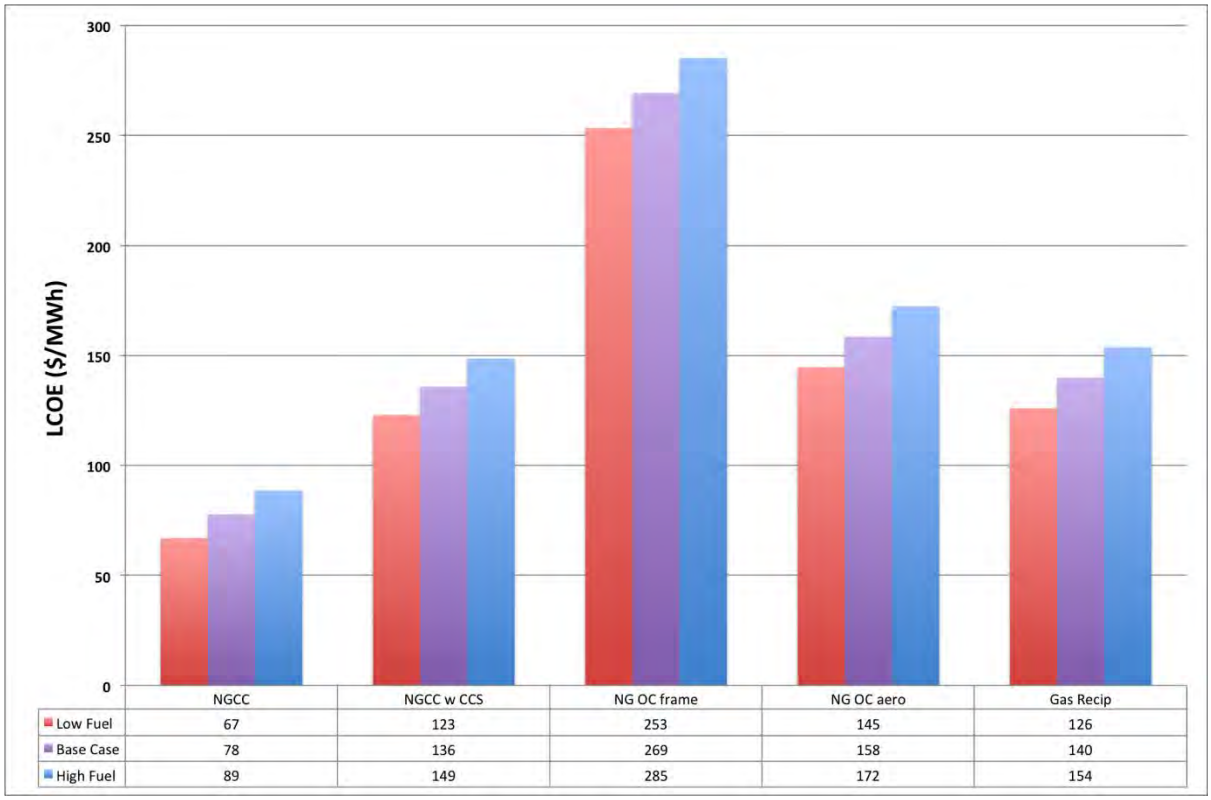
Table 56: Nuclear fuel cost sensitivity of LCOE ($/MWh)

	Large-scale nuclear
Low fuel	175
Average fuel	180
High fuel	186



	BC IGCC	BC IGCC w CCS	BK IGCC	BK IGCC CCS	BC SCPC	BC SCPC CCS	BC USCPC	BC USCPC CCS	BK SCPC	BK SCPC CCS	BK USCPC	BK USCPC CCS	BK Oxy w CS
Low Fuel	125	209	113	183	76	174	78	175	70	155	71	157	157
Base Case	128	215	122	195	80	179	82	180	79	168	80	169	169
High Fuel	132	220	131	208	84	185	86	186	88	180	89	181	181

Figure 73: Coal fuel cost sensitivity of LCOE ($/MWh)



	NGCC	NGCC w CCS	NG OC frame	NG OC aero	Gas Recip
Low Fuel	67	123	253	145	126
Base Case	78	136	269	158	140
High Fuel	89	149	285	172	154

Figure 74: Gas fuel cost sensitivity of LCOE ($/MWh)

7.5 Capacity factor sensitivity

The assumed capacity factor can have a significant effect on the LCOEs of renewable and fossil-fuel technologies. A sensitivity analysis was conducted for the non-baseload fossil-fuel and all renewable cases to examine the effect of their capacity factors on their LCOEs. The capacity factor sensitivities are given in Table 57 and Table 58 for the gas turbine and engine cases.

The capacity factor ranges are summarised in Table 59 and the renewable technology capacity factor sensitivity cases are given in Figure 75.

Table 57: Natural gas turbine capacity factor sensitivity of LCOE ($/MWh)

	Open cycle			
	Capacity factor (%)	Frame	Capacity factor (%)	Aero
Low	5	325	15	177
Average	7.5	269	20	158
High	10	203	25	136

Table 58: Engine capacity factor sensitivity of LCOE ($/MWh)

	Engine			
	Capacity factor (%)	Gas	Capacity factor (%)	Diesel
Low	30	149	30	284
Average	40	140	45	275
High	50	129	60	265

Table 59: Summary of renewable capacity factor ranges (%)

	Solar PV					Solar thermal with storage	Wind
	Residential	Commercial	Fixed	SAT	DAT		
Low	14	17	19	25	30	40	35
Base case	18	18.5	20.5	26.5	31	48	39
High	20	20	22	28	32	55	42

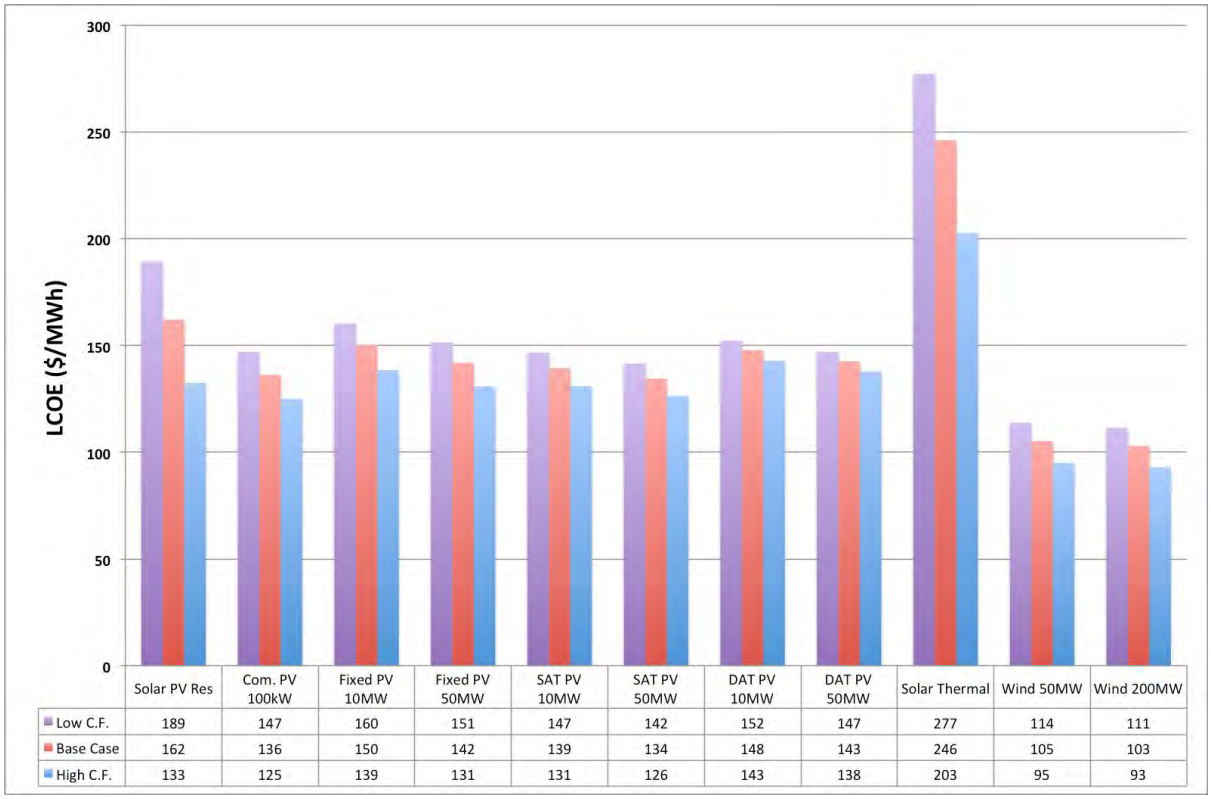


Figure 75: Renewable capacity factor sensitivity of LCOE ($/MWh)

Note: Refer to Table 59.

7.6 Capital cost sensitivity

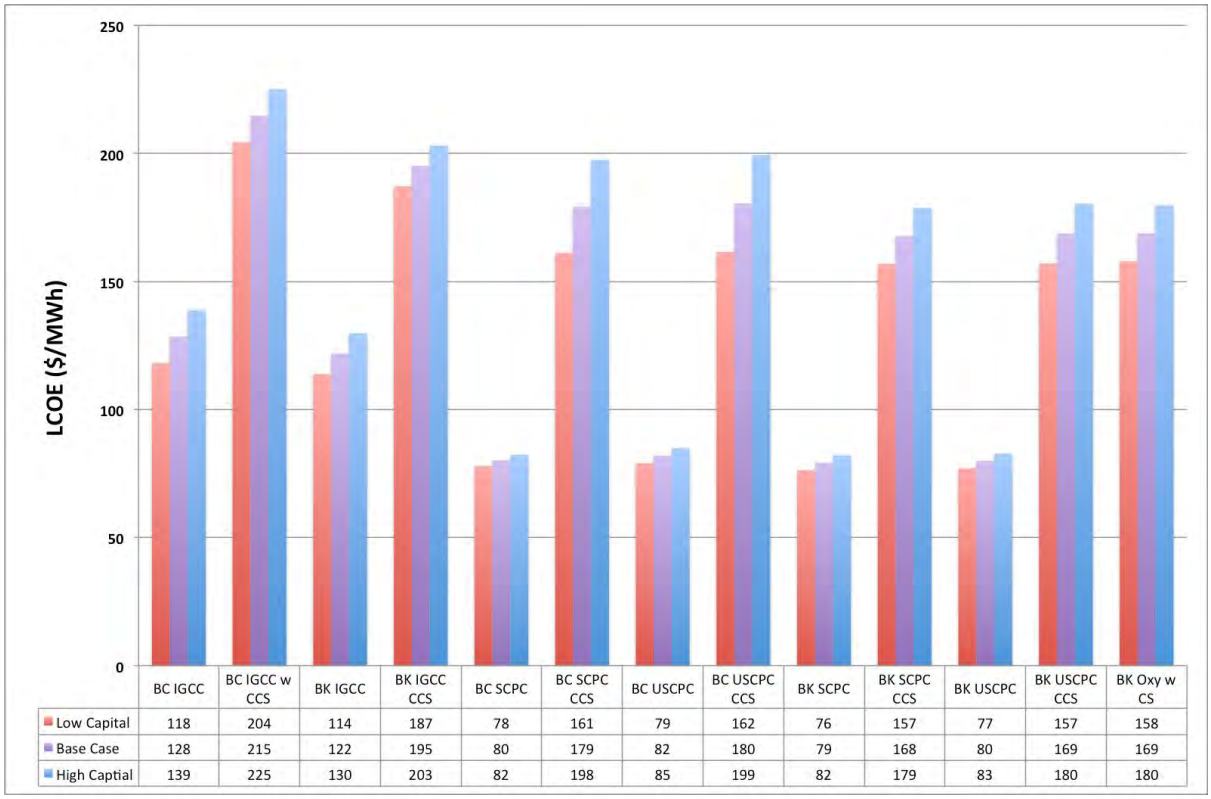
For all of the technologies, a capital cost range was applied based on the maturity of the plant and the uncertainty surrounding the cost estimate. The capital cost sensitivities are given in Table 60 and Table 61 for the diesel engine and nuclear cases, respectively. The coal, gas and renewable technology cases are given in Figure 76, Figure 77 and Figure 78.

Table 60: Diesel engine capital cost sensitivity of LCOE ($/MWh)

	Capital ($/kW)	Diesel engine
Low	950	273
Average	1,000	275
High	1,050	276

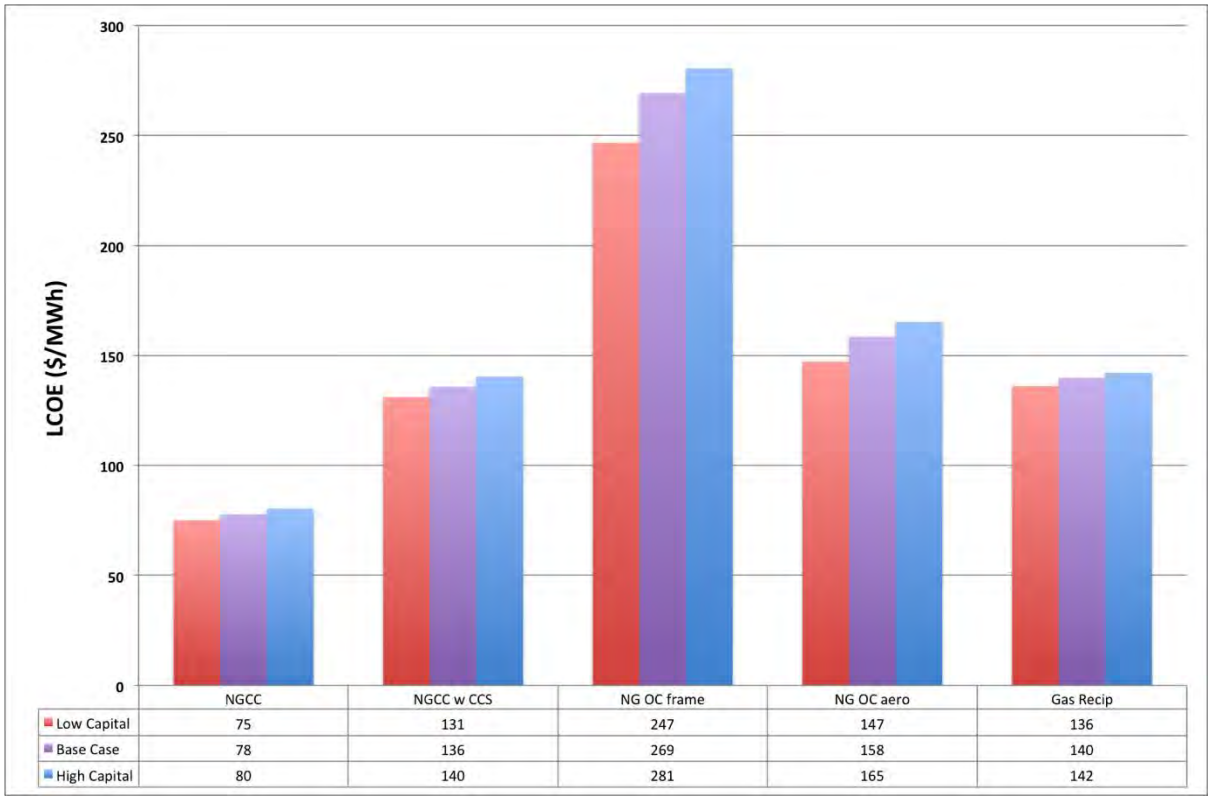
Table 61: Nuclear capital cost sensitivity of LCOE ($/MWh)

	Capital ($/kW)	Large-scale nuclear
Low	7,000	147
Average	9,000	180
High	11,000	213



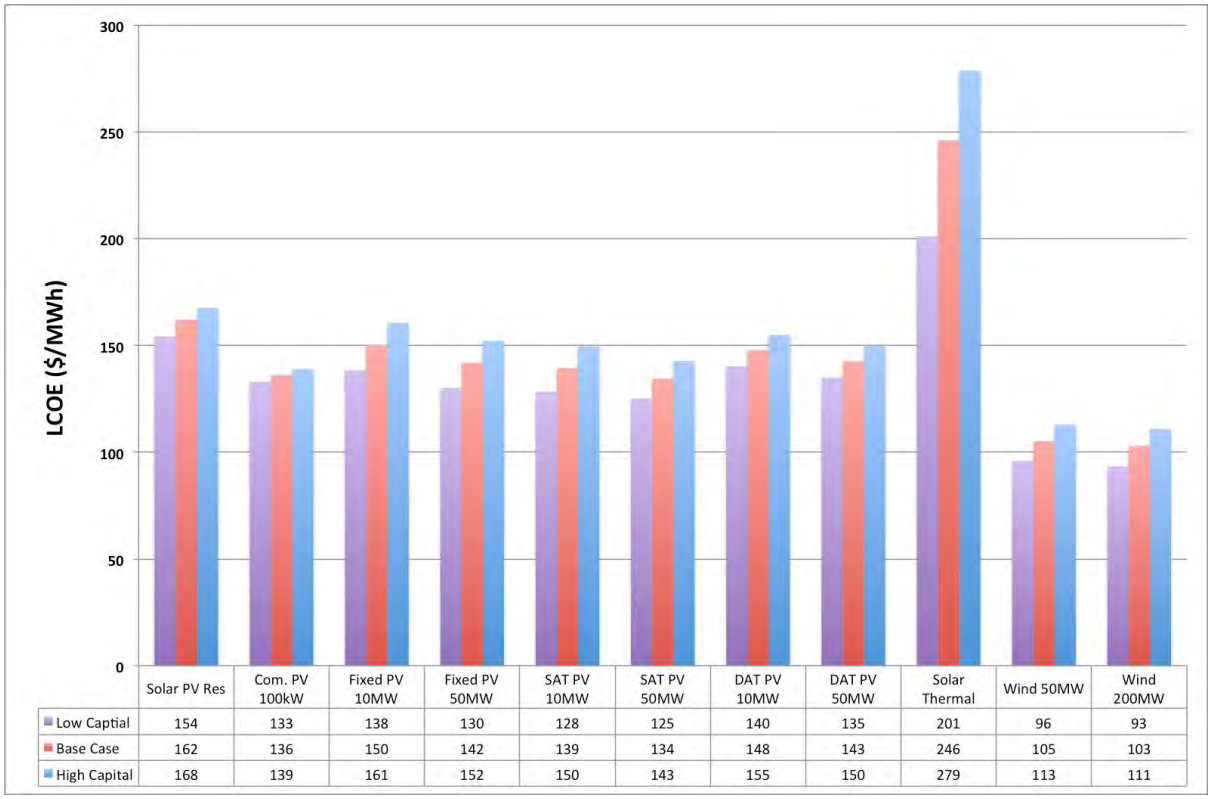
	BC IGCC	BC IGCC w CCS	BK IGCC	BK IGCC CCS	BC SCPC	BC SCPC CCS	BC USCPC	BC USCPC CCS	BK SCPC	BK SCPC CCS	BK USCPC	BK USCPC CCS	BK Oxy w CS
Low Capital	118	204	114	187	78	161	79	162	76	157	77	157	158
Base Case	128	215	122	195	80	179	82	180	79	168	80	169	169
High Captial	139	225	130	203	82	198	85	199	82	179	83	180	180

Figure 76: Coal capital sensitivity of LCOE ($/MWh)



	NGCC	NGCC w CCS	NG OC frame	NG OC aero	Gas Recip
Low Capital	75	131	247	147	136
Base Case	78	136	269	158	140
High Capital	80	140	281	165	142

Figure 77: Gas capital sensitivity of LCOE ($/MWh)



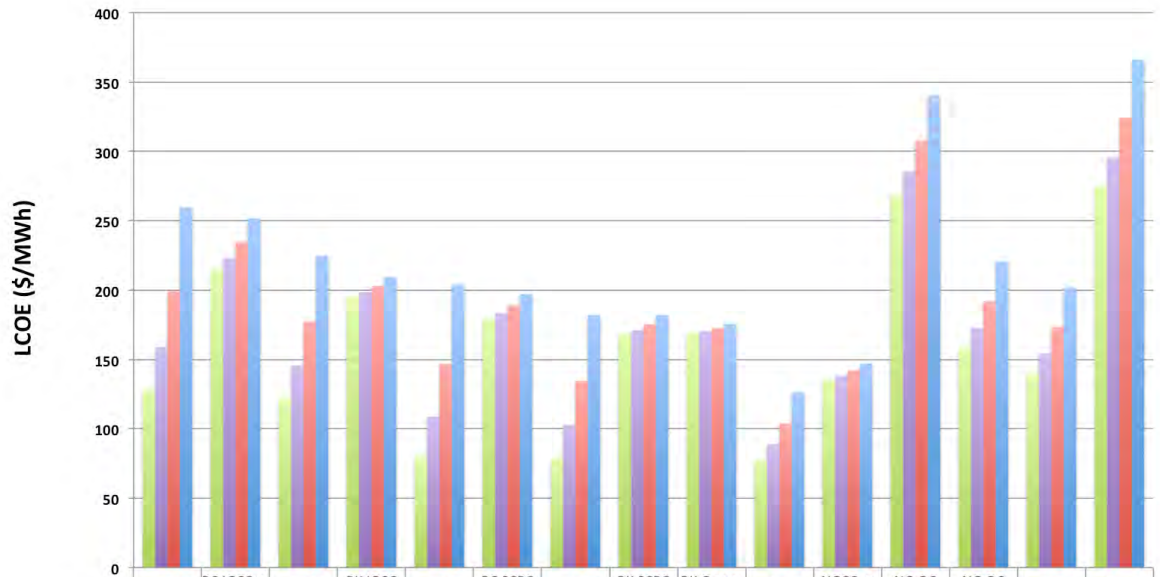
	Solar PV Res	Com. PV 100kW	Fixed PV 10MW	Fixed PV 50MW	SAT PV 10MW	SAT PV 50MW	DAT PV 10MW	DAT PV 50MW	Solar Thermal	Wind 50MW	Wind 200MW
Low Captial	154	133	138	130	128	125	140	135	201	96	93
Base Case	162	136	150	142	139	134	148	143	246	105	103
High Capital	168	139	161	152	150	143	155	150	279	113	111

Figure 78: Renewable capital sensitivity of LCOE ($/MWh)

7.7 Carbon cost sensitivity

While there is currently no carbon price in Australia, a sensitivity analysis was completed for three carbon prices (shown in Figure 79):

- *Low carbon price:* the minimum carbon price ($30 t/CO2-e) required for the LCOE of black supercritical coal to equal that of wind power (the cheapest fossil-fuel and renewable technologies)
- *Medium carbon price:* the minimum carbon price ($70 t/$CO_2$-e) required for the LCOE of black supercritical coal to equal that of solar power (the cheapest fossil-fuel and next renewable technology)
- *High carbon price:* the minimum carbon price ($130 t/$CO_2$-e) required for the LCOEs of black supercritical coal with and without CCS to be equal.



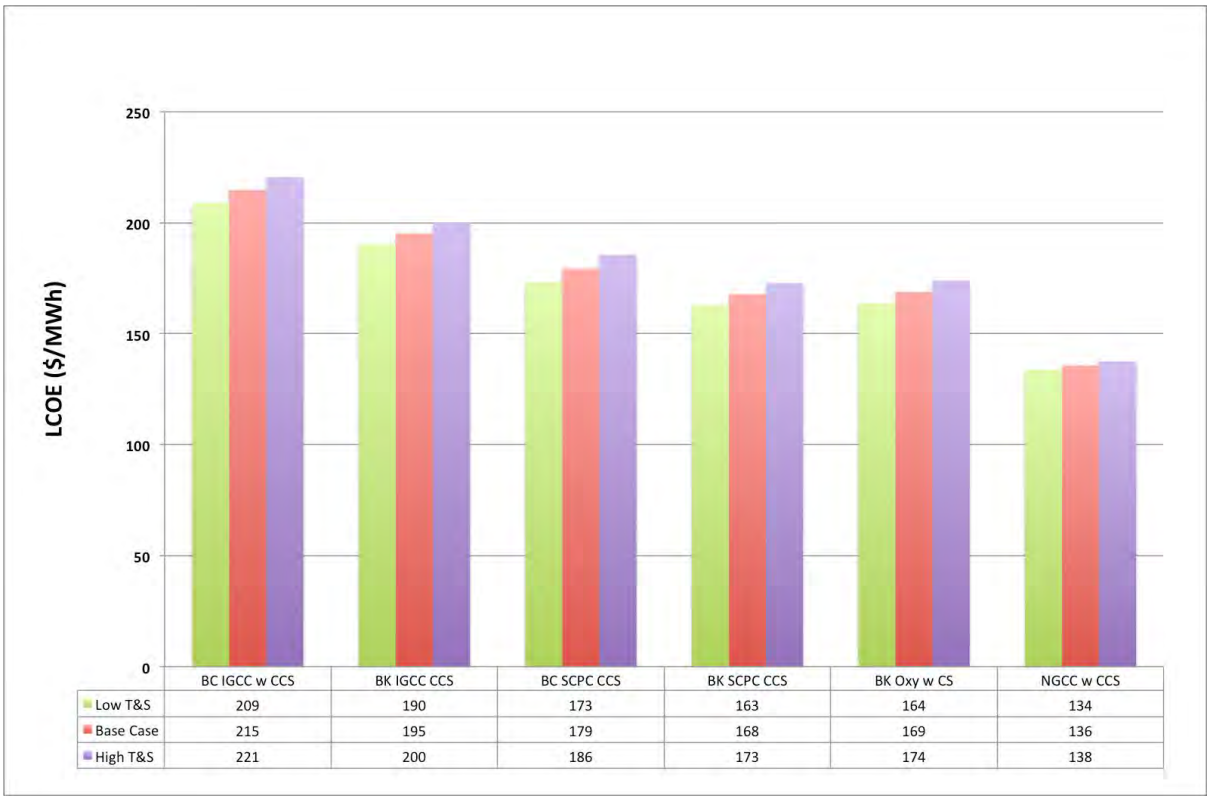
	BC IGCC	BC IGCC w CCS	BK IGCC	BK IGCC CCS	BC SCPC	BC SCPC CCS	BK SCPC	BK SCPC CCS	BK Oxy w CS	NGCC	NGCC w CCS	NG OC frame	NG OC aero	Gas Recip	Diesel
Base Case	128	215	122	195	80	179	79	168	169	78	136	269	158	140	275
Low Carbon	159	223	146	198	109	183	103	171	170	89	138	286	173	154	296
Medium Carbon	199	235	177	203	147	189	135	175	173	104	142	308	192	173	324
High Carbon	260	252	225	209	204	197	182	182	176	126	147	341	221	202	366

Figure 79: Fossil fuel carbon price sensitivity of LCOE ($/MWh)

7.8 CO_2 transport and storage sensitivity

While there is currently no carbon transport and storage infrastructure in Australia, a sensitivity analysis was completed for three transport cost scenarios (shown in Figure 79):

- low transport and storage cost—$10/t
- base case transport and storage cost—$15/t
- high transport and storage cost—$20/t.



	BC IGCC w CCS	BK IGCC CCS	BC SCPC CCS	BK SCPC CCS	BK Oxy w CS	NGCC w CCS
Low T&S	209	190	173	163	164	134
Base Case	215	195	179	168	169	136
High T&S	221	200	186	173	174	138

Figure 80: Transport and storage cost sensitivity of LCOE ($/MWh)

7.9 Overall cost of electricity ranges and rankings

There are a number of factors leading to uncertainty in the estimates and variability in the results of this study. All of the cost estimates included in this report have an inherent uncertainty due to the level of detail included in the cost estimate. Factors that affect the cost estimates include:

- volatility in the price of power plant equipment
- rapid changes global economic conditions
- changes in anticipated capacity expansion.

The following charts (Figure 81 to Figure 84) show the combined impact of uncertainty ranges for plant capital costs, fuel costs, project- and site-specific costs, capacity factor ranges and CO_2 transportation and storage costs. While they still may not capture the absolute extremes of cost estimates, they provide a broader range of estimates due to the uncertainties:

- The low-end estimates of the charts assume a best case scenario: capital cost estimates and fuel prices are at the low end of the sensitivity ranges investigated above. For renewable technologies, the lowest and highest available resource was assumed.
- The high-end estimates of the charts assume the higher side of the uncertainties: capital cost estimates and fuel prices are at the high end of the sensitivity ranges investigated above. For renewable technologies, the highest available resource was assumed.

The LCOE was also calculated for 2030 using future fuel cost forecasts, GALLM and road map capital cost estimates, and road map technology improvements.[1] There remains a high degree of uncertainty around all of the factors that contribute to a 2030 estimate. The 2030 LCOE estimates are given in Figure 85 to Figure 87. While the road map has capital estimates for 2030, GALLM does not estimate capital for all the technologies in this study.

[1] See Chapter 15, Section 15.14 for a description of the road map capital estimating methodology.

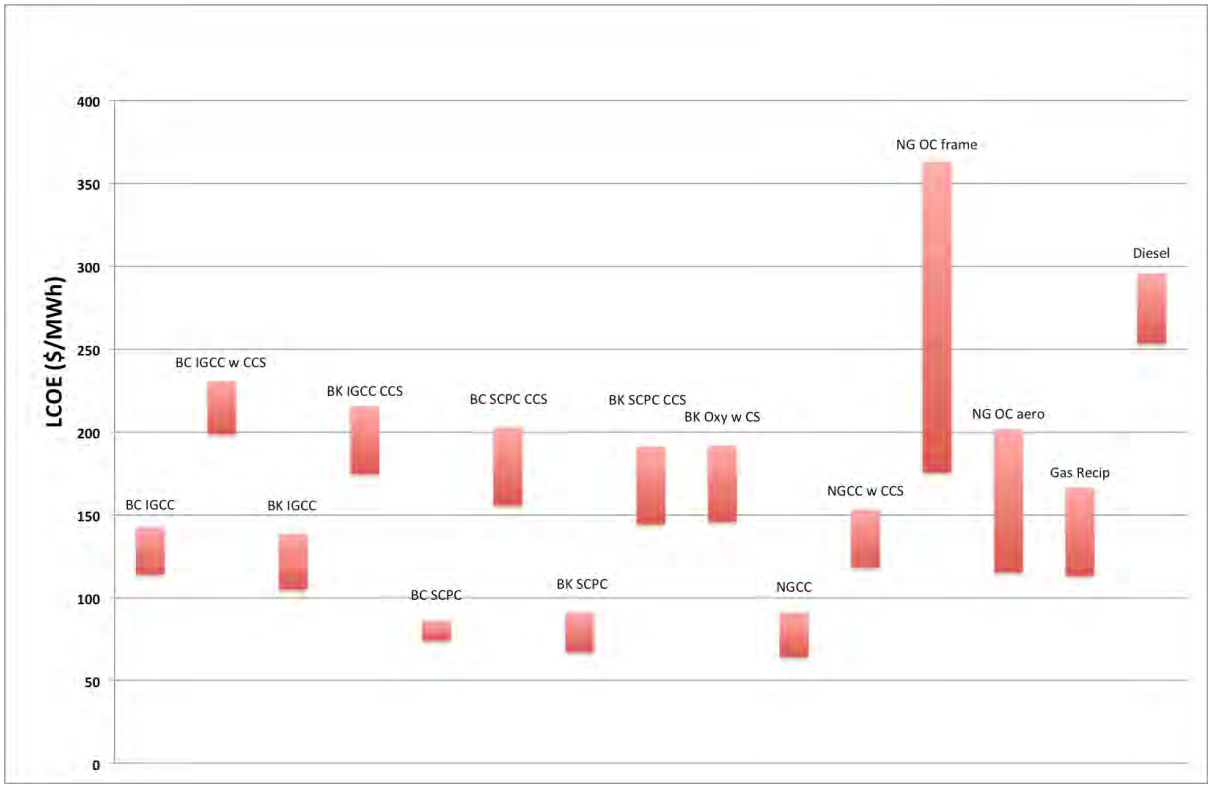


Figure 81: Fossil-fuel LCOE ranges for 2015

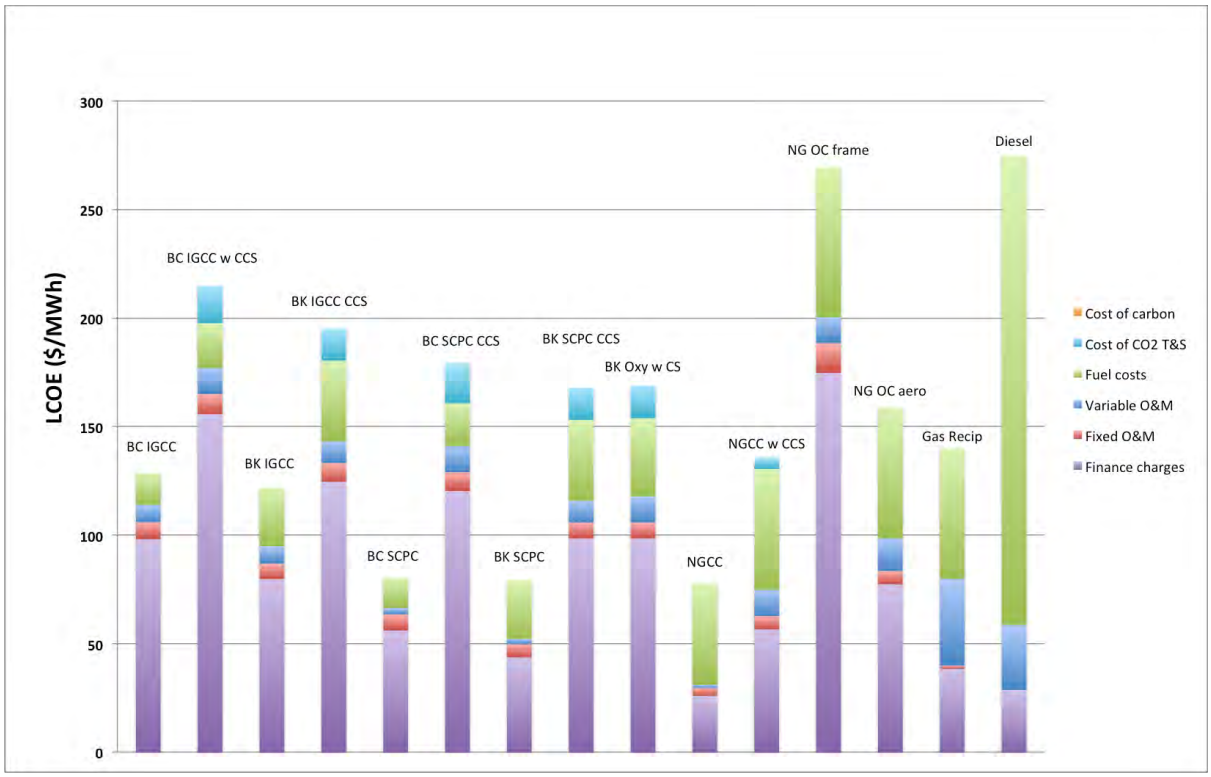


Figure 82: Fossil-fuel average LCOE components for 2015

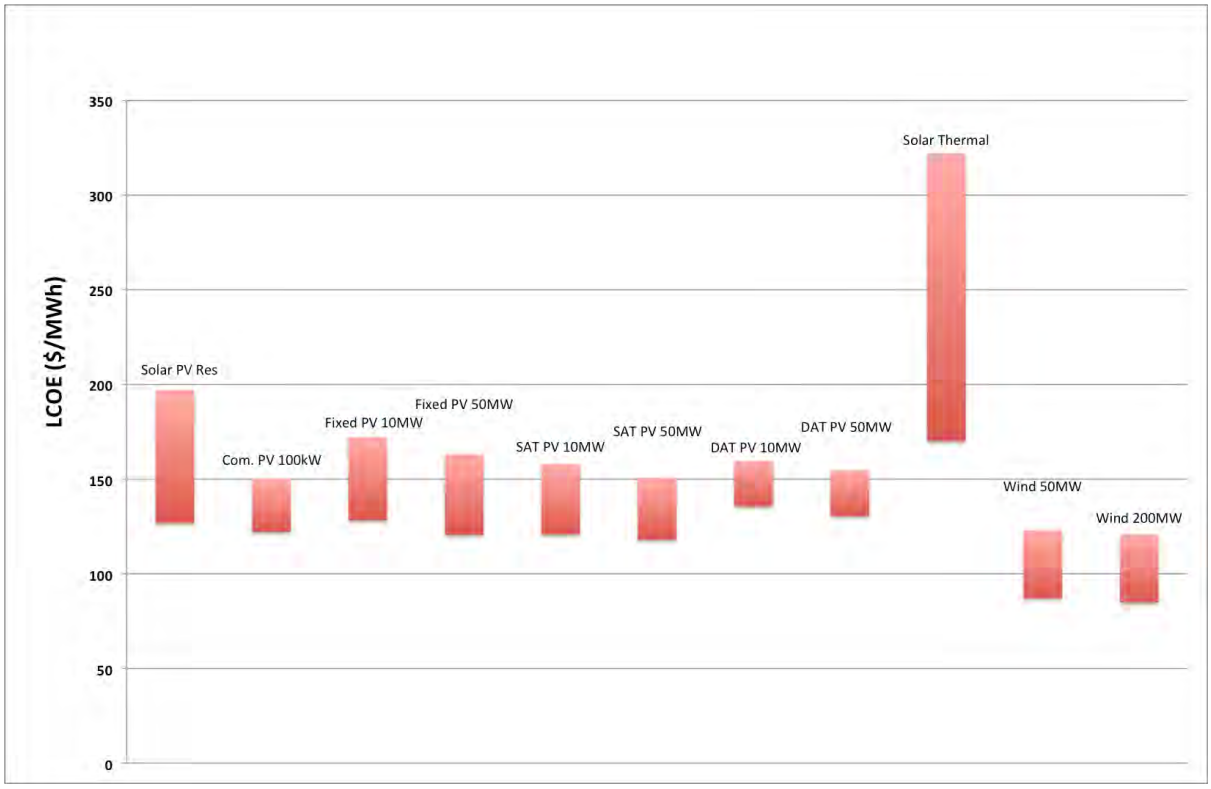


Figure 83: Renewable LCOE ranges for 2015

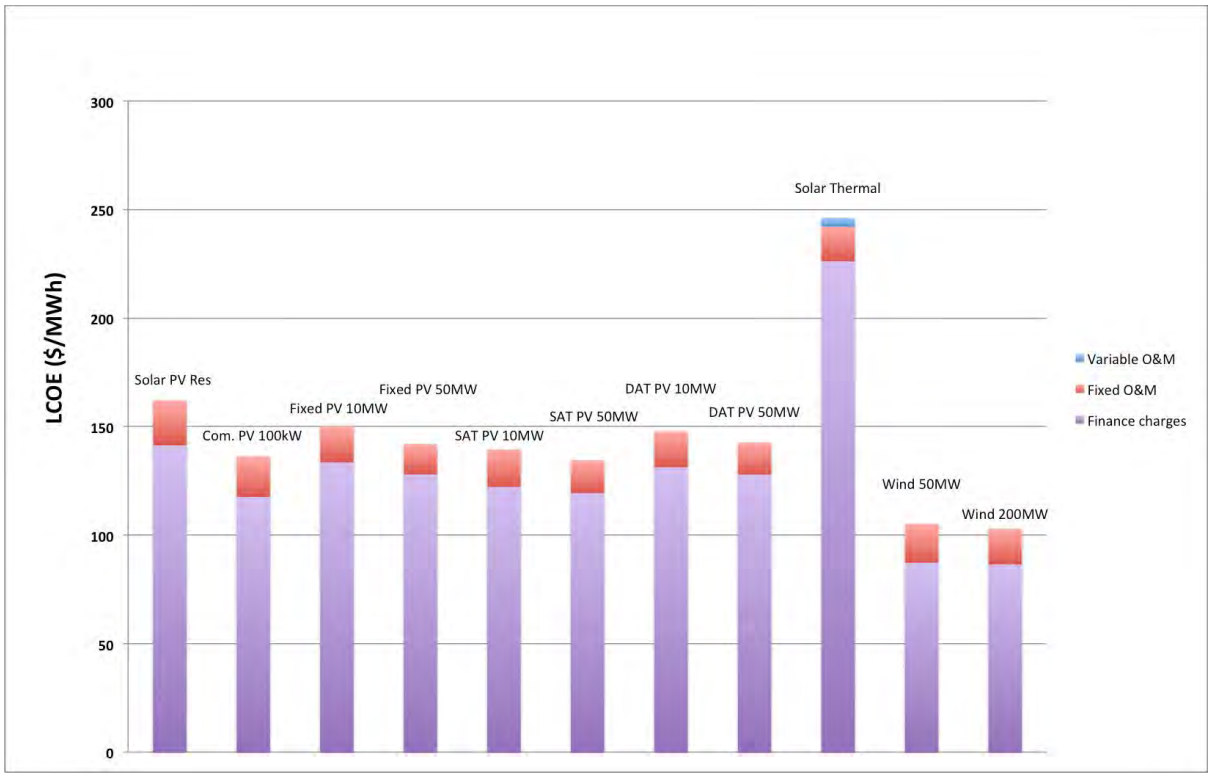


Figure 84: Renewable average LCOE components for 2015

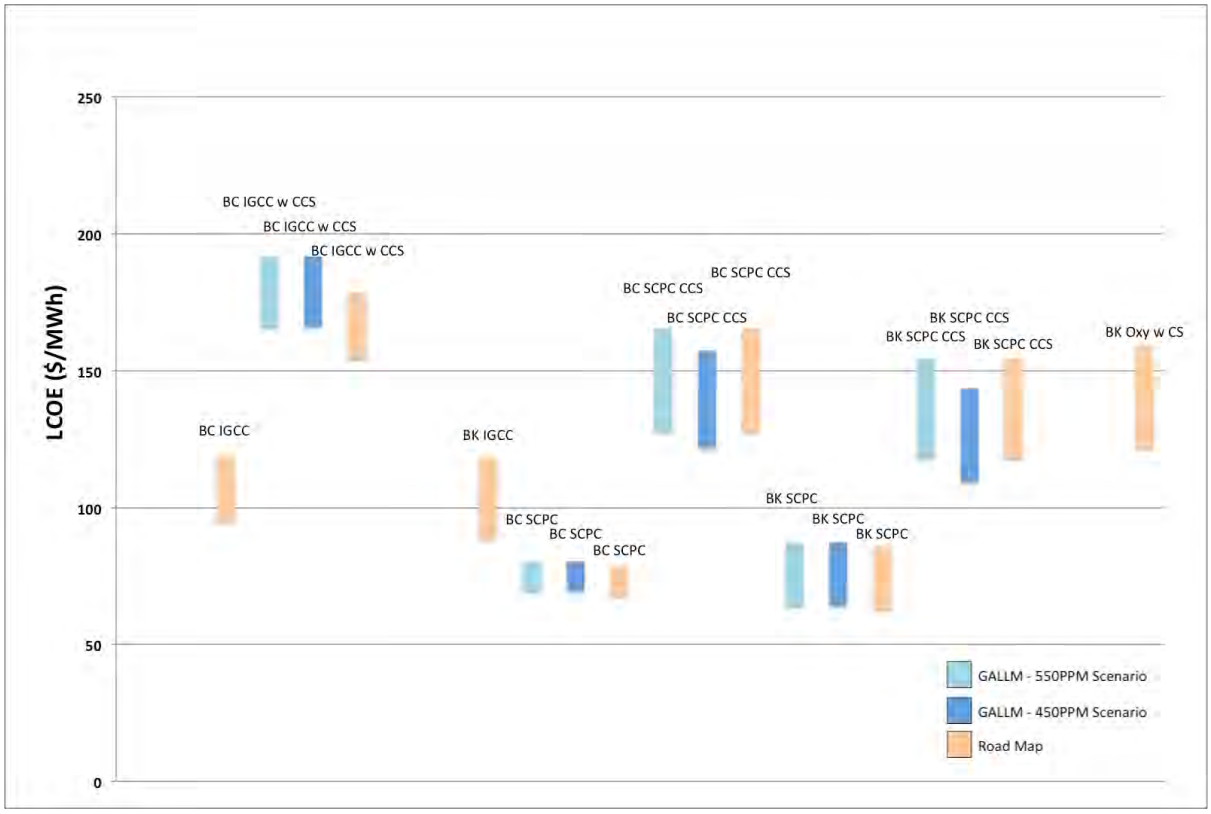


Figure 85: Coal-based LCOE ranges for 2030

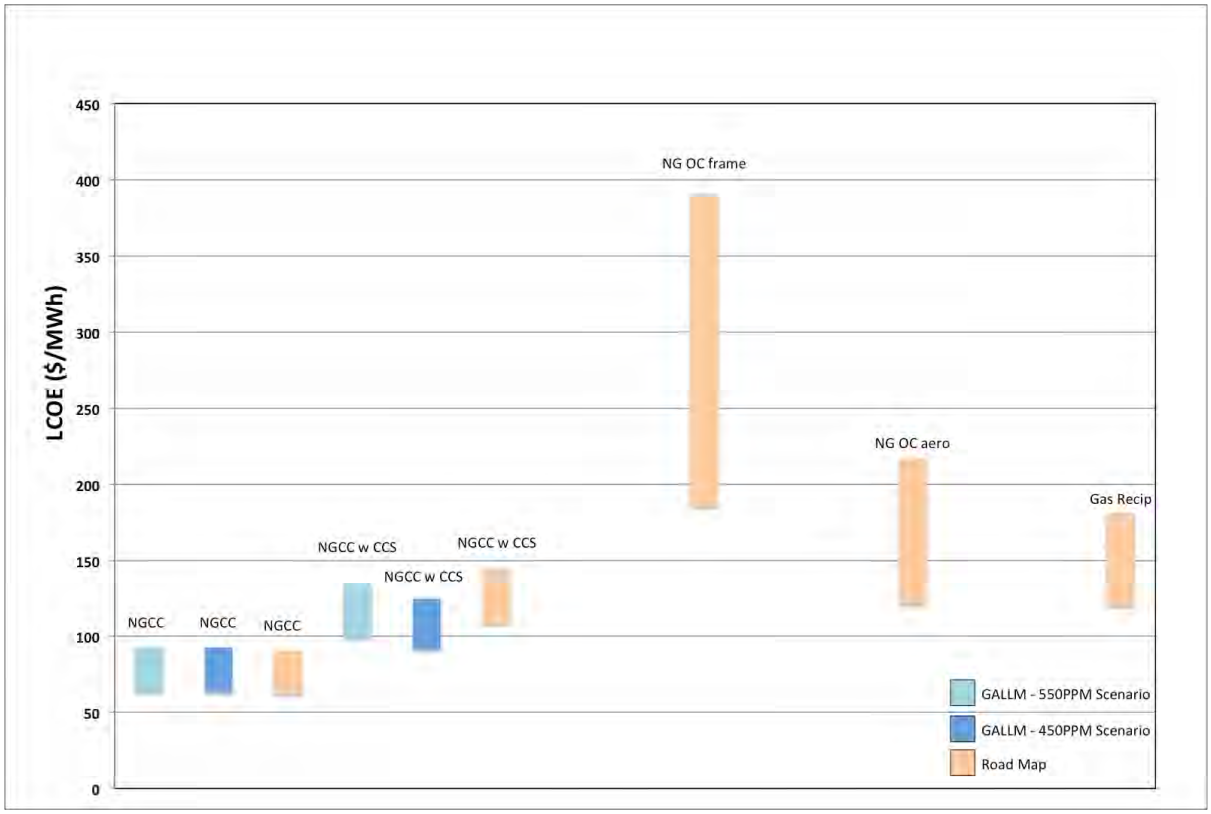


Figure 86: Gas-based LCOE ranges for 2030

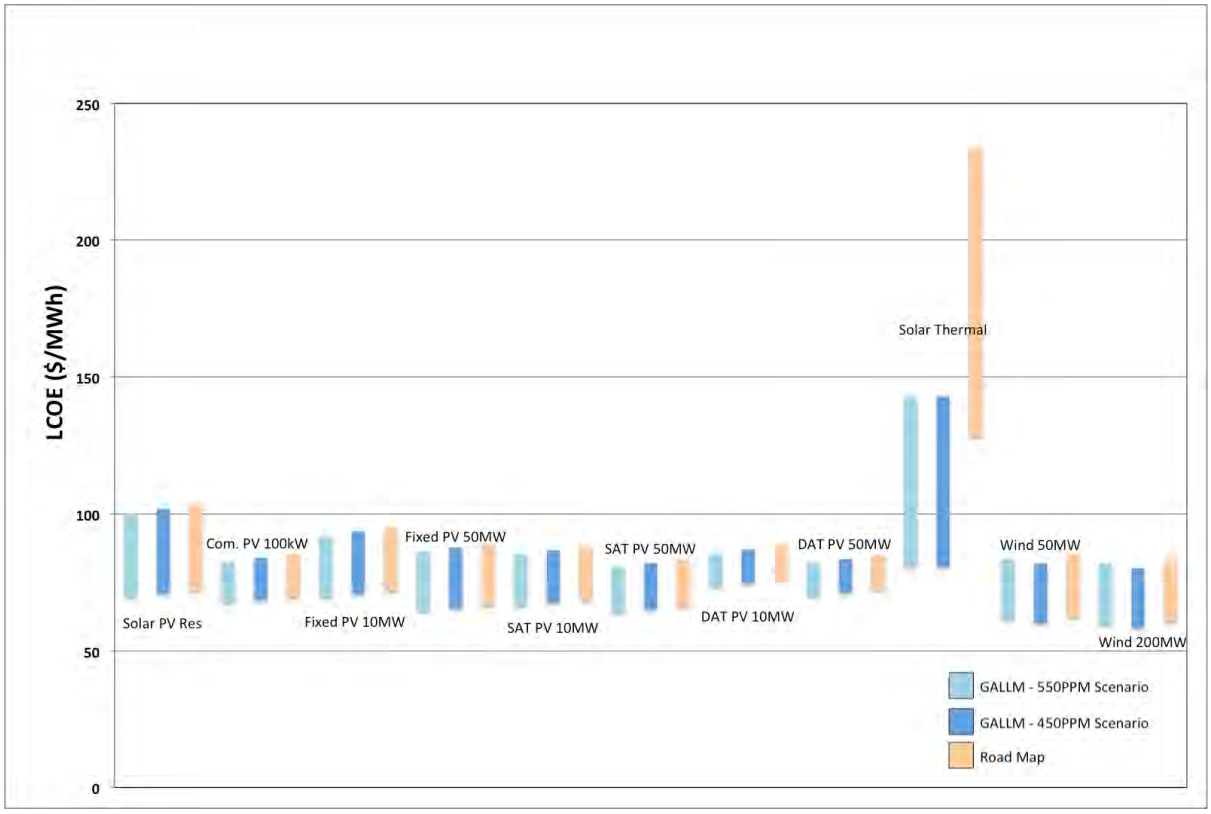


Figure 87: Renewable LCOE ranges for 2030

8 ENERGY STORAGE TECHNOLOGY

Energy storage—highlights:

- Energy storage technologies can increase the efficiency of operating electricity grids. Their technological and economic development will play a key role in the planning and designing of future systems.
- Storage systems allow for better matching between load and generation, increasing the opportunity for selecting the lowest cost generation sources. Storage can act:
    - as an alternative to peaking generation, by injecting energy into the grid at peak times
    - to support baseload generators, by smoothing demand across the day
    - to support variable renewables, by shifting production to match the system load.
- Behind-the-meter storage with the opportunity for centralised control may provide the greatest value for both consumers and the market.
- There is currently a strong focus on battery technologies, particularly lithium ion batteries, but pumped hydro storage, molten salt storage and other technologies may play a valuable role in the future.

This chapter is not meant to replace or replicate significant recent reports published by the AEMC, ARENA and the AEMO that consider the relative merits of specific energy storage technologies in detail. All storage technologies currently require further cost reductions to be economically viable in most applications in urban Australia, but there are likely to be a number of early adopters or specific uses in which the economic benefits will justify the costs. At the same time, costs are continuing to fall and a significant number of technologists and market participants are developing products with cost-reduction potential. Therefore, we highlight the opportunities and consequences of energy storage in the market, identify several promising technologies, and provide references to supplementary, technology-specific information as appropriate.

8.1 Introduction

Energy storage is an intrinsic part of the operation of the grid, enabling electricity to be supplied on demand. This includes chemical storage in fossil fuels (for example, ancient solar energy stored in coal) and storage in water reservoirs for hydropower stations. The key ability of storage in this context is to enable more flexibility by separating energy production and consumption through time.

More often, however, the term ‘energy storage’ is used to refer to energy reservoirs that can charge from and discharge into the grid, and do so regularly on timescales ranging from hours to days. The growth of on-grid storage has been limited; most storage capacity installed worldwide is in the form of pumped hydro, but environmental concerns have limited the take-up of new sites, while competing technologies have not been cost-effective.

More recently, interest in existing and emerging storage technologies has been driven from two directions. First, higher penetrations of variable renewables in the grid, as well as the rapid take-up of behind-the-meter embedded generation (mainly rooftop solar PV), has increased the market opportunity for flexible generation and consumption. Wind and solar technologies (as well as technologies such as run-of-river hydro) must 'use or lose' their energy resource at each moment, and so energy storage may enable higher penetrations of those technologies.

At the same time, battery storage costs have fallen significantly, driven by requirements for portable electronics as well as larger-scale applications, raising the possibility of cost-competitive storage technology applications in the grid. In particular, behind-the-meter storage coupled with rooftop solar PV could be a significantly disruptive technology.

Although storage costs and uses are separate from those of energy-producing technologies, the availability of low-cost storage in the future could drive quite different outcomes. The fundamental role of storage is to shift energy production and consumption to more convenient (that is, lower cost) times. Therefore, storage may compete with conventional generators (particularly peaking generators) for supplying energy at times of high demand, or may complement baseload generators or variable renewable technologies by better matching electricity demand to their production across the day.

This chapter provides an overview of the role of storage in the market and how it should be considered when evaluating the future grid.

8.1.1 Energy storage fundamentals

Energy storage units are defined by several key characteristics:

- *Power output rating:* The storage unit's power output rating or peak discharge rate in kW or MW is the maximum load that it can deliver. For example, in a residential context, a lower maximum power output limits whether an air conditioner and induction stove can be operated simultaneously. In some cases, storage units can operate at higher peak outputs for a brief period before overheating or other constraints are enforced; this can be valuable for facilitating brief periods of high use.
- *Charging power rating:* Depending on the technology, the storage unit's maximum charging power rating may be different from its power output rating. This is the rate at which the unit can be recharged; a high rating can be useful for taking advantage of low-price charging periods.
- *Energy rating:* The unit's energy rating or capacity, measured in kWh, MWh or hours at full discharge rate, is the total amount of energy that can be supplied from the unit, and hence the total *time* that a given activity (such as running a stove) can be undertaken using the unit.
- *Cycle count:* Most storage units have a lifetime that is best measured in cycles (charge and discharge). For batteries, the cycle count is affected by the depth of discharge that is used (that is, the minimum level that the storage unit is allowed to drop to). Lower depths of discharge reduce the effective energy rating of the storage unit but can increase the cycle count, such that the total energy throughput of the unit over its lifetime is higher. For other technologies, the cycle count may reflect wear and tear on the unit.

- *Round-trip efficiency:* The storage unit's round-trip efficiency is the (typically AC) energy delivered from the unit divided by the (typically AC) energy input to the unit. This accounts for losses in the storage process, such as inverter and other power electronics for battery storage, turbine inefficiencies for pumped hydro, and so on. Low-efficiency storage units will be more expensive (all else being equal) and will increase the total energy production required in the system.

In general, a broad range of power and energy ratios can be achieved for any given storage technology, but some technologies are better suited for one role or another. For example, flywheel technologies can be discharged rapidly but do not have large energy capacities.

8.1.2 Generator, load or demand-side management

Storage acts as both a load and a generator in the market, charging when energy is cheap and discharging at times of peak demand or to meet another requirement in the market. However, in contrast to peaking generators, the output of which is limited only by fuel constraints (such as gas pipeline pressures), production from an energy storage unit is limited by the amount of stored energy, and further constrained by the need to refill that storage (that is, to act as a load) after generation.

Therefore, we consider that energy storage should more accurately be considered as a demand-side management or load-shifting tool, rather than as a generation technology. In fact, due to inefficiency in energy storage, storage units will *increase* the total load on the system, but allow the load to be met at more opportune (and, one hopes, lower net cost) times. This can allow more efficient use of the existing generation fleet, more efficient choices for new generation, or both. An exception is concentrating solar power with storage, which cannot directly charge from the grid and may more closely represent an energy-limited conventional generator.

The operation of the storage unit depends on the specific application it was installed for, as discussed further below.

8.1.3 Cost assessments

Several key challenges exist for quantifying and forecasting storage costs.

First, due to the rapid growth in some storage technologies (particularly batteries), technology efficiency, quality and production costs have all improved significantly over recent years. This has meant that reports on 'today's' storage costs are at risk of being out of date even before publication.

Second, for emerging storage technologies, uncertainties about technologies and future take-up rates mean that forecasts of future costs will be quickly rendered obsolete in the light of updated information.

Finally, even specifying the costs depends on the desired application. In the reports cited in this chapter, costs can be presented as:

- dollars per nameplate power rating ($/kW), which is suitable for applications where peak power output is the critical variable
- dollars per nameplate storage capacity ($/kWh), which is suitable for applications that require the shifting of energy
- levelised cost ($/kWh-delivered), which takes into account the varying lifetimes and efficiency ratings of different technologies, but which also requires assumptions about behaviour and use.

This chapter provides summaries of publicly available costs of 'off the shelf' storage systems, as well as publicly available trajectories of future costs.

8.2 Storage technologies

Figure 88 shows one way of classifying storage technologies—according to how they store their energy. This can include more conventional generation (fuel cells, hydrogen storage) that acts as distributed (embedded) stored energy, physical storage processes (flywheels, thermal storage) and electrochemical storage (batteries).

In this section, we provide an overview of some of the more advanced or promising storage technologies. Some of them are well established, while others are still being developed for commercial deployment.

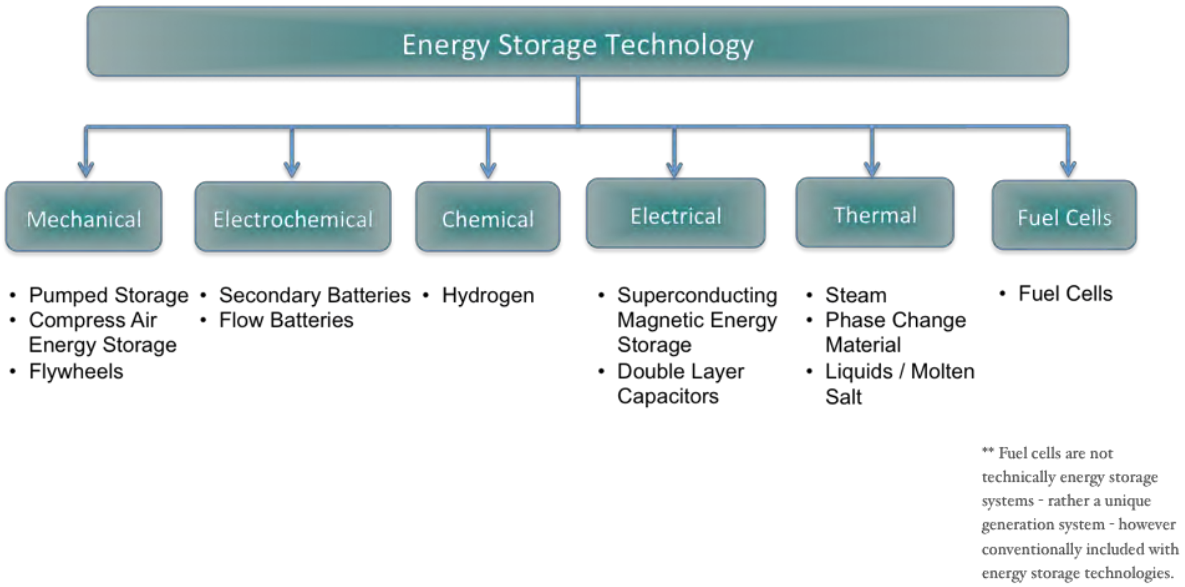


Figure 88: Overview of energy storage technologies

Source: http://www.powerfactbook.com (accessed October 2015—subscription required).

8.2.1 Battery storage

Batteries store energy through electrochemical processes and are the most flexible and versatile storage technology as they are capable of both small-scale embedded applications and large installations. In particular, batteries can be designed with a broad range of ratios between power output and energy storage, allowing flexibility across a range of applications. They are also self-contained systems that are generally low maintenance and, when integrated with the appropriate power electronics, may be able to provide off-the-shelf storage to residential and commercial customers.

Batteries already play a number of critical roles in electricity systems, including supplying off-grid households and providing uninterruptible power supplies for residential, commercial and grid applications. However, to date, they have not been cost-effective for general use in urban areas, or as viable alternatives to peaking capacity. Nevertheless, with growing consumer interest in behind-the-meter storage, many technologies are now being pursued. This section reviews a number of potential technologies, but we note that there are many in-development battery storage technologies that might provide significant cost reductions or other benefits yet to be identified.

Lead-acid batteries

Lead-acid batteries have existed since the mid-1800s. They are used in a variety of applications, including in cars and off-grid power supply. As a mature technology, conventional lead-acid batteries are unlikely to have significant cost-reduction potential. However, there are emerging advanced lead-acid technologies that provide superior performance over conventional lead-acid batteries, including longer lifetimes, very fast response times (by incorporating supercapacitor-like technologies) and faster charging rates.

For example, CSIRO has developed and licensed the UltraBattery,[1] which combines lead-acid technology with supercapacitors, such as those used to power camera flashes. The UltraBattery is reported to have a longer lifetime, a longer cycle life and more competitive costs than a conventional lead-acid battery.

Barriers to this technology include cost-competitiveness against competing technologies, limitations on depth of discharge, performance under Australian climatic conditions and regulations for safe disposal.

Lithium ion batteries

Lithium ion (Li-ion) batteries include a broad class of technologies using a range of materials but all using lithium ions as a key feature of the battery chemistry. Globally, Li-ion batteries are used extensively in portable electronics, and more recently in electric vehicles. This has led to cost reductions and interest in deploying them in grid applications, including residential behind-the-meter storage.

Li-ion batteries can be manufactured to achieve almost any size-to-power ratio, have long lifetimes and are able to store large amounts of energy for their size. They also feature high round-trip efficiencies (up to 98%, although typical efficiencies are 90–95%, not including AC–DC conversion), and can accept high depth of discharge levels (typically 80%). This makes them highly flexible and suitable for a range of applications, from providing rapid and frequent ancillary services through to daily cycling in residential or commercial applications.

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[1] www.csiro.au/en/Research/EF/Areas/Energy-storage/UltraBattery (accessed October 2015).

Deployment in grid applications has been limited to date, particularly in Australia, but several companies have recently announced plans to roll out off-the-shelf storage systems to consumers. The most notable is Tesla's Powerwall storage unit, which the company will produce at a new 'gigafactory' under construction at Sparks, Nevada, in the United States.[2]

Li-ion batteries require important safety considerations, since lithium is combustible and overcharged batteries can ignite; this must be protected against through power electronics. Lithium is also a rare earth metal, and long-term resources and costs are uncertain.

The cost of Li-ion batteries is difficult to assess due to both significant recent (and ongoing) price reductions for the batteries and the lack of publicly available 'fully installed' costs for any recent systems. Reported prices also vary widely depending on whether they include associated electronics, the inverter and installation costs. Nevertheless, Figure 89 shows that there has been a clear historical trend towards declining costs over the past decade. There is a broad market consensus that costs will continue to fall in the future.

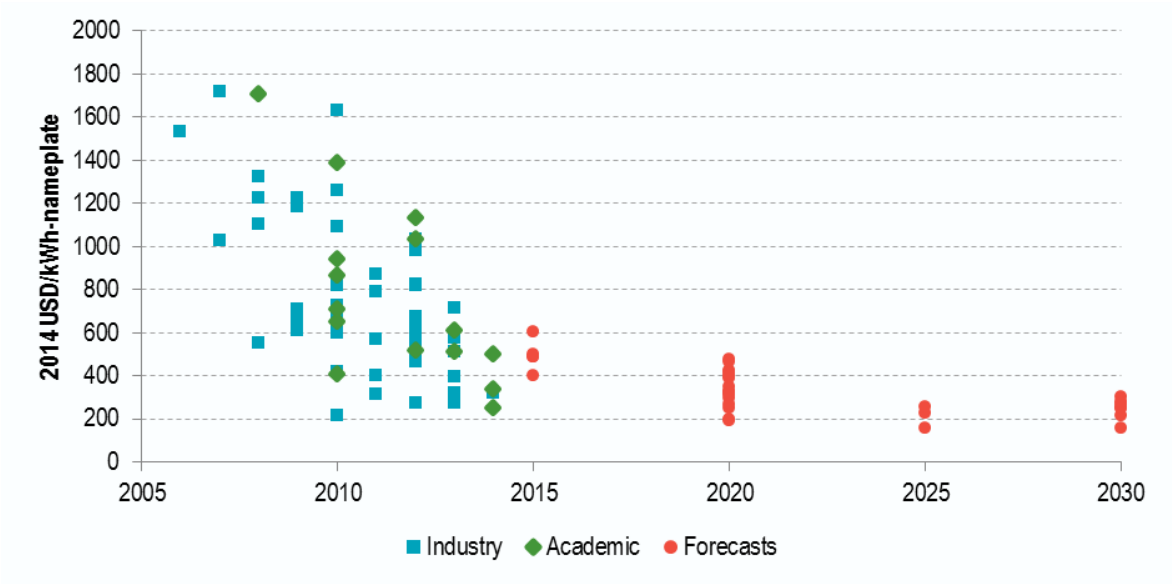

Figure 89: Historical trends in Li-ion battery costs reported in publications

Source: www.teslamotors.com/en_AU/gigafactory (accessed October 2015).

The recently announced Tesla Powerwall will not be widely available until 2016 but may be a useful benchmark for near-term modelling. The household product (a 7 kWh storage unit designed for daily cycling) has a retail price of US$3,000 (around A$4,600, including GST). Although full details are not yet available, the price is not expected to include the cost of the rectifier and inverter (to convert AC to DC and back again for the battery), but this will otherwise be a 'plug and play' technology. The remaining components could be shared with a residential or commercial solar PV system. Currently installed inverters are not likely to be compatible with the Powerwall (requiring an additional inverter to be purchased), but future solar PV inverters could allow a Powerwall (or other storage system) to be installed then or at a later date for just the cost of the system plus installation. This would also apply to older systems requiring an inverter replacement (many older inverters were warranted for only 10 years).

[2] www.teslamotors.com/en_AU/gigafactory (accessed October 2015).

Several companies have proposed 'fully installed' costs for the Powerwall plus an inverter in Australia, as collated by the AEMO in its *Emerging technologies information paper* of June 2015.[3] That analysis is reproduced in Table 62.

Table 62: Estimated fully installed Powerwall costs, including inverter

Agency	Estimated cost ($/kWh, based on 7 kWh system)
Recommended retail price (excl. installation)	657
AEMO	1,214
UBS	739
Morgan Stanley	597
SunWiz	1,272

The range of costs indicated highlights, again, uncertainty about current and future technology costs, as well as inconsistencies between what is included in the 'system' and what is not. The AEMO proposed a cost-reduction trajectory of 12% year on year on the fully installed cost; this is consistent. While this trajectory is reasonable for a planning scenario, costs could fall much faster if there is a technology breakthrough or just rapid global take-up, as occurred with rooftop solar PV.

Flow batteries

Flow batteries have a flowing electrolyte that flows between a storage tank and a reaction chamber. Therefore, they contain more parts that some other battery technologies and are typically larger, but they can usually be fully discharged on a regular basis without problems, have good lifetimes, and are broadly environmentally friendly.

Although flow batteries are still developing as a technology, several companies have commercial products available for grid applications. Given their larger size, they may be more likely to be used for commercial- and utility-scale customers rather than residential customers.

Table 63 highlights some of the characteristics of currently available flow battery technologies.

[3] www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report/~/media/Files/Electricity/Planning/Reports/NEFR/2015/Emerging%20Technologies%20Information%20Paper.ashx (accessed October 2015).

Table 63: Existing flow battery characteristics

	Imergy ESP30 (vanadium)	ViZn Z205 (zinc-iron redox)	Redflow LSB (zinc-bromide)	Uni.System (vanadium)
Energy	120–200 kWh	125–160 kWh	10 ft–260 kWh 20 ft–660 kWh	Up to 2.2 MWh
Duration	Up to 7 hours	Up to 5.65 hours	Varies on container	Up to 15 hours
Cycles	100,000	N/A	'Guaranteed indefinite life'	10,000+
Depth of discharge	100%	100%	100%	100%
Efficiency	70–75% DC/DC	56–70%	80% DC/DC	65–70% AC/AC

Source: *Energy Storage Update* (2015), http://analysis.energystorageupdate.com/flow-battery-deals-build-manufacturing-base-commercial-phase (accessed October 2015).

One company (Redflow) recently announced a 50% reduction in price over six months for two of its flow battery productions, bringing technology costs to US$9,750 for an 11 kWh system (A$1,360/kWh).[4] This price appears to be for the system alone, so installation and the inverter would be additional costs.

Although this price is currently higher than prices for state-of-the-art Li-ion batteries, the significant cost reductions over 6 months, combined with growing competition in the sector, may drive further cost reductions in the next few years.

Battery cost projections

CSIRO recently released modelling commissioned by the AEMC in which it examined battery costs and storage take-up levels. [5] The CSIRO GALLM learning curve model was used to develop cost projections for battery technologies into the future, as shown in Figure 90. 'Lead acid' refers to advanced lead-acid technologies (as discussed above); zinc bromide is a type of flow battery.

This suggests that battery costs in 2030 could be less than half the costs of the cheapest units currently available, and with significantly more flexibility to choose the most appropriate battery for a given task. Combined with a forecast 35% reduction in inverter costs (Figure 91), this will significantly improve the economics of battery storage.

[4] www.asx.com.au/asxpdf/20150826/pdf/430t3zt7rtzx1q.pdf (accessed November 2015).
[5] www.aemc.gov.au/Major-Pages/Integration-of-storage/Documents/CSIRIO-Future-Trends-Report-2015.aspx (accessed November 2015).

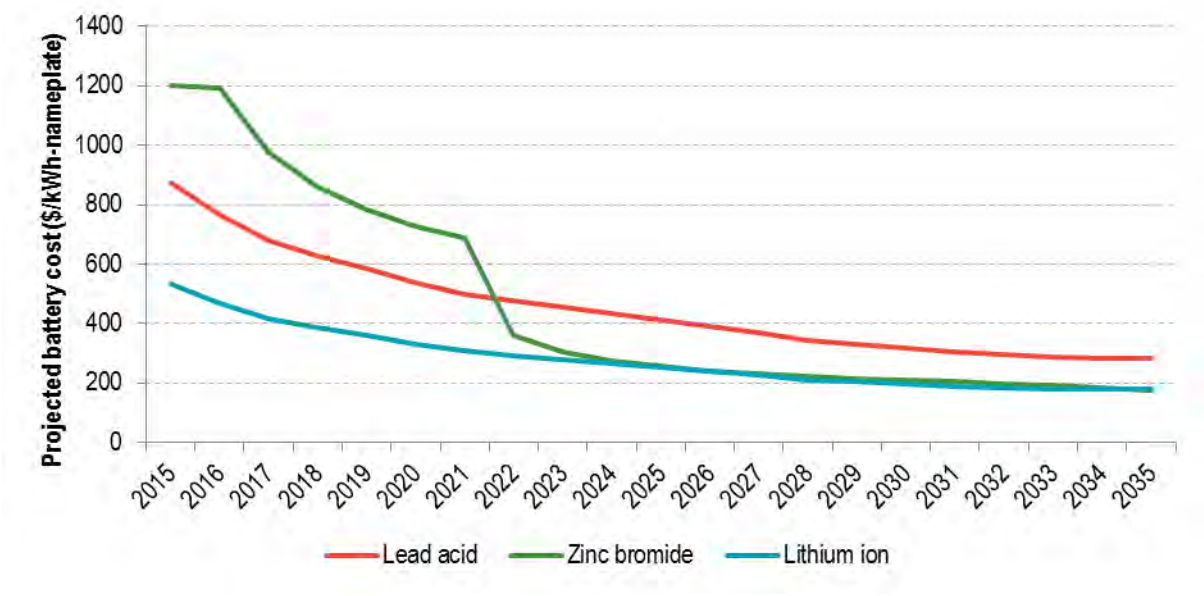

Figure 90: Projected battery costs

Source: AEMC (2015), www.aemc.gov.au/Major-Pages/Integration-of-storage/Documents/CSIRIO-Future-Trends-Report-2015.aspx (accessed November 2015).

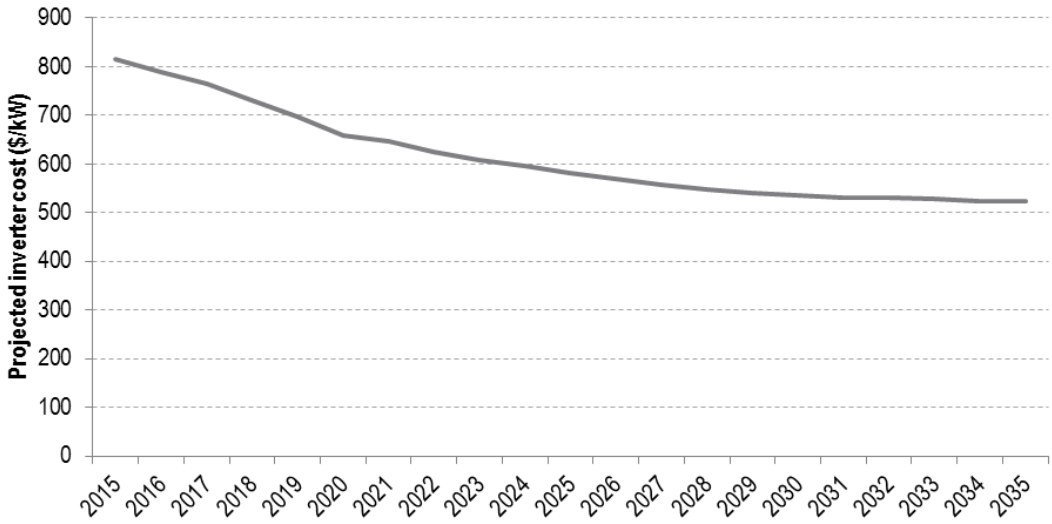

Figure 91: Projected inverter costs

Source: www.aemc.gov.au/Major-Pages/Integration-of-storage/Documents/CSIRIO-Future-Trends-Report-2015.aspx (accessed November 2015).

8.2.2 Flywheels

Flywheels for energy storage involve heavy, spinning weights that store energy through rotational momentum. Although they typically have lower energy density than batteries, they can be charged and discharged quickly, making them useful for applications such as ancillary services.

8.2.3 Pumped hydro

Pumped hydro storage is a mature technology for storing very large amounts of energy. Typical pumped hydro schemes can have rated capacities in the range of 100–1000 MW with discharge times in the order of hours to days.[6] The capabilities of the schemes are highly dependent on the local terrain and the construction of the accompanying dams. Because of these constraints, providing 'generic' or 'typical' operational and cost profiles for these schemes can be challenging.

In general, the schemes consist of two bodies of water separated in the vertical plane by a height usually greater than 80 m. This height is commonly referred to as the 'head' height and is a key parameter in determining the potential energy that can be stored in the scheme. Typically, one reservoir is an existing body of water, while the other is constructed based on local geographical features (for example, a small valley may be suitable for damming). Some pumped hydro storage systems use seawater as their primary reservoir, which provides a convenient source (particularly if cliffs by the ocean enable a large height difference) but requires additional engineering to cope with salt water.

Electricity is produced by converting the potential energy stored in the body of water at height into electrical energy through a turbine and generator. By increasing either the height or the volume of the water in relation to the generator, more electrical energy can be produced. By reversing this process, by consuming electrical energy from the grid to activate pumps to move the water from the lower dam to the upper dam, electrical energy is effectively stored in the form of water at an elevated height.

Cyclic efficiencies for pumped hydro schemes have been steadily increasing throughout the past 50–60 years, and more recent projects have achieved efficiencies of 80%.[7]

In Australia, there are three main pumped hydro schemes in operation; Tumut III, Shoalhaven and Wivenhoe. While a number of possible sites have been identified for new-entrant schemes, none has so far progressed to construction due to a combination of cost, revenue, environmental and technical constraints.

Recently, Genex announced that the proposed Kidston pumped hydro scheme in northern Queensland has moved into the prefeasibility development stage. This project benefits from the presence of two abandoned mining pits that are arranged such that upper and lower dams for a scheme could be formed. This significantly reduces the cost of constructing the associated dam works required for a greenfield site. Genex has estimated the total cost of the 330 MW/1650 MWh Kidston project to be $282 million ($854/kW or $200/kWh-nameplate), which is competitive with other storage technologies.

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6 http://content.webarchive.nla.gov.au/gov/wayback/20140212001051/http://www.climatechange.gov.au/sites/climatechange/files/files/reducing-carbon/APPENDIX4-ROAM-report-on-pumped-storage.pdf (accessed November 2015).

7 http://webarchive.nla.gov.au/gov/20140211194248/http://www.climatechange.gov.au/reducing-carbon/aemo-report-100-renewable-electricity-scenarios; ROAM report on pumped storage modelling for AEMO 100% Renewables project, September 2012 (accessed November 2015); www.alstom.com/Global/Power/Resources/Documents/Brochures/hydro-pumped-storage-power-plant.pdf (accessed November 2015).

Future take-up of pumped hydro storage in Australia will require the identification of suitable sites that are near to transmission lines and are not subject to environmental concerns. Studies by ROAM Consulting for the AEMO 100% Renewables Study[8] and by the Melbourne Energy Institute[9] have indicated that a large number of potential sites exist, both inland and coastal (saltwater). The Melbourne Energy Institute found that costs could be as low as $100–200/kWh, although this could vary significantly between sites.

8.2.4 Molten salt storage

Concentrating solar thermal power stations can store heat gathered during the daytime to use at night. Currently, this is achieved by using large tanks of molten salt: salt is pumped from the 'cold' tank to the 'hot' tank during the day, absorbing heat from the concentrating solar array, and pumped back again during the night (see Section 3.2.1 for more detail).

Coupling solar thermal power stations with thermal storage is distinct from coupling solar PV plants with electrical storage. In the former case, all energy used to charge the storage must come from the solar plant; in the latter, any generator can be used to charge the battery storage. Nevertheless, molten salt storage can improve the use of the solar power plant and help to differentiate the technology's production profile from that of rooftop solar PV.

8.3 Roles of storage

8.3.1 The role of energy storage in the market

Storage can play a number of key roles in the energy market. In this section, we give a non-exhaustive list of storage applications, with a particular focus on those that most affect the generation sector.

8.3.2 Utility-scale energy arbitrage

Arbitrage broadly describes the role of storage in purchases of electricity from the grid during low-price periods and sales of it back to the grid in high-priced periods. To be profitable, the frequency of the charge–discharge cycles and the price differential between charging and discharging periods must both be high enough to cover the capital and operating costs of the storage unit over its lifetime. Strong market price forecasting capabilities are likely to be needed to ensure that the storage unit has capacity available to supply in the highest price periods, even if that means charging in 'moderately' priced periods.

8.3.3 Consumer/commercial tariff avoidance

Behind-the-meter storage has been the subject of considerable recent discussion. Similarly to utility-scale arbitrage, it allows consumers whose tariff varies by time of day to shift their demand for energy to lower cost times. More significantly, it allows consumers with rooftop PV systems to store that energy for use in the evening, rather than exporting it to the grid. Because consumer tariffs are typically higher than the value of the exported energy (as the tariffs include network charges, green scheme costs and other components), this is a significant opportunity for consumers to earn value through arbitrage.

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8 http://content.webarchive.nla.gov.au/gov/wayback/20140212001051/http://www.climatechange.gov.au/sites/climatechange/files/files/reducing-carbon/APPENDIX4-ROAM-report-on-pumped-storage.pdf (accessed November 2015).

9 www.energy.unimelb.edu.au/files/site1/docs/39/20140227%20reduced%20.pdf (accessed November 2015).

At the highest level, the impact on the grid from this behaviour will be similar—demand will be higher during the middle of the day and lower in the evening. However, unless appropriate incentives and control systems can be agreed upon with the consumers, the full value to the grid (and hence the benefits from optimising the generation) may not be able to be realised. For example, while the grid might benefit from spreading out the charging of the storage systems during the day and thereby smoothing demand, without other incentives, consumers would be likely to prefer to charge their systems as quickly as possible, thereby avoiding the risk of cloud cover.

8.3.4 Ancillary services

Ancillary services are those needed to support the delivery of energy in the grid. They are typically divided into distinct categories: regulation services and contingency services.

Regulation services

Regulation services provide frequent, short-timescale adjustments to power output to ensure that supply and demand remain matched at all times under normal system conditions. Typically, this service is provided by gas turbines, which are able to vary their output up or down around an average output level, but other technologies also provide the service. In the NEM, it is provided through regulation frequency control ancillary services (regulation FCAS), while in the WEM the equivalent load-following service is provided by Synergy.

In a well-operated system, upwards and downwards variations balance out over relatively short timeframes (5 to 30 minutes), making this an ideal 'energy-neutral' service for energy storage to provide. Furthermore, appropriate energy storage systems are typically able to respond faster to changing conditions, therefore providing greater support per unit of installed capacity.

Both flywheel and battery storage systems have been used to provide regulation services in several markets in the United States and Canada since 2008.

Contingency services

Providers of contingency services offer to rapidly increase or decrease their output in response to the failure of a significant generator or load, respectively, thereby rapidly restoring the supply–demand balance. Although this is similar to the regulation service, the change in supply or demand is usually larger and over a shorter timeframe, requiring a significant response to rebalance the system.

Typically, a number of respondents provide this service, operating on distinct timescales. First responders provide a response within 6 seconds before gradually handing over to other providers who could potentially sustain that response for longer timeframes (5–15 minutes), thereby freeing up the fastest responders for the event.

The requirement for a rapid but potentially sustained response places performance requirements on storage technologies, but battery storage could probably provide the fastest response services, while pumped hydro storage could probably provide the slowest.

Significantly, some energy storage technologies (particularly batteries) can provide very fast response services (within 0.5–1 seconds), which can improve the security of the power system.

8.3.5 Managing short-term intermittency

Management of intermittency or variability in generator output is currently provided through the regulation ancillary services, and costs are recovered on a 'causer pays' basis. Therefore, generators with intermittent output—particularly solar PV farms, which might be affected by brief periods of cloud cover—may be able to install energy storage systems to act as short-term smoothing, and also reduce generator ramp rates.

8.3.6 Network augmentation deferral

Acting as demand-side management, storage can reduce the stress on transmission or distribution network assets, effectively reducing local peak demands and ultimately delaying or avoiding the need for expensive upgrades.

8.3.7 Power quality management

In Australia, managing power quality means maintaining a constant 50 Hz sinusoidal wave for the operational frequency of the grid. It is desirable for the frequency to be maintained at 50 Hz to avoid adverse outcomes for the operation of the grid and damage to equipment and infrastructure.

Through the use of a range of control schemes, storage technologies can monitor and respond to system changes to maintain the 50 Hz frequency. This can be achieved by varying a set of key parameters specific to the type of technology used. Both traditional coupled induction generators (such as pumped hydro) and decoupled inverter-based schemes (such as batteries) can assist in maintaining the power quality of the system. In particular, in the future controllable inverters may provide a valuable source of power quality management for system and network operators.

8.4 Summary of applications

Table 64 summarises storage roles, characteristics and opportunities.

Table 64: Storage roles and opportunities

Storage role	Storage characteristics	Market and revenue opportunities
Utility-scale arbitrage	High cycle life and round-trip efficiency	Limited in near term but potential off-grid opportunities Opportunity for benefit stacking with T&D deferral
Regulation ancillary services	High power output and rapid response High cycle life	Limited in the NEM Potential WEM and off-grid opportunities
Contingency ancillary services	High power output and rapid response Infrequent usage, but required to be available (limited benefit stacking)	Service is currently low-cost in the NEM, and no market exists in the WEM Potential longer term opportunities
Consumer/ commercial tariff avoidance	Requires low round-trip levelised cost	Significant opportunities to couple with rooftop solar PV
Managing intermittency	Characteristics vary with generation technology	As with regulation service, managing intermittency is currently low cost in NEM, but could have value in WEM or off grid Could also be used to reduce financing costs by firming up contracts
Network augmentation deferral	Required to operate over peak demand period Likely to be available for benefit stacking at other times (e.g. arbitrage)	Very high value in specific locations, low value in others—depends on local supply–demand balance
Power quality management	All storage can provide value	Likely to be value stacking opportunities, including arbitrage and network augmentation deferral

8.5 Implications for future generation development

Storage ultimately allows for better matching between load and generation, increasing the opportunity for selecting the lowest cost generation sources. Just as a strong transmission network allows for selecting lower cost generation sources that are geographically remote from the load, storage systems allow for flexibility through time as well. Furthermore, although its role in integrating variable renewables has been widely publicised, a strong take-up of storage could enable a greater use of existing or future baseload generation (at the expense of peaking capacity), provided the technologies are cost-competitive.

Because most storage technologies charge directly from the grid, they can be repurposed to support whichever class of technologies are lowest cost, and therefore provide value to the system. Furthermore, with the exception of concentrating solar power with storage, even storage systems built in conjunction with another technology do not charge directly or exclusively from that plant: an independent storage system would (or should) operate in an identical fashion. Therefore, the value of storage cannot be determined solely by considering a single generator in the market, unless that generator is a price setter in most periods.

For these reasons, it is generally not appropriate (except for concentrating solar power with molten salt storage) to consider combinations of technologies (such as solar PV with storage) as a single unit for the purposes of cost or comparison to other technologies. Rather, the value that storage can provide should be assessed in the context of the entire grid or market under consideration.

8.5.1 Peaking generators

Storage can act as an alternative to peaking generation by injecting power into the grid at times of high demand or low supply. This would tend to depress prices and therefore reduce market opportunities for peaking generation (as well as for subsequent storage systems).

In general, such storage could effectively substitute for peaking generation (such as open cycle gas turbines) on a megawatt for megawatt basis. Recent studies have suggested that because storage systems can also take advantage of daily arbitrage opportunities, they can access additional revenue streams not available to traditional peakers.[10]

The typically rapid response of energy storage units may also be able to respond more quickly to shortfalls in supply, which can reduce the overall cost of delivery (rapid response generation is particularly valuable in grids with high market price caps, such as the NEM.[11]

8.5.2 Baseload technologies

While injecting energy into the grid at peak times, storage units will draw energy from the grid at low load times, thereby smoothing the load shape across the day. This can allow for a greater penetration of generation that is lowest cost when run at high capacity factors and reduce the need for peaking generation with comparatively high short-run costs.

8.5.3 Variable renewables

Storage may also help to increase the economic penetration of variable (non-dispatchable) generation. Although low penetrations of variable renewable generation can be readily integrated into the grid, at higher penetrations, if the generator output does not match the underlying load shape of the grid, greater flexibility from either load or generation will allow a higher economic penetration. Storage can assist by charging during periods of high renewable generation, thereby increasing demand for energy (and hence market revenues for renewable generators). This energy can then be injected into the grid during periods of low renewable generation, again providing an alternative to peaking generation or requiring dispatchable baseload generators to vary their output. The flexibility of storage units is likely to be increasingly valued at high penetrations of variable renewable generation.

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[10] https://theconversation.com/storage-can-replace-gas-in-our-electricity-networks-and-boost-renewables-48101 (accessed November 2015).

[11] http://wartsila.prod.avaus.fi/docs/default-source/Power-Plants-documents/downloads/White-papers/asia-australia-middle-east/Value-of-Smart-Power-Generation-For-Utilities-in-Astralia.pdf?sfvrsn=4 (accessed November 2015).

8.6 The Australian context

Although storage is being deployed globally, Australia's climate, geography and markets create some unique conditions.

8.6.1 Wholesale market arbitrage

Currently, the cost differentials between peak and off-peak times in the electricity market are unlikely to be sufficient to incentivise arbitrage.

In the future, however, the growth of both rooftop and utility-scale solar PV systems, combined with falling costs, may close the gap between costs and revenues. In particular, the regular nature of PV production has globally, and increasingly in Australia, resulted in daytime prices being as low or lower than overnight prices. This means that the storage units providing arbitrage could be cycled at least daily, and potentially twice daily if overnight charging is used to meet the morning peak. This provides a clear market for storage and a high utilisation factor—both essential features, given the high upfront cost of storage technologies.

Such storage could be:

- *installed at utility scale*, providing daily arbitrage in the wholesale market, which would not be specific to solar PV (this allows for the greatest flexibility in choice of storage technologies)
- *embedded within distribution grids* (or, potentially, transmission grids) at specific locations to manage the export of solar PV from high-penetration neighbourhoods (such units could also assist with managing local peak demands, thereby reducing or deferring expenditure on the network)
- *embedded behind residential or commercial meters*, allowing consumers to avoid purchasing energy from the grid and increasing the economically viable size of rooftop solar PV installations (these units could be controlled by pre-set charging and discharging patterns, or operated remotely by grid operators or retailers to maximise benefits to the network).

Additionally, large-scale storage (particularly pumped hydro storage) may be used to shift energy across several days, allowing for periods of low renewable generation or of particularly high demand. However, it is unlikely that such behaviour will be economically viable in the short term, given the opportunity cost of 'missing' a daily charge and discharge cycle. Potentially, if demand and renewable generation forecasting is accurate enough, some storage units may defer their charging or discharging to take advantage of particularly high or low periods. Aggregators of storage (and, potentially, other demand-side management or generation options) may be able provide financial incentives for this type of behaviour, including trading in established futures contracts, such as caps.

8.6.2 Single-wire earth return networks

Single-wire earth return (SWER) networks are used to connect rural loads using only a single wire. The ground completes the circuit, significantly reducing connection costs. Although they are relatively uncommon elsewhere, Australia's geography has resulted in around 65,000 km of SWER lines being constructed.

However, SWER networks face unique challenges, particularly when it comes to reliability and maintaining local voltages within the required ranges. To manage peak loads, in particular, additional active power management units can be needed, increasing the cost of supply.

Battery storage has been identified as a potential option for improving both the quality and the reliability of electricity supply on SWER networks. For example, Ergon in Queensland is rolling out 25 kVa/100 kWh batteries across its network, which it predicts could cut SWER network augmentation costs by 35%.[12]

Ergon SWER battery program

Queensland's regional grid operator is rolling out Grid Utility Support Systems (GUSS) to help support its SWER (remote load) network. Each unit can provide 25 kW of output for 4 hours (100 kWh capacity) and will be used both to reduce peak demand (and therefore avoid transmission infrastructure upgrades) and to manage the voltage and support the local networks, including enabling a higher penetration of rooftop PV. After investigations since 2006 and a trial in Far North Queensland in 2013, 20 Li-on batteries are to be supplied by S&C Electric Company. Installation is expected to begin in late 2015 or early 2016.

8.6.3 Ancillary services

Currently, ancillary services in the NEM are relatively low cost, and there are many potential providers. Therefore, energy storage is unlikely to be a cost-effective provider of those services. However, ancillary service costs in the WEM remain an ongoing concern, and it is possible that, subject to changes in the market rules, storage could be a competitive provider of load-following or 6-second contingency (spinning reserve) services.[13]

[12] www.ergon.com.au/about-us/news-hub/media-releases/regions/general/battery-technology-on-electricity-network-and-australian-first (accessed November 2015).
[13] www.imowa.com.au/docs/default-source/rules/other-wem-consultation-docs/2014/2014-ancillary-services-study-ey-final-report.pdf?sfvrsn=0 (accessed November 2015).

9
POST-COMBUSTION RETROFIT

Post-combustion retrofit—highlights:

- It is technically and economically feasible to retrofit post-combustion capture (PCC) to wet- or dry-cooled black coal power plants.
- A significant energy penalty is incurred when PCC is added to an existing plant. In addition, the sulphur dioxide/NO_x controls add significant capital costs to a retrofit.
- The levelised cost of electricity from PCC-retrofitted power plants is less than from a new-build pulverised black coal plant with dry cooling.
- Improved solvents will reduce the economic and energy penalties of retrofitting PCC.

9.1 Introduction

With many GW of installed coal-fired plants worldwide, and many new plants being built, it is conceivable that CO_2 emissions will need to be removed from existing coal-fired plants to reduce global greenhouse gas emissions to acceptable levels.

EPRI recently completed a series of detailed economic and engineering studies examining the feasibility of retrofitting post-combustion capture (PCC) of CO_2 to existing pulverised coal and/or circulating fluidised-bed power plants for six North American sites (Figure 92).

Figure 92: Locations of the six plants included in the EPRI study

Retrofitting PCC systems to pulverised coal plants may also be a viable and cost-effective option for reducing CO_2 emissions from the Australian power generation sector.

In this chapter, EPRI uses costs and lessons from its North American site-specific PCC retrofit studies to estimate the performance and cost impacts of integrating an amine (monoethanolamine, or MEA) solvent PCC system into Australian black coal fired plants.[1]

The chapter investigates the effects of dry cooling versus wet cooling, along with the potential for improved solvents currently under development to influence the overall economics.

9.2 Plant equipment and layout

The PCC design used here consists of:

- 2 absorber trains
- 1 regenerator per absorber train (2 in total)
- 1 compression train per regenerator (2 trains in total)
- 8 reboilers per regenerator (16 reboilers in total).

The layout of key PCC components is shown in Figure 93.

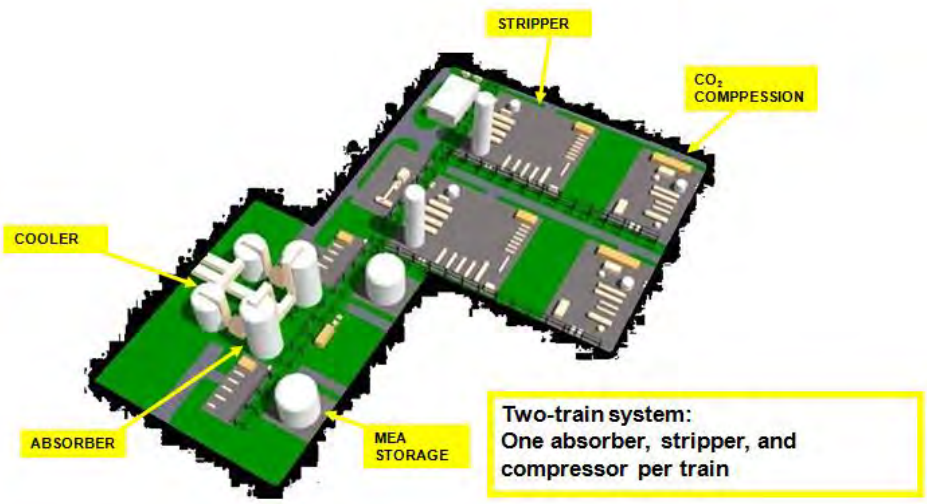

Figure 93: Monoethanolamine PCC unit (excluding flue gas desulphurisation and selective catalytic reduction and cooling towers)

Layouts for a black coal power plant, before and after an MEA PCC retrofit, are shown in Figure 94 and Figure 95. They include as part of the refit the addition of flue gas desulphurisation (FGD) and selective catalytic reduction (SCR) equipment not currently found in Australian units, as well as all additional cooling equipment required for the capture equipment. FGD and SCR systems are needed because sulphur compounds and nitrogen dioxide in the flue gas will react with the MEA solvent to form degradation products and increase the cost of solvent make-up. The FGD system typically removes sulphur compounds to below 10 ppmv.

[1] Australian brown coal power station retrofits were not included in this study, as the base plants in the original EPRI study did not allow accurate and reliable cost and performance translations to low-rank coals.

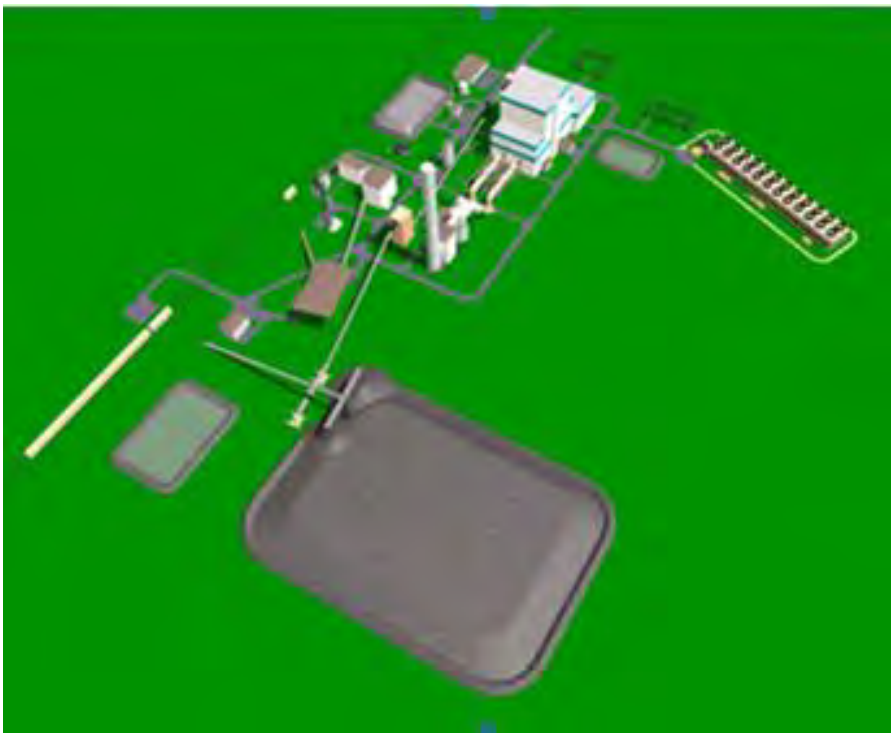

Figure 94: Typical pulverised coal plant layout before PCC retrofit

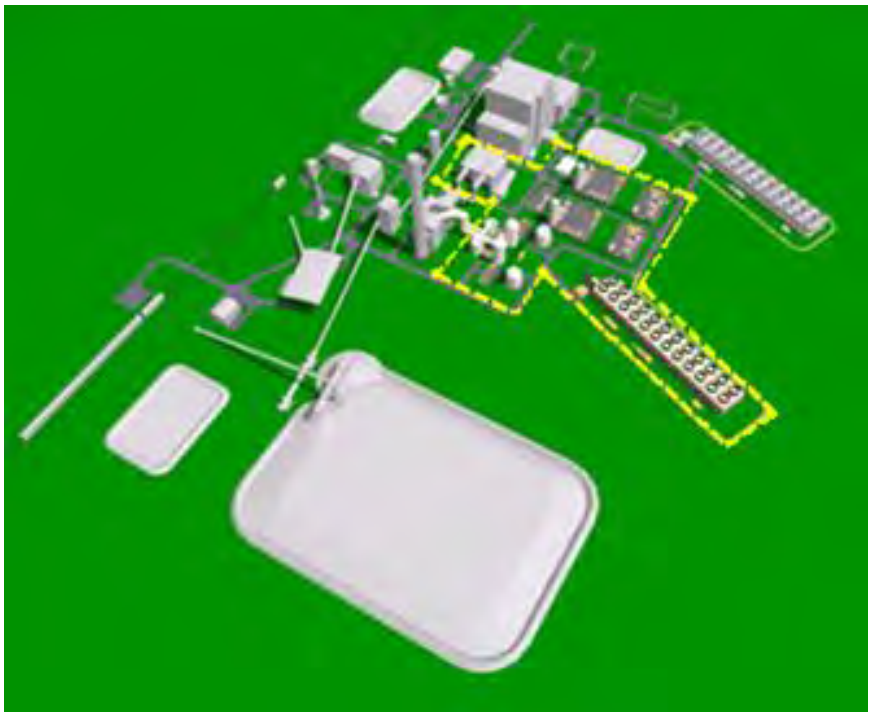

Figure 95: Pulverised coal plant layout after PCC retrofit

In a best case scenario, in which space is available near the plant, about 4 hectares is needed for the new PCC plant (including the additional cooling tower, FGD and SCR).

9.3 Integration

Figure 96 and Figure 97 show the integration of a PCC plant (shaded in blue) and an existing pulverised coal plant. The following points should be noted:

- The design allows operation with or without CO_2 capture and allows 90% capture to be retrofitted with minimal intrusion to the existing plant steam turbine.
- The PCC plant retrofit obtains steam for solvent regeneration via the crossover between intermediate-pressure (IP) and low-pressure (LP) systems in the existing plant. A back-pressure steam turbine is introduced to step down the steam to the correct conditions for solvent stripping in the reboiler. It minimises the energy penalty incurred in removing the valuable steam from the original steam turbine arrangement.
- The heat from the hot condensate returning from the reboiler is used via heat exchangers to supplement feedwater heating. In this way, all condensate sent to the once-through steam generator is polished (not bypassed) in order to prevent any potential water chemistry problems.

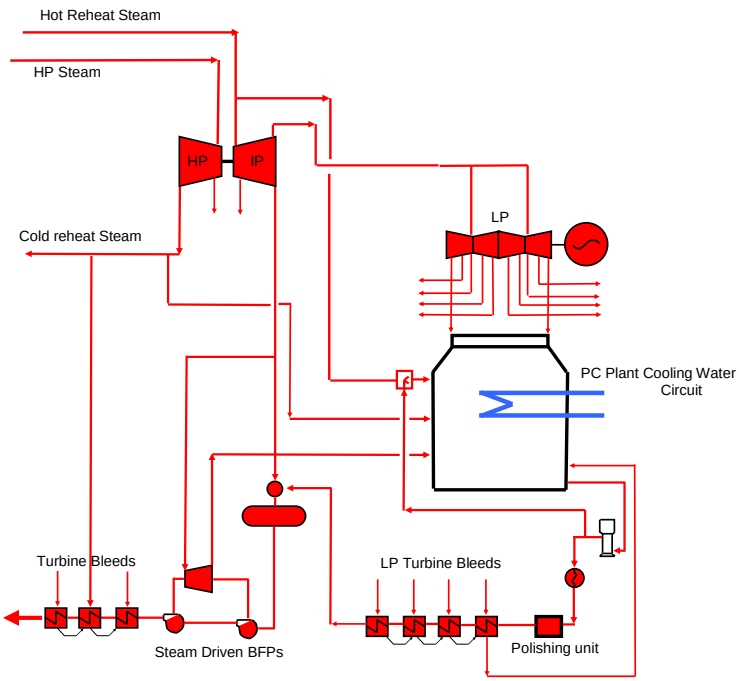

Figure 96: Schematic of turbine and feedwater heater circuit for plant without CO_2 capture

BFP = boiler feed pump BPST = back-pressure steam turbine;

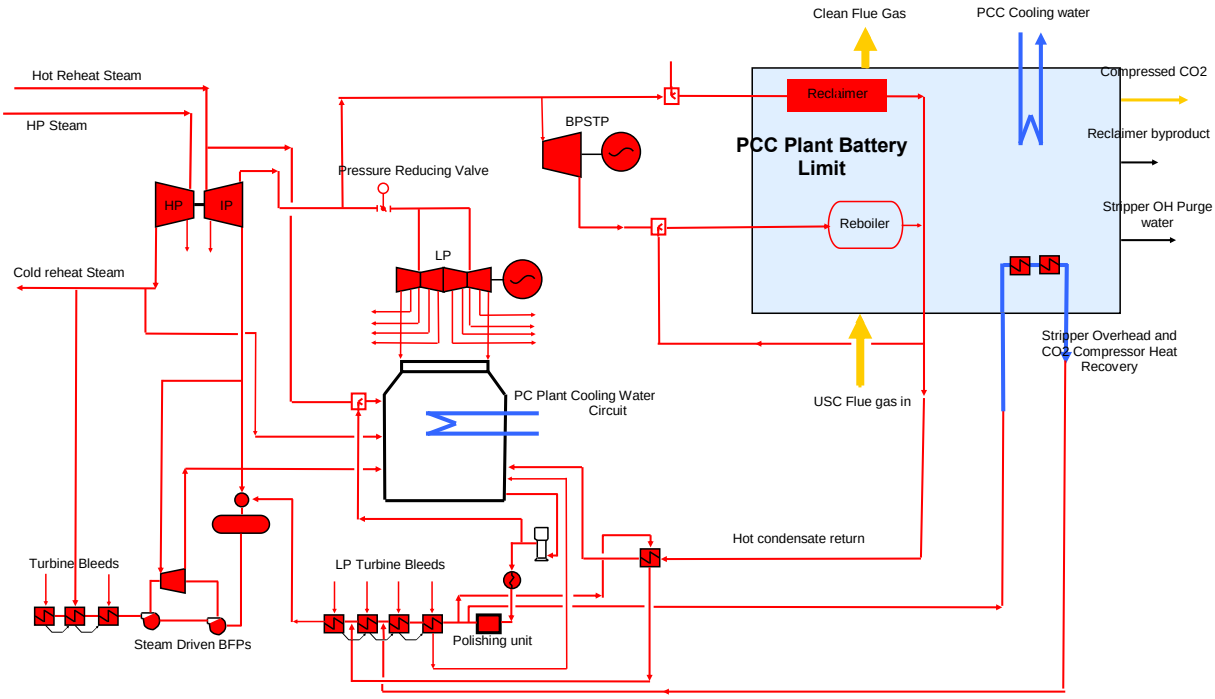

Figure 97: Schematic of pulverised coal plant integration with PCC plant

9.4 Steam cycle design and operational realities

Retrofitting a power plant with a PCC plant introduces dramatic changes to parts of the plant, whereas other parts are almost totally unaffected (for example, the boilers are unaffected but the flue gas system downstream of the boilers is substantially affected). Other major changes to the plant relate to the operation and performance of the steam turbine (primarily the LP turbine) and the LP feedwater heaters.

The main impact on the steam cycle results from the extraction of large quantities of LP steam for use in the PCC plant. Most of this steam is returned to the plant as hot condensate. The MEA PCC plant needs steam at 4.1 bar, and where steam is to be extracted from the cycle is a key decision. As steam is extracted from the overall turbine steam flow path, the pressure at the extraction point drops. The pressure drop is roughly proportional to the remaining flow past that point. So, if half of the steam at a given location is extracted, the pressure at that location will drop to half its normal value unless some means is incorporated to prevent or limit the drop in pressure. Because the volume of steam extracted is quite large, the usual location for the extraction is the crossover line from the IP turbine exhaust to the LP turbine inlet (the LP crossover), as shown in Figure 98.

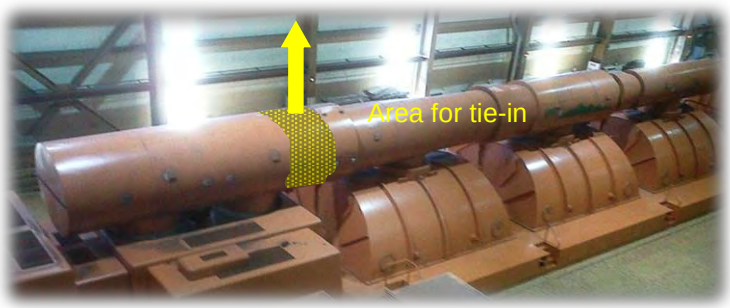

Figure 98: A typical IP/LP crossover on a turbine

For example, if the normal full-load operation crossover pressure in the existing plant is ~9.4 bar, after the extraction of PCC steam it would fall to ~4.8 bar, which is high enough to supply the PCC plant. However, allowing the exhaust of the IP turbine to fall to 4.8 bar would greatly increase the loading and power production of the turbine, and it is usually the case that an IP turbine as designed cannot tolerate the extra loading. Major steam path modifications would be needed to allow the IP turbine to operate in this way. The steam path redesign would also have to consider plant operation when the PCC plant is not in service, when the IP exhaust pressure returns to 9.4 bar.

To provide the flexibility of generating both with and without capture and to avoid major modifications to the IP turbine (and the LP), the proposed solution is to add a pressure control valve downstream of the crossover extraction location. The valve will maintain IP turbine exhaust pressure at its normal value, so the IP turbine is unaffected. Controls will be implemented such that this valve controls IP exhaust pressure to the value appropriate to the loading of the IP turbine. Because the pressure drop across the valve represents a loss in power production, the turbine designer should be consulted to see whether some reduction in IP exhaust pressure is allowed. If so, the controls for the pressure control valve would be set up to allow the IP turbine to expand to the allowed pressure to maximise the IP turbine's power production and minimise the overall power loss.

For the purposes of this study, it is assumed that no additional loading of the IP turbine is allowed, so IP turbine exhaust pressure at full load is held at its normal operating pressure.

When the PCC plant is in service, the LP turbine operates in a 'hybrid' part-load mode. Reducing the LP turbine inlet flow to half of its normal value is a normal operating condition for the turbine when the plant is at half load. However, by heating most of the feedwater using PCC waste heat recovery there is little or no feedwater flow through the low-temperature feedwater heaters, thus greatly reducing or eliminating the extraction flow from the LP turbine to those heaters. This helps to recover some of the lost power of the LP turbine, but it would be a different operation from that is normally encountered in part-load situations. However, operating in this manner should not create operational problems for the LP turbine.

9.5 Plant performance

The summarised performance results of the MEA retrofit to a pulverised black (wet-cooled) coal fired plant are shown in Table 65.

Table 65: Performance results for Australian black coal wet-cooled units before and after PCC retrofit

	Existing unit (wet cooled)	Existing unit (wet cooled) with MEA solvent retrofit	Existing unit (wet cooled) with improved solvent retrofit[a]
Gross power output, MW_e	915	773	813
Auxiliary load, MW_e	70	203	203
Sent-out power output, MW_e	845	570	610
Sent-out plant efficiency, % HHV	36.0	24.7	26.7

a: The improved solvent is not currently offered by suppliers. It is included here based on ongoing process technology improvements.

The first column shows the performance results of the existing plant without PCC, based on mechanical wet cooling towers. This has an initial sent-out plant efficiency of 36% before any capture is added (this efficiency figure is typical for Australian coal plants of this type[2]). The auxiliary load is from coal pulverisers, pumps and fans used in the combustion process and steam generator. (Note that the baseline efficiency of an older existing plant, before retrofit, is assumed to be lower than that of a similar sized new-build plant, which would be likely to incorporate more advanced steam conditions.)

The second column shows the plant retrofitted with a fully integrated MEA solvent capture plant with an estimated heat of regeneration requirement of about 3,210 kJ/kg CO_2. The gross power output drops as a result of a considerable portion of the steam generated now being diverted to the capture system. The auxiliary load is also increased from that of the initial plant due to the demands of the capture system's solvent circulation pump, gas side booster fans and CO_2 compression train. This results in a total efficiency penalty of 11.6% compared to the reference plant without capture. The overall power output drops 32.5% from the original 845 MW_e (sent-out) output of the reference plant.

The third column shows the effect of applying an improved solvent with an estimated heat of regeneration requirement of about 2093 kJ/kg CO_2. The improved solvent requires less steam to regenerate and therefore raises the gross MW_e output. The improved solvent is based on the performance results obtained from pilot testing at the National Carbon Capture Centre.[3] Although not proven at full scale, EPRI believes it to be representative of the way the current set of solvents is heading over the next few years.

Table 66 shows the same black coal cases as above but applied to a baseline plant that uses a dry cooling system before retrofit instead of mechanical wet cooling towers. The gross power output is reduced further as a direct result of the different cooling system. The penalty associated with a base plant using dry cooling is approximately 2 percentage points.

Table 66: Performance results for Australian black coal dry-cooled units before and after PCC retrofit

	Existing unit (dry cooled)	**Existing unit (dry cooled) with MEA solvent retrofit**	**Existing unit (dry cooled) with improved solvent retrofit[a]**
Gross power output, MW_e	883	745	784
Auxiliary load, MW_e	78	215	214
Sent-out power output, MW_e	805	530	570
Sent-out plant efficiency, % HHV	34.3	22.7	24.7

a: The improved solvent is not currently offered by suppliers. It is included here based on ongoing process technology improvements.

[2] ACIL Tasman (2009), *Fuel resource, new entry and generation costs in the NEM*, April 2009.
[3] www.nationalcarboncapturecenter.com (accessed November 2015).

9.6 Retrofit performance comparisons

Figure 99 shows the performance trends for a selected number of black coal cases.

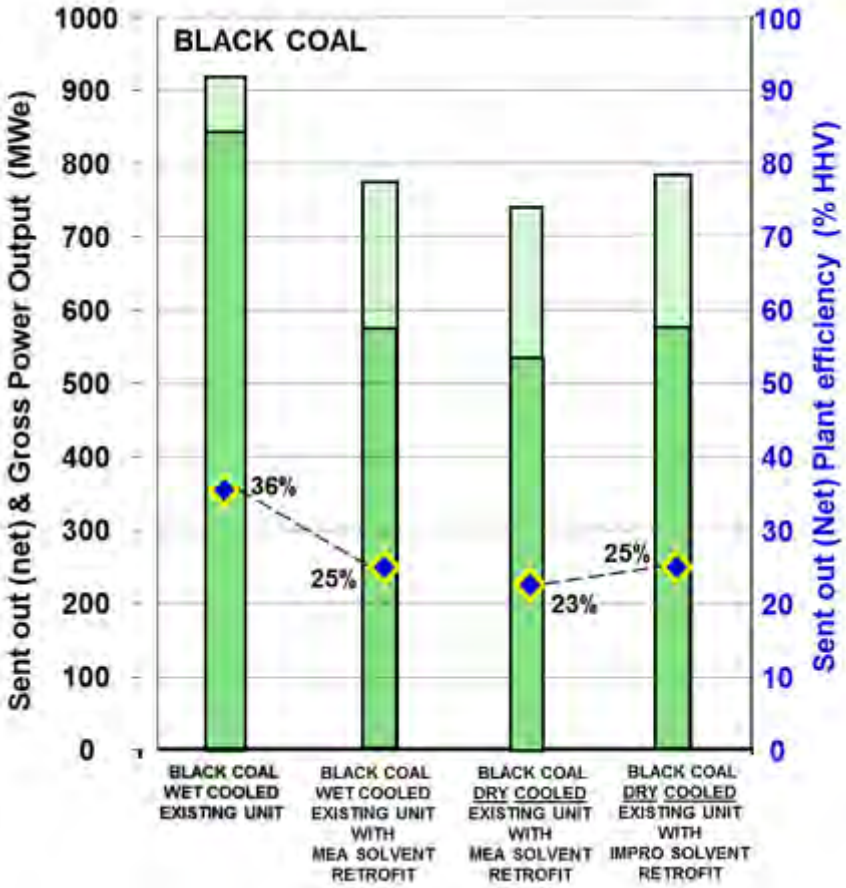

Figure 99: Black coal power plant output and sent-out efficiency comparisons

A dry cooled base plant with the MEA solvent retrofit is the poorest performer, as it includes the penalty for the capture process and the inefficiencies associated with the air cooled baseline. However, the benefits in performance associated with using an improved solvent offset the impact of the base plant's dry cooling system.

9.7 Total plant cost for PCC retrofit

Table 67 and Figure 100 show the total plant cost (TPC) on a $/kW$_e$ basis for the various PCC retrofit scenarios, alongside the costs of a new-build ultra-supercritical plant with PCC.

Each retrofit case assumes that its existing pulverised coal base plant without capture is a paid-off asset and, just as importantly, that the existing asset is in good condition to continue operating for many years to come. Note that some existing assets, depending on their age and condition, may need investment in the base plant to achieve this life extension with capture fitted (as in the current Boundary Dam repowering in Saskatchewan); however, such base plant upgrades are not included in the figures below.

The retrofit TPC therefore only includes the PCC plant (absorbers, strippers reboilers compressors and so on), the necessary coal plant modifications, the FGD and SCR addition and the additional PCC cooling system requirements, either dry or wet cooled depending on the original system employed.

No specific costs or equipment quotes were generated for this section of the report. Rather, the economic analysis is based on the costings from earlier US EPRI studies.

All retrofit costs are initially based on derived 2009 US dollar estimates for US locations. Appropriate factors have then been applied to convert the values to 2015 Australian dollar estimates and an Australian (New South Wales) location for the black coal. Note that the initial US retrofit estimates were all based on a +/–30% target level of accuracy.

The FGD and SCR costs here are based on typical published US values for equipment retrofit of $400/kW for FGD and $350/kW for SCR (both before the capture derate). These estimates were adjusted to an Australian location and converted to 2015 Australian dollars.

Table 67: Total plant cost estimates for retrofit to dry cooled plants (2015 A$)

	Dry cooled new build with MEA solvent	**Dry cooled existing unit with MEA solvent retrofit**	**Dry cooled existing unit with improved solvent retrofit**
PCC equipment retrofit cost ($/kW$_e$)	–	2,450	2,250
FGD + SCR retrofit cost ($/kW$_e$)	–	1,950	1,850
TPC total ($/kW$_e$):	**6,750**	**4,400**	**4,100**
% of new build cost	100%	65%	60%

Note: The $/kW$_e$ estimates shown in this table include the derate from capture.

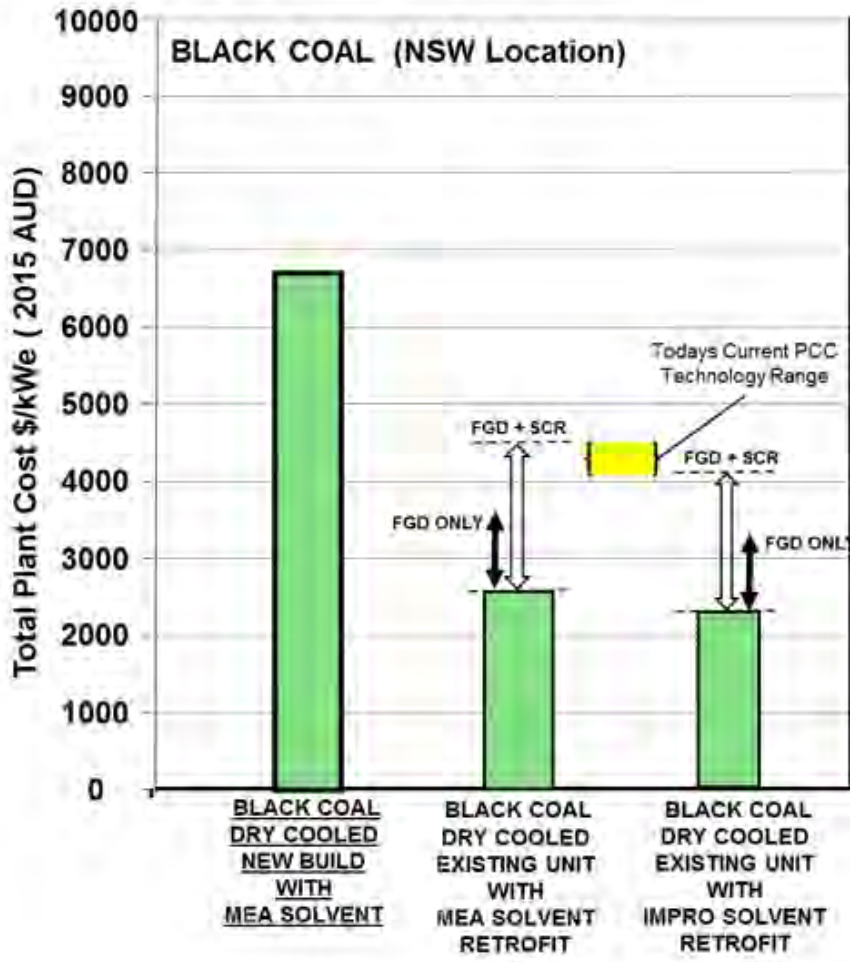

Figure 100: Total plant cost comparison: new build PCC vs. retrofit PCC to a paid off asset

EPRI recognises that today's PCC technology has evolved from MEA solvent systems but has not yet reached full-scale application of the improved solvent. Therefore, PCC technologies being offered today by suppliers for full-scale applications are estimated to sit within the yellow highlighted range.

In addition to the retrofit cost cases shown in the above figure, the costs of a new build, dry cooled supercritical coal plant with PCC are presented. They are included here to illustrate the difference between retrofit CCS and new-build CCS technology costs. Dry cooling technology was selected wet cooling systems for new-build plants may become less common due to water usage concerns. These new-build dry cooled costs are taken from cases provided in the new-build technology comparison sections of this report.

The new-build plant has some notable advantages over the retrofit cases:

- Baseline net efficiency before PCC is better, resulting in a lower retrofit percentage point penalty.
- FGD and SCR components of a new-build greenfield plant are usually lower in cost than in a retrofit, in which space is usually limited and the existing equipment causes complications (for example, retrofit factors of 1.3 for FGD and 1.6 for SCR are typical in US plants).

When comparing the retrofit results presented here, the following points are noteworthy:

- Less upfront capital investment is required for PCC retrofit to a paid-off plant than a for a new-build plant with PCC.
  - In $/kW$_e$ terms, a retrofit to a dry cooled MEA plant is estimated at around 65% of the total capital outlay for a new dry cooled plant with capture.
  - A retrofit to a plant using improved solvent is estimated at 60% of the total capital outlay for a new plant.
- Due to Australia's existing rules for SOx and NOx pollutants, the adding of FGD and SCR upstream of the PCC equipment in an existing PC plant would be a significant portion of the overall retrofit outlay.
  - As shown, including both FGD and SCR systems for the existing Australian plants adds 44% to the complete CCS retrofit cost.
  - In other locations worldwide, where higher sulphur coals are used and environmental legislation has meant that such air quality control systems are already installed and operational, obviously the additional capital impact to add CCS is significantly lower.
  - While retrofit FGD and SCR costs are included in this broad EPRI analysis, previously published Australian PCC retrofit studies have reported that it is more economic to install only low-No$_x$ burners (not SCR) and no deep FGD than to suffer the additional amine losses. Therefore, the costs in Figure 100 (for FGD + SCR) could be significantly reduced (~45%) if the SCR component were, as some specific Australian research recommends.[4]
- In the case of Australia, where droughts are frequent and long-term water availability is a major concern, the perceived benefits from an improved solvent system with a lower heat of regeneration would certainly help to alleviate the impact of dry cooling technology on power plants, assuming that the improved solvent system could be offered commercially without requiring significant additional capital above the current MEA-based systems.

9.8 Levelised cost of electricity for PCC retrofit

Table 68 and Figure 101 show the increase in LCOE associated the various PCC retrofit scenarios. This is the additional cost of electricity associated with adding capture; it excludes the baseline plant cost (dependent on the operational cost of the baseline plant) and also the extent to which the baseline plant is a paid-off asset (typically dependent upon years of operation).

Table 68: Estimated LCOE increase for PCC retrofit (2015 A$)

	Wet cooled existing unit with MEA solvent retrofit	Wet cooled existing unit with improved solvent retrofit	Dry cooled existing unit with MEA solvent retrofit	Dry cooled existing unit with improved solvent retrofit
PCC equipment retrofit	89	83	96	89
FGD + SCR retrofit	32	30	34	32
Total LCOE increase ($/MWh):	121	113	130	121

[4] Dave (2001), *Economic evaluation of capture and sequestration of CO_2 from Australian black coal-fired power generation*.

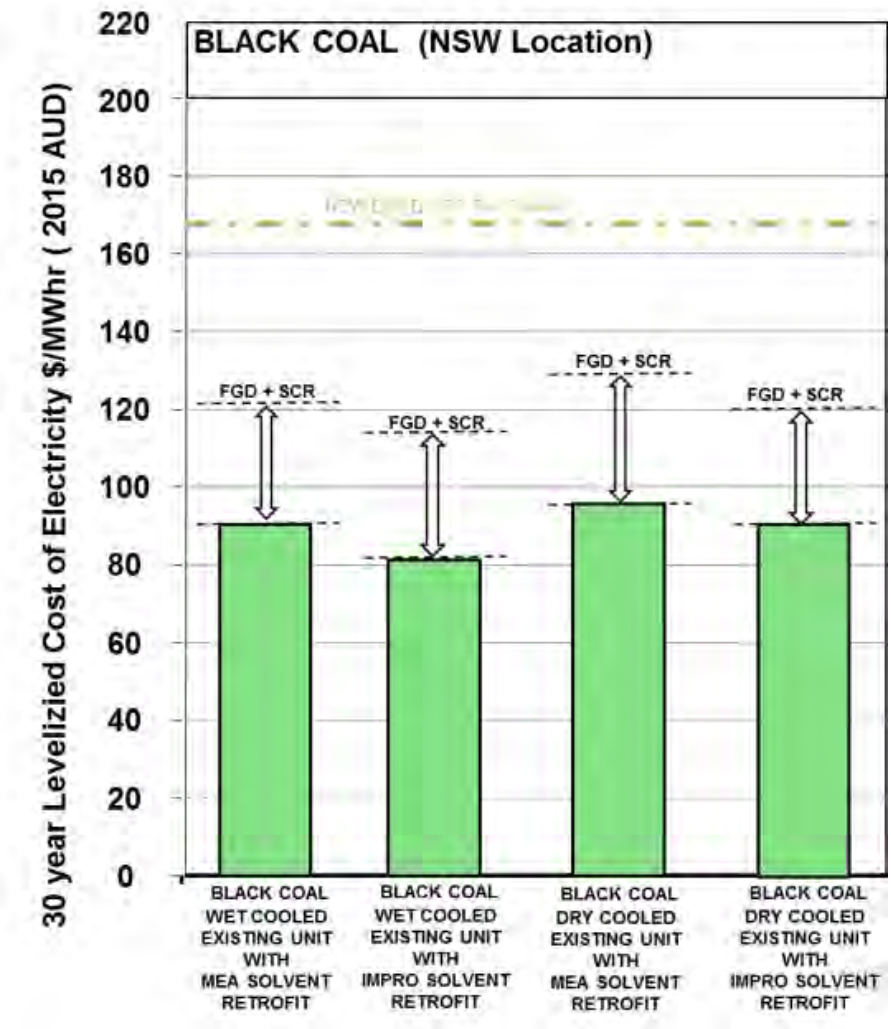

Figure 101: Estimated LCOE increase from PCC retrofit

From the results above, the following points are noteworthy.

If we consider that a new build black coal plant with PCC would be required to be dry cooled and would produce electricity at an estimated LCOE of A$168/MW/hour (the dotted green line), then:

- an existing wet cooled black coal plant in New South Wales would need to be producing electricity under A$40/MW/hour before adding MEA PCC capture to compete with a new build.
- An existing dry cooled black coal plant in New South Wales would need to be producing electricity under A38/MW/hour before adding MEA PCC capture to compete with the new build.

If SCR could be excluded from the retrofit costs, then these LCOE margins for the existing plants would improve slightly. Alternatively, if the condition of the existing plant required significant upgrades in order to ensure an additional ~25 years of reliable operation, then the LCOE margins would be narrowed.

9.9 Conclusion

In this chapter, EPRI has endeavoured to translate what was learned from its detailed US studies, while also identifying the unique features that influence Australian retrofit scenarios.

Undoubtedly, the most accurate way to generate retrofit cost and performance numbers is to undertake individual studies on existing Australian full-size plants by engineering companies. (this was the approach EPRI took in its North American studies, using an engineering team from Nexant and Bechtel).

10
CARBON DIOXIDE TRANSPORT AND STORAGE

The authors of this chapter are Professor Dianne Wiley, Dr Peter Neal, Dr Minh Ho and Dr Gustavo Fimbres Weihs from UNSW Engineering.

They thank CarbonNet, Coal Innovation NSW, CTSCo, the Western Australian Department of Mines and Petroleum and Dr Charles Jenkins for invaluable input to this chapter. They also thank Anggit Raksajati and Zikai Wang for assistance with calculations.

CO_2 transport and storage—highlights:

- This chapter provides tools for estimating the bare equipment costs of pipelines, booster pumps, wells, platforms and monitoring to enable users to complete their own CO_2 transport and storage studies.
- The tools are based on specific operating conditions and engineering assumptions. Variations in factors such as material costs, topography and geological properties may lead to different costs.
- The integrated optimisation of capture, transport route, operating conditions and injection strategies may lead to cost reductions.
- Based on the case studies in Chapter 20, the total plant cost (excluding owner's and risk-adjusted costs) for CO_2 transport, injection and monitoring is likely:
    - to vary between $5/t and 14/t injected for cases involving short transport distances to storage formations with good characteristics
    - to be almost $70/t injected for cases involving the transport of small volumes of CO_2 over long distances to storage formations with poorer characteristics.

10.1 Introduction

This chapter provides building block datasets for CO_2 transport and storage; in Chapter 20, selected case studies of Australian carbon capture and storage (CCS) are analysed. The building block datasets are provided in the form of figures, tables and equations to enable users to estimate costs and performance for the pipeline transportation and geological storage of CO_2. Additional information in Chapter 21 has been provided to enable users to understand the assumptions behind the data, the scope of the data provided and how they may be able to supplement the data for cases that are beyond the scope of the examples examined here.

The costs and performance data are suitable for scoping studies and comparisons. They are based on rule-of-thumb techniques for estimating equipment sizes and the costs of individual items of equipment and associated services. They have been benchmarked against performance data in the literature as well as data provided by stakeholders wherever possible. The building block datasets provide bare erected costs (BEC) that cover the purchase and installation of the equipment and supporting facilities. They exclude equipment purchase contingencies and project contingencies. This is in contrast to the case studies in Chapter 20, which include equipment and project contingencies and are provided as total plant costs (TPC). All costs in both chapters exclude risk-adjusted costs and owner's costs, which can be significant, especially for proving up storage sites. Chapter 17 discusses how project costs change over time and the difference between different levels of cost estimates. Further, all costs and performance data provided are subject to uncertainties and could therefore change over time as technologies, storage capacities, equipment costs and other variables change. For real projects and installations, more detailed engineering design studies are necessary.

The generic datasets provided in this report are designed to cover the majority of cases expected to be of interest in Australia from 2015 to 2030. The generic categories are:

- pipelines (onshore and offshore)
- recompression (for intermediate or well-head boosting)
- wells (onshore and offshore)
- storage facilities (onshore distribution networks and offshore injection platforms)
- monitoring and verification (onshore and offshore).

10.2 General assumptions

The general assumptions used for generating the datasets are listed in the following sections.

10.2.1 CO_2 purity

It is assumed that the CO_2 transported and stored is high purity (as produced by state-of-the-art solvent absorption capture technology). If the CO_2 contains impurities, then either further purification would be required or further analysis would be needed to evaluate the transport and storage performance and costs. Costs would be likely to be higher than shown in this chapter.

10.2.2 Equipment

CO_2 is assumed to be delivered to the injection site at 8 MPa, which means that recompression would be required at the well-head before injection. This differs from the case studies, in which the CO_2 is typically delivered to the well-head at sufficient pressure for injection.

10.2.3 Costs

All costs are in 2015 values. Original cost estimates from different years have been escalated to 2015 values using either the Chemical Engineering Plant Cost Index or the IHS-CERA Upstream Capital Cost Index, as noted. These indices measure current costs across a diverse range of projects and include the effects of inflation, technology and industry activity. Between 2014 and 2015, the indices dropped 15% and 14%, respectively, largely because of the downturn in the oil and gas industry caused by low oil prices.

All of the components required for CO_2 transport and storage are mature commodity priced technologies; therefore, large cost reductions due to technology learning between 2015 and 2030 are not anticipated. However, a 2% reduction in cost per year can be expected due to overall efficiency gains.

The annual fixed operating costs for each type of equipment can be estimated as a percentage of the capital cost. Recommended percentages are given in subsequent sections.

10.3 Building blocks

The information in this section is designed for users to be able to construct their own cases. Therefore, the assumptions have been selected to allow for maximum flexibility in case design. This means that there may be significant scope in specific cases for cost reductions through optimising the different transport and storage components across the CCS chain.[1]

10.3.1 Transport operations

Transport operations assessed in this section consist of pipelines and booster pumps. Pipeline transport is considered to be the least cost long-term CO_2 transport option onshore and for short distances offshore.[2] It offers significant economies of scale as flow-rate increases, but is capital cost intensive. Other options are road, rail and ship (marine) transport. Although road and rail transport costs can be around 10 times larger for long-term projects, they may be cost-competitive for specific cases. This is because road, rail and ship transport have lower capital requirements and may be more suited for short-term projects. Furthermore, shipping has substantial economies of scale with transport distance. Road, rail and ship transport are also more flexible than pipeline transport because routes can be changed and injection can be switched to a different storage site (for example, if more injection capacity is required). This makes them ideal during the pilot and ramp-up stages of a project. In addition, many offshore storage basins or enhanced oil recovery opportunities around the world may be more easily accessible by ship.

Knowing a transport distance and CO_2 flow-rate, the performance and cost of pipelines and booster pumps can be estimated using the building block datasets provided in the figures and tables. The building blocks assume CO_2 is supplied at 8 MPa, which is also the minimum operating pressure needed to ensure that it stays in a dense phase. To achieve this minimum pressure, compression is needed after the CO_2 is captured or separated from the emission source. To achieve transport and storage pressures, additional booster compression will be required unless the CO_2 is compressed to a higher pressure at the source.

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[1] See, for example, GA Fimbres Weihs, DE Wiley (2012), 'Steady-state design of CO_2 pipeline networks for minimal cost per tonne of CO_2 avoided', *International Journal of Greenhouse Gas Control*, 8:150–168; A Burnham, J Han, CE Clark, M Wang, JB Dunn, I Palou-Rivera (2012), 'Life-cycle greenhouse gas emissions of shale gas, natural gas, coal, and petroleum', *Environmental Science and Technology*, 46(2):619–627.

[2] IPCC (Intergovernmental Panel on Climate Change) (2005), *IPCC special report on carbon dioxide capture and storage*, Working Group III of the IPCC, B Metz, O Davidson, HC de Coninck, M Loos, LA Meyer, Cambridge, UK and New York, US, p. 190.

Pipelines

In this section, the pipelines are designed using X70 steel and a 1500 lb flange rating (rated to 25.5 MPa upper working pressure). They are assumed to operate isothermally at 25°C (onshore) and 20°C (offshore), with a maximum allowable working pressure (MAWP) of 15 MPa. The selected flange rating is higher than the selected MAWP in order to provide a margin of safety for dynamic operating excursions above the MAWP. The effects of different pressure limits and flange classes are discussed below.

The pipelines are designed following Australian Standard AS2885.1,[3] and the pipeline thickness is determined using the standard equation with a weld joint factor of 1, a corrosion allowance of 1 mm and a design factor of 0.72. These values are expected to provide sufficient thickness for effective ductile fracture propagation control in pipelines carrying high-purity CO_2. If impurities are present, the pipeline walls will probably need to be thicker. This should be checked with more detailed modelling.

The selected design factor is typical for gas pipelines in rural areas.[4] According to ISO 13623,[5] the design factor is a function of population density but ultimately only depends on the maximum hoop stress allowed. DNV-RP-J202[6] recommends the use of design factors in the range of 0.45–0.83 depending on population density and location, while AS2885.1 specifies a maximum value of 0.80.

Onshore pipeline transport distances used for the building blocks range from 15 km to 1,400 km; offshore pipeline transport distances range from 15 km to 150 km (measured from the shore-crossing to the injection site) at an average water depth of 80 m. These ranges are chosen to cover typical onshore and offshore transport distances in Australia. Onshore pipelines are assumed to be laid according to Australian Standards into open, flat ground. The effect of topography is discussed below.

The pipeline performance and cost results have been benchmarked against data from WorleyParsons supplied to the Carbon Storage Taskforce[7] and against stakeholder data. Costs have been updated to 2015 values using the Chemical Engineering Plant Cost Index. The upper diameter limit of 1,400 mm is based on advice provided by industry stakeholders. Given the limited data available, the pipeline cost is assumed to be a continuous function. In practice, large diameter pipelines (greater than 1,000 mm) may incur additional manufacturing and transport costs.

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[3] Standards Australia (2012), *AS 2885.1 Pipelines—Gas and liquid petroleum—Design and construction*.
[4] J Barnett, R Cooper (2014), *The COOLTRANS Research Programme: learning for the design of CO_2 pipelines*, 10th International Pipeline Conference, Calgary, Alberta, Canada.
[5] International Organization for Standardization (2009), *ISO 13623 Petroleum and natural gas industries—Pipeline transportation systems*.
[6] Det Norske Veritas (2010), *RP-J202 Design and operation of CO_2 pipelines*.
[7] WorleyParsons (2009), *Small diameter pipelines: total installed cost budget estimates*, Department of Resources, Energy and Tourism, Canberra, Australia; WorleyParsons (2009), *Summary of Pipeline Sizing Study*, Department of Resources, Energy and Tourism, Canberra, Australia.

Figure 102 shows the nominal pipeline diameter (in 50 mm increments) as a function of flow-rate and distance, while Figure 103 shows the associated pressure gradient changes (that is, pressure loss per unit length of pipeline). These figures apply to both onshore and offshore pipelines. The diameter increases with both distance and flow-rate to compensate for frictional pressure losses. By multiplying the pressure gradient by distance, the pipeline inlet pressure can be determined. This pressure can be used in injection operations to determine the booster pump duty.

Data for the pipeline capital cost are presented in two formats. In Figure 104, the absolute capital cost (A$ million) is shown for a given flow-rate and distance, while Figure 105 shows the unit pipeline capital cost (A$ per unit flow-rate per unit distance). Although absolute capital cost increases with flow-rate and distance, the unit pipeline capital cost becomes almost independent of flow-rate at high enough values (typically beyond 20 Mt/y).

Other than costs for compression and recompression, the operating cost of transport pipelines is related to pipeline maintenance and can be estimated using a percentage of the capital cost (for example, 1%).

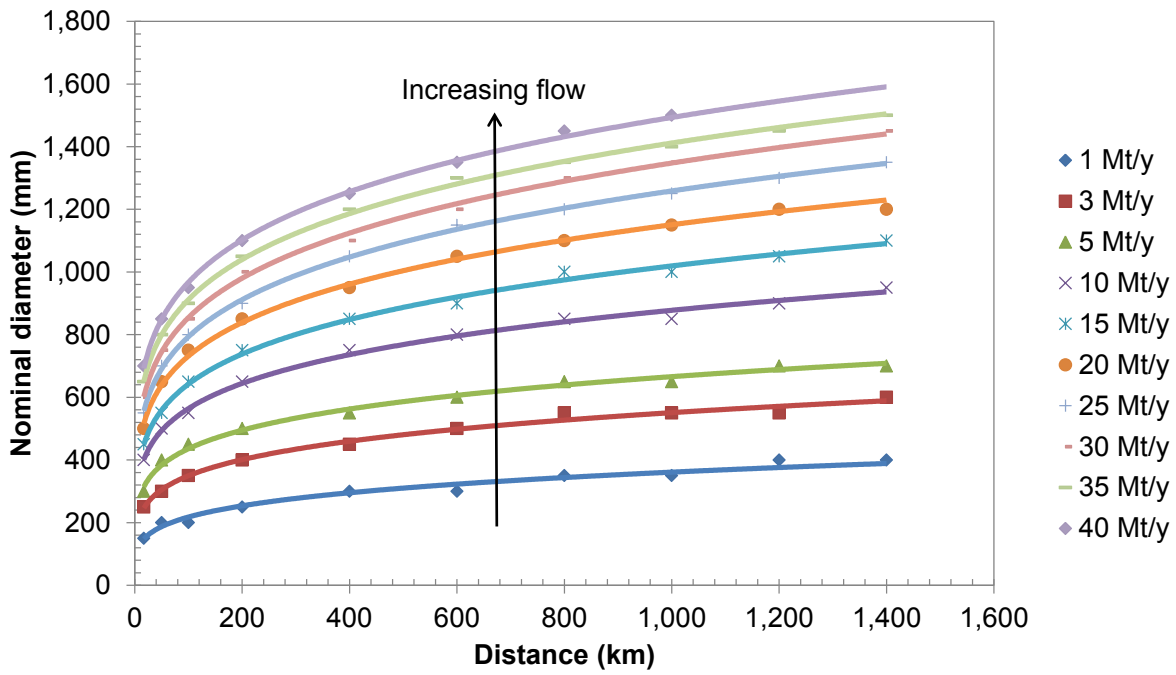


Figure 102: Pipeline diameter as a function of distance and flow-rate for steel grade X70 and flange class CL1500

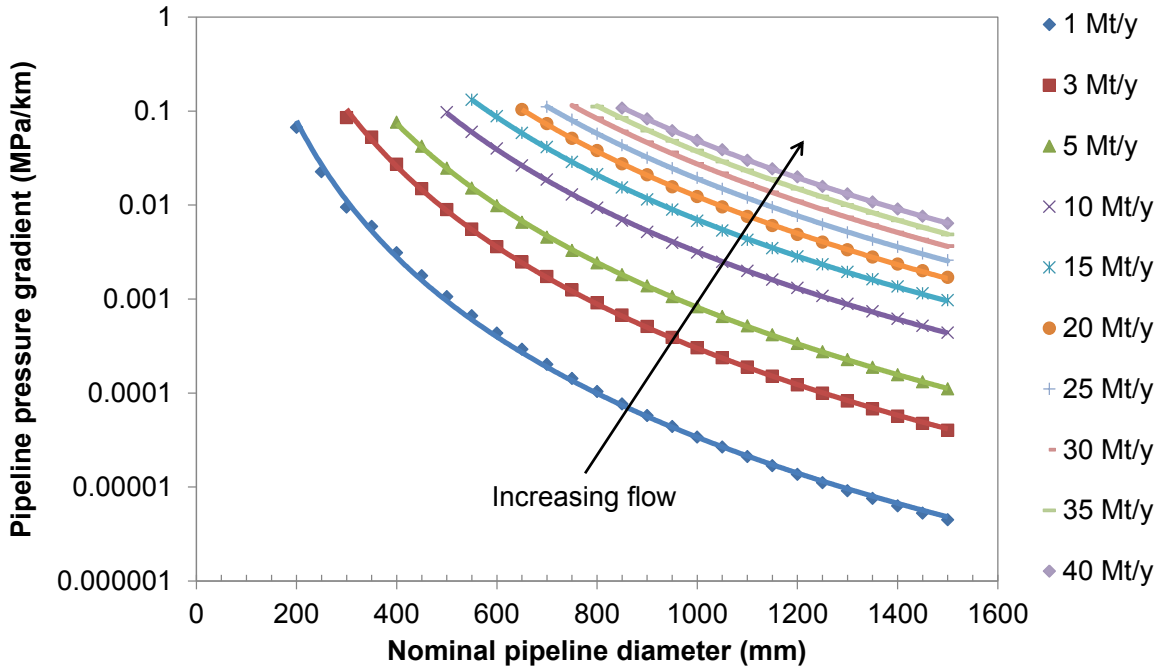
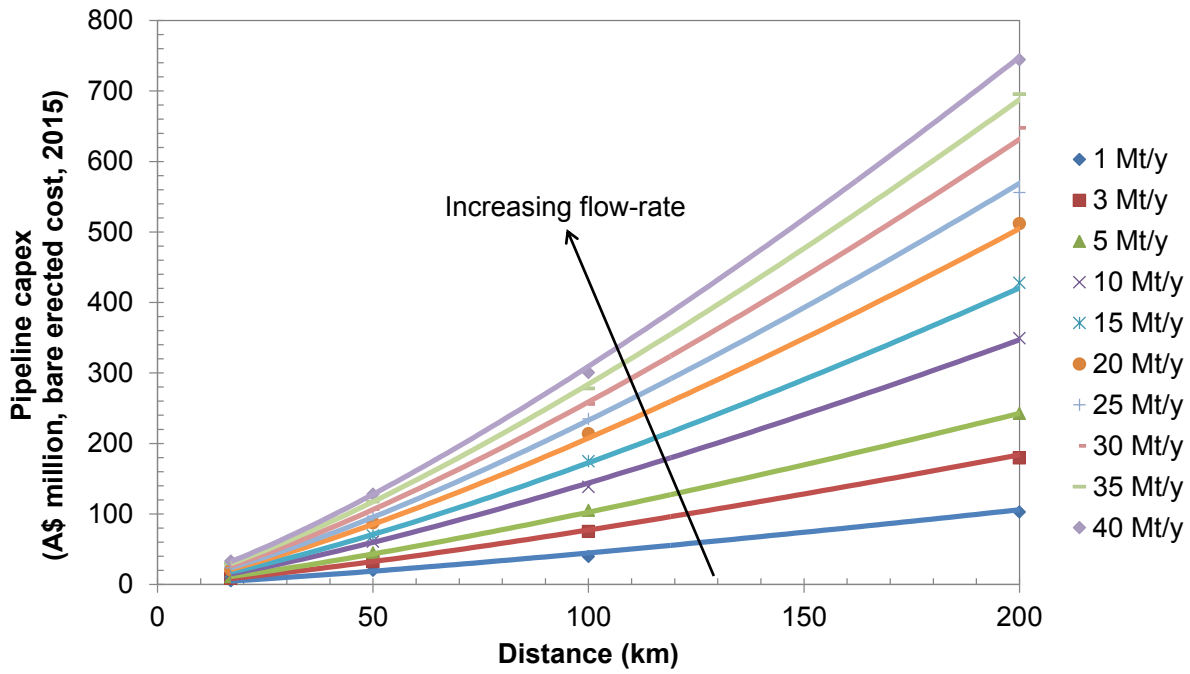
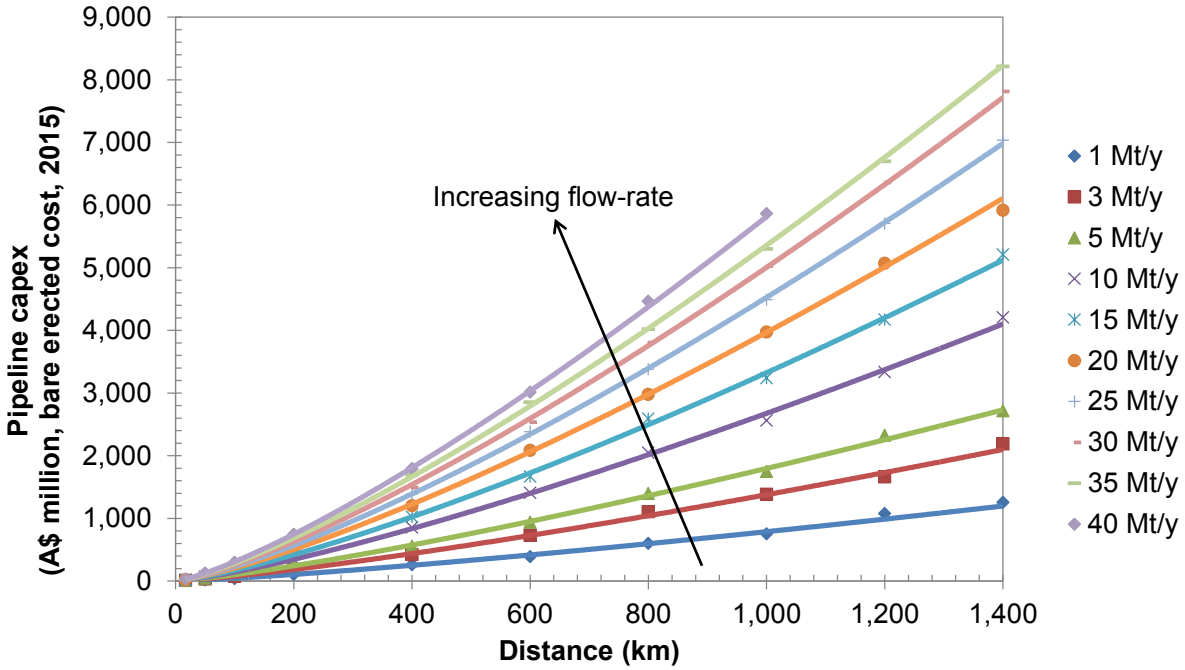


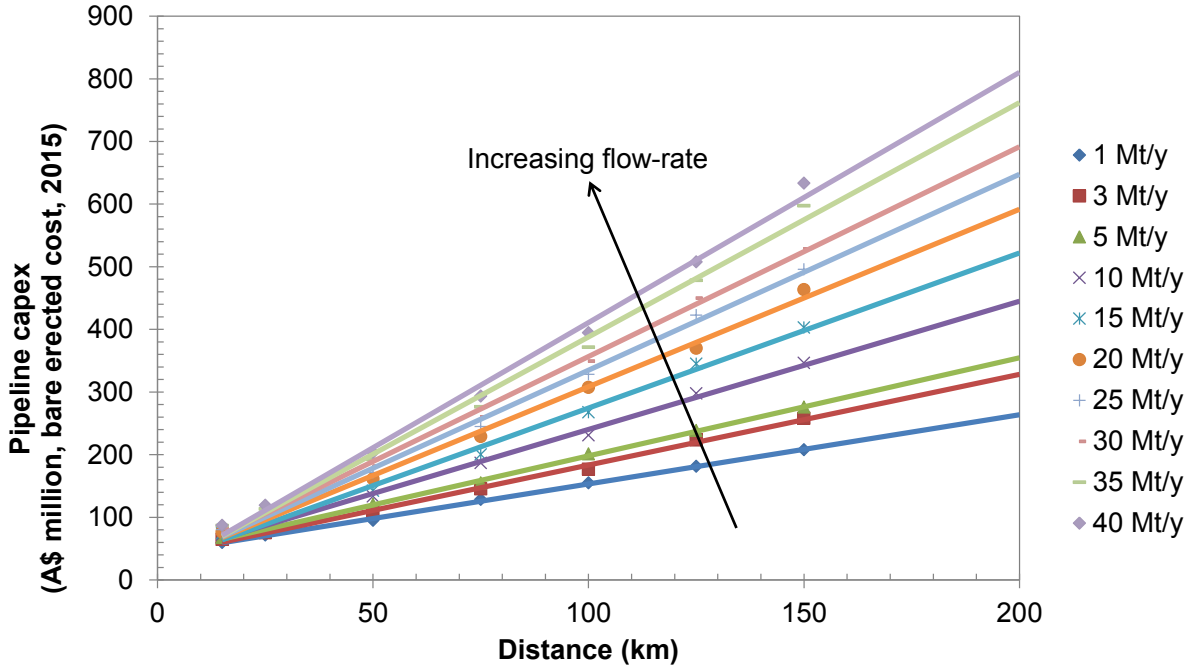
Figure 103: Pipeline pressure gradient as a function of distance and flow-rate for steel grade X70 and flange class CL1500



(a)

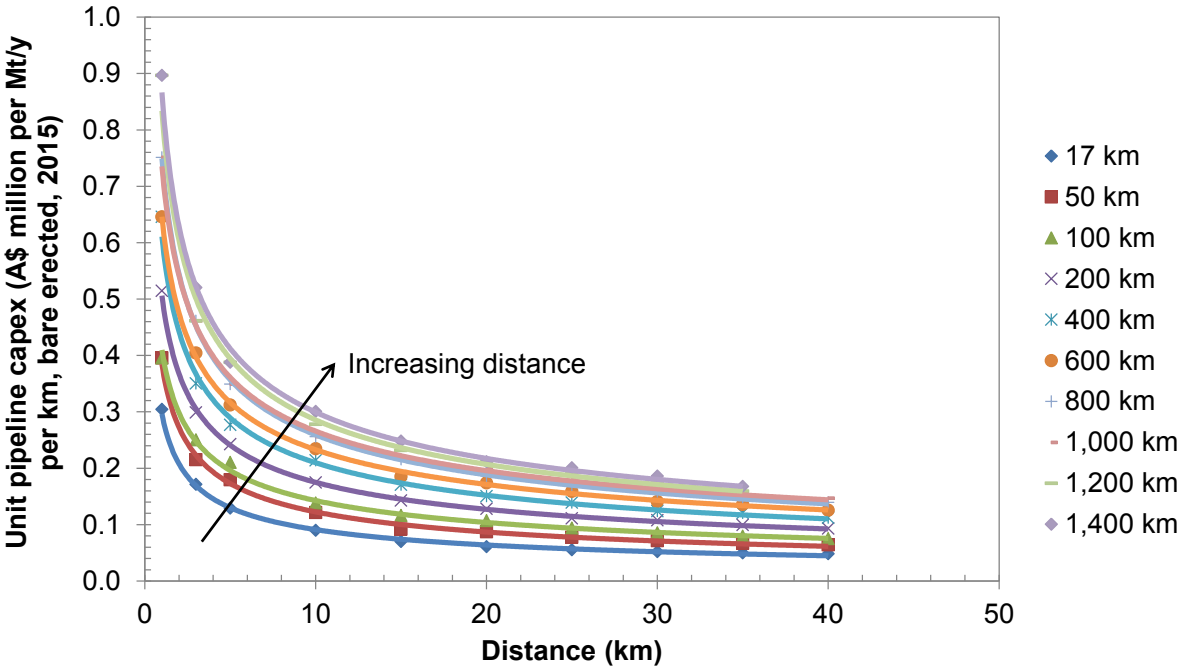


(b)

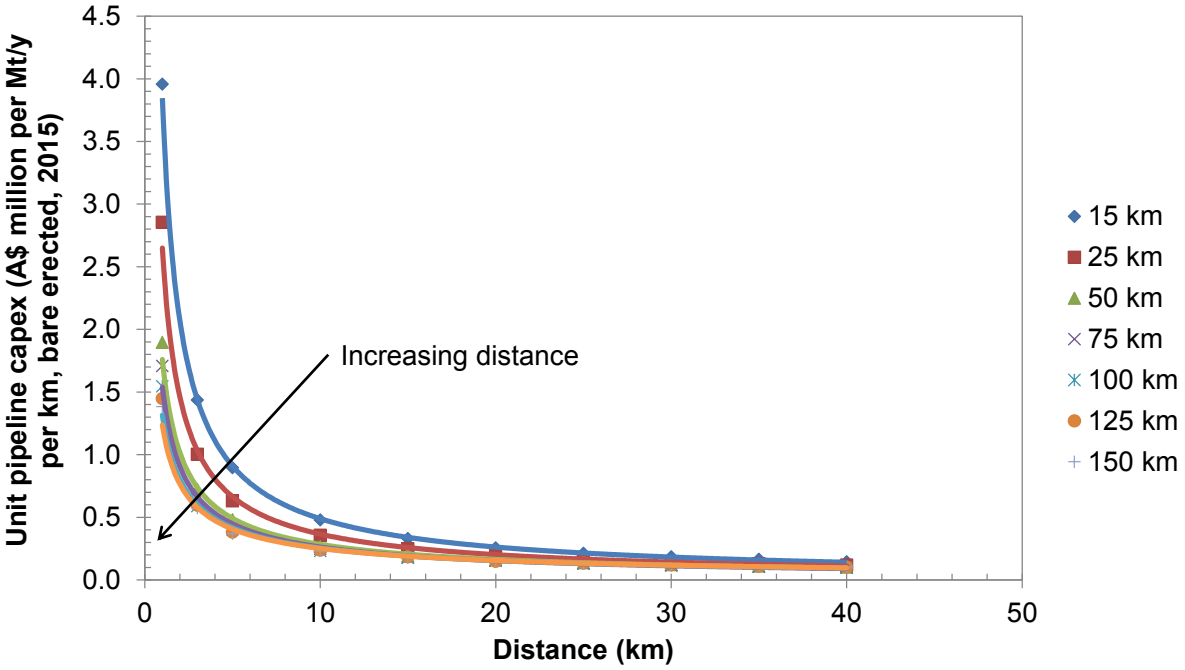


(c)

Figure 104: Pipeline capital cost as a function of flow-rate for transport (a) onshore (15–100 km) (b) onshore (15–1,400 km) (c) offshore (15–200 km)



(a)



(b)

Figure 105: Pipeline unit capital cost as a function of flow-rate for transport (a) onshore and (b) offshore

Effects of a different working pressure and flange class

As pressure increases, both the density and viscosity of dense-phase CO_2 increase. These properties have competing effects on pressure losses along a pipeline: higher viscosity increases friction, but an increased density reduces the fluid velocity at the same mass flow-rate. For dense-phase CO_2 at high Reynolds numbers (about 10^6), pressure loss increases proportionally to the ratio of the cube root of viscosity over density and is dominated by the density. Thus, the pressure gradient decreases as the pressure increases. This means that operating CO_2 pipelines at a higher pressure lowers pressure losses and allows the CO_2 to be transported for longer distances without the need for recompression. For example, the pressure drop per unit length at 18 MPa is about 7% lower than that at 13 MPa. But operating at a higher pressure requires a higher flange class and greater pipeline thickness to prevent ruptures due to the higher internal pressure.

The choice of operating pressure can also be affected by the pressure required for injection at the end of the pipeline. The 1500 lb flange rating used in this chapter permits safe operation at a MAWP higher than 15 MPa, but operating at a higher MAWP would require a thicker pipeline with higher costs than those provided here. Thus, for specific projects, it may be possible to reduce the total cost for transport and storage by delivering the CO_2 at the required injection pressure, thereby avoiding additional recompression at the well-head.

The number of boosting stations along the pipeline provides another opportunity to trade off between capital costs for pipelines and compression and operating costs. The optimal design of a transport and storage network therefore depends on many factors, including the cost of energy, the cost of steel, the transport distance and the economic parameters.[8]

Effects of networks and phased increases in flow-rate

As more CO_2 capture projects are developed, the requirement for CO_2 transportation will increase. Depending on the timing of new projects, CO_2 pipelines can be overdesigned to cater for increasing CO_2 flow-rates over time. Additional booster pumps can also be added over time to cater for at least some increase in flow-rate. In the case of overdesigned pipelines, this means that the pipelines will be under-used during the first years of operation, increasing transport costs above the optimal values presented here. However, there are significant economies of scale in transport costs due to the use of larger pipeline diameters. Thus there is a cost trade-off between under-using larger capacity pipelines and building several optimally designed lower capacity pipelines. The trade-off not only depends on the degree of underutilisation, but also on other factors such as the price of steel, the transport distance and the cost of capital.[9] The phasing trade-off is of particular importance to the design of trunklines in pipeline networks, as feeder pipelines to the network are more likely to be operated at their nominal capacity as dictated by the CO_2 capture rate of the associated source.

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[8] Z Wang, GA Fimbres Weihs, D Wiley (2011), *A GIS-based integrated CCS transport pipeline network for South-East Queensland*, CO2CRC Research Symposium 2011, Adelaide, Australia.
[9] Z Wang et al., *A GIS-based integrated CCS transport pipeline network for South-East Queensland*.

Effects of topography and seasons

The transport costs presented here do not include the effects of topography or seasonal temperature changes. Some types of topography (such as rocky terrain) will increase transport costs due to increased pipe-lay costs. In other cases, pipeline developers may choose to avoid such terrain (such as mountain ranges), which may result in increased transport distance and hence cost. Some regions of interest in Australia, such as south-east Queensland,[10] do not present significant topographical obstacles for pipeline construction, so the costs here should provide reasonable cost estimates for scoping studies. For other regions, an adjustment factor should be applied to the data provided. One tool for estimating adjustment factors and optimal pipeline routes is GA Explorer.[11]

The data presented here are for a fixed onshore temperature of 25°C and an offshore temperature of 20°C. These temperatures may differ with specific project locations and seasons. Real projects require more detailed modelling of local and seasonal effects in order to determine the appropriate pipeline design for all anticipated operational conditions.

Recompression

Recompression using booster pumps is needed to keep the CO_2 in a dense phase whenever the pressure drops below about 8 MPa. This pressure is higher than the critical pressure of CO_2 and provides a safety margin to ensure that the CO_2 stays in the dense phase.[12] The amount of recompression required either along the pipeline or at the well-head needs to be sufficient to transport the CO_2 from the source to the storage site, to overcome frictional losses in the pipeline and to enable the injection of the CO_2 into the storage formation. The building blocks provided here enable the determination of the capital and operating costs of recompression. The original recompression cost data were provided by Shedden Uhde for a Latrobe Valley CO_2 storage assessment[13] and have been updated using the Chemical Engineering Plant Cost Index.

Figure 106 provides the capital cost of booster pumps as a function of flow-rate, while the booster pump duty (assuming a compression efficiency of 85%) is shown in Figure 107. The blue line in Figure 106 shows the optimal cost based on discrete frame sizes of the booster pumps (1 Mt/y, 7.6 Mt/y and 13.2 Mt/y), while the black line shows the linear trend for the results. The capital cost for the booster pumps increases with flow-rate because larger frames and more booster pumps are required. Booster pump duty increases linearly with flow-rate and logarithmically with discharge pressure.

Estimating the operating cost for recompression requires the fixed operating costs (which can be estimated as 4% of capital cost) and the variable operating costs (which requires the booster pump duty and the cost of the energy used to power them). Energy for booster pumps may be supplied directly from the electricity grid or from a purpose-built generator. While grid-average costs of fuel or electricity can be used in built-up areas or near power grids, energy costs in remote areas or offshore may be significantly higher.

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[10] Z Wang et al., *A GIS-based integrated CCS transport pipeline network for South-East Queensland*.
[11] Geoscience Australia (2014), *GA Explorer*, www.ga.gov.au/explorer-web/ (accessed 10 September 2015).
[12] ZEP (2011), *The costs of CO_2 transport: post-demonstration CCS in the EU*, European Technology Platform for Zero Emission Fossil Fuel Power Plants.
[13] S van Wagensveld, P Ferguson (2005), *CO2CRC Latrobe Valley CO2 Storage Assessment Pre-Feasibility Study*, Shedden Uhde Australia Pty Ltd.

Furthermore, the generation of the electricity will produce CO_2 emissions, which should be included when calculating the amount of CO_2 emissions avoided.

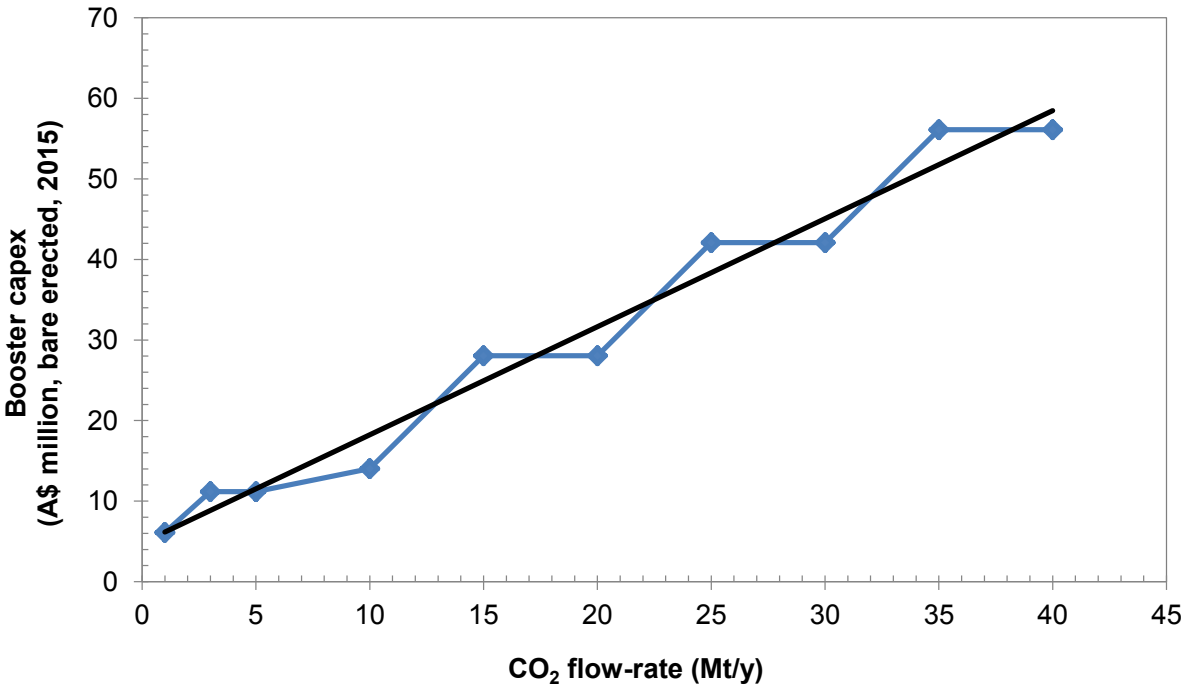

Figure 106: Recompression capital costs as a function of flow-rate

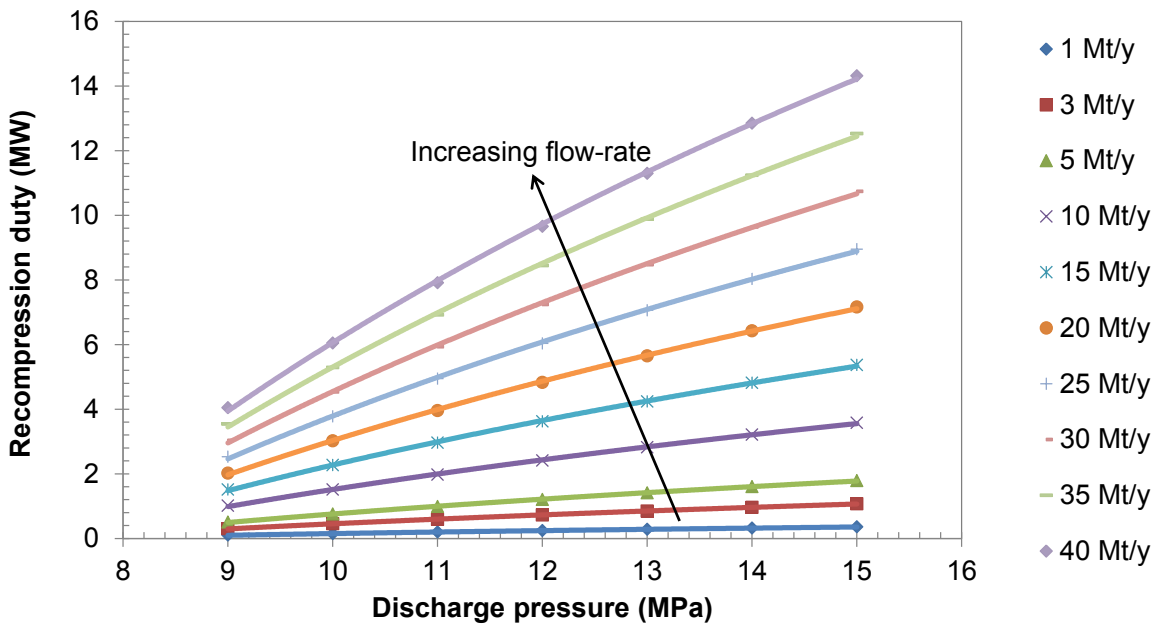

Figure 107: Pumping duty as a function of discharge pressure and flow-rate

10.3.2 Injection operations

CO_2 injection operations involve the exploration and appraisal of storage sites (or sinks), the drilling and completing of wells, the injection of CO_2 and the monitoring of storage sites both during and following injection. These operations are supported by surface facilities, such as platforms.

A geological formation requires three characteristics in order to be suitable for CO_2 storage:

- *Capacity:* This is the amount of accessible pore space under given geological, engineering and economic constraints. Because of these constraints, the total pore volume of the storage formation must be greater than the volume of the total amount of CO_2 to be injected.
- *Injectivity:* This reflects the ease with which CO_2 can be injected into the storage formation and affects the number of wells needed to inject at a given flow-rate.
- *Containment:* This is the presence of one or more trapping mechanisms that will control the movement of the CO_2 in the subsurface and prevent it reaching the atmosphere or valuable subsurface resources (such as groundwater and natural gas).

Injection costs (either onshore or offshore) have three major components: well drilling, storage site facilities and monitoring. The following sections provide building blocks for those components.

Wells

The number of wells needed for an injection project is a function of the CO_2 flow-rate and storage formation properties. The key properties are permeability, thickness, total vertical injection depth, areal extent of the formation, the fracture pressure gradient and the ratio of maximum injection pressure to fracture pressure.

Further assumptions used for developing the datasets here are as follows:

- Injection occurs over 25% of the areal extent of basins. This accounts for areas that are unavailable for injection operations because of their geology (for example, because they have no seal or have poor permeability) or geography (such as built-up areas and national parks). However, this assumption may be too conservative for particular formations and closures.
- The bottom third of the formation thickness is perforated for injection. This maximises the ability for CO_2 to migrate away from the injection zone under buoyancy. As depth increases, the well cost, formation pressure and maximum injection pressure usually increase, while permeability and porosity usually decrease. These trends create a trade-off between factors that favour fewer wells (well costs, formation pressure and maximum injection pressure) and those that favour more wells (permeability and porosity). Therefore, in deep, very thick formations it may be cheaper to not drill wells to the bottom of the formation and to perforate somewhere in the middle of the formation.

Because there is a very large combination of formation properties, Figure 108 provides three examples of the relationship between the total CO_2 injected over 30 years (expressed as flow-rate) and the number of wells. A more extensive set of examples is in Figure 143.

The total injection rates for different numbers of wells are estimated using MonteCarbon, which is a scoping tool developed by UNSW Australia.[14] MonteCarbon solves Darcy's law for multiple injection wells to estimate the injection rate or bottom-hole pressure.[15] The tool uses analytical models that account for the different numbers of wells and a wide range of formation properties, such as permeability, relative permeability, porosity, thickness, depth and areal extent. The models account for the effects of well interference using super-positioning techniques. The predictive capability of MonteCarbon has shown good agreement between the analytical and numerical computations conducted with commercial reservoir simulation packages.

In practice, extensive reservoir simulation is needed to estimate the number of wells and optimise well placement. Reservoir simulators account for storage formation heterogeneity and well interference, as well as enabling optimisation such as sweet spot analysis. Further, since MonteCarbon is based on discrete datasets, bespoke reservoir simulation enables the assessment of injectivity for the particular properties of a storage formation and the associated uncertainties.

Top-hole pressure (shown in Figure 109) is calculated with a vertical pipe equation[16] using 8.681-inch tubing as well as the flow-rate and the bottom-hole pressure required for injection. The bottom-hole pressure (provided by booster pumps either at the well-head or elsewhere along the pipeline) is the product of the fracture pressure gradient, the injection depth and the highest safe injection pressure (HSIP) ratio. HSIP ratios can vary from 60% up to 90% depending on the geomechanical context and the project's risk management strategy.

If the combination of transport distance and flow-rate means that the CO_2 cannot be delivered to site at the top-hole pressure required, then well-head boosting is used. If booster pumps are needed offshore, they are assumed to be placed on the platform (when platforms are used). Otherwise, subsea booster pumps could be used. Using booster pumps on a platform is estimated to increase the platform cost by the equivalent cost of five extra wells.

For the data presented here, the original cost of vertical wells at different depths comes from data provided by RISC[17] to the Carbon Storage Taskforce for different Australian sedimentary basins. The RISC costs were based on historical data collated by APPEA for oil and gas wells. Oil and gas wells, such as those in the APPEA database, are generally drilled quickly in order to minimise the time a drilling rig is required on site and mainly use logging and coring tools for exploration and appraisal wells. The costs used in this study have been updated using the IHS-CERA Upstream Capital Cost Index, benchmarked against recent well costs and calibrated against stakeholder data. In the case of offshore wells, the benchmarking has resulted in well costs being increased by 75% beyond the effect of indexation. Furthermore, the offshore costs presented here are for wells drilled in shallow water (less than 100 m deep). Wells drilled on the flanks of the continental shelf or in deep water are likely to be significantly more expensive. Costs of wells may also vary significantly between projects and between drilling contractors.

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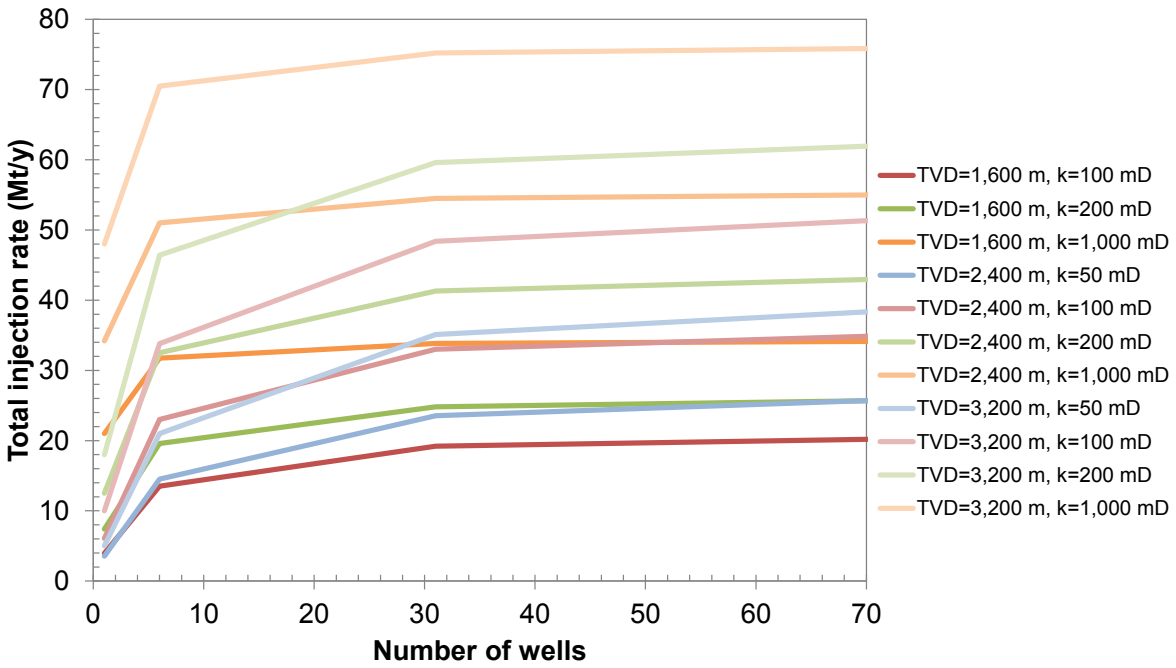
[14] E Azizi, Y Cinar, WG Allinson, PR Neal, K Michael (2013), *Launching MonteCarbon, a CO_2 injectivity and storage capacity estimator software*, CO2CRC Research Symposium 2013, Wrest Point, Tasmania, Australia.
[15] E Azizi (2013), 'An analytical modelling study of pressure build-up at CO2 injection wells in saline formations', PhD thesis, University of New South Wales.
[16] Adapted from HB Bradley (1989), *Petroleum engineer's handbook*, p. 34.29, Equation 60.
[17] RISC (2009), *CO_2 injection well cost estimation*, Department of Resources, Energy and Tourism, Canberra, Australia.

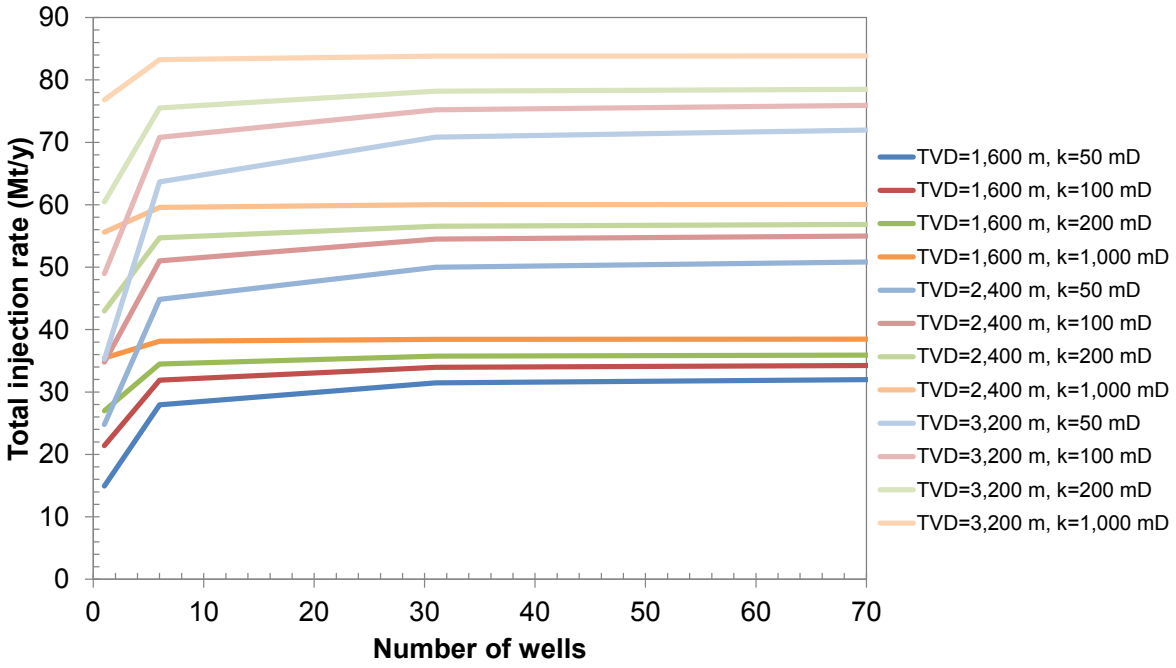
The costs of drilling simple vertical wells and completing them with standard cement, casing and tubing are shown in Figure 110. The costs are reported relative to oil prices of US$50/bbl and US$100/bbl, which are used as a proxy for industry activity, which affects rig availability and rates. If specialised cement, casing and tubing are required, there could be a significant increase in completion costs.

Stakeholders have advised that it is likely that many CO_2 storage wells will require coring and logging, either because of regulatory requirements or the need to reduce uncertainty in the properties of sealing and storage formations. Therefore, the figure also shows the cost of wells plus a nominal coring and logging cost of A$0.93 million/well and A$1.1 million/well for oil prices of US$50/bbl and US$100/bbl, respectively.

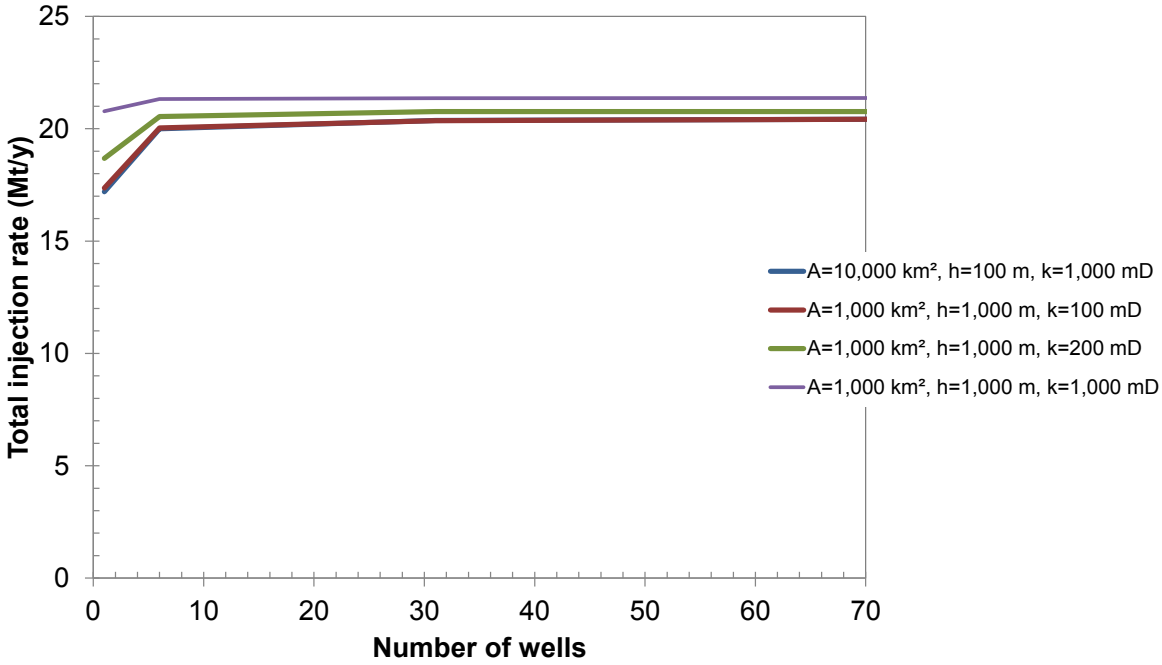
The operating costs for wells (mainly for well maintenance) can be estimated as 2% of the capital cost.



(a) A = 10,000 km^2, h = 100 m and ϕ = 20%



(b) A = 1,000 km^2, h = 1,000 m and ϕ = 20%



(c) d = 3,200 m and ϕ = 5%

Figure 108: Total injection rate as a function of numbers of wells for various combinations of permeability (k), injection depth (d), areal extent (A), thickness (h) and porosity (ϕ)

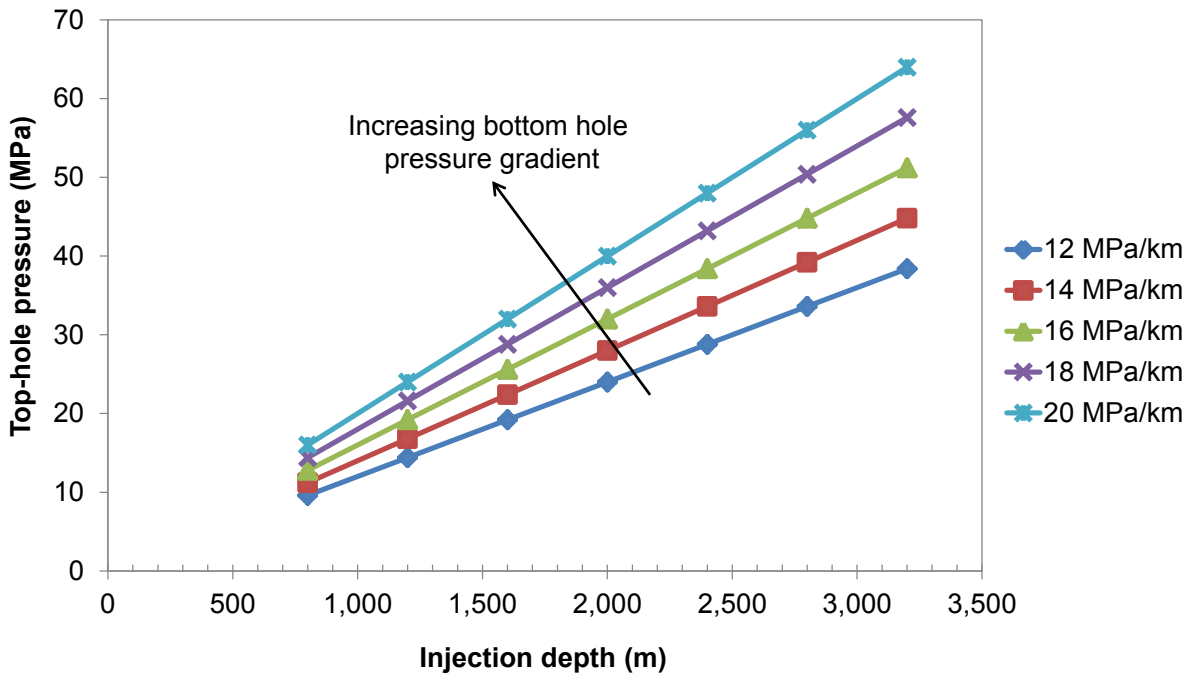
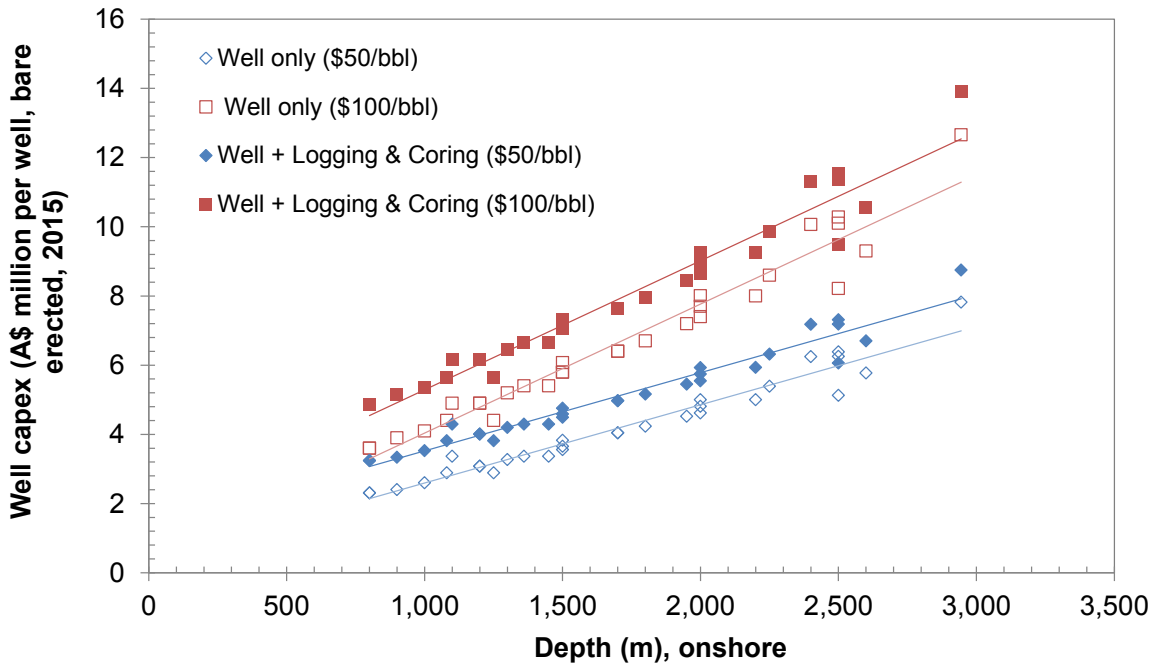
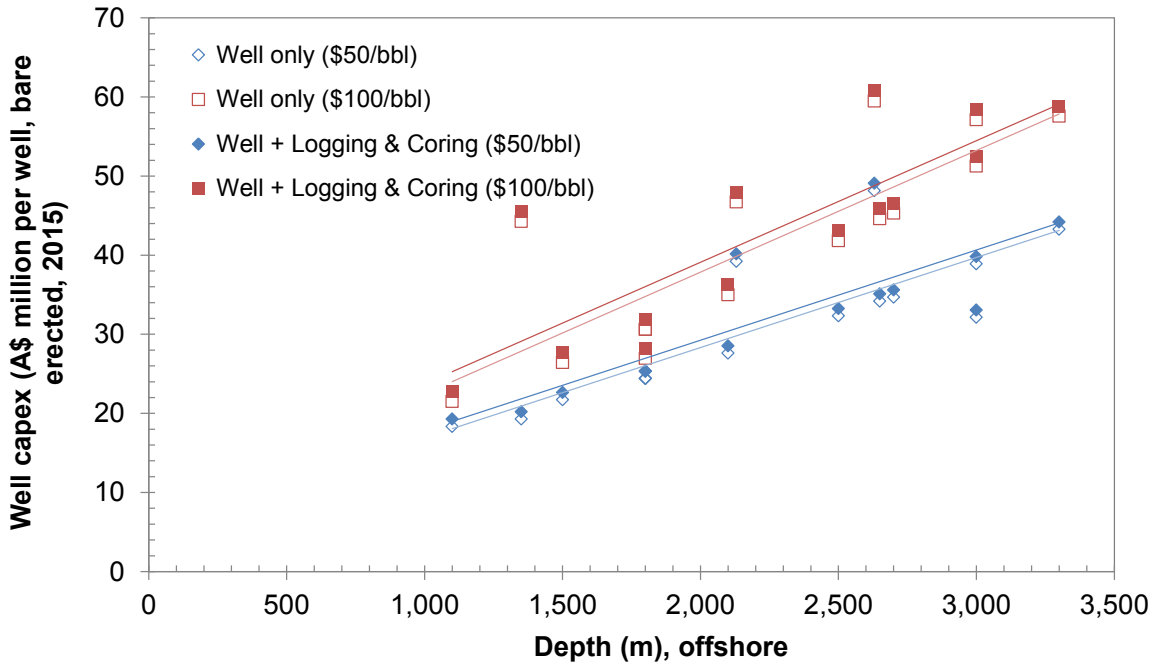


Figure 109: Top-hole pressures as a function of total vertical depth and bottom-hole pressure gradient



(a)



(b)

Figure 110: Vertical well drilling costs ($/well) for oil prices of US$50/bbl and US$100/bbl and as a function of injection depth (a) onshore and (b) offshore

While the data provided here is for vertical wells, horizontal wells can also be used for CO_2 injection. Horizontal wells are more expensive to drill than vertical wells because they are usually 'longer'. However, horizontal wells offer increased contact area with storage formations and therefore greater 'per well' injectivity. Therefore, there is a trade-off that will determine whether using horizontal wells will increase or decrease total cost.

The data provided here are based on the use of oil and gas drilling rigs. Some consideration has been given in Australia to the use of mineral exploration rigs and water-bore rigs. Although these rigs are less powerful and therefore take longer to drill to the final depth, they are much cheaper to hire and therefore offer the possibility of reducing the total cost of wells. On the basis of data provided by stakeholders, using a mineral rig could save up to two-thirds on a dollar per unit depth basis.

However, the choice of rig must be made after considering the target depth, the types of rock that the rig will have to drill through and whether coring or logging is required. If the rock is hard, then less powerful rigs may take longer to drill the well and lead to the well being more expensive than one drilled with an oil and gas rig. Furthermore, the cheaper rigs cannot drill the larger diameter holes required for proper logging and coring.

Storage facilities

This section provides the building blocks to estimate costs for facilities needed to support onshore and offshore injection.

For onshore projects, the cost of a simple distribution network to take the CO_2 from the end of the pipeline out to one or more injection wells is provided in Figure 111. The cost is reported per km of well spacing as a function of the number of wells and flow-rate.

For offshore projects, the cost of platforms as a function of the number of wells is provided in Figure 112, using a limit of five well slots per platform. The original costs for steel jacket platforms with minimal topsides provided by Shedden Uhde[18] and others have been updated using the IHS-CERA Upstream Capital Cost Index.

Depending on whether the facilities are onshore or offshore and the amount and type of topsides on platforms, the operating cost can be estimated at between 2% and 4% of the capital costs. A key factor in the estimation of platform operating costs is whether the topsides include rotating equipment, such as pumps and compressors. Such equipment may not be required for supplying injection pressure to the CO_2, but may be needed for the recirculation of corrosion or hydrate inhibitors and other functions. The maintenance requirements of any rotating equipment will determine the platform staffing requirements and therefore the operating costs.

For onshore facilities, the data provided are based on a simple distribution network. More detailed distribution network design may reveal significant opportunities to reduce pipeline size and length by introducing multiple injection centres with a number of wells and by optimising the connections between wells.

For offshore platforms, the economies of scale for costs shown are limited by the number of well slots per platform. Costs could be reduced if more slots are available. For example, the Fortescue platform in the Gippsland Basin has more than 20 well conductors. Furthermore, operating costs could be reduced by eliminating as much rotating equipment from the platforms as possible. However, maintenance costs for the platforms themselves could still be significant.

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[18] S van Wagensveld, P Ferguson (2005), *CO2CRC Latrobe Valley CO_2 Storage Assessment Pre-Feasibility Study*, Shedden Uhde Australia Pty Ltd.

In the oil and gas industry, subsea completions are increasingly being used, rather than platforms. This trend may carry over into offshore CO_2 storage operations. Subsea completions are more expensive to install than platforms but offer significant reductions in operating costs. They have already been used in the Snohvit project[19] and have been considered for other CCS projects. As this technology is still maturing, there is still some uncertainty about costs. Indicative costs are A$30–35 million per well[20] scaled to 2015 costs using the IHS-CERA Upstream Capital Cost Index.

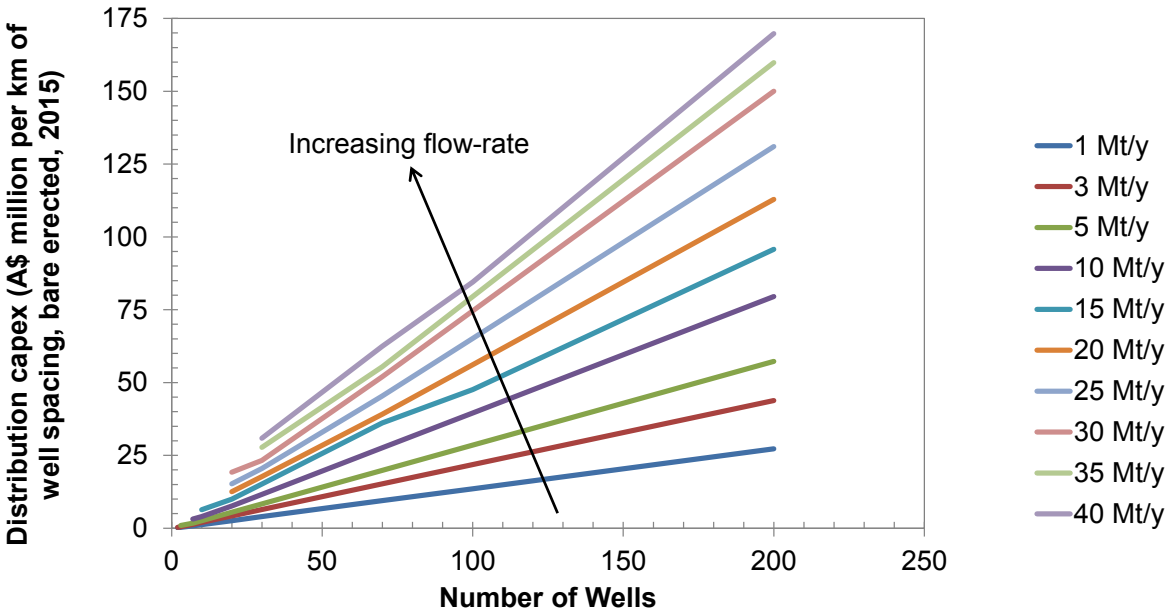


Figure 111: Onshore distribution capital costs as a function of number of wells or flow-rate for onshore injection

[19] www.statoil.com/en/ouroperations/explorationprod/ncs/snoehvit (accessed October 2015).
[20] IEA (2005), *Building the cost curves for CO_2 storage: European sector*, IEA Greenhouse Gas R&D Programme; MA van der Broek (2010), *Modelling approaches to assess and design the deployment of CO_2 capture, transport, and storage*, Proefschrift, Utrecht University.

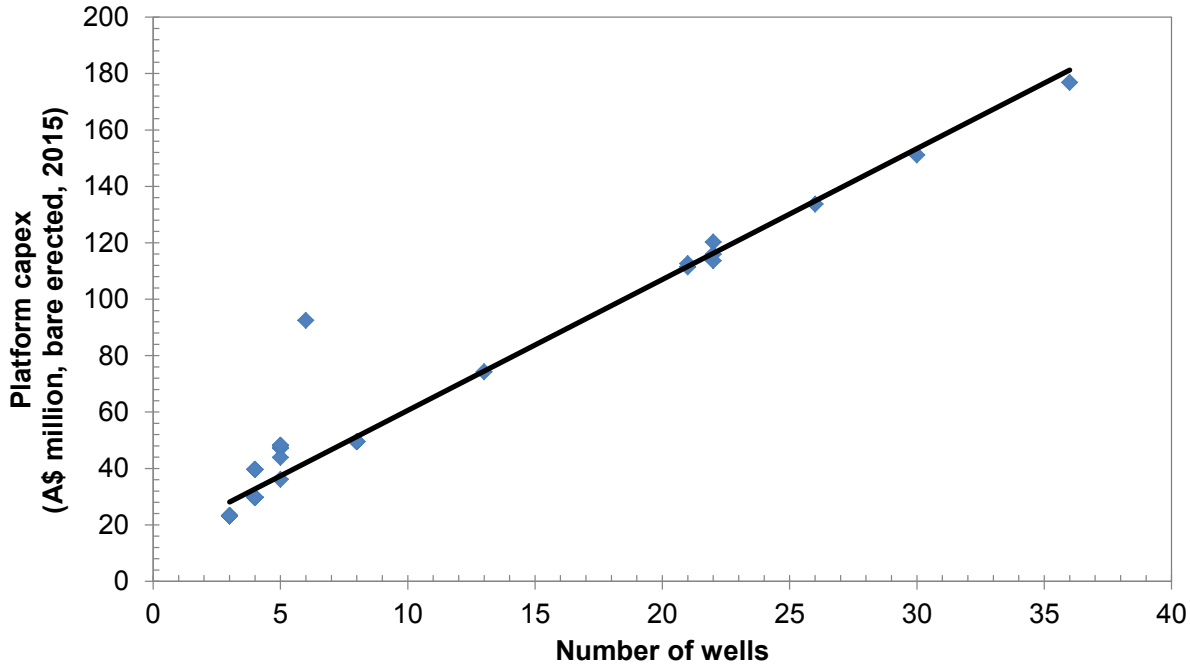


Figure 112: Offshore platform capital costs as a function of number of wells for offshore injection

Monitoring

This section provides the building blocks to estimate costs for the monitoring of onshore and offshore storage sites.

As very few large-scale CCS projects are in operation, the exact nature of monitoring programs is still uncertain. The key goals of a monitoring program will be to establish that CO_2 is behaving according to predicted patterns, to provide early detection of unexpected migration and to underpin the social licence to operate.

A recent review of CCS monitoring summarises the wide range of technologies available.[21] The choice of technologies and the strategies for using them will be determined by a combination of regulatory requirements, geological conditions and the risk preference of project proponents.

Currently, it is expected that a survey program would include seismic surveys every five years and vertical seismic profiling (VSP) on a complementary 5-year cycle. However, not all formations are conducive to seismic monitoring, either because of the nature of the formation (for example, carbonate formations) or because of the rate and size of the injection in relation to the characteristics of the formation. Therefore, it is likely that pressure monitoring and limited environmental surveillance may also be used.

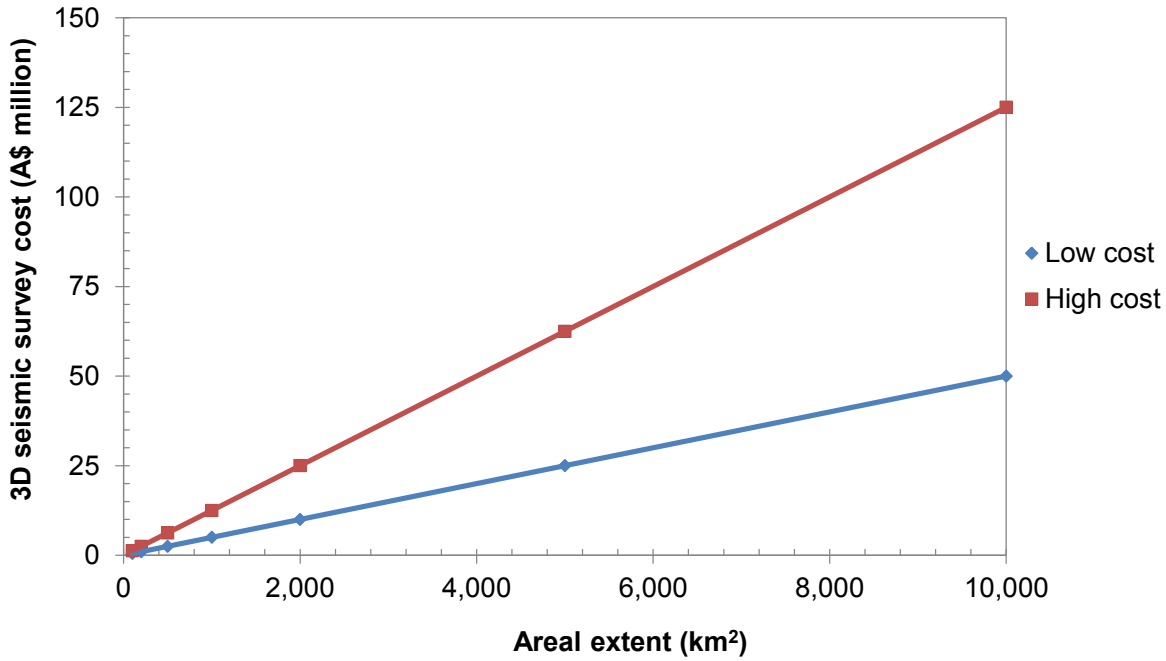
[21] C Jenkins, A Chadwick, SD Hovorka (2015),. 'The state of the art in monitoring and verification—ten years on', *International Journal of Greenhouse Gas Control*, 40(1):312–349.

Projects may include dedicated monitoring wells, which can be used for measuring pressure, conducting VSP logs and taking samples of the formation water. The number of monitoring wells needed is uncertain—it could be a fixed number (such as three) along the likely migration path or could be a ratio (for example, one monitoring well for every 10 injection wells).

The costs of seismic surveys for onshore storage sites are provided in Figure 113, while the costs of offshore surveys are provided in Figure 114. The costs are based on those reported[22] for the Carbon Storage Taskforce and have been updated using the IHS-CERA Upstream Capital Cost Index.

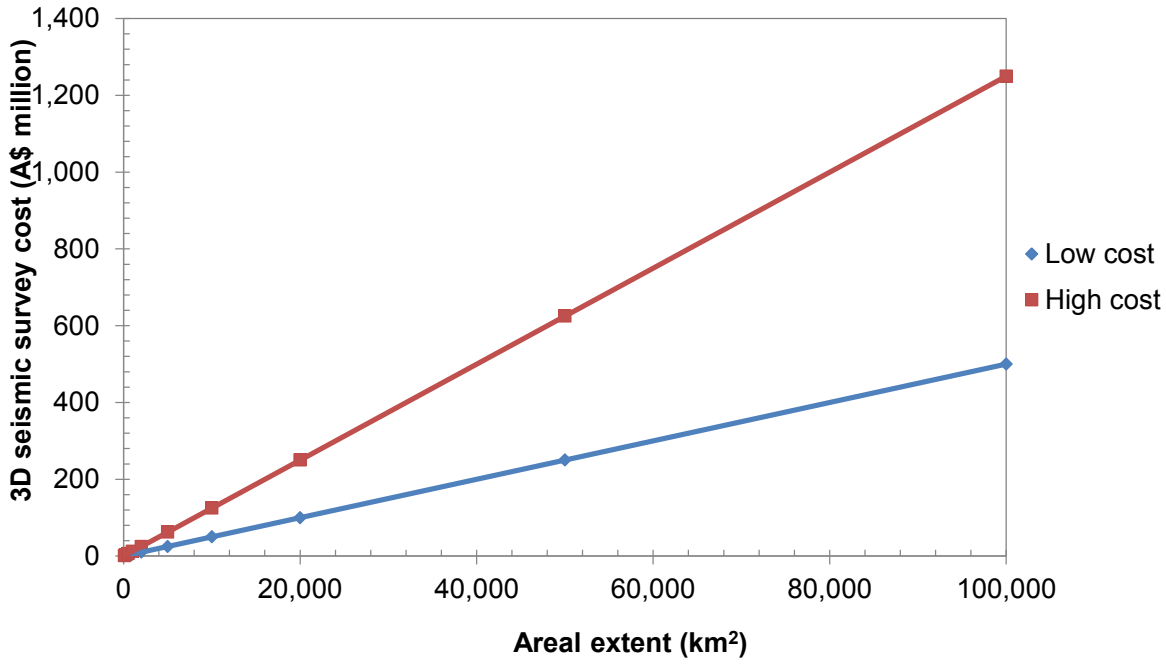
The cost of VSP logs is provided in Figure 115. These costs have been taken from literature values[23] and updated to 2015 values using the IHS-CERA Upstream Capital Cost Index. It is likely that for shallow monitoring, reflection seismic will completely dominate the costs of monitoring.

Because of the periodic nature of monitoring, the costs can be grouped with capital or operating costs depending on the phase of the project.



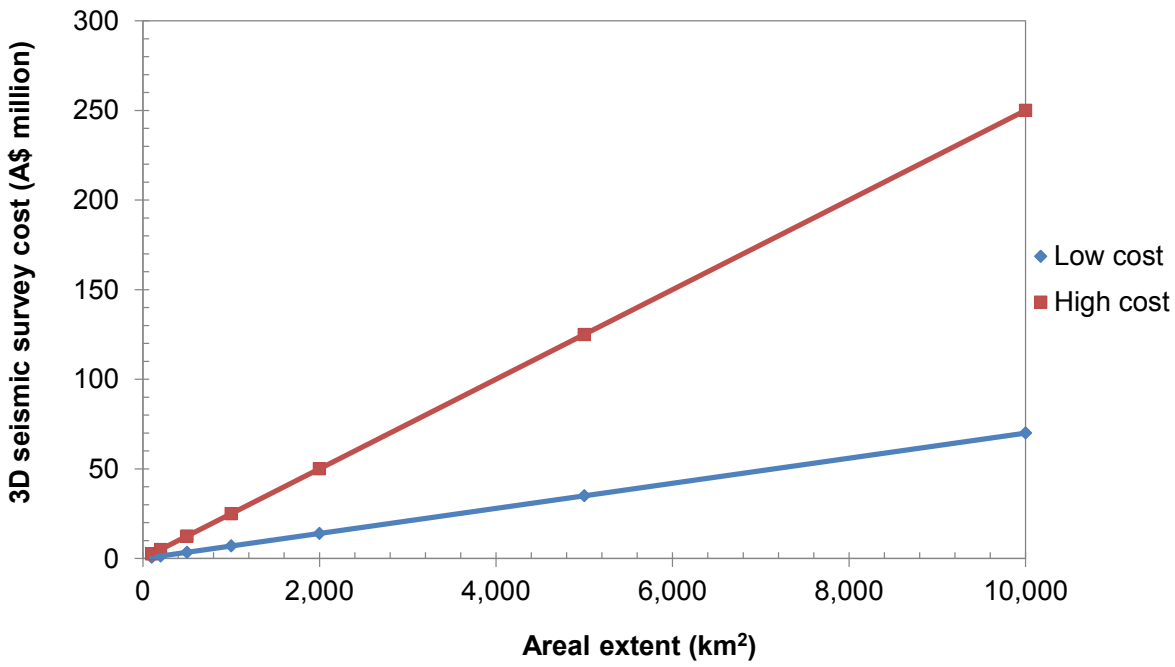
(a)

[22] K Spence (2009), *Exploration and development of carbon storage sites: an estimate of activity levels, resource requirements and costs*, Carbon Storage Taskforce.
[23] SM Benson (2006), *Monitoring carbon dioxide sequestration in deep geological formations for inventory verification and carbon credits*, Society of Petroleum Engineers.

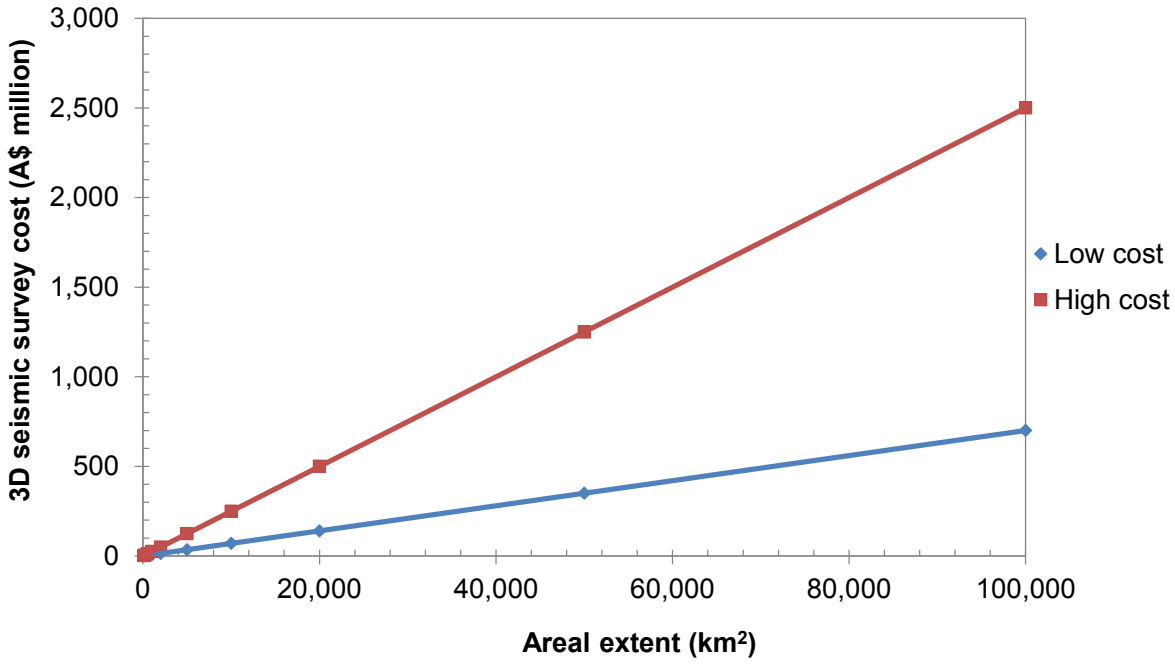


(b)

Figure 113: The cost of onshore seismic surveys as a function of areal extent (a) 0–10,000 km² and (b) 0–100,000 km²



(a)



(b)

Figure 114: The cost of offshore seismic surveys as a function of areal extent (a) 0–10,000 km² and (b) 0–100,000 km²

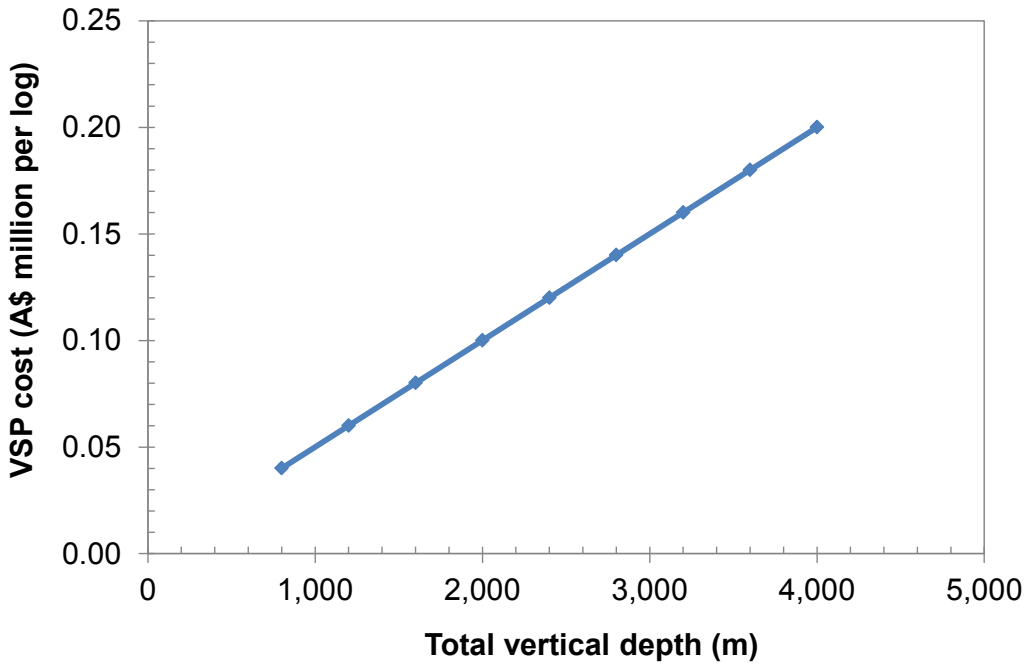


Figure 115: The cost of vertical seismic profile logs as a function of well depth

11 GRID CONNECTION

Grid connection—highlights:

- A critical consideration for a new generation plant is the way it gets connected to the grid. From small-scale distributed generators to large-scale generators, access to the grid is paramount.
- Transmission lines can range from $0.4 million to over $2 million per kilometre, depending on the application, with accompanying transformers totalling $5–20 million.
- Efficient outcomes can be achieved by optimising the operation of new generation plants within the constraints of the existing network and new grid developments.
- The utilisation of network connection assets is a material consideration for whole-of-project costs.
- Network augmentation costs associated with both distribution and transmission connected projects should be considered.
- Losses, reliability, security and capacity requirements affect the total connection costs.

11.1 Introduction

A critical consideration for the construction of new-entrant generation is the means of connection to the electrical system. From small-scale distributed energy resources to large-scale multi-unit thermal generators, the necessity to design and implement safe, efficient and low-cost means to transmit power is paramount.

Traditionally, electrical grids have been designed around a one-directional flow of power. Large-scale thermal and renewable generators produce power in discrete locations, typically at a great distance from the loads to be serviced. It is common for these distances to exceed 300–500 km from the generator to the loads to be serviced, such as major cities or industrial sites.

To enable the transfer of power from the generation areas to the load centres, a series of interconnected transmission and distribution lines are located along strategic easements to allow the power to be transferred and consumed where it is needed. Significant capital expenditure has been invested in these transmission assets, which in Australia typically connect power stations located near thermal coal and gas reserves with the major load centres of the capital cities.

Transmission assets can have technical lives in the order of 40–50 years and deployment costs ranging from tens to hundreds of millions of dollars. With the increasing penetration of new-entrant renewables and the approaching end-of-life of a number of incumbent

generators, opportunities to continue to maximise the use of the transmission assets need to be critically analysed.

Developers and stakeholders need to appreciate the limitations and capabilities of various transmission technologies from both a technical and a financial perspective. Through many decades of constructing and operating large-scale grids, various operators and network service providers have amassed a wealth of knowledge for the implementation of transmission solutions for new-entrant generators.

By co-optimising the operation of the new-entrant generators with the constraints of the existing network and greenfield transmission developments, efficient outcomes can be achieved for a range of stakeholders.

11.1.1 Transmission fundamentals

Commonly, the term 'transmission' has been used to describe the means of connecting two points in an electrical system, using a set of conductors. However, in the context of electrical grids operated in Australia, this term specifically relates to a subset of electrical infrastructure and equipment.

Transmission systems and lines can typically be defined by the following characteristics:

- A transmission system is a set of interconnected transmission lines grouped into a defined geographical area.
- Transmission lines operate in the high- to ultra-high voltage levels, usually in the range of 132 kV to 500 kV. This voltage is sometimes referred to as the 'line to line' voltage. By increasing the voltage of the transmission line, greater power transfer capabilities can be realised. Because power is equal to the product of voltage and current, by increasing the voltage the current reduces for the same unit of power transferred across the line. As current is the key limiting factor in a conductor's ability to transfer power, reducing current while maintaining the same power transfers is very desirable. The compromise for running higher voltages is the increased cost of the accompanying infrastructure, security and technical requirements.
- Power transfer capabilities for transmission lines can range from 50 MVA to 3500 MVA. A large number of parameters determine the expected transfer capability of the lines. Parameters such as operational voltage, conductor type and construction, tower arrangement, ambient conditions, terrain and easement width all influence the expected transfer capability of the line. This rating is typically set by the thermal capacity or current rating of the transmission line. When power is transferred across a conductor, heat is induced in the line, usually as a result of resistive losses, corona and the skin effect. This heat can usually be dissipated by prevailing ambient conditions. However, if temperatures exceed certain levels for a period of time, the conductor can experience thermal expansion and sag, such that it becomes too close to the ground and causes a fault. It is critical that the transmission lines are operated within their predefined limits, considering the prevailing weather conditions.
- Transmission losses as a result of transferring power between two substations can be material and result in a significant 'cost' or reduction in revenue to stakeholders. Typically, generators receive revenue from the market based on the energy that is delivered to a reference node. Due to losses, the delivered energy can be lower than the energy generated by the project. Reducing the operational voltage or increasing the length of transmission from adjacent connection points contributes to higher losses. The

expected impact of transmission losses on a site is typically considered in the initial scoping/pre-feasibility phase of the project.

- Transmission lines are unaffected by the various generation technologies. For example, a megawatt produced by a wind farm appears electrically the same as a megawatt produced from a thermal generator.

11.1.2 Voltage selection and historical applications

From a technical standpoint, it is usually desirable to connect a generation asset to the highest voltage level possible. This has a number of advantages, such as reduced likelihood of transmission congestion, which can reduce the export capacity for a generator that is sharing transmission capacity with other generators. Higher operational voltages also produce lower losses for the same power transfer requirements. Additionally, from a reliability standpoint higher operational voltages can be less susceptible to remote contingencies and faults.

Connections made to higher voltage levels typically have a comparatively higher cost of connection. In some cases, a twofold increase in the connection voltage can result in a more than doubling of the associated connection costs.

Historically in Australia, large thermal generation power stations with capacities greater than 1,000 MW connect at voltage levels from 275 kV to 500 kV. Large-scale renewable projects in the order of 50–200 MW have typically made connections to the transmission system at voltages ranging from 132 kV to 220 kV. However, some larger wind farms of several hundred MW connect directly at the 500 kV level.

11.2 Transmission technologies

In this section, we provide an overview of some of the transmission technologies deployed in Australia. Most of them are well established, while a select group of others have increased in popularity for specific uses.

11.2.1 Ultra-high voltage transmission

Ultra-high voltage (UHV) transmission lines in Australia have typically been developed with the primary purpose of facilitating the use of low-cost fuel sources in the Latrobe Valley in Victoria and the Hunter Valley in New South Wales. Due to the location of the coal deposits in those regions, which are several hundred kilometres from the main load centres, multiple 500 kV circuits were constructed to transfer power from the generators to the load.

While there are other coal-fired thermal generators around Australia in other regions and networks, 500 kV transmission lines have not been cost-justified because of the smaller total capacity of the power stations in those areas. In the transmission networks in Queensland, South Australia and Western Australia, large baseload coal-fired power stations have been connected via high-voltage (HV) 275–330 kV transmission lines.

Circuits at 500 kV voltage levels can transfer power in the order of 2,000–3,500 MVA. The generation assets in the Latrobe and Hunter valleys are capable of generating several thousand megawatts. For these flow paths, multiple 500 kV circuits from the generators to bulk supply points were needed to meet security requirements set by network operators.

The scale of infrastructure and land required for these transmission lines is significant. Easement widths for a single 500 kV tower are typically around 70 m[1] and can be hundreds of kilometres long. The associated substation works and switching bays for these lines can require areas greater than 15,000 m^2.[2] For example, South Morang substation in Victoria is one of the largest substations in Australia; its 500 kV switching buses require a developed area of approximately 25,000 m^2.

Because significant resources are needed to deploy 500 kV transmission assets, the financial costs associated with the infrastructure can be significant and are not typically paid for a single stand-alone project. Costs for such transmission lines are in the order of $1.4–1.8 million/km. The associated transformers and switchgear can exceed $50 million per substation.[2]

Because of the location and size of new-entrant renewables projects, 500 kV connections have not been developed in great numbers. The one notable exception is the Macarthur wind farm in southern Victoria. Due to the considerable size (420 MW) of the wind farm and the proximity of 500 kV transmission line from Heywood to Moorabool about 15 km from the site, a 500 kV connection was made to the transmission system.

Because most new-entrant renewables around Australia are not located near a 500 kV transmission line or are of modest capacity, 500 kV connections have not typically been considered. Rather, the renewables developments have been chosen on an opportunistic basis to be close to the existing transmission system. Generally, there is little chance of transmission congestion arising from locating renewables on existing lines because the power transfer from the point of injection travels along all possible transmission paths, and the addition of another point of injection simply causes power flows throughout the network to adjust. The only condition under which this does not apply is when there is excess generation competing for a path to a load and the total transmission capacity in the direction of flow is at the rated output.

With increasing levels of renewables in localised areas requiring the development of 'renewables hubs' or the construction of large geothermal plants, new 500 kV transmission augmentations may be needed in the future. However, based on the development prospects and locations of this suite of technologies and softening demand and energy growth across Australia, the development of 500 kV transmission lines is likely to be limited in the short to medium term. The use of a transmission line to transfer power from a single wind farm with annual capacity factors even exceeding 40% would not be justifiable for more than a short distance from the existing grid. Hence, there has been little or no new transmission constructed for any renewable generation in Australia to date.

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[1] www.parliament.nsw.gov.au/prod/la/qala.nsf/ad22cc96ba50555dca257051007aa5c8/ca25708400173f67ca2570ab00814fd2?OpenDocument (accessed November 2015); www.transgrid.com.au/being-responsible/public-safety/living-and-working-with-powerlines/PublishingImages/Pages/default/Easement%20Brochure.pdf (accessed November 2015).

[2] AEMO (2012), *100% Renewables Study: electricity transmission cost assumptions*, AEMO.

11.2.2 High-voltage transmission

HV transmission lines in Australia typically range from 132 kV to 330 kV and make up the majority of lines in the transmission systems. The higher operational voltages in this range, (220–330 kV) serve as the main backbone of the transmission system in each of the regions. These transmission lines facilitate the bulk transfer of energy directly from the regional generation centres to the main load centres.

A common transmission design principle is to connect generation assets to the 220–330 kV voltage level, which is usually an efficient means of connecting large generation sources (200–1,400 MW) to the transmission system. Historically, single thermal generation units have been sized around the 200–500 MW level and arranged into banks of two to eight units. This total generation capacity is well matched to the thermal ratings of 220–330 kV transmission lines.

By matching the generation capabilities of high capacity factor generators with a transmission line with a similar thermal capacity, the transmission line can be used to a very high rate.

Due to the decentralised nature of loads, which can comprise residential, commercial and industrial demands throughout a transmission system, lower voltage transmission lines are typically used to service those loads. From the 220–330 kV transmission backbone, power is transferred to 110–132 kV bulk supply points that interface with the distribution network.

The bulk supply points typically have a number of voltage level busbars. Voltages that can be present at the bulk supply points include 11, 33, 66, 110 and 132 kV, as well as the HV connection of 220–330 kV.

The South West Interconnected System (SWIS) in Western Australia has three main generation centres to the north, east and south of the main load centre in Perth. To facilitate the transfer of energy from those generation areas into the load centre, the transmission system comprises a ‘wagon wheel’ arrangement. The 330 kV transmission lines create a ring around the load centre, with 132 kV transmission lines tying the 330 kV substations into the centre.

Owing to the decentralisation of major loads, the Queensland transmission system comprises a multiple-circuit 275 kV backbone running from the south of the state up to Far North Queensland. Large generators are connected along the backbone, and loads are serviced by 132 kV transmission lines that branch off the 275 kV transmission lines.

Throughout the transmission systems in Australia, a number of large industrial facilities such as mines, refineries and smelters are directly connected to 220–330 kV transmission lines. Due to their high load requirements (100–900 MW), 220–330 kV connections are typically needed for these facilities.

Most new-entrant large-scale renewables that have entered transmission systems across Australia have made connections at the 132–330 kV level. In some cases, projects in the order of 30–50 MW have made connections to medium-voltage (MV) bus bars in transmission substations. Connections to 66–110 kV bus bars have been made where the thermal limits of the associated equipment can support the capacity of the generator.

Because of the wide range of nominal voltage levels and thermal capabilities between transmission lines from 132 kV to 330 kV, obtaining current cost estimates for this infrastructure can be challenging. The costs associated with this equipment are highly dependent on the location and the technical requirements of the facility. The thermal and security requirements of the transmission asset and the possibility for future generation and load growth in the area must be considered.

The cost of 132–330 kV transmission lines can be in the order of $0.4–1.1 million/km depending on the voltage level and the number of circuits. The associated substation and switchgear can range from $10 million to $50 million depending on the arrangement of the substation.

11.2.3 Transformers

As discussed above, substation works comprising transformers and associated switchgear can materially contribute to the costs of connecting to the transmission system for a new-entrant generator.

Transformers primarily facilitate a connection between two transmission lines of varying voltage levels. These connections are made with the use of transformers and associated switchgear.

Costs for transformers are driven mainly by the nominal voltage levels of the connection terminals, the thermal rating and the number of phases for each transformer unit. Typically, for transformers with nominal voltages greater than 220 kV, three single-phase transformers are used as a set when connected between two transmission circuits. Using single-phase units for high voltages is usually preferred due to cost, transportation, maintenance, reliability and security constraints.

11.2.4 High-voltage direct current

An alternative to AC transmission is to send power as direct current (DC); this is known as high-voltage direct current (HVDC) transmission. The main advantage of this approach is lower losses over the transmission line/cable and the ability to efficiently transfer power in submarine or subterranean applications. One key consideration when implementing an HVDC scheme is the expenditure needed for the converter stations at each end of the link, which interface with the rest of the AC grid. Therefore, HVDC is best suited for long-distance transmission or where overhead transmission is not a viable option. Long-distance applications are pursued where the reduction in losses offsets the additional expense of the converters. Typically, the distance at which HVDC schemes break even with high-voltage AC is in the order of 500–700 km.

These schemes consist of two main components: the HVDC cable (which transmits the HVDC current) and terminal/converter stations (which convert AC input to DC output and back again). The HVDC terminals act as an interface between the AC transmission system and the DC cable.

Figure 116 shows an indicative loss curve for an AC and DC transmission connection at varying line lengths. In this example, the AC and DC options have the same operational voltage, conductor type and power injection. The DC option is assumed to have 4% losses in the converter station and associated switchgear, whereas the AC option has 1% losses in the accompanying transformers and switchgear.

Initially, the losses for the DC option are higher than for the AC due to the associated switchgear to operate the DC line. As the line length increases, the impact of the skin effect and higher effective resistance causes the AC losses to increase at a higher rate compared to the DC option. In the range of 500–600 km, the DC and AC options have comparable losses. Beyond 600 km, the DC option produces lower losses than the equivalent AC transmission option.

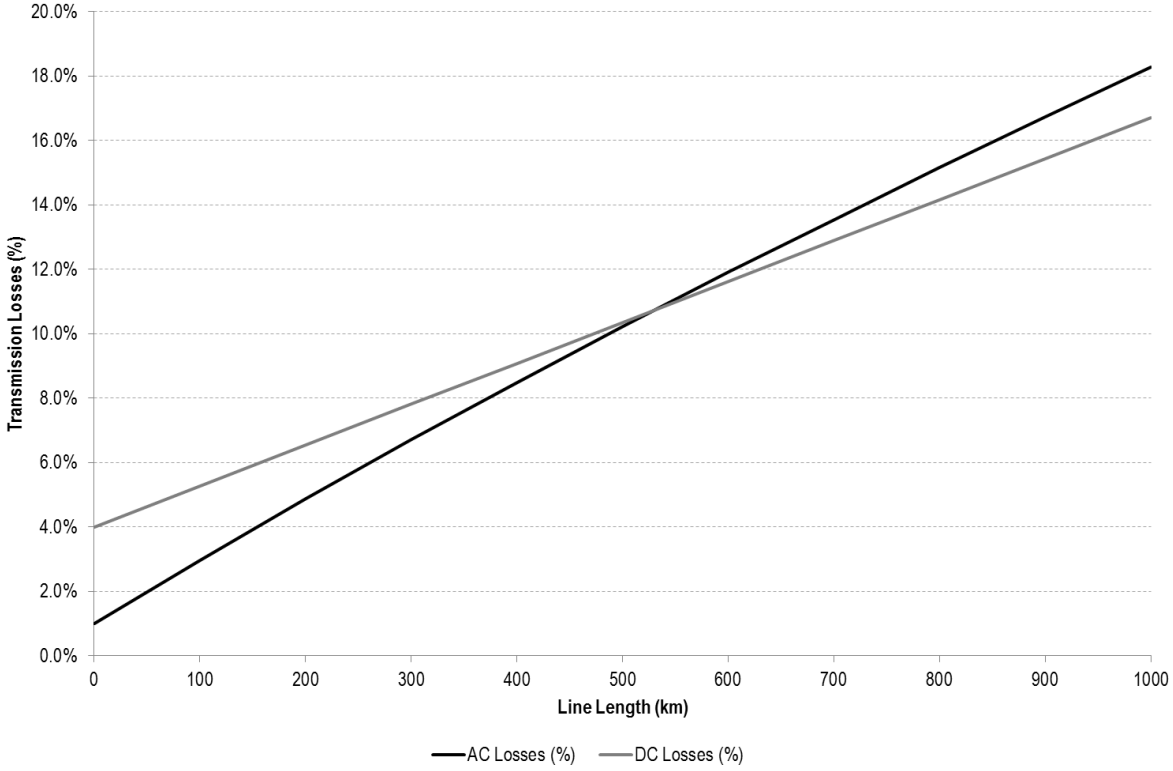

Figure 116: AC and DC transmission losses

HVDC schemes have a number of advantages over the more common AC transmission infrastructure in being able to actively control the flow of power between two points. Some HVDC schemes have the ability to provide black-start support (if a section of the transmission system is completely blacked out, the HVDC scheme can provide support to restart the system). Additionally, HVDC schemes mitigate the effect of high-impact outages or faults between adjacent transmission systems by providing a barrier through which the fault cannot propagate. With this added control and these fault mitigation attributes comes an increased cost for the terminal stations compared with an equivalently rated AC substation.

Due to these cost considerations, HVDC schemes have typically been deployed in subterranean and submarine applications, where AC transmission has limited capabilities. Additionally, because DC transmission produces lower losses than an equivalent AC scheme due to reduced skin effect, applications in which power must be transferred over greater distances favour HVDC.

Two alternatives for integrating an HVDC line or cable with an AC grid are currently used: line commutated converters and voltage source converters.

Line commutated converters

Line commutated converters (LCCs) are converter terminal stations (which convert between AC and DC power) that are most commonly used in HVDC applications in which high transfer capabilities are required. LCCs are controlled based on the operation of the two AC grids connected at either end of the HVDC scheme. The converter stations use a combination of switches and gates called thyristors and diodes to convert the AC waveform from the grid into a DC waveform for HVDC transmission and back into an AC waveform at the receiving end.

LCC HVDC schemes rely heavily on both AC grids providing a 'strong' AC waveform (typically provided by a number of large generators) to control the operation of the converter stations. Additionally, due to the operational envelope of the thyristors and diodes, there can be a dead-band in which, for low power transfers, the scheme cannot transfer power.

Basslink, which connects Victoria to Tasmania via a 290 km submarine cable, is an Australian example of an LCC HVDC scheme. Basslink has a nominal transfer capability of 500 MW, with a dead-band threshold of approximately 40 MW. An LCC scheme was selected for this application because of the need to transfer large amounts of power between two strong grids.

Because thyristors are a mature technology, the costs of LCC HVDC schemes are lower than those of voltage source converter (VSC) schemes. Because of this cost difference, LCC schemes are typically found in applications with lower technical constraints, which can include the strength of the connected grids, the required footprint for converter stations and the transfer capability envelope.

Voltage source converters

VSC HVDC schemes are typically used where there are a number of technical constraints on the systems to be connected. For example, they are commonly used in offshore wind-power applications where, for periods when the wind farm is at low dispatch levels, the converter stations can continue operating while connected to a 'weaker' AC waveform. Additional benefits for offshore wind include the ability to provide lower power transfers and a smaller terminal footprint, which are critical because of space limitations on offshore rigs.

VSC HVDC schemes consist of insulated-gate bipolar transistors (IGBTs), as opposed to the thyristors in LCC applications. IGBTs are more flexible in their ability to be controlled and therefore do not rely on the AC waveform of the interconnected grids to operate. IGBTs can be controlled by either a local or a remote control system, which allows the converter station to produce an AC waveform without reliance on an existing AC grid. This is a very desirable capability for connections made to weaker grids that can benefit from the adaptive control of the VSC HVDC scheme.

Murraylink, which connects South Australia and Victoria, and Directlink in northern New South Wales are Australian examples of VSC HVDC schemes. VSC schemes for these sites were selected based on the increased flexibility and moderate transfer capability of this HVDC scheme.

11.3 Distribution technologies

Small- to medium-scale generators are connected to the distribution network. The installed capacities of these projects ranges from single kilowatts for rooftop solar schemes to multiple megawatts for medium-sized solar, wind, biomass and fossil-fuel generation sets.

Historically, distribution networks have been designed with a single direction of power flow from the transmission bulk supply point to the residential or commercial consumer. With the increasing number of distributed energy resources, at times of high dispatch these power flows can begin to be exported to the transmission system.

This change in flow direction brings with it both technical and financial challenges for distribution network service providers and other relevant stakeholders.

In Australia, distribution networks primarily comprise three-phase distribution lines ranging from 415 V up to 132 kV. The power transfer capability of the networks ranges from multiple kilowatts to tens of megawatts.

Due to these constraints, identifying areas where medium-scale projects (around 5–20 MW) can be sited can be challenging. Most connections of medium-scale projects to distribution systems have been made near bulk supply points with 33 kV or 66 kV bus bars. This brings some of the advantages of being connected to the transmission system, including a reduction in congestion risk, coupled with lower connection costs for the project.

Distribution network service providers have raised concerns that, with an increasing level of penetration from distributed energy resources, both the operation and the design of distribution networks may need to be revised. With the increasing frequency of bidirectional power transfers, both distribution transformers and lines need to be able to securely operate the network to a level expected by consumers. With this increase in technical requirements for the network comes a greater cost for the distribution infrastructure and equipment, as well as greater consideration for network security requirements.

While every connection to a distribution network should be assessed on a case-by-case basis, typical voltage connection levels for varying sized projects can be inferred. For example, system capacities and connection voltages are shown in Table 69.

Table 69: Distribution connection capacities and voltage

Asset capacity (MW)	Connection voltage (kV)
<1 MW	0.415–11
<3 MW	11
>3 MW	33

Source: www.energex.com.au/__data/assets/pdf_file/0004/241690/00657-Customer-Standards-for-Embedded-Generators-30kW-to-5000kW.pdf (accessed October 2015).

Most new-entrant distributed energy resource installations in Australia have been small-scale rooftop solar systems. They are connected to the distribution network under AS 4777.2005—Grid connection of energy systems via inverters for systems less than 30 kW. With a number of state and national schemes incentivising the take-up of these systems, the operational profiles of distribution networks have materially changed in the past 5–10 years.

Much work has been done by a number of bodies to determine the costs associated with increasing levels of distributed energy resource penetration. Most notable in the Australian context are studies and investigations currently being undertaken by the Clean Energy Council.[3] Those studies have found that there can be an optimal distributed energy resource penetration level for specific network topologies to reduce both operational and maintenance costs, including the potential deferral of network augmentations. In the context of distributed energy resources, it is critical to consider the associated costs of network augmentations with the introduction of the new resource. This can potentially allow for a comparison of both distributed and transmission connected projects on a consistent basis.

11.4 Transmission costs

Determining costs for transmission infrastructure assets can be challenging because of the wide range of applications and operational profiles of those assets. In addition, while not directly captured in the values shown in the tables below, local factors such as terrain, easement availability, ambient conditions and fluctuations in commodity and exchange rates all influence the expected costs of these assets.

The values shown below should be used as a guide only and are not a substitute for detailed design and construction costs estimates for transmission augmentations specific to any project. Additionally, the values here have typically come from sources used in planning studies and estimates due to the limited number of published costs associated with specific components and asset sizes.

For transmission assets, both single- and double-circuit options are shown. Single circuits consist of only one set of three-phase conductors per tower. Double-circuit towers provide for two sets of three-phase conductors and are a preferred connection scheme if mitigating the impact of contingency events is required. The transfer capability estimates provide for an indicative power transfer level of the asset and can be used as a guide in determining the capacity of projects that could connect to these lines or transformers.

For example, based on the tables below, a 400 MW wind farm would typically connect directly to a transmission line using a ‘T’ connection or an existing substation at 220–330 kV. If the wind farm connects at a 330 kV single circuit and requires 20 km of new line, the line would cost in the order of $14 million and the transformer would cost $10 million. This estimate excludes the cost of switchgear and protection systems and the acquisition of the required land and easements.

[3] http://www.cleanenergycouncil.org.au/fpdi/ (accessed October 2015).

Table 70: Transmission line costs

Asset description	**Technical transfer capabilities (MVA)**	**Cost ($m/km)**
500 kV double circuit	5000–7000	1.8
500 kV single circuit	2500–3500	1.4
220, 275, 330 kV double circuit	1600–2600	0.9–1.7
220, 275, 330 kV single circuit	800–1300	0.7
132 kV double circuit	200–500	0.64–1.28
132 kV single circuit	75–234	0.28–0.71

Sources: www.cleanenergycouncil.org.au/fpdi (accessed October 2015); SKM and Western Power (2008), *Transmission asset cost benchmarking*, 20 June; ElectraNet SA (2013), *Lower Eyre Peninsula reinforcement*, RIT-T, January.

Table 71: Distribution line costs

Asset description	**Technical transfer capabilities (MVA)**	**Cost ($m/km)**
11–33 kV single circuit	1–20	0.18–0.22
66 kV single circuit	10–100	0.2–0.4

Sources: Department of Resources, Energy and Tourism (2013), *Energy efficiency opportunities in electricity networks*, May; www.aer.gov.au/system/files/ActewAGL%20-%20B16.1%20Molonglo%20zone%20substation_RIT-D%20-%202014.pdf (accessed October 2015); United Energy (2014), *Dromana Supply Area RIT-D*, July; ElectraNet SA (2013), *Lower Eyre Peninsula reinforcement*, January.

Table 72: Transformer costs

Asset description	Technical transfer capabilities (MVA)	Cost ($m)
500/330–220 kV	600–1000	15–18
330/220 kV	225–700	8–12
275/132 kV	200	7.4–10
220/110 kV	150	5
132/22 kV	-	6.5–7.1
110/33 kV	50–100	2.4–3.6
33/11 kV	5–20	1–2

Sources: AEMO (2012), *100% Renewables Study: electricity transmission cost assumptions*; www.cleanenergycouncil.org.au/fpdi (accessed October 2015); ElectraNet SA (2013), *Lower Eyre Peninsula reinforcement, RIT-T*, January; ElectraNet SA (2003), *Proposed new large network asset SESA region*, November.

Table 73: High-voltage alternating current cable costs—submarine

Asset description	Technical transfer capabilities (MVA)	Cost ($m/km)
132 kV	189	1.70
220 kV	314	2.18

Note: Typically, AC submarine cable lengths are limited to 50–70 km.

Table 74: High-voltage direct current cable costs

Asset description	Technical transfer capabilities (MW)	Cost ($m/km)
±150 kV Bipole submarine cable	352	1.57
±300 kV Bipole submarine cable	704–1306	1.64–3.12
±300 kV Bipole subterranean cable	770–1253	1.49–2.18

Source: http://www.cleanenergycouncil.org.au/fpdi/ (accessed October 2015).

Table 75: High-voltage direct current converter station costs

Asset description	Technical transfer capabilities (MW)	Cost ($m)
VSC converter stations	400	$150

Source: http://www.cleanenergycouncil.org.au/fpdi/ (accessed October 2015).

Table 76: Offshore platform costs

Asset description	Technical transfer capabilities (MW)	Cost ($m)
VSC converter station	500–1000	$68–108
132–220/33 kV AC	-	$44–55

Source: http://www.cleanenergycouncil.org.au/fpdi/ (accessed October 2015).

12 FROM CONCEPT TO FULLY ENGINEERED PROJECT

This chapter was written by Dr Nikolai Kineav and Prof. Chris Greig.

From concept to fully engineered project—highlights:

- Project cost estimates for first-of-a-kind/early-mover technologies can change (and usually increase) significantly through the project development phases. This should not be unexpected. Whatever the technology, major complex engineering projects see cost increases from concept to delivery.
- A first-of-a-kind plant always carries additional upwards cost risk as the project develops.
- The key reasons for project cost increases are factors related to:
    - the financial environment (currency exchange rates, interest rates)
    - economics (inflation, cost escalation)
    - regional productivity changes
    - project development effort (transition from generic engineering designs and cost estimates to more detailed design, taking into account site- and process-specific issues).

12.1 Introduction

This chapter illustrates the escalation of project cost estimates for first-of-a-kind and early-mover technologies through the project development process. The approach is to examine a specific Australian case study—the ZeroGen IGCC with CCS proposal. The projected operational costs of the technology are not included in this chapter.

12.2 Case study for the ZeroGen Project

This Australian project is a unique opportunity to examine the project development of a developing technology. It was also a large, complex engineering project. No equivalent renewable energy projects are available for examination.

12.2.1 Background and project history

ZeroGen was a project study commissioned in 2006 to demonstrate the viability of commercial-scale IGCC technology integrated with CCS technology. The project was undertaken under the Queensland Clean Coal Act and funded by a combination of the Queensland and Australian governments and Australian Coal Association Low Emissions Technology Pty Ltd (ACALET).

The project was cancelled in 2011 due to the lack of a business case, undefined funding arrangements, problems obtaining appropriate CO_2 storage tenements and uncertain revenue streams. While the various study documents contain proprietary information, a comprehensive case study, including lessons learned, has been published.[1]

During the study, the level of engineering definition, work breakdown structure and cost estimation methodology were specified by ZeroGen and subjected to review by independent engineering contractors.

Several plant sites were examined. The preferred location was determined by optimising several factors: the negotiation of potential access to fuel from the Ensham mine, a minimised site development cost, a favourable connection to the electricity grid and an inexpensive supply of process water.

Extensive CO_2 storage exploration and appraisal activities were undertaken for the adjacent Northern Denison Trough, but that site was found to not be technically and economically feasible for storage. Desktop studies using existing data for the Surat Basin suggested indicative storage costs around one-eighth of those for the Northern Denison Trough. However, the project was cancelled before further field assessments could be made.

This carbon storage exploration and appraisal program was one of the most exhaustive undertaken for the purposes of carbon sequestration globally.

Despite the project being cancelled, it was chosen as an example because it was one of most comprehensive publicly available Australian-based studies of cost estimates in early mover technology.

12.2.2 Plant configuration

ZeroGen was planned to be a 400 MW net (500 MW gross) IGCC power plant integrated with CCS technology. It was to be located near the Ensham mine lease in Queensland. The proposed plant was designed to initially capture 65% (2 Mt/pa) of CO_2 emissions during a demonstration phase, before increasing to 90% during commercial operation.

Mitsubishi Heavy Industries (MHI) was selected as the primary IGCC technology provider and engineering, procurement and construction (EPC) contractor for the project. Royal Dutch Shell was selected to assist with the transport and storage of CO_2, while other contractors would provide the remaining balance of the plant. MHI and Shell were contracted on a fee-for-service basis to provide engineering studies, infrastructure and logistics analysis and cost-estimation services.

The pre-combustion capture system comprised a sour shift reaction (catalysts by Johnson & Mathey), UOP acid gas removal (Selexol™) and wet sulphuric acid production (Haldor Topsoe), and each technology provider was contracted, also on a fee-for-service basis, to provide technology licences and engineering and cost estimating services.

It was proposed that the captured CO_2 be transported via pipeline to a geological formation that is suitable for CO_2 geosequestration in the vicinity of the site.

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[1] A Garnett, C Greig, M Oettinger (eds) (2012), *Zerogen IGCC with CCS: a case history*, a special limited-edition publication of the Queensland Government, ISBN 978 1 74272 114 9.

12.2.3 Initial cost estimates

Methodology

The initial cost estimates were preliminary only, and so were based on very limited engineering. There was a clear understanding that the estimates were likely to vary as engineering design progressed.

The initial estimates were prepared using a range of methodologies, including:

- benchmarking to recent investment costs, such as power line transmission infrastructure and pipelines in $/km
- benchmarking and scaling of other IGCC projects, including factoring or scale-up of recent investment costs, such as for sections of the MHI Nakoso IGCC demonstration project in Japan
- reference to cost estimates studies published by EPRI
- the escalation of costs to the fourth quarter of 2008, based on an assessment of the costs (or cost estimates) of large-scale process industry projects completed between 2005 and 2008 (costs were then escalated based on MHI's experience and advice about cost-escalation in Australia)
- the conversion of US Gulf Coast labour productivity and costs for local construction, based on a productivity ratio of 1 and an exchange rate of US$0.90 to AS$1.00
- a nominal central Queensland site selection, with no site-specific or enabling infrastructure costs allowed
- factoring of construction and installation activities as a percentage of direct costs, based on the experience of ZeroGen Pty Ltd and MHI project personnel, covering:
  - civil works
  - structures (installed)
  - mechanical and piping (installed)
  - electrical, control and instrumentation (installed)
  - construction facilities
- factoring of EPC management costs as a percentage of total direct costs
- making general allowances based on experience for insurance and permitting, land access, native title clearance and compensation.

Estimates

The initial cost estimates are shown in Table 77.

Table 77: Initial cost estimates for ZeroGen (A$ million)

Item	Cost
IGCC facility	3,254
CO_2 transport and storage	736
Subtotal	3,990
Development costs (feasibility study and FID)	286
Total	$4,276

12.2.4 Final cost estimates

Methodology

The final estimation methodology used a mixture of vendor quotations, factored estimates and first principles (materials, labour and facilities) build-up. The project was divided into sections, which included:

- owner's costs
- the power plant with carbon capture
- enabling works (pipelines, infrastructure)
- carbon transport and storage
- operation readiness and start-up.

Costs within each section were calculated using four key approaches:

- pre-FEED engineering to identify major equipment and bulk material needs
- obtaining budget quotations from equipment manufacturers based on project specifications
- obtaining budget quotations from Australian contractors for plant construction and key infrastructure and logistical requirements
- using historical project data to estimate benchmark prices for certain elements of the project.

In all cases, labour costs and productivity were benchmarked in line with enterprise agreements in place for major liquefied natural gas projects in Gladstone, Queensland.

Required contingency was applied to the project capital costs in the following forms:

- a direct contingency allowance to address a range of known risk and probability events
- a supplementary funding reserve to account for unknown events inherent in first-of-a-kind projects, including design changes, force majeure events, gross estimate errors and unforeseen changes to laws or regulations.

The methodology for calculating the contingency involved identifying all potential risk and opportunity events, removing those that were inherently procedural or were possible to include in baseline estimates. Remaining significant risks were ranked based on likelihood and severity and costed using Monte Carlo techniques, and a P_{50} value was chosen for the direct contingency allowance.

The supplementary funding reserve was then calculated by subtracting the forecast outcome cost from the (likely) maximum outcome cost (P_{80}) estimate.

In the case of the ZeroGen project, a supplementary funding reserve was not taken into account because of the very detailed scope of the prefeasibility study (which essentially took the prefeasibility study to a FEED level of engineering effort and associated logistics analysis). However, in a typical prefeasibility study the supplementary reserve funding should arguably be taken into account.

The escalation of the capital cost during construction was calculated over the period from 2012 to 2017. ZeroGen identified a number of key influences that were predicted to contribute significantly to the value of any escalation. They included:

- construction wages and productivity
- mechanical, electrical and drilling equipment
- cement, piping and steel materials
- the balance of the project.

These influences were assigned a range of escalation values based on escalation indices over the 2006–2008 (pre-financial crisis) period, and the project schedule was used to determine when the escalation would be applied. The final value was calculated using Monte Carlo techniques and considered escalation (P_{50}), enterprise agreement mandatory labour cost escalation and residual escalation on project contingency.

Estimates

The final project cost estimates are shown in Table 78.

Table 78: Final project cost estimates for ZeroGen (A$ million)

Item	Cost
ZeroGen owner's cost	$300
Enabling works	$620
Power plant	$3,900
Carbon transport and storage	$800
Operation readiness and start-up	$140
Total base case estimates	**$5,760**
Direct project contingency	$520
Escalation	$650
Total fully loaded capital cost	**$6,930**

12.3 Reasons for cost estimates growth

There are two major groups of reasons for project cost escalation:

One group is related to financial and economic factors and includes escalation due to exchange rate variation, escalation due to input cost increases and inflation, and adjustments to the regional productivity level.

The other group is related to project development and includes scope growth, design growth and cost-estimation methodology changes. However, it is difficult to estimate the pure input of changes to cost-estimation methodology, as it is accompanied by more detailed engineering design and changes in the project scope. For simplicity, this chapter considers only two components of the project development factors: more detailed engineering design and growth of the project scope.

12.3.1 Financial and economic factors

Financial escalation

Financial escalation consists of two parts: the alignment of initial cost estimates done for the scoping study in 2008 to the 2010 basis of estimate, and escalation through the projected time of design and construction (for the period between 2010 and 2017)

The alignment of the initial cost estimates was escalated by 5% per year, resulting in the addition of A$300 million (7% of the initial total project cost estimate) to the baseline project cost.[2]

Further escalation for the 2010–2017 period, performed with the methodology described above, resulted in the addition of a further $520 million (12% of the initial total project cost estimate) to the total project cost.

Currency exchange rates adjustment

Adjustment to the 2010 forex currency exchange rate resulted in the addition of a further $240 million (6% of the initial total project cost estimate) to the baseline project cost.

Regional productivity adjustment

Initial cost estimates were based on Australian work productivity and labour costs being on parity with those of the United States Gulf Coast. However, benchmarking against recent Australian projects indicated that a more reasonable productivity factor of 1.2 and labour cost factor of 1.3 should be applied (with an overall factor of 1.56—Australia being less productive). This resulted in a further increase of $300,0000,000 (7% of the initial total project cost estimate).

The overall project cost rise due to financial and economic factors was $1,360 million (32% of the initial total project cost estimate).

12.3.2 Project development factors

Scope growth

The early phases of the project study were very generic and did not consider site-specific issues. The later detailed study took into consideration the availability (or lack) of enabling and direct infrastructure, such as roads, transmission lines and pipelines, the costs of the camp, and so on. This necessary scope addition resulted in an increase in project cost estimates of $505 million (12% of the initial total project cost estimate).

Design growth

More detailed engineering of first-of-a-kind/early-mover technology projects typically identifies new process- and site-specific design issues, which usually result in project cost increases to deal with real and perceived risks through more robust engineering. In the case of the ZeroGen project, such design growth resulted in a project cost increase of $816 million (19% of the initial total project cost estimate).

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[2] This escalation could be partly attributed to relatively high inflation rates (3–4%) and partly to the mining boom, when Australian capital costs escalated rapidly from the original estimate due to high demand for qualified labour.

The overall project cost rise due to project development (design and scope) factors was $1,321 million (31% of the initial total project cost estimate).

The total project cost increase is summarised in Figure 117.

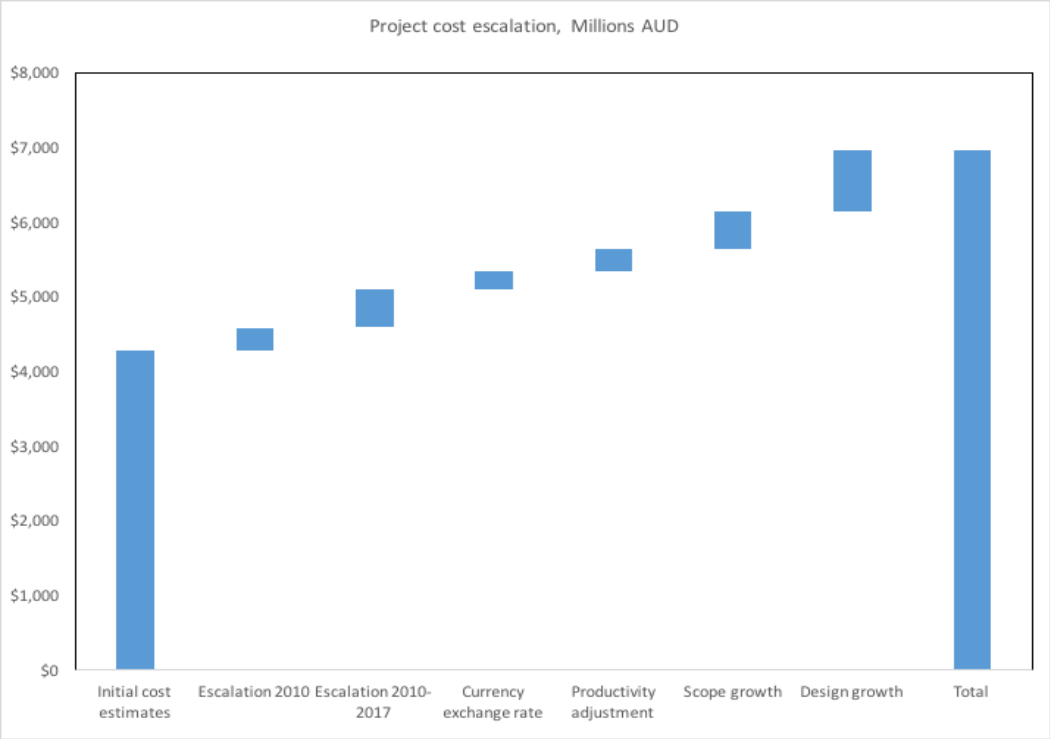

Figure 117: Project cost escalation during the cost study

12.4 Conclusions

Project cost estimates for first-of-a-kind/early-mover technologies can change (and usually increase) significantly through the project development phases.

The key reasons for increases can be divided into two major types:

- Factors related to the financial environment (currency exchange rates, interest rates), economics (inflation, cost escalation) and regional productivity changes.
- Factors related to the project development effort. Those factors appear to be due to the transition from generic engineering designs and cost estimates to more detailed design, taking into account site- and process- specific issues. This also includes changes in the cost estimation methodology from generic methods (based on scaling existing data from benchmark projects) to more rigorous methods (based on the detailed engineering, budget quotations from service and equipment suppliers, and cost probability modelling).

While these changes in cost estimates through the project development phase are typically increases, it is not possible to accurately predict the extent of the changes.

The effect of the first group of factors could be minimised by more careful choice of financial, economic and productivity assumptions. The effect of the second group depends on the maturity of the technology and the project team's experience in the particular jurisdiction. What is clear, however, is the need for a more conservative application of contingencies than has traditionally been considered.

13 MODULARISATION

This chapter formed a part of the regional cost factors study, *EPRI 2015: Australian generation technology cost update conversion factors*, by WorleyParsons.

Modularisation—highlights:

- For projects in Australia, the fabrication of modules is generally performed in places such as Indonesia or China. Due to their lower labour costs, offsite modularisation in these locations can result in a 10–15% net saving in installation labour costs over the on-site fabrication of the modularised items, depending on the location of the project.
- The distance that a prefabricated module needs to be transported is a key factor in the economics of modularisation. Plants close to port infrastructure are likely to be high-quality candidates to take advantage of modularisation.

Modularisation in construction is based on the premise that it is less expensive and more efficient to fabricate in a workshop than on a project site.

When implemented smartly, modularisation can result in cost savings. Generally, as average site labour costs increase, so does the likelihood that modularisation will be cost-effective. However, the level of cost-effective modularisation will vary from project to project and from site to site.

A number of key factors must be considered in determining how much modularisation should be implemented for a specific project, including:

- additional costs for shop fabrication
- reduced costs for onsite labour
- proximity to port and/or barge facilities
- proximity to rail access
- quality of road access to the site
- load size and transportation restrictions
- additional fabrication costs to/from the fabricator
- constructability and construction sequencing
- additional requirements for onsite lifting equipment
- requirements/restrictions imposed by organised labour
- potential increased costs for engineering and design
- safety.

On United States power projects, it is common practice to require that equipment and other components be modularised to the greatest extent practical, where ‘practical’ is a function of site accessibility and transportation/delivery considerations.

Savings associated with workshop fabrication can be quickly eroded by increased transportation costs unless the project has good port access and transportation infrastructure and the modules are sized so as to not to incur onerous transportation charges.

Modules sized for standard shipping via ocean freight, rail or truck transport have the lowest transportation costs. Oversized loads are subject to additional restrictions, permitting and, in the case of truck transport, escort requirements, all of which result in increased costs.

Projects that must be accessed via secondary roads as opposed to major highways may encounter further size and weight restrictions or limitations. Depending on the size and weight of the loads, infrastructure upgrades, such as bridge reinforcement, may be required. Narrow roadways mean that obstructions such as trees, signs and so on have to be removed. The associated costs must be borne by the project.

In addition to transport requirements, constructability (including additional requirements and costs for on-site lifting equipment) and, most importantly, safety must always be considered in the design and sizing of modules.

Victoria and south-western Western Australia have good port access and major highways. Queensland and New South Wales have good port access, but limited road infrastructure, particularly in the more remote areas. Rail access is limited to major cities only.

For projects in Australia, the fabrication of modules is generally performed in places such as Indonesia or China. Because of their lower labour costs, off-site modularisation in these locations can result in 10–15% net savings in installation labour costs compared to the on-site fabrication of the modularised items, depending on the project's location.

14
DESIGN BASIS

14.1 Introduction

This chapter provides a guide to the assumptions made when assessing the various power generation technologies examined in this study. It outlines the technical parameters of the plants, characterises the site conditions, and establishes fuel properties and emissions criteria, where applicable. Establishing a clear design basis makes it possible to compare costs and performance for a range of technologies in a consistent manner.

14.2 Fossil-fuel technologies

14.2.1 Duty cycle, size, location and cost boundary

Duty cycle

The fossil-fuel plants considered in this study are baseload units, with the exception of open cycle gas turbines and reciprocating engines, which are modelled with lower capacity factors Table 77).[1]

Table 79: Fossil fuel capacity factor assumptions

Technology	Capacity factor (%)	Role
Pulverised coal	85	Baseload
Integrated gasification combined cycle	80	Baseload
Natural gas combined cycle	85	Baseload
Natural gas open cycle—frame	5 -10	Peaking
Natural gas open cycle—aeroderivative	15–25	Peaking / shoulder
Reciprocating engines	30–50	Shoulder / backup storage

Generating unit size

The baseload fossil-fuel plants in this study are less than 500 MW in capacity, as it is expected that additional capacity to the grid will be limited to less than 500 MW.

Ultra-supercritical pulverised coal is included in the study at 650 MW for comparison purposes.

[1] These capacity factors vary significantly in practical applications; recent trends show a decrease in baseload capacity factors.

Location

The site location chosen for this study is a generic greenfield site in Australia at an elevation of 110 m. The sites for the brown and black coal technologies are assumed to be at the mine mouth, removing the need for a nearby rail line or road for fuel delivery. Dry cooling systems are necessary for all the technologies, so no assumption is made about the site's proximity to a raw water supply.

The Hunter Valley in New South Wales is assumed to be the site location for all technologies except for the brown coal technologies, which are sited in the Latrobe Valley in Victoria.

Cost boundary

The cost boundary is viewed as being generally equivalent to the generating unit boundary enclosed by the plant's security fence.

For a steam plant, this boundary includes all major parts of the unit, such as boilers and turbine generators, fuel storage yards and all support facilities needed to operate the plant. The support facilities include fuel, fluxent and sorbent receiving/handling and storage equipment; emissions control equipment for particulates, sulphur dioxide and CO_2, when included in the plant design; wastewater treatment facilities; and shops, offices and personnel support facilities. CO_2 compression equipment and energy penalties are included for plants with CCS, but the capital costs for the CO_2 pipeline and provision for sequestration are not. The cost boundary also includes the step-up transformer, but not the switchyard or associated transmission lines.

The following general assumptions apply to all cases, as appropriate:

- The site is assumed to be relatively level and free from hazardous materials, archaeological artefacts, sites of cultural significance, and excessive rock. Soil conditions are considered adequate for spread footing foundations. The soil bearing capability is assumed adequate, so that piling is not needed to support the foundation loads.
- The combustion turbines, steam turbines and other critical balance of plant equipment are assumed to be enclosed. The gasifiers, heat recovery steam generators (HRSG), boilers, and air quality control systems are assumed to be suitable for outdoor service.
- The switchyard and any associated transmission lines and access are excluded from the capital cost scope.

14.2.2 Ambient conditions

Average ambient temperature operation

Annual average ambient air conditions for Australia are listed in Table 80; they are based on ambient conditions given in the *Technical guidelines: generator efficiency standards* by the Australian Greenhouse Office in December 2006.[2]

[2] Australian Greenhouse Office (AGO) (2006). *Technical guidelines: generator efficiency standards*, Department of the Environment and Heritage, Canberra, Australia, December.

Table 80: Temperature assumptions

Component	Value
Dry bulb temperature	25°C
Wet bulb temperature	19.5°C
Relative humidity	60%
Atmospheric pressure	1.0 bar
Equivalent altitude	110 m

14.2.3 Fuel systems

Fuel types and characteristics

Two coal types are considered for the coal-fired technologies: Hunter Valley black coal and Latrobe Valley brown coal. The characteristics and analyses of these coals are shown in Table 81; they are based on reference coals in the *Technical guidelines: generator efficiency standards*.[3]

The plant sites are assumed to be at the mine mouth, with conveyors delivering coal from the mine to the site. Coal storage is sized for 5 days of storage.

Table 81: Australian coal characteristics

Coal composition	Black coal (Hunter Valley) % as received	Brown coal (Latrobe Valley) % as received
Moisture	7.50	61.50
Carbon	60.18	26.31
Hydrogen	3.78	1.85
Nitrogen	1.28	0.23
Chlorine	0.00	0.00
Sulphur	0.43	0.15
Oxygen	5.63	9.16
Ash	21.20	0.80
Heating value (as received)		
Higher MJ/kg	24.82	9.92
Lower MJ/kg	23.84	8.06

Natural gas composition is also based on the reference gas given in the *Technical Guidelines: Generator Efficiency Standards* (Table 82).[3]

[3] AGO (2006). *Technical guidelines: generator efficiency standards*.

Table 82: Natural gas characteristics

Natural gas composition	Mole % dry basis
Methane	90.91
Ethane	4.50
Propane	1.04
n-Butane	0.21
i-Butane	0.13
Helium	0.04
Nitrogen	1.11
CO_2	2.06
Heating value	
Higher MJ/SCM	38.55
Lower MJ/SCM	34.77

Diesel fuel is defined as diesel that meets the standards and has the recommended values in the 'Diesel fuel quality standard' pages of the Department of the Environment's website (Table 83).[4]

Table 83: Diesel characteristics

Parameter	Value
Sulphur (max)	1 ppm
Centane index (min)	51
Density	820 (min)–850 (max) kg/m^3
Distillation T95	360°C (max)
Calorific value (HHV)	46 GJ/tonne
Carbon content	86% used in this study Typical range 84–87%
Hydrogen	Typical range 16–33%

[4] https://www.environment.gov.au/topics/environment-protection/fuel-quality/standards/diesel (accessed October 2015).

14.2.4 Resource potential

Most of Australia's black coal is in New South Wales and Queensland, while brown coal is found mostly in Victoria (Figure 118).

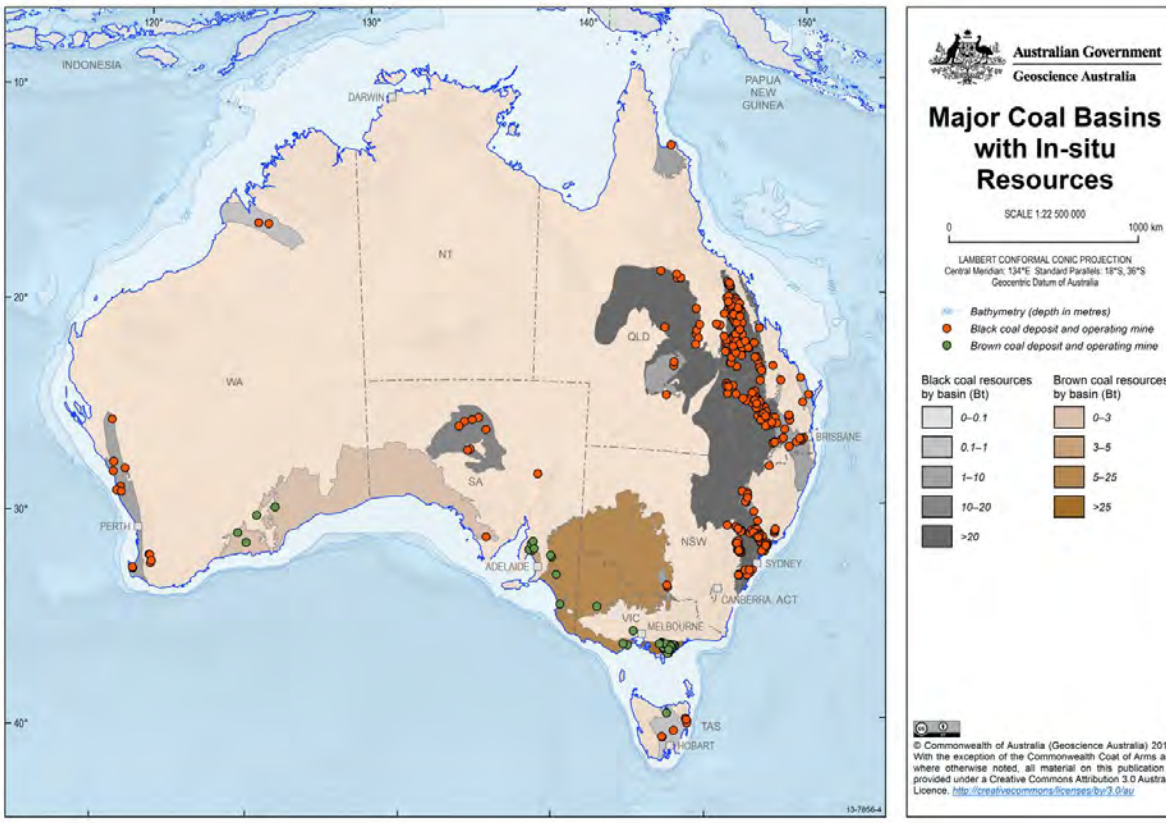

Figure 118: Australian coal resources

Source: www.minerals.org.au/file_upload/images/coal/coal_maps/13-7856-4_large.jpg (accessed October 2015).

14.2.5 Other factors

CO_2 capture and storage

All technologies that include CCS have a CO_2 capture rate of 80–95%. The recovered CO_2 contains no more than 100 ppmv total sulphur and is compressed to 15 MPa before exiting the plant boundary. The reasons for this relatively high CO_2 purity requirement are as follows:

- There are legislative and environmental permitting considerations at the state, territory and Commonwealth levels.
- Technological issues, including dynamic events such as compressor/pipeline/well trips and start up/shut down can play an important part in the emissions profile and meeting permit conditions (that is, there is sometimes a need to vent the CO_2 stream during upsets).
- Having low hydrogen sulphide in the CO_2 to be vented is likely to be an important part of any environmental compliance strategy.
- Public acceptance is required, given the toxicity of hydrogen sulphide.

The CO_2 pipeline and storage area for sequestration are not included in these capital cost estimates; however a $15/t cost is added to the levelised cost of electricity.

Emissions criteria

Existing coal-fired power plants in Australia are not required to include any sulphur dioxide or nitrogen oxide (NO_X) controls due to the very low sulphur content of the coals that they use. Except for reductions of sulphur dioxide required for process reasons, no sulphur dioxide or NO_X reduction systems are included. Typically, the CCS technologies require the control of sulphur dioxide to avoid the poisoning of amines used in those processes. For amine-based capture systems, this requires the removal of sulphur dioxide down to a level of ~10 ppmv.

Particulate emissions are controlled through the use of electrostatic precipitators for the pulverised coal units. Other than dry low-NO_X combustors used in the gas turbines, no additional emissions controls are added.

Dry cooling

Due to the limited water supply in Australia, dry cooling systems are incorporated for all plant units. Individual projects may need to consider some supplementary cooling based on local temperature conditions.

Ash handling

Due to water supply conditions in Australia, ash removal is handled dry.

14.3 Renewable technologies

14.3.1 Resource potential

A high-level map of the renewable energy resources in Australia is shown in Figure 119.

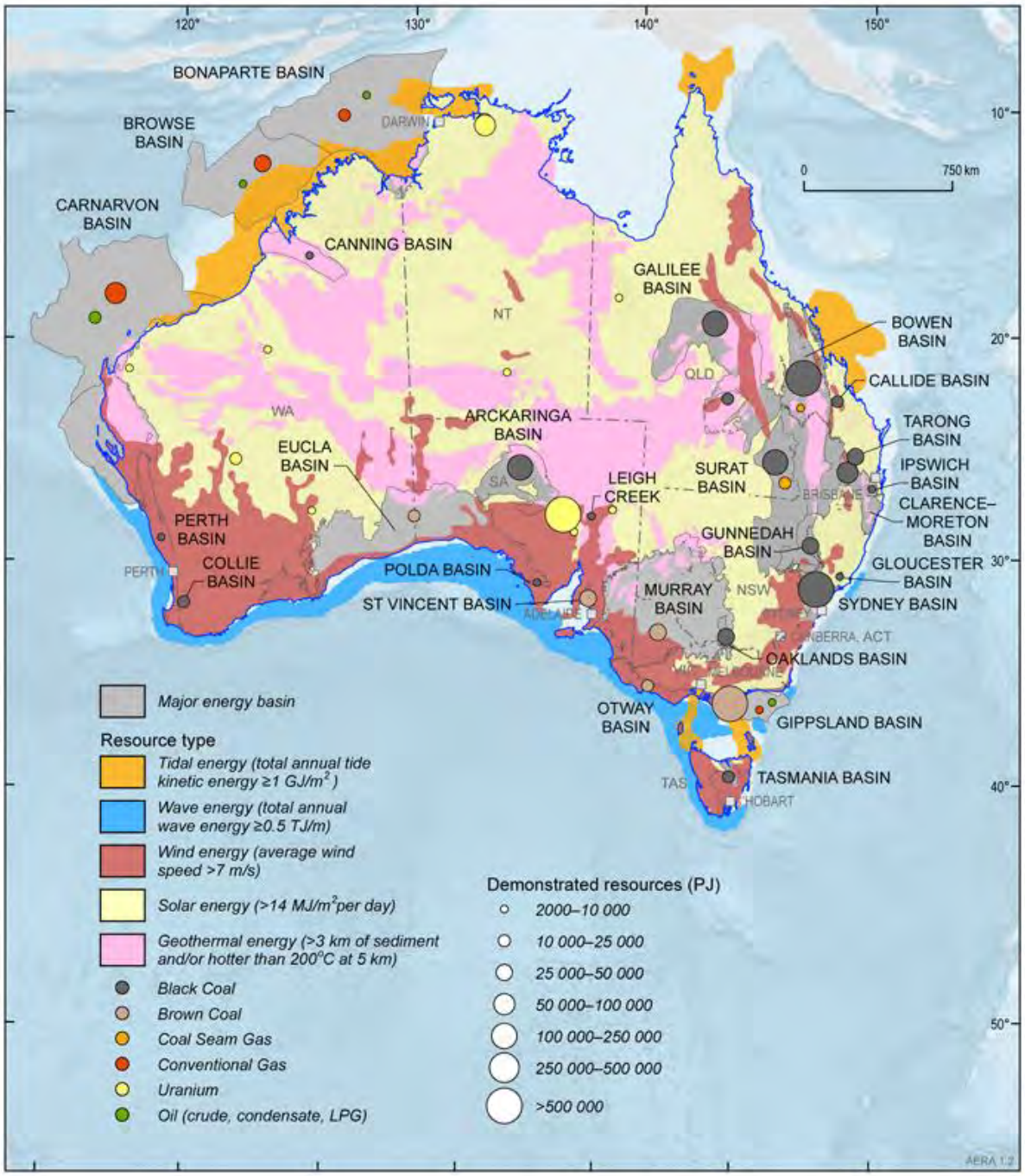

Figure 119: Australian renewable resources

Source: www.ga.gov.au/news-events/news/latest-news/release-of-updated-australian-energy-resource-assessment (accessed October 2015).

Wind turbines

Generating unit size

The onshore wind farms investigated in this study all consist of 3 MW turbines. The two farm sizes investigated are 50 MW and 200 MW.

Cost boundary

The generating unit boundary includes the area in which all unit components are located. For wind farms, this area includes interconnections among the turbines and a substation, in addition to the wind turbines, foundations and control systems.

The cost boundary does not include transmission lines.

Resource potential

Figure 120 shows the average speed in m/s of wind resources in Australia.

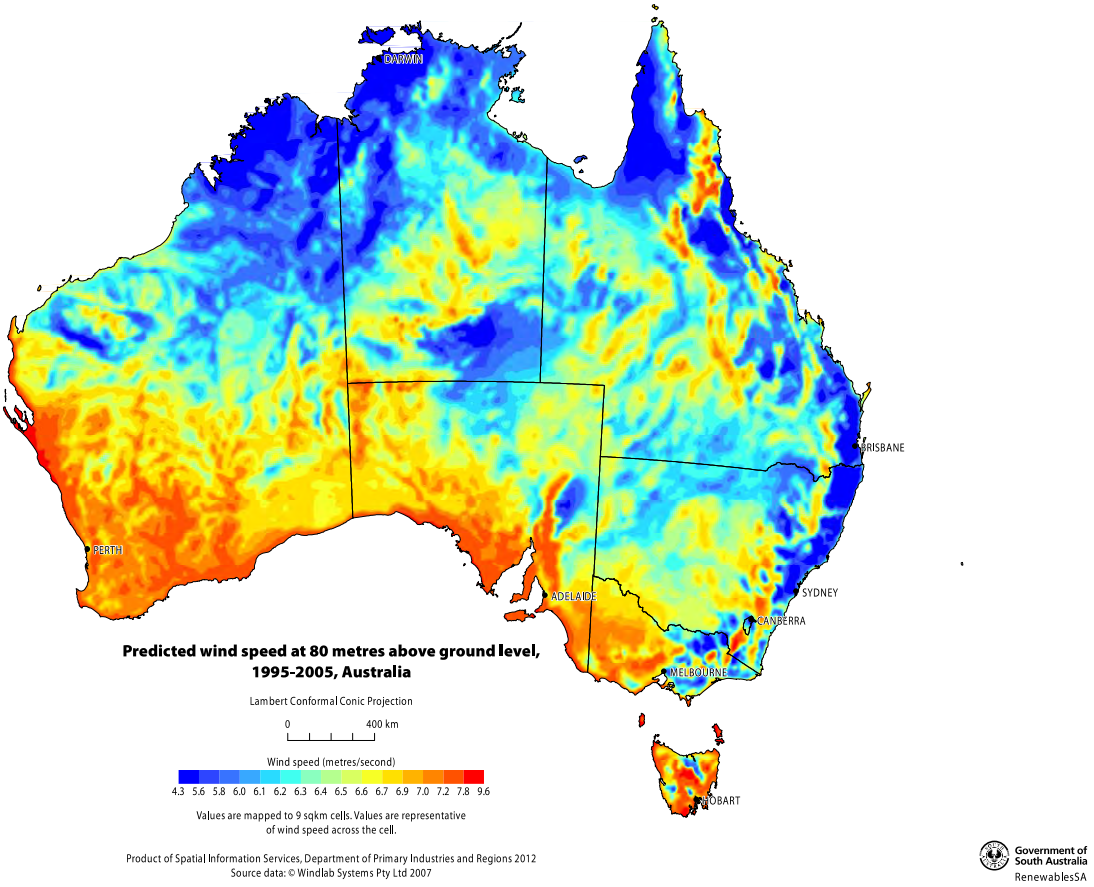

Figure 120: Wind resources in Australia

Source: www.renewablessa.sa.gov.au/files/121219-windresourcemappingaustralia.pdf (accessed October 2015).

Offshore wind

Offshore wind has been developed at commercial scale globally in shallow waters. No resource maps have been developed for offshore wind in Australia. This is in part due to the narrowness of the continental shelf.

14.3.2 Solar thermal

Generating unit size

The central receiver plant evaluated is a 1 × 125 MW plant with 6 hours of direct two-tank molten salt storage.

Cost boundary

The generating unit boundary includes the area in which all the unit components are located. For solar thermal plants, this area includes the collectors, any thermal storage units, the steam generating unit and the power island, as well as any support facilities needed to operate the plant and an interconnection substation.

Resource potential

Concentrating solar thermal power technologies, such as parabolic trough and central receiver technologies, require direct normal irradiance. This requirement means that incident sunlight must strike the solar collectors at an angle of 90° for the sunlight to be reflected onto the receivers.

Figure 121 shows the annual average of the number of hours the sun shines daily, and Figure 122 shows an annual average of daily solar exposure throughout Australia.

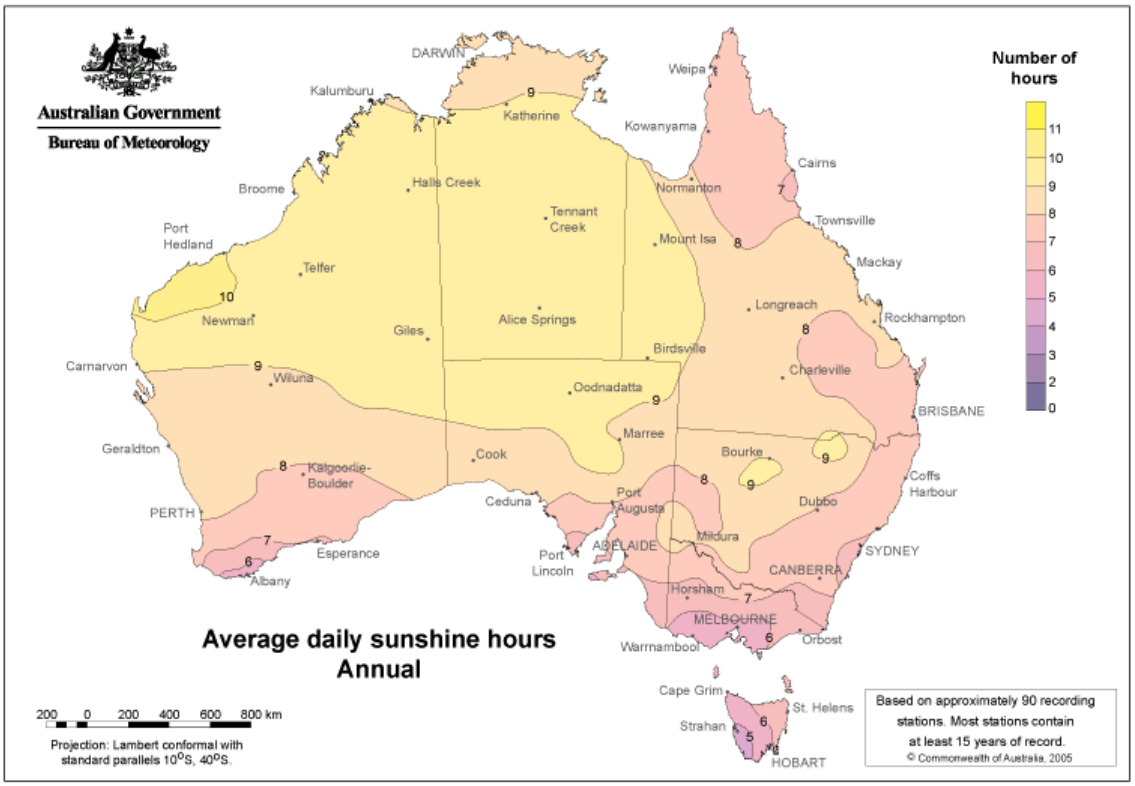

Figure 121: Australian annual average number of sunshine hours per day

Source: www.bom.gov.au/jsp/ncc/climate_averages/sunshine-hours/index.jsp (accessed October 2015).

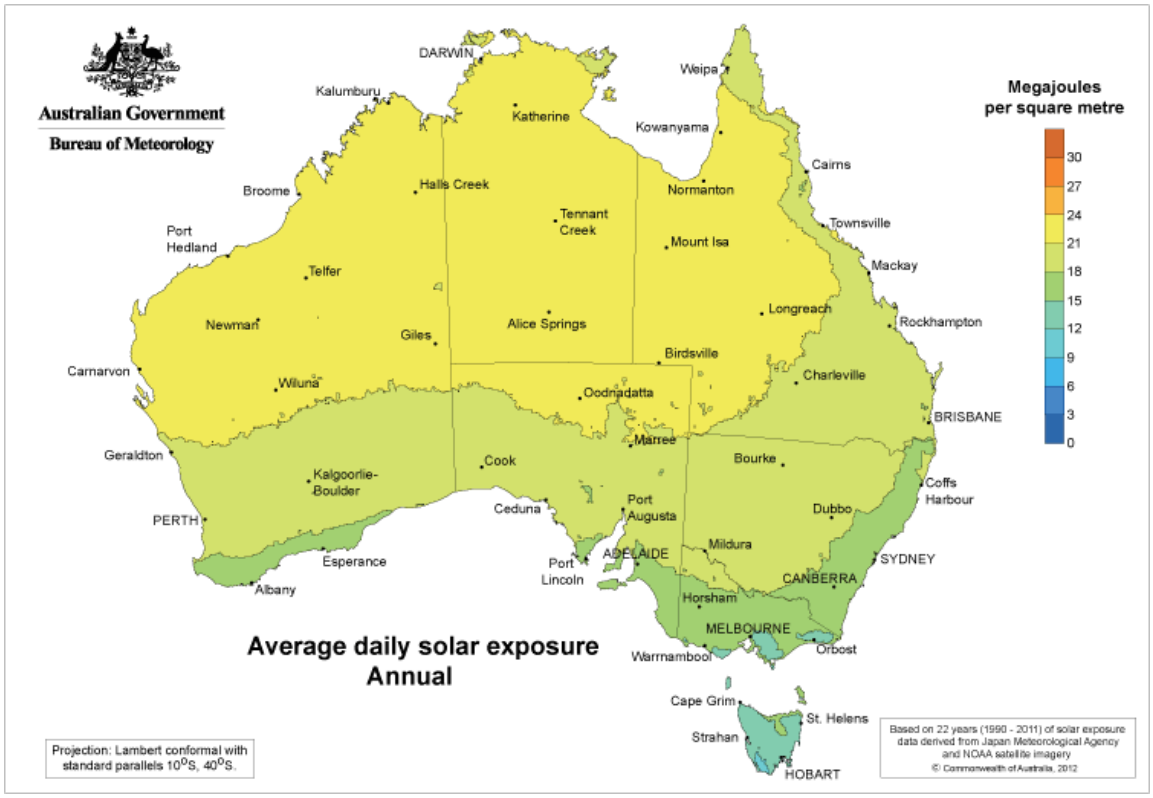

Figure 122: Australian annual average solar exposure per day

Source: www.bom.gov.au/jsp/ncc/climate_averages/solar-exposure/index.jsp (accessed October 2015).

14.3.3 Solar photovoltaic

Generating unit size

The solar PV systems evaluated in this study are residential (5 kW), commercial (100 kW) and utility-scale (10 MW and 50 MW) systems.

Fixed flat plate, single-axis tracking and double-axis tracking systems are evaluated.

Cost boundary

The generating unit boundary includes the area in which all the unit components are located. For solar PV plants, this area includes the solar PV arrays, support structures, inverters, a solar tracker if required, wiring, and an interconnection substation.

Resource potential

Flat-plate PV systems use global horizontal irradiance, which is the total amount of radiation received from above by a horizontal surface and includes both direct normal irradiance and diffuse horizontal irradiance (see Figure 123 for Australian global horizontal irradiance). Ground-mounted PV panels are usually installed at a latitudinal tilt, which optimises annual energy production.

Figure 121 shows the annual average of the number of hours the sun shines daily.

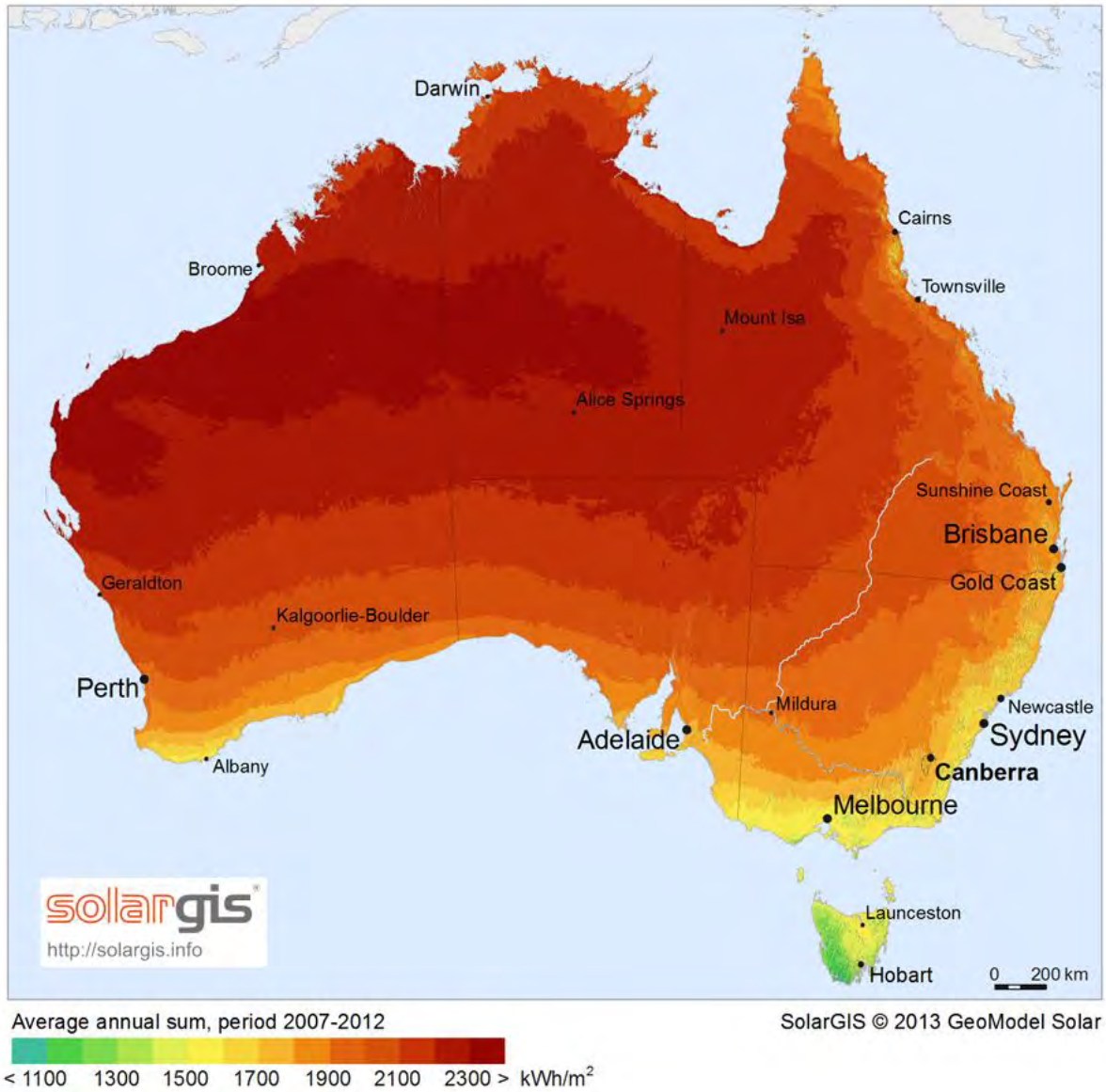

Figure 123: Solar global horizontal irradiance

Source: http://solargis.info/doc/_pics/freemaps/1000px/ghi/SolarGIS-Solar-map-Australia-en.png (accessed October 2015).

14.4 Nuclear technology

14.4.1 Size, location and cost boundary

Generating unit size

A Generation III/III+ nuclear reactor at 1,100 MW, similar to the AP1000 unit, was chosen for this study.

Location

There are four primary criteria for the siting of nuclear power plants in Australia[5]:

- proximity to appropriate existing electricity infrastructure
- proximity to major load centres (that is, large centres of demand)
- proximity to transport infrastructure to facilitate the movement of nuclear fuel, waste and other materials
- access to large quantities of water for cooling.

For this study, Jervis Bay, which is legally part of the Australian Capital Territory but is on the south coast of New South Wales, was chosen as the coastal location for a potential large-scale nuclear power facility.

Cost boundary

The generating unit boundary includes the area in which all unit components are located. For a nuclear plant, this includes the nuclear reactor, the power block and all support facilities needed to operate the plant, such as wastewater treatment facilities. The cost boundary also includes the interconnection substation, but not the switchyard and associated transmission lines. While all other technologies considered in this study are assumed to use dry cooling and therefore do not need cooling water intake structures, most current nuclear technologies require wet cooling. Therefore, seawater cooling and associated cooling water intake structures are also included in the plant design and cost boundary.

14.4.2 Resource potential

Nuclear fuel typically consists of uranium dioxide enriched to 3–5% (by weight) uranium-235. Natural uranium, mixed oxide consisting of both plutonium and enriched uranium oxides, thorium, and actinides are also used as nuclear fuel. Figure 124 shows geological regions and mineral deposits of uranium ores in Australia. Darker regions represent areas with greater amounts of uranium.

[5] www.tai.org.au/documents/downloads/WP96.pdf (accessed October 2015).

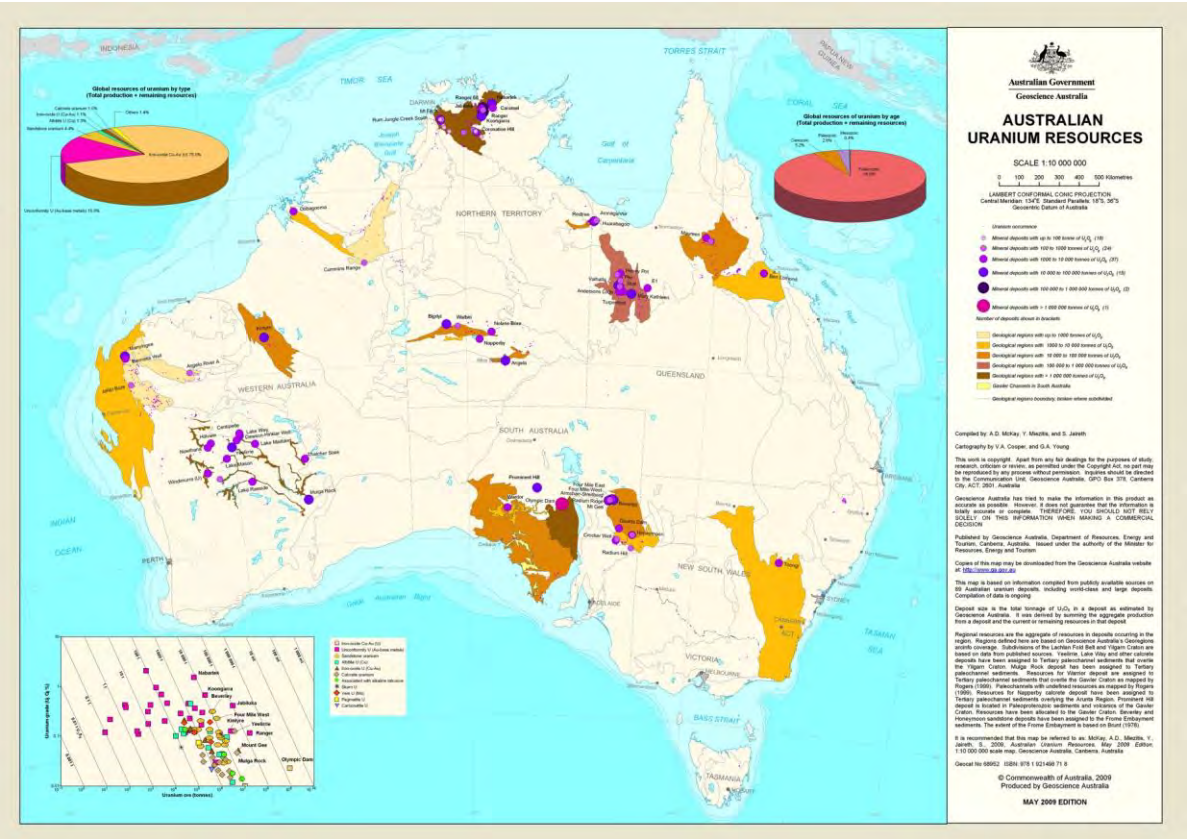

Figure 124: Australian uranium resources

Source: www.ga.gov.au/image_cache/GA14065.jpg (accessed October 2015).

15 CAPITAL COST ESTIMATING BASIS

15.1 Fossil-fuel plant estimating methodology

Three levels of capital cost data were gathered for this study: two were based directly on Australian knowledge and experience, and the third translated US Gulf Coast data using detailed and high-quality conversion factors.[1] The three tiers of data are described in Table 84.

Table 84: Capital cost data sources

Tier 1	These data were provided by study participants and were based on recently constructed power plants or studies completed to 'financial close' detail.
Tier 2	These data were provided by study participants and were based on significant industry experience or screening cost studies. This data tier was generally used to validate multiple Tier 1 sources and also the EPRI Tier 3 data.
Tier 3	These data were provided by EPRI when no Tier 1 data were available. Cost conversion factors provided by WorleyParsons were used to convert the EPRI US Gulf Coast data to Australian conditions. All Tier 3 data were 'sense checked' using Tier 2 data.

Due to the lack of recent fossil-fuel plant construction in Australia, EPRI prepared Tier 3 total plant cost (TPC), 'capital cost', and operation and maintenance (O&M) cost estimates for each of the fossil-fuel technologies and cases evaluated.

The estimates carry an accuracy of +/–30%, consistent with the screening study level of information available for the various power technologies in the study.

EPRI used its in-house Technical Assessment Guide database and conceptual estimating models for the capital cost and O&M cost estimates. Costs were then converted from the US Gulf Coast figures to Australian figures by applying factors for material costs, labour productivity, crew rates and currency.

All capital and O&M costs are presented as 'overnight costs' expressed in June 2015 Australian dollars.

Capital costs are presented at the TPC level. TPC includes:

- equipment (complete with initial chemical and catalyst loadings)
- materials
- labour (direct and indirect)
- engineering and construction management
- contingencies (process and project).

[1] Refer to Chapter 19.

Owner's costs are excluded from TPC estimates.

15.2 Power plant maturity

The estimates include estimates for technologies with different commercial maturity levels. The estimates for the non-CO_2-capture pulverised coal and CCGT cases represent well-developed commercial technology or '*n*th plants'. The non-CO_2-capture IGCC cases are also based on commercial offerings; however, there have been very limited sales of these units so far. These non-CO_2-capture IGCC plant costs are less mature in the learning curve, and the costs listed reflect the 'next commercial offering' level of cost rather than mature *n*th-of-a-kind cost. Thus, each of these cases reflects the expected cost for the next commercial sale of each of the technologies.

15.3 CO_2 removal maturity

The post-combustion CO_2 removal technology for the pulverised coal, oxy-combustion and CCGT capture cases is based on component technology that is mature but has not been incorporated into the power industry. This technology is currently in the initial stages of commercial-scale demonstration but remains unproven in power generation applications.

The pre-combustion CO_2 removal technology for the IGCC capture cases has a stronger commercial experience base. Pre-combustion CO_2 removal from syngas streams has been proven in chemical processes under similar conditions to those in IGCC plants, but has not been demonstrated in IGCC applications. While no commercial IGCC plant yet uses CO_2 removal technology in commercial service, there are currently IGCC plants with CO_2 capture under construction and in well-developed planning stages.

15.4 Contingencies

Both the project contingency and the process contingency costs represent costs that are expected to be spent in the development and execution of the project that are not yet fully reflected in the design. It is industry practice to include project contingency in the TPC to cover project uncertainty and the cost of any additional equipment that would result during detailed design. Likewise, the estimates include process contingency to cover the cost of any equipment modification or additional equipment that would be required as a result of continued technology development. A more detailed discussion of contingency Is in Section 15.9.

15.5 Contracting strategy

The TPC estimates are based on an engineering, procurement, and construction management (EPCM) model that is becoming a common approach for projects. The EPCM structure allows owners to have a more substantial influence on project execution by the direct procurement of major equipment and subcontracts, in exchange for risk retention. This approach lends an element of transparency to a process that, at times, can be fairly opaque in a true engineering, procurement and construction (EPC) arrangement. For an experienced and sophisticated owner, the savings in fees and damages caps will be substantial. Also, it allows owners to take advantage of direct cost participation and of risk decay as the project proceeds. Finally, an EPCM structure offers an element of routine project engagement and oversight that is missing from many EPC-based projects.

15.6 Estimate scope

The estimates represent a complete power plant facility on a generic site. Site-specific considerations, such as unusual soil conditions, special seismic zone requirements or unique local conditions (accessibility, local regulatory requirements and so on), are not considered in the estimates.

The estimate boundary limit is defined as the total plant facility within the fence line, including coal receiving equipment and areas, but terminating at the high-voltage side of the main power transformers and at the fence line for cases where CO_2 is captured.

The reference site is characterised as a generic Hunter Valley site in New South Wales. For the brown coal cases, a Victoria mine-mouth location is assumed.

Labour costs are based on Hunter Valley or Victorian rates and productivities in a competitive bidding environment.

15.7 Capital costs

EPRI developed the capital cost estimates for each plant using its in-house Technical Assessment Guide database and conceptual estimating models for each of the specific technologies. A reference bottom-up estimate for each major component or system provides the basis for the estimating models. Costs are broken down into major equipment, materials, and construction labour. This provides a basis for subsequent comparisons and easy modification when comparing specific case-by-case variations.

Key equipment or system costs for each of the cases are calibrated to reflect recent power or process projects. They include costs for:

- pulverised coal boilers
- gasifiers
- combustion turbine generators
- steam turbine generators
- circulating water pumps and drivers
- cooling systems
- condensers
- air separation units
- main transformers.

The post-combustion CO_2 costs were calibrated from in-house information.

A number of other key estimate considerations were also included:

- No vendor quotations were provided specifically for this study.
- Labour costs are based on Australian rates and productivities.
- The estimates are based on a competitive bidding environment, with adequate skilled craft labour available locally.
- Labour is based on an average 51-hour working week. Allowances for meals and travel are included.
- The estimates are based on a greenfield site.
- The site is considered to be in Seismic Zone 1, relatively level and free from hazardous materials, archaeological artefacts, or excessive rock. Soil conditions are considered adequate for spread footing foundations. The soil bearing capability is assumed to be adequate, such that piling is not needed to support the foundation loads.
- Costs are limited to within the fence line, terminating at the high-voltage side of the main power transformers, representing the interconnection substation
- Engineering and construction management costs are estimated as a percentage of bare erected cost.
- All capital costs are presented as 'overnight costs' in mid-2015 Australian dollars. Escalation to period-of-performance is specifically excluded.

15.8 Exclusions

The TPC estimates include all anticipated costs for equipment and materials, installation labour, professional services (engineering and construction management), and contingency. The following items are excluded:

- escalation to period-of-performance
- owner's costs—including land acquisition and right-of-way; permits and licensing; royalty allowances; economic development; project development costs; allowance for funds used during construction; legal fees; owner's engineering; pre-production costs; initial inventories; furnishings; owner's contingency; and so on.
- all taxes, with the exception of payroll taxes
- site-specific considerations—including the seismic zone, accessibility, local regulatory requirements, excessive rock, piles, laydown space, and so on.
- CO_2 injection wells
- additional premiums associated with an EPC contracting approach
- import duties.

15.9 Treatment of contingencies

15.9.1 Project contingency

Project contingencies have been added to each of the capital accounts to cover project uncertainty and the cost of any additional equipment that could result from detailed design. The project contingencies represent costs that are expected to occur. Each bare erected cost

account was evaluated against the level of estimate detail, field experience and the basis for the equipment pricing to define project contingency.

The capital cost estimates associated with the plant designs in this study were derived from various sources, which include prior conceptual designs and actual design and construction of both process and power plants.

15.9.2 Process contingency

Process contingency is intended to compensate for uncertainties arising as a result of the state of technology development. Some examples of how process contingencies have been applied to the estimates are:

- *gasifiers and syngas coolers:* 10% on all IGCC cases—at the next commercial offering
- *oxy-combustion boiler technology:* 20%
- *CO_2 removal system:* 15% on all post-combustion capture cases—process unproven at scale for power plant applications
- *combustion turbine generator:* 5% on all IGCC non-capture cases (syngas firing); 5% on all IGCC capture cases (hydrogen firing)
- *instrumentation and controls:* 5% on all IGCC accounts and 5% on the pulverised coal and CCGT capture cases—integration issues.

The process contingencies as applied in this study are consistent with the Association for the Advancement of Cost Engineering (AACE) international standards.

All contingencies included in the TPC, both the project and process, represent costs that are expected to be spent in the development and execution of the project.

15.10 Operations and maintenance costs

The production costs or operating costs and related maintenance expenses (O&M costs) pertain to those charges associated with operating and maintaining the power plants over their expected lives. There are two components of O&M costs; fixed O&M, which is independent of power generation, and variable O&M, which is proportional to power generation. These costs include:

- Fixed
  - operating labour
  - maintenance—material and labour
  - administrative and support labour
- Variable
  - consumables
  - waste disposal
  - co-product or by-product credit (that is, a negative cost for any by-products sold)
  - fuel.

15.10.1 Operating, maintenance, and administrative labour

Operating, maintenance and administrative labour are determined based on the number of personnel appropriate for each specific case. The average base labour rate used to determine annual cost for each category is:

- administrative labour—A$24/hour

- operating labour—A$38/hour
- maintenance labour—A$31/hour.

The associated labour burden rate is estimated at 30% of the base labour rate. The associated overhead rate is estimated at 25% of the base labour rate.

Productivity adjustments to account for the different crew and productivities rates and regional variations are not included.

15.10.2 Maintenance material

The maintenance material costs were developed based on the reference values that are expected for each area for each technology. A systematic analysis was then used to adjust each value, based on technical or equipment cost values. Generally, maintenance cost was evaluated on the basis of relationships of maintenance cost to initial capital cost. This represents a weighted analysis in which the individual cost relationships were considered for each major plant component or section. The exception to this is the maintenance cost for the combustion turbines, which is calculated as a function of operating hours.

15.10.3 Consumables

The cost of consumables was determined on the basis of individual rates of consumption, the unit cost of each specific consumable commodity, and the plant's annual operating hours.

Quantities for major consumables were taken from technology-specific heat and mass balance diagrams developed for each plant. Other consumables were evaluated on the basis of the quantity required using reference data.

The quantities for initial fills and daily consumables were calculated on a 100% operating capacity basis. The annual cost for the daily consumables was then adjusted to incorporate the annual plant operating basis, or capacity factor.

Initial fills of the consumables and chemicals are different from the initial chemical loadings included with the equipment pricing in the capital cost.

Table 85 indicates the consumables that are included in the O&M cost for each technology.

Table 85: Consumables, by technology

IGCC	Pulverised coal	Engines	CCGT
Water	Water	Water	Water
Water treatment chemicals	Water treatment chemicals	Lubrication oils	Water treatment chemicals
Carbonyl sulphide, Claus, hydrogenation catalyst	Balls (horizontal ball mill)	Fuel filters	Sulphuric acid
Limestone	Limestone		Soda ash
Caustic	Sulphuric acid		Caustic
Hydrogen chloride	Rolls (vertical ball mill)		Supplemental fuel
Balls (vertical ball mill)	MEA solvent		MEA solvent
Supplemental fuel	Supplemental fuel		
acid gas removal solvent (MDEA or Selexol)			

15.10.4 Waste disposal and by-products

Waste quantities and disposal costs were determined and evaluated in a manner similar to that applied to consumables. Table 86 indicates the waste streams and potential by-products that are included in the O&M cost for each technology.

Table 86: Waste and by-products, by technology

IGCC	Pulverised coal	CCGT
Wastewater	Wastewater	Wastewater
Fly ash	Fly ash	Reclaimer waste
Bottom ash	Bottom ash	
Spent catalysts	Reclaimer waste	
Slag	Gypsum	
Sulphur		

Some of these waste streams retain some commercial value. Sulphur (for a number of industrial applications), gypsum (for wallboards and as a fertiliser supplementation), fly ash (for pozzolanic concrete) and bottom ash (for grit blasting) all represent potential revenue streams. However, the value of any of these by-products is highly dependent on economic conditions and the proximity to ready markets. For the purposes of the O&M analysis, the value of these waste streams is assumed to be zero.

15.11 Renewable plant estimating methodology

Renewable technology costs were estimated by EPRI using a combination of in-house data and adjustment factors developed by EPRI's subcontractor (WorleyParsons). Recent EPRI studies were used as a baseline for the cost estimates. When necessary, those costs were adjusted to match the design basis for the current study, such as by adjusting to the size of the plant or the inclusion of thermal storage. Based on information about current market trends, these baseline estimates were then adjusted to mid-2015 US dollars. Once capital and O&M costs were established for a US-based plant with the same design as the design basis, cost estimates were adjusted to Australian dollars based on the adjustment factors developed by WorleyParsons (described in Section 15.13).

15.12 Nuclear plant estimating methodology

Nuclear technology costs were estimated by EPRI using a combination of in-house data and adjustment factors developed by WorleyParsons. Because a detailed estimate of nuclear plant costs has not been developed recently, a range of high-level nuclear plant cost estimates from EPRI's *Integrated generation technology options*[2] report was used as a baseline for the cost estimates. These baseline estimates were adjusted to mid-2015 US dollars and then adjusted to Australian dollars, based on the factors developed by WorleyParsons.

15.13 Adjustments to Australian costs

The total installed cost of the technologies associated with each of the design cases is estimated based on US Gulf Coast delivery and installation on an 'overnight' basis. WorleyParsons[3] developed translation factors to adjust for Australian costs to account for differences in productivity, craft labour rates, bulk material costs and currency exchange rates. The labour rate was developed by comparing the crewing cost for two large-scale projects—one in the United States and the other in Australia. The projects selected were of a size such that the workforce included a substantial proportion of all labour crafts to offset any bias associated with craft selection. It is assumed for this analysis that, while the crews would include apprentices as well as supervisory personnel, the average wage would be close to journeyman scale. For this cost update study, Hunter Valley in New South Wales is used as the reference location for all generation technologies other than the brown coal cases. For the brown coal cases, a Victoria mine-mouth location is assumed.

WorleyParsons also developed regional variability factors for locations in Victoria, central Queensland (Surat Basin) and the south-western corner of Western Australia.

15.13.1 Currency exchange rate

All factors pertaining to material costs and labour rates are presented on a US dollar basis and may be affected by changes in the currency exchange rate. The rate of exchange used in developing the cost factors was A$1.30 to US$1.00 (at approximately 30 June 2015).

Note that the relationship between the exchange rate and the conversion factors is not necessarily linear. The relationship depends in part on the ratio of local versus foreign content.

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[2] EPRI (2013), *Program on Technology Innovation: integrated generation technology options 2012*, EPRI, Palo Alto, California, product ID 1026656.
[3] Refer to Chapter 19 for the full report.

15.13.2 Methodology

The factors were developed in close collaboration between WorleyParsons' US-based and Australia-based estimating teams.

Labour productivity factors

The labour productivity factors reflect the standard experience-based factors used by WorleyParsons' in-country personnel to convert from US Gulf Coast (USGC) productivity to specific project locations in Australia.

Crew rate factors

All-inclusive crew rates were developed for the USGC and for each of the Australian locations. The USGC rates are based on published wages and fringe benefits for 'merit shop' labour (labour under conditions based on law but not necessarily a union agreement) and include premium time costs associated with a 50-hour working week. No additional allowances are included for either travel or living expenses or for incentives to attract craft labour.

The Australian rates are based on labour agreements in place for 2015 for each of the specified regions. They include overtime associated with the expected working week as well as travel and living allowances appropriate for the region. The Australian rates were developed in Australian dollars and converted to US dollars at the exchange rate noted above.

Crews were grouped by discipline and multiplied against the associated crew hours from a representative non-specific power plant to arrive at the discipline averages.

15.13.3 Material cost factors

The methodology used for calculating the material cost factors varies by discipline and takes into account the availability of locally sourced equipment and materials versus those items that are typically imported into Australia. In general, mechanical and electrical equipment items, instrumentation and valves are considered to be imported. The balance of the bulk material items are generally considered to be available in-country.

Material cost factors for the imported items include an adjustment for overseas freight of 8%. No adjustments are made for inland freight on imported items, as the reference USGC pricing is expected to include delivery to the site. The material cost factor for concrete (complete) is based on a direct comparison of 2015 pricing between the USGC and Australia.

A direct pricing comparison was also done for structural steel (fabricated). The results indicated a significantly higher cost for in-country fabricated steel relative to the United States—as much as 1.5 times for the Hunter Valley and even more for the other locations. However, for large projects, it is expected that worldwide sourcing would be considered, keeping the pricing levels more on par with the United States. Import duty is generally 5%; however, Australia has signed a number of free trade agreements, so there can be variations to duties depending on the country of origin.

For the remainder of the bulk material items the costs were escalated based on the appropriate rates for the respective country, and the escalated costs were spot-checked for reasonableness. The Australian costs were then converted to US dollars for comparison to the US costs.

See Chapter 19 for detailed cost factors.

15.13.4 General

It is common for estimates to be developed by applying conversion factors to a reference estimate. However, estimate factors have some limitations, and it is important to recognise that using this approach generally results in a slight degradation of overall estimate accuracy.

Factors developed for estimate conversion purposes are considered to be 'point factors'; that is, they represent a specific point in time. These factors can change quickly and markedly based on both worldwide and local market conditions such as supply and demand, fluctuations in international commodity pricing, fluctuations in exchange rates, political unrest, project-specific equipment/material sourcing requirements, and so on. Users of information in this report should consider these elements and make the appropriate adjustments or add the appropriate qualifiers to the factored estimate.

Consideration must be given to the basis of the reference estimate used for conversion to ensure that no material differences exist between its basis and the basis used to develop the cost factors.

15.14 Road map capital estimating methodology

Technology road mapping is a strategic approach to R&D planning. Road maps are used as communication tools to align technology plans with organisational strategies, to articulate long-term plans and to prioritise research investments. Technology road maps are used to guide investments in research, to articulate research questions of interest and to inform stakeholders of the potential benefits of new technology.

Road maps show how current power generation technologies may be transformed by 2030. Those transformations can include efficiency improvements, emissions reductions and capital cost reductions. Cost reductions are achieved by a combination of learning-by-doing and incorporating advanced technologies.

The road maps represent international subject matter consensus on milestones for technology development, legal and regulatory needs, investment requirements, public engagement and outreach, and international collaboration.

In this report, 2030 capital cost road map data is presented alongside Global and Local Learning Model (GALLM) results.

16 GALLM CAPITAL COST FORECAST METHODOLOGY

16.1 Introduction

This chapter briefly describes how CSIRO's Global and Local Learning Model (GALLM) works. The data used in the GALLM and the resulting cost projections are used in two scenarios of global carbon abatement actions in order to establish the global context, given Australia's largely technology price-taking role.

16.2 The GALLM cost projection methodology

While 'learning by doing' has often been observed as a stable relationship between costs and technology deployment, its use as a cost projection technique has been limited by the need to project or forecast deployment, which is itself a function of costs. Building on international literature, CSIRO solved this problem by constructing GALLM, which solves costs and deployment simultaneously by applying mixed integer linear programming. The main attraction of this projection approach, compared to others, is that all the inputs and assumed relationships are transparent.

Technology deployment and costs are projected at both the global and the local scale. Learning curves (also known as 'experience curves') are a key input into the model.

Learning curves refer to the observed phenomenon that the costs of new technologies tend to reduce with the cumulative production of the technology. More specifically, costs tend to reduce by an approximately constant factor for each doubling of cumulative production.[1] This observation makes it possible to create cost projections based on projections of the future take-up of a technology. Projections are created from a mathematical equation as follows:

$$IC_t = IC_0 \times CC_t^{-b}$$

where IC is the investment cost of a technology at CC cumulative capacity at a given future point in time t, IC_0 is the investment cost at a given starting period or capacity, and b is the learning index. This index is related to the learning rate as follows:

$$LR = 100 - 2^{-b}$$

where LR is the learning rate, represented as a percentage.

[1] TP Wright (1936), 'Factors affecting the cost of airplanes', *Journal of the Aeronautical Sciences*, February, 3:122–138; KJ Arrow (1962), 'The economic implications of learning by doing', *Review of Economic Studies*, 29(3):155–173; A Grübler, N Nakicenovic, DG Victor (1999), 'Dynamics of energy technologies and global change', *Energy Policy*, 27(5):247–280.

16.3 The different stages of technology learning

As technologies progress through different levels of technical and commercial maturity, their learning rate reduces.[2] This is shown schematically in Figure 125, in which the slope of the curve represents the learning rate. During the early commercialisation stages, learning rates may be around 20%. During the pervasive diffusion stage or intermediate stage, they may fall to around 10%. Finally, when the technology is mature, little or no learning may be observed.

Accordingly, in GALLM, the learning rates for technologies and their components differ, depending on the maturity of the technology. For the emerging and early learning technologies, two learning rates are applied; the second, lower learning rate begins when the technology reaches the diffusion or intermediate stage (or 'transition capacity'), as shown in Figure 125. In the case of electricity generation technologies, this tends to occur once a technology has been around for at least 50 years.[3]

More detail on GALLM can be found elsewhere.[4]

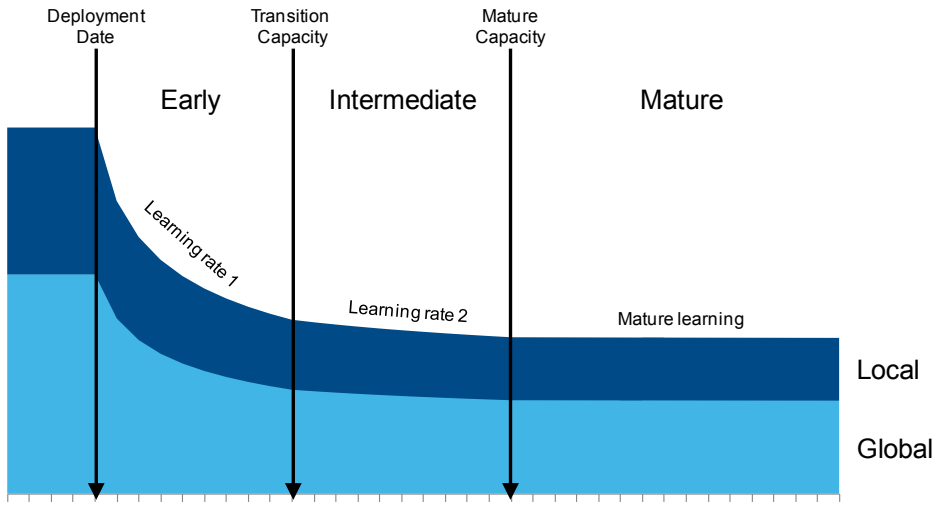

Figure 125: Schematic of changes in the learning rate as a technology progresses through its development stages after commercialisation

16.4 GALLM assumptions and data used

The version of GALLM used in this study contains 20 different electricity generation technologies and three regions (the developed world, the less developed world and Australia). This study provided current electricity generation technology performance data to use in

[2] Grübler et al., 'Dynamics of energy technologies and global change'.
[3] C Wilson (2012), 'Up-scaling, formative phases, and learning in the historical diffusion of energy technologies', *Energy Policy*, 50(0):81–94; C Wilson, A Grübler (2011), 'Lessons from the history of technological change for clean energy scenarios and policies', *Natural Resources Forum*, 35:165–184.
[4] JA Hayward, PW Graham (2012), *Australian electricity generation technology cost projections: application of a global and local learning model*, CSIRO, Australia, https://publications.csiro.au/rpr/download?pid=csiro:EP123123&dsid=DS1; JA Hayward, PW Graham (2013), 'A global and local endogenous experience curve model for projecting future uptake and cost of electricity generation technologies', *Energy Economics*, 40:537–548.

GALLM, including 2015 capital costs, fuel efficiencies, and operating and maintenance (O&M) costs.

Two carbon price scenarios were modelled for this report. They are consistent with the world reaching ~450 ppm CO_2-e and ~550 ppm CO_2-e in the atmosphere by 2050.[5] Other assumptions, such as global and regional electricity demand, CO_2 storage sites, policies related to renewable energy targets and feed-in tariffs or other support schemes, existing capacities of electricity generation technologies and learning rates are based on data previously used in GALLM.[6] The learning rates assumed are shown in Table 87.

Table 87: Technologies used in this study with GALLM learning rates

Technology	Learning component	Learning rate		Mature learning (%/year)
		1 (%)	**2 (%)**	
Brown coal, IGCC			5	0.5
Black coal, pulverised				0.5
Black coal, IGCC			5	0.5
CCS technology	G	11	5	0.5
CCS local build	L	20	20	0.5
Brown coal CCS, BOP	L			0.5
Black coal CCS, BOP	L			0.5
Gas with CCS, BOP	L			0.5
Gas combined cycle	G		2	0.5
Nuclear	G		3	0.5
Solar thermal	G	15	7	0.5
Photovoltaic modules	G	20	20	0.5
Photovoltaic, BOP	L	15	15	0.5
Wind turbines	G		4	0.5
Wind installation	L	11	11	0.5

G = global; L=local; IGCC = integrated gasification combined cycle; PV = photovoltaic; CCS = carbon capture and storage; BOP = balance of plant.
Sources: L Schrattenholzer, A McDonald (2001), 'Learning rates for energy technologies', *Energy Policy*, 29:255–261; ES Rubin, S Yeh, M Antes, M Berkenpas, J Davison (2007), 'Use of experience curves to estimate the future cost of power plants with CO_2 capture', *International Journal of Greenhouse Gas Control*, 1(2):188–197; IEA (2008), *Energy technology perspectives: scenarios and strategies to 2050*, OECD–IEA, Paris, 643; l Neij (2008), 'Cost development of future technologies for power generation—a study based on experience curves and complementary bottom-up assessments', *Energy Policy*, 36(6):2200–2211; JA Hayward, PW Graham (2013), 'A global and local endogenous experience curve model for projecting future uptake and cost of electricity generation technologies', *Energy Economics*, 40:537–548.

[5] L Clarke, K Jiang, K Akimoto, M Babiker, G Blanford, K Fisher-Vanden, J-C Hourcade, V Krey, E Kriegler, A Löschel, D McCollum, S Paltsev, S Rose, PR Shulka, M Tavoni, B Van der Zwaan, P van Vuuren (2014), 'Assessing transformation pathways', *Climate change 2014: mitigation of climate change*, contribution of Working Group III to the Fifth Assessment Report of the IPCC, O Edenhofer, R Pichs-Madruga, Y Sokona et al., Cambridge University Press, Cambridge, UK, and New York, US.
[6] JA Hayward, PW Graham (2013), 'A global and local endogenous experience curve model for projecting future uptake and cost of electricity generation technologies', *Energy Economics*, 40:537–548.

Each region in GALLM has its own electricity demand, O&M costs, fuel costs, fuel efficiencies, existing plant capacity, capacity factors, capital costs and government policies, such as feed-in tariffs, renewable energy targets and constraints on nuclear construction. The capital cost is reduced or increased by a percentage depending on the region in order to recognise differences from the global average. Those differences are included in the objective function of GALLM, where total system costs are optimised. The regional technology cost adjustments make no difference to the projected global technology mix produced by GALLM, as each region is self-contained (that is, there is no electricity trade).

16.5 Results

The projected capital costs from GALLM under the 550 ppm and 450 ppm carbon price scenarios are shown in Figure 126 and Figure 127, respectively. Under both scenarios, the majority of the cost reductions occur in the next 20 years. This is due to several factors. First, emerging technologies experience their largest cost reductions at low levels of capacity (and it is easier to double a smaller level of capacity). Second, the learning rate for some technologies is reduced as they mature. This reduces the capacity for cost reductions.

The carbon price also has an impact, as it is initially only in the developed world but by 2020 it is in all regions of the model. This means that more low-emissions technologies are needed to meet demand, which increases their cumulative capacity and thus cost reductions. This can be seen in Figure 128 and Figure 129, which show the contribution of each technology to demand under the 550 ppm and 450 ppm carbon price scenarios, respectively. From 2020, under both scenarios, rooftop and utility-scale solar and gas combined cycle expand most significantly. In the 2030s, CCS technologies gradually increase their capacity, while conventional coal-fired generation phases down by 2035. Under the 450 ppm scenario, the phasing down is more rapid from 2020 to 2030. There is also significantly more generation from gas with CCS under the 450 ppm compared to the 550 ppm scenario. This technology essentially replaces gas combined cycle generation from the 2045 onwards.

A summary of the 2015 and 2030 capital costs, by technology, is shown in Table 88.

Table 88: Summary of capital costs, 2015 and 2030 (A$ 2015 / kW)

Technology		550 ppm	450 ppm
	2015	2030	2030
Brown coal, IGCC	6,150	5,634	5,634
Brown coal with CCS	8,515	7,091	6,524
Black coal, pulverised	3,000	2,783	2,783
Black coal, IGCC	5,000	4,863	4,863
Black coal with CCS	6,765	5,462	4,908
Gas, combined cycle	1,450	1,406	1,409
Gas with CCS	3,065	1,987	1,516
Nuclear	9,000	8,974	8,876
Solar thermal	8,500	3,916	3,903
Rooftop PV	2,100	1,243	1,257

Large-scale PV	2,300	1,108	1,128
Wind	2,608	2,040	1,973

IGCC = integrated gasification combined cycle, PV = photovoltaic

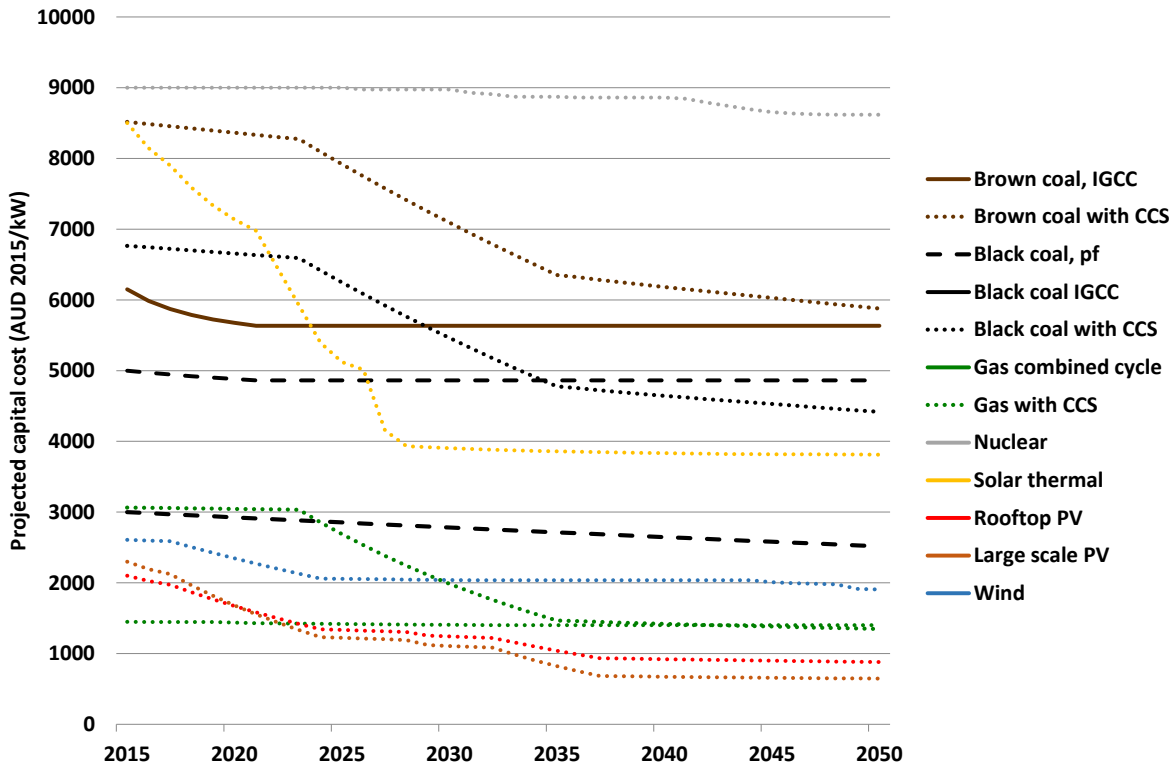

Figure 126: Projected capital costs under a 550 ppm carbon price scenario

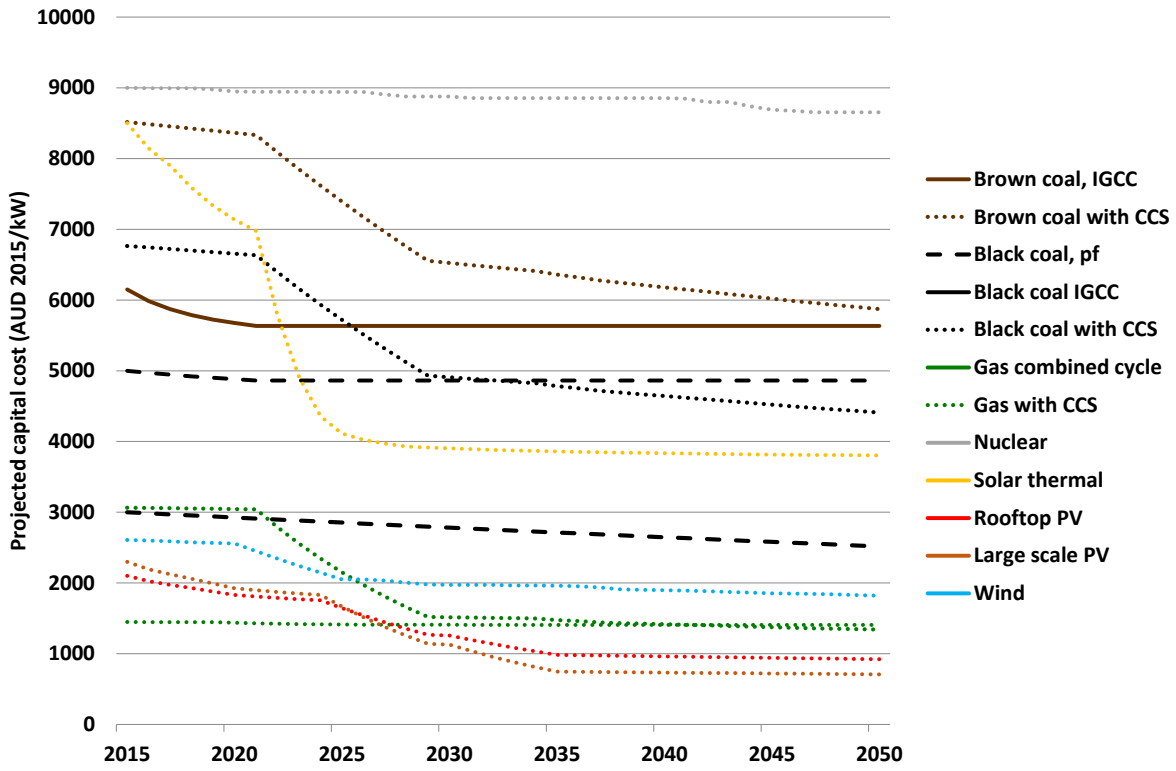

Figure 127: Projected capital costs under a 450 ppm carbon price scenario

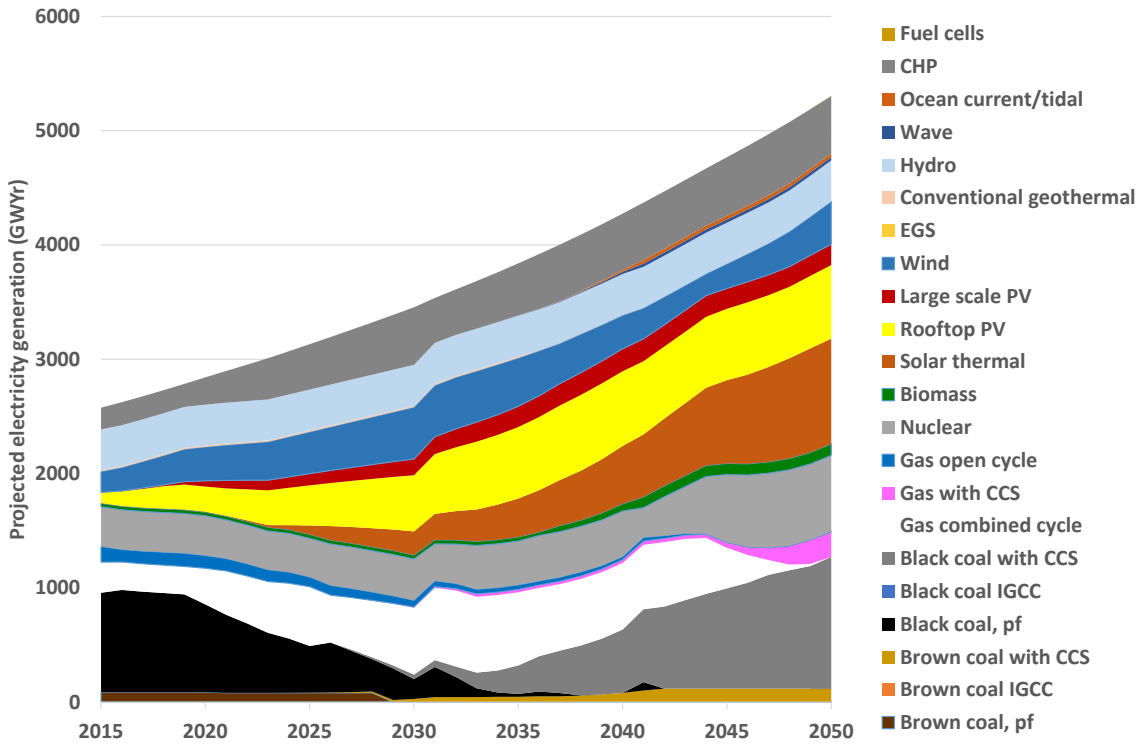

Figure 128: Projected electricity generation under 550 ppm carbon price scenario

CHP = combined heat and power; EGS = enhanced geothermal systems; pf = pulverised.

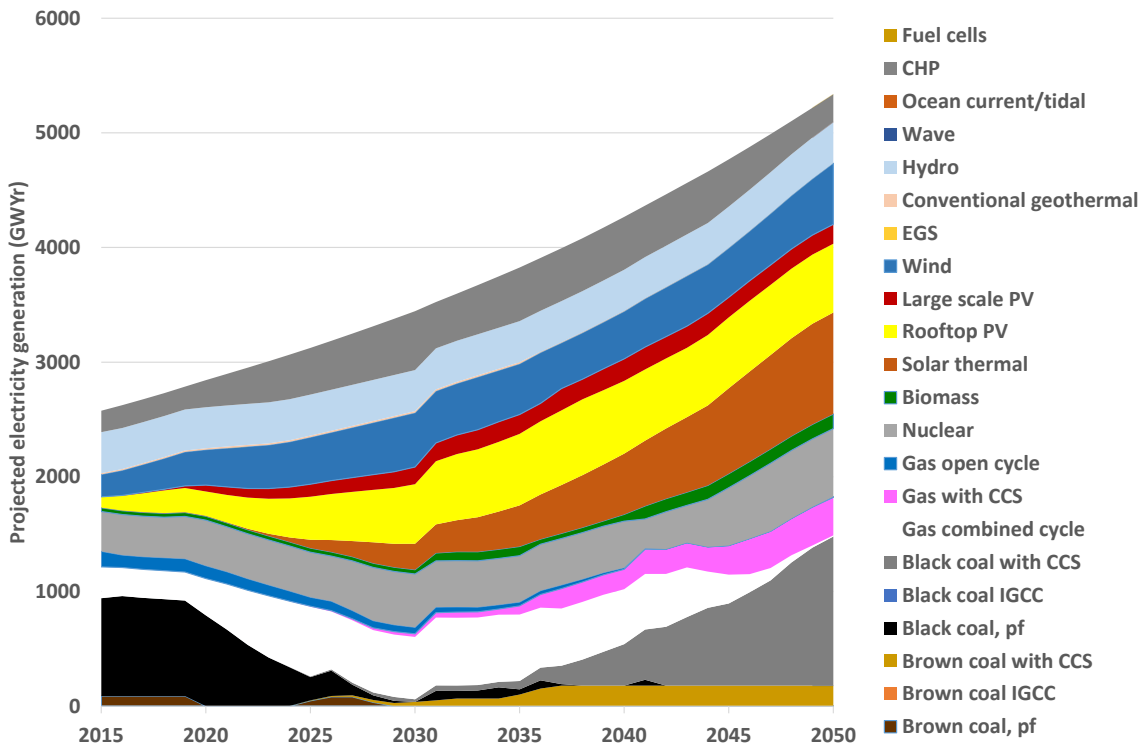

Figure 129: Projected electricity generation under 450 ppm carbon price scenario

CHP = combined heat and power; EGS = enhanced geothermal systems; pf = pulverised.

17
COST OF ELECTRICITY METHODOLOGY

17.1 Introduction

This chapter introduces the revenue requirement method, which has traditionally been used in the electric utility industry for the economic comparison of alternatives. Electric utilities are allowed to charge rates to recover all costs associated with building and operating a facility to provide safe and reliable electric service to the utility's customers, including a fair rate of return on investments. These costs include the annual costs of operating a plant as well as capital additions, which are in addition to the initial costs of total plant investment described in Chapter 15.

The components of revenue requirements and how they are calculated are described in this chapter, with emphasis on the calculation of capital-related, or fixed charge, revenue requirements—the portion of requirements related to the recovery of the booked cost. Booked costs are essentially the total capital requirement (defined in Chapter 15) at the date the plant is placed in service and include all capital necessary to complete the entire project.

Table 89 shows the economic parameters used throughout this report for capital and cost of electricity calculations.

Table 89: Economic parameters

		Current dollars		Constant dollars	
Type of security		**Cost (%)**	**Return (%)**	**Cost (%)**	**Return (%)**
Debt	70%	8.0	5.6	5.4	3.8
Equity	30%	11.5	3.5	8.8	2.6
Total annual return			9.1		6.4
Inflation rate	2.5%				
Income tax rate	30%				
Discount rate					
After tax			7.4		5.3
Before tax			9.1		6.4

Note: Constant or real dollars exclude the effects of inflation. Current or nominal dollars include the effect of general inflation.

17.2 The components of revenue requirements

17.2.1 Overview

The components of revenue requirements can be divided into two parts:

- the *carrying charges*, also called *fixed charges*, related to the booked cost at the time the plant enters service as well as capital additions over the life of the plant
- the operating expenses, which include fuel and non-fuel operating and maintenance (O&M) costs.

Note that in Figure 130 all O&M costs are grouped as expenses; however, they must be considered in their fixed and variable components.

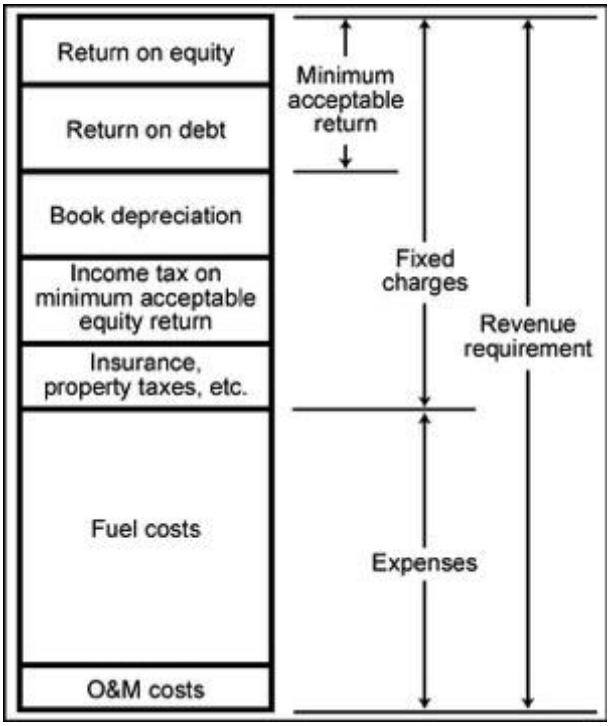

Figure 130: Revenue categories for the revenue requirement method of economic comparison

Utility investments in generation, transmission, distribution and general plant can last 30 years or longer, and the booked costs are recovered over a period of time that is an approximation of the expected useful life for the particular investment. This is called the book life. Thus the booked costs for utility plants are recovered over roughly the period of time that the investment is used in providing services to the utility's customers. The recovery of the booked costs is through an annual depreciation charge, which is a rough estimate of the extent to which an investment is used up, or obsolesces, each year of its useful life. The annual fixed charges include annual depreciation.

As discussed in Chapter 15, construction expenditures are financed and accumulate Allowance for Funds Used During Construction. The sale of bonds and debentures as debt financing and the sale of common and preferred stock as equity financing are the primary means of financing utility investments.

Expenses are treated differently from the booked costs. They are recovered on an as-you-go basis, directly through revenues collected from customers.

17.2.2 The nature of fixed charges

Fixed charges are an obligation incurred when a utility plant is placed in service and they remain an obligation until the plant is fully depreciated. They must be collected from customers regardless of how much or how little the facility is used or how the market value of the facility changes.

The difference between the new book value (the unamortised portion of the investment) and the current market value of the plant is called a 'sunk' cost. The important characteristic of sunk costs is that they cannot be affected by management decisions. They are obligations that must be met irrespective of management decisions other than bankruptcy. Thus, the retirement of a utility plant, for example, will not affect the obligation of the utility to pay the fixed charges. Future capital additions and expenses to operate the plant are determined by management decisions. These costs are referred to as *increment costs.*

However, the fixed charges themselves can change. Changes in the cost of money, income tax rates, property tax rates, property assessments or insurance rates would result in changes in fixed charges. For example, if changes in financial markets lead to lower interest rates and return on equity, the fixed charges would decline.

17.2.3 The components of fixed charges

Annual fixed charges include the following components:

- book depreciation
- return on equity
- interest on debt
- income taxes
- property taxes, insurance, and other taxes.

Depreciation

There are two types of depreciation. The first is *book depreciation,* which is a measure of the extent to which a utility plant is used up or becomes obsolete. Book depreciation is used in setting rates and is charged directly to customers. The second is *tax depreciation*, which is used for computing income taxes and affects the fixed charges indirectly through income taxes.

While there are a number of ways of determining book depreciation and collecting the charges from customers, the electric utility industry uses the straight-line method. The annual depreciation is the booked cost divided by the book life of the plant. The book life for fossil-fuel, nuclear and solar plants in this study is 30 years, and the book life for wind plants is 20 years, as shown in Table 88. Note that some economic evaluations of solar PV plants assume a book life of 20 or 25 years. PV panels experience performance degradation as they age and therefore may have a shorter productive lifetime than the 30 years assumed in this report. Research into PV panel degradation is ongoing. An assumption of a 20-year lifetime would increase the cost of PV electricity by about 10%.

Table 90: Book lives and book depreciation for utility plants

Plant type	Book life (years)	Annual depreciation (%)
Fossil / nuclear / solar plants	30	3.33
Wind plants	20	5.00

Experience suggests that the scrap value of a coal-fired plant covers around 10% of decommissioning and site reclamation costs. This figure is significantly higher for other technologies, such as wind and some gas plant. For this study, it is assumed that the net salvage value is zero: the salvage value of a utility plant just equals the cost of reclaiming the site. Thus, annual depreciation is 3.33% of initial investment for fossil, nuclear and solar plants and 5% for wind plants.

In typical electricity utility economics, depreciation charges would be used to purchase the debt and equity initially used to finance the construction of a project. In the context of a utility company facing a need to expand utility plant, depreciation represents one of the sources of funds for investment.

Tax depreciation differs from book depreciation in two respects. First, the government can allow for the recovery of the investment for tax purposes over a period shorter than the book life of the utility plant. Second, the schedules for tax depreciation may allow for a larger portion of the recovery in the earlier years than is allowed with book depreciation.

Straight-line tax life depreciation was assumed for this Australian study. The tax life for fossil fuel, nuclear and solar plants was assumed to be 30 years, and for a wind plant 20 years. These tax lives are consistent with the depreciation guidelines from the Australian Taxation Office.[1]

Return on equity

Equity financing is selling ownership in the utility by issuing preferred or common stock. Equity holders earn a return on their investments in a utility plant and is supposed to be:

- sufficient for a utility to maintain its financial credit
- capable of attracting whatever capital may be required in the future
- comparable to the rate earned by other businesses facing similar risks.

The return is earned only on the portion of the unamortised investment—that is, the portion that has not been depreciated.

Interest on debt

Money from debt financing is acquired by mortgaging a portion of the physical assets of the company through *mortgage bonds* or by issuing an IOU without providing physical assets as collateral through *debentures*. Both mortgage bonds and debentures carry an obligation to pay a stated return. These interest payments take precedence over returns to equity holders.

[1] Taxation ruling TR 2015/2, https://www.ato.gov.au/law/view/document?LocID=%22ITD%2FEF20151%22&PiT=99991231235958

As with return on equity, interest is earned only on the unamortised investment. The key characteristics of equity and debt are summarised in Table 91.

Income taxes

Income taxes are the product of the income tax rate and taxable income. The tax rate represents a composite of the federal and, if applicable, state income tax rates. The income tax rate used for this study is the 30% company tax rate that applies in Australia.

Because book and tax depreciation rates typically differ over the book life of a utility plant, there can be a difference between income taxes actually paid and those that *would be paid* if book depreciation were used for computing income taxes. This difference is referred to as *deferred taxes*. Deferred taxes increase over the tax life and then decline to zero by the end of the book life. The effect of accelerated depreciation for tax purposes is to shift the tax burden to the later years of operation.

Table 91: Key characteristics of utility securities

Offering	Type	Life	Obligation to pay return	Relative level of return	Vote at annual meeting	Liquidation priority
First mortgage bond	Mortgage on physical assets	30–35 years	First (fixed)	Lowest	No	First
Debenture	Unsecured obligation	10–50 years	Second (fixed)	Second lowest	No	Second
Preferred stock	Part-owner of company	Usually perpetual	Third (usually fixed)	Second highest	Sometimes	Third
Common stock	Part-owner of company	Perpetual	Last (variable)	Highest	Yes	Last

Traditionally, there have been two ways of treating deferred taxes in the electricity utility industry. Under the *flow-through* method, the tax deferrals are flowed through to customers when they occur—that is, the lower taxes are translated directly into lower electricity rates. Under the *normalisation* method, deferred taxes are accumulated in a reserve account. With the latter method, electric utilities collect revenues as though income taxes were based on book depreciation. In the early years of an asset's life, revenues for taxes collected from customers exceed the taxes levied by the government. In the later years, deferred taxes in the reserve account decline as annual book depreciation exceeds annual tax depreciation. The purpose of the normalisation method is to create an additional source of internally generated funds for new investment. Consequently, the normalisation method is used for computing revenue requirements.

Property taxes and insurance

Property taxes and insurance are calculated as the product of the insurance and tax rate and the total capital required. Typical fossil-fuel power plant percentages are about 1.0% for property taxes and 1.0% for insurance.

17.2.4 Calculating annual capital revenue requirements

The annual capital, or fixed, charge is the sum of the book depreciation, return on equity, interest on debt, income taxes, and property taxes and insurance for a given year. To calculate the lifetime revenue requirement of a plant, the present value of these annual capital charges is calculated for each year and summed to determine the total present value. The present value is calculated based on the weighted average cost of capital (WACC) or discount rate, which is the product of the cost of debt (or interest rate) and the percentage of debt financing plus the product of the cost of equity and the percentage of equity financing. For example, in this study, the nominal before tax discount rate is calculated as:

(% debt) x (cost of debt) + (% equity) x (cost of equity) = discount rate
70% x 8%/year + 30% x 11.5%/year = 9.1%/year Eq. 17-1

The present value for each year is calculated using the equation:

$$P/F = 1/(1 + i)n \qquad \text{Eq. 17-2}$$

where P is the present value, F is the annual capital cost for the given year, *i* is the discount rate, and n is the year of the capital cost minus the year to which the costs are being present valued. For example, if the year of the cost is 2030 and the cost is being present valued to 2010, then n = 20.

The present values for each year are then summed to calculate the total present value for the plant. Using this total present value and the discount rate, the annual capital payment required for the plant can be calculated using the equation:

$$A/P = [i(1+i)n] / [(1+i)n - 1] \qquad \text{Eq. 17-3}$$

where A is the regular annual payment, P is the present value, *i* is the discount rate, and n is the number of years over which the payments are made.

The equivalent payment that must be made each year to cover the capital costs of the plant, or the annual revenue requirement, has now been calculated.

17.2.5 Calculating the cost of electricity

Cost of electricity calculations combine the capital and O&M costs of a plant with the expected performance and operating characteristics of the plant into a cost per MWh. This procedure allows for comparisons of technologies across a variety of sizes and operating conditions and allows for the comparison of the cost of electricity from a new plant with that from an existing plant. The cost of electricity typically consists of three components: the capital costs, the O&M costs and the fuel costs. In some studies, such as this one, a fourth component, CO_2 transportation and sequestration, is also included for cases that include CO_2 capture. These different cost components, when presented independently, typically have different cost units. However, they must all have the same cost unit basis when combined to calculate the cost of electricity (typically $/MWh).

Annual MWh produced

The amount of electricity produced by a plant in a given year is a key piece of information for calculating the levelised cost of electricity (LCOE). The maximum number of megawatt-hours that a plant could produce in one year would occur if the plant operated at full load 24 hours a day for 365 days a year (8760 hours/year). In practice, a plant will be shut down at times during the year, either for maintenance or because the electricity is not needed and it would be uneconomic to operate the plant. The capacity factor is the ratio of the actual amount of electricity produced by the plant over the maximum amount that could be produced.

To calculate annual electricity production, the size of the plant is multiplied by the number of hours that it operates (the capacity factor of the plant multiplied by 8760 hours/year). For example, a 500 MW plant that operates with an 85% capacity factor produces 3,723,000 MWh/year. A plant that operates for more hours in a year ultimately has more hours of electricity generation over which to spread its annual revenue cost requirements.

Constant versus current dollars

Cost of electricity is often presented on a levelised basis. Like the annual revenue requirement presented above, this is the consistent cost of electricity that would need to be collected annually to achieve the same present value as the actual capital and operating expenses of the plant. The LCOE can be presented in two ways: constant (or real) dollars and current (or nominal) dollars. In a constant-dollar analysis, the effects of inflation are not taken into account when looking at future costs, while in current-dollar analysis the effects of inflation are taken into account. While both methods are completely valid, it is important to know which method has been used when comparing cost results. Current-dollar analysis results are always higher than constant-dollar results because they account for year-by-year inflation in the cost of fuel, O&M costs and the cost of money. This report uses constant-dollar analysis.

Capital contribution to cost of electricity

Capital costs for power plants are often presented in dollars per kilowatt. Using the annual revenue requirement calculated, the cost in $/kW is multiplied by the overall size of the plant (sent-out basis) to determine the cost on a dollar basis. This revenue requirement is then divided by the number of megawatt-hours produced, as described above, to determine the capital cost on a $/MWh basis.

O&M contribution to the cost of electricity

Fixed O&M costs throughout this report are presented on a dollar per kilowatt-year basis. Costs can be converted to a dollar basis by multiplying the cost on a dollar per kilowatt-year basis by the unit size. For a current-dollar analysis, the year-by-year costs are calculated using general inflation. In constant-dollar analysis, as was performed in this study, inflation is not taken into account, and therefore the fixed O&M costs are levelised over the life of the plant. The dollar-per-year fixed O&M costs are then divided by the annual output of the plant to calculate the fixed O&M cost of electricity.

Variable O&M costs are often already presented as $/MWh costs and so do not need any conversion to find the cost of electricity contribution. As with fixed O&M costs, for current-dollar analysis the year-by-year costs are calculated using general inflation, while for constant-dollar analysis the variable O&M cost remains the same throughout the life of the plant.

Fuel contribution to the cost of electricity

The annual cost of fuel is calculated by multiplying the fuel cost in dollars per gigajoule by the heat rate of the plant. Once again, for current-dollar analysis, the year-by-year costs are calculated using general inflation, while in constant-dollar analysis the cost remains the same throughout the life of the plant.

CO_2 transportation and sequestration contribution to the cost of electricity

Finally, for plants that include CO_2 capture, CO_2 transportation and sequestration (T&S) costs were calculated by multiplying the amount of CO_2 captured on a kilogram per hour basis by an assumed cost in dollars per kilogram for T&S and dividing by the unit size of the plant to determine the $/MWh cost. The base cost of CO_2 T&S assumed in this study is $15/tonne (see Chapters 1 and 20 for more information).

18
TECHNOLOGY DEVELOPMENT CURVES

A technology development curve can help analyse the maturity of products, processes and industries. Such curves are a useful tool to assist in the estimation of a product's or process's time to market, demonstration cost, eventual price once fully developed, and the effort required for commercialisation. Figure 131 shows a typical technology development curve, showing the R&D and early development stages, the first commercial plant and when the technology is mature.

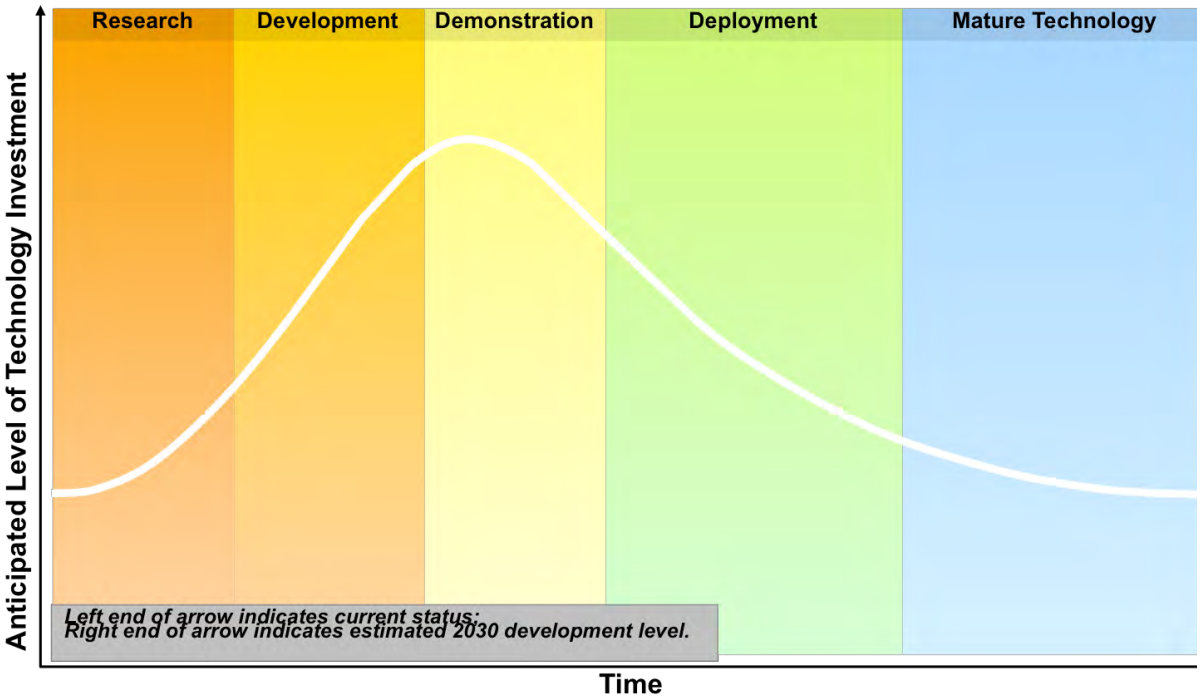

Figure 131: Technology development curve

For any technology to advance from an initial concept or the early phases of R&D, someone will have to bear the significant cost and risk to carry the project to demonstration. However, once a technology is developed and the 'bugs' are worked out, subsequent installations benefit from the accumulation of lessons learned.

As a technology moves along the continuum of development, the accuracy of performance and cost estimates tends to improve. At the R&D level, technologies face a high degree of both technical and estimation uncertainty. The bandwidth of the uncertainty depends on the number of new and novel parts in the technology and the degree of scale-up needed to reach commercial-scale application.

The status of a technology, based on the maturity of its components, is critical in meeting the cost and performance estimates when scaling up from pilot to demonstration to commercial. Figure 132 illustrates, in general, the sequence of steps and the potential impact on cost.

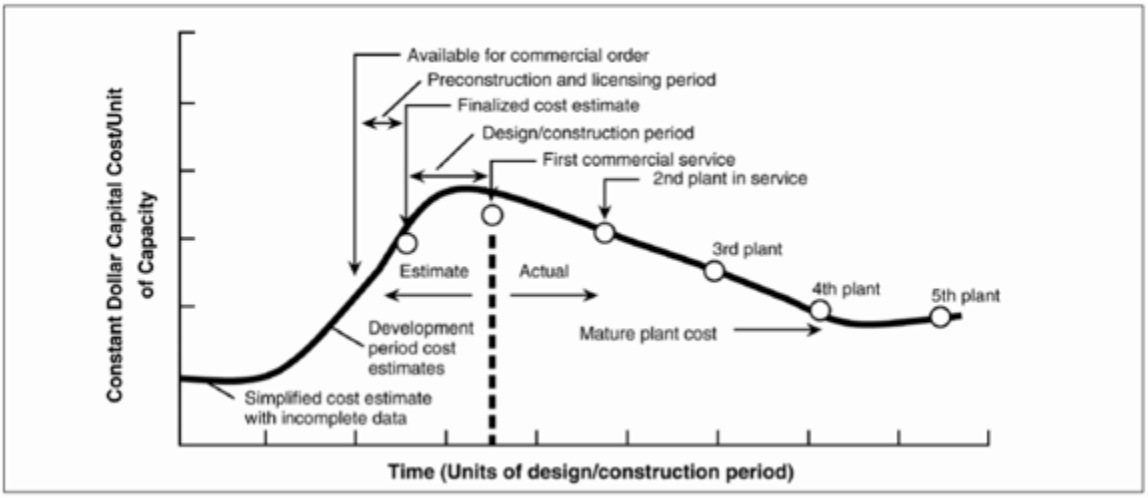

Figure 132: General capital cost learning curve

Technical readiness levels (TRLs) are a different set of metrics that enable the assessment of the maturity of a particular technology and the consistent comparison of maturity between different types of technology—all in the context of a specific system, application and operational environment. Table 92 provides a high-level description of the TRL scale, showing the progression from basic research (TRL-1) to system operations (TRL-9). Figure 133 shows an example timeline of particular TRLs.

Table 92: Technology readiness level descriptions

Technology readiness level	Description
TRL-9	Commercial operation
TRL-8	Demonstration at >25% commercial-scale
TRL-7	Pilot plant at >5% commercial-scale
TRL-6	Process development unit (0.1% to 5% of full-scale)
TRL-5	Component validation in relevant environment
TRL-4	Component tests in lab
TRL-3	Proof of concept
TRL-2	Application formulated
TRL-1	Basic principles observed

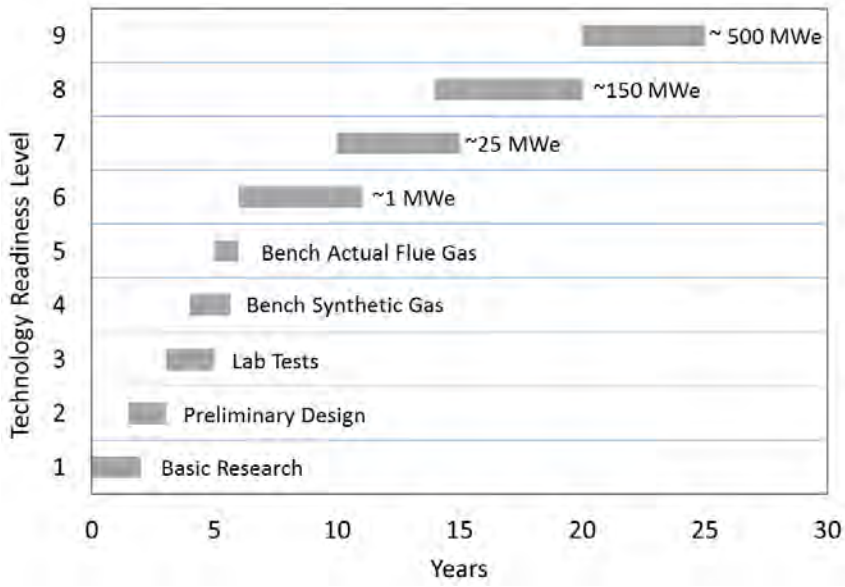

Figure 133: Example development timelines

'Learn by doing' or 'experience' curves describe the phenomenon of cost reductions due to experience. These curves describe the cost reductions associated with the learnings from the first commercial service plant to the *n*th-of-a-kind plant in the capital learning curves and represent the right hand side of the technology development curve.

For the three technologies shown on the learn-by-doing curve in Figure 134, the initial starting costs are different, although the slopes are similar for the initial learning phases. Different technologies will have different timescales for the cost reductions and the fully mature or *n*th plant final costs.

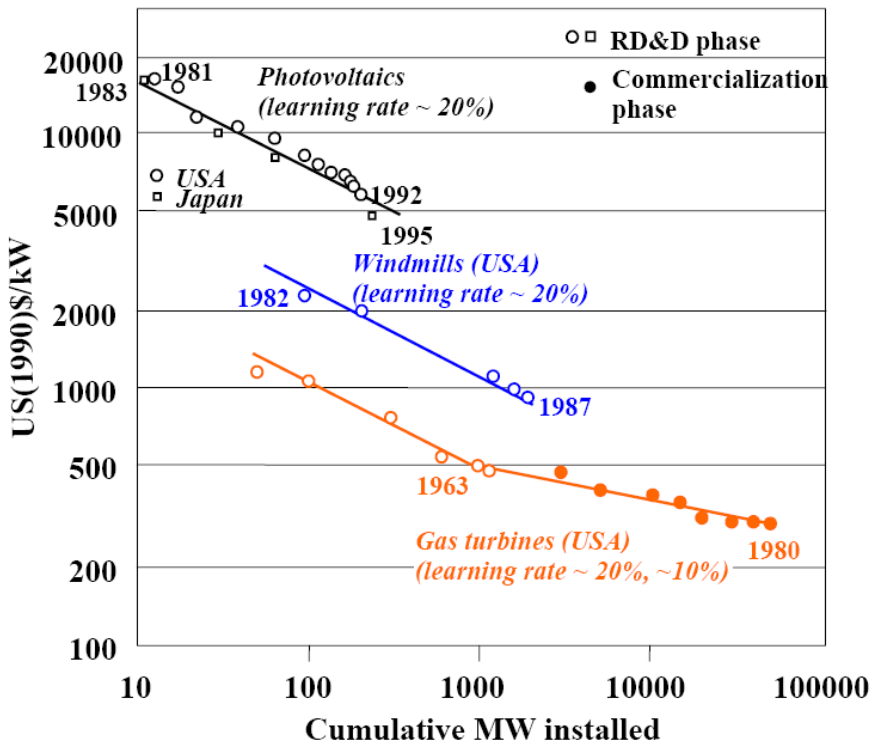

Figure 134: Learn by doing

19 REGIONAL COST STUDY

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19.1 Introduction

WorleyParsons was tasked with developing factors to be used in converting capital cost estimates developed by others from a US Gulf Coast (USGC) cost basis to an Australian cost basis.

WorleyParsons developed factors for a reference location in the Hunter Valley, New South Wales, as well as regional variability factors for locations in Victoria, central Queensland (Surat Basin) and south-western Western Australia.

19.2 Currency exchange rates

All factors pertaining to material costs and labour rates are presented on a US dollar basis and may be affected by changes in the currency exchange rate. The rate of exchange used in developing the cost factors is A$1.30 to US$1.00 (at approximately 30 June 2015).

Note that the relationship between the exchange rate and the conversion factors is not necessarily linear. The relationship depends in part on the ratio of local to foreign content.

19.3 Methodology

The factors were developed in close collaboration between WorleyParsons' US-based and Australia-based estimating teams.

19.3.1 Labour productivity factors

The labour productivity factors reflect the standard experience-based factors used by WorleyParsons' in-country personnel to convert from USGC productivity to specific project locations in Australia.

19.3.2 Crew rate factors

All-inclusive crew rates were developed for the USGC and for each of the Australian locations. In general, the crew rates include:

- base wages
- fringe benefits
- payroll taxes and insurance
- contractor's supervision
- indirect craft
- travel and living allowances (where required)
- premium time (overtime) associated with the anticipated working week
- site office

- small tools and consumables
- construction equipment
- safety
- balance of construction indirects
- contractor's overhead and profit.

The USGC rates are based on published wages and fringe benefits for 'merit shop' labour (labour under conditions based on law but not necessarily a union agreement) and include premium time costs associated with a 50-hour working week. No additional allowances are included for either travel or living expenses or for incentives to attract craft labour.

The Australian rates are based on labour agreements in place for 2015 for each of the specified regions. They include overtime associated with the anticipated working week as well as travel and living allowances appropriate for the region. The Australian rates were developed in A$ and converted to US$ at the exchange rate noted above.

Crews are grouped by discipline and multiplied against the associated crew hours from a representative non-specific power plant to arrive at the discipline averages.

19.3.3 Material cost factors

The methodology used for calculating the material cost factors varies by discipline and takes into account the availability of locally sourced equipment and materials compared with those items that are typically imported into Australia. In general, mechanical and electrical equipment items, instrumentation and valves are considered to be imported. The rest of the bulk material items are generally considered to be available in-country.

Material cost factors for the imported items include an adjustment for overseas freight of 8%. No adjustments are made for inland freight on imported items, as the reference USGC pricing is expected to include delivery to the site.

The material cost factor for concrete (complete) is based on a direct comparison of 2015 pricing between the USGC and Australia.

A direct pricing comparison was also done for structural steel (fabricated). The results indicated a significantly higher cost for in-country fabricated steel relative to the United States—as much as 1.5 for the Hunter Valley and even more for the other locations. However, for large projects, it is expected that worldwide sourcing would be considered, keeping the pricing levels more on par with the United States. Import duty is generally 5%; however, Australia has signed a number of free trade agreements, so there can be variations to duties depending on the country of origin.

For the remainder of the bulk material items, the costs were escalated based on the appropriate rates for the respective country, and the escalated costs were spot-checked for reasonableness. The Australian costs were then converted to US dollars for comparison to the US costs.

19.4 Hunter Valley cost factors

The Hunter Valley cost factors are shown in Table 93.

Table 93: Hunter Valley cost factors

	Hunter Valley vs. USGC			
Discipline	**Labour productivity factor**	**Crew rate factor**	**Material cost factor**	**Currency exchange rate (A$:US$)**
Civil	1.40	1.49	1.20	1.30
Electrical bulks	1.40	1.52	1.16	1.30
Electrical equipment	1.40	1.70	1.08[a]	1.30
Insulation	1.40	1.65	1.02	1.30
Instrumentation and controls	1.40	1.70	1.08[a]	1.30
Mechanical equipment	1.40	1.87	1.08[a]	1.30
Piping and valves	1.40	1.80	1.07	1.30
Concrete	1.40	1.50	1.50	1.30
Structural steel	1.40	1.55	1.13[b]	1.30

a: Based on US costs (inclusive of domestic freight), modified to include overseas freight at 8%.
b: Based on US costs (inclusive of domestic freight), modified to include overseas freight at 8% and import duty at 5%.

19.5 Regional sensitivities

Similarly to the Hunter Valley factors, each of the regional labour productivity and individual discipline crew rate factors was initially developed relative to the USGC. They were then adjusted to set Hunter Valley as the reference case at a factor of 1.00. Regional material cost factors were evaluated relative to Hunter Valley only. They are shown Table 94.

Table 94: Regional sensitivities—Hunter Valley versus other regions

		vs. Hunter Valley		
Factor	**Hunter Valley (reference)**	**Queensland**	**Victoria**	**Western Australia (south-west)**
Labour productivity	1.00	1.21	0.93	1.00
Weighted average crew rate	1.00	0.92	1.07	0.89
Material cost				
Civil	1.00	1.22	1.00	1.29
Concrete (complete)	1.00	1.14	1.06	1.14
Balance of equipment and materials	1.00	1.02	1.00	1.00

Expanded tables showing the individual discipline crew rate factors as well as the weighted average crew rate and labour productivity factors relative to both the USGC and the Hunter Valley are presented in Section 19.8

Similarly to the United States, local pricing for civil commodities and concrete will vary by region. The costs of the rest of the equipment and materials are expected to remain relatively constant. The 2% increase shown for Queensland reflects an increase in the average cost of inland transportation of 4–6%.

Costs for locally fabricated structural steel in Queensland, Victoria and Western Australia are all higher than in the Hunter Valley. However, as with the Hunter Valley, it is expected that worldwide sourcing would be considered.

For the Hunter Valley, Victoria and Western Australia, the working week is on a rotating schedule: 56 hours over 6 days, followed by 46 hours over 5 days, for an average of 51 hours/week. The working week for Queensland varies slightly at 56 hours over 6 days, followed by 47.6 hours over 5 days, for an average of 51.8 hours/week.

All rates include allowances for travel, meals and living away from home (Queensland having significantly more travellers than the other locations). No allowances have been included for labour camps; it is expected that adequate housing will be available in the surrounding areas. As project sites become more remote, this would need to be re-evaluated on a case-by-case basis.

19.6 Comparison to published data

A comparison of the factors developed for the Hunter Valley against published information on labour productivity and crew rates re-affirmed WorleyParsons' findings. The primary references were Cost Data On Line Inc., Richardson Products, *International cost factor location manual, 2014–2015 edition* ('Richardson') and Compass International, *Global construction costs yearbook* ('Compass').

19.6.1 Labour productivity

With regard to labour productivity, the USGC has been the most studied region in the United States. It is basically considered to be the gold standard for US labour productivity. With only minor exceptions, it has the best in the country. This, coupled with the generally lower cost of merit shop labour in that region, makes it a commonly used reference against which labour productivity and labour costs are measured.

Both Richardson and Compass provide high-level information on relative productivity factors (multipliers) for a number of cities in the US and around the globe. Richardson also provides a 30-city US average. Richardson does not include a specific rate for the USGC, but does include a couple of cities considered to fall within the region. The Richardson US 30-city average productivity factor (based on open shops) is roughly 1.10, as compared to its USGC cities. Compass indicates that open-shop productivities relative to the USGC generally range from 1.0 to 1.15. The Compass factors for union productivity are even greater, ranging from 1.05 to 1.4, with most falling in the range of 1.1 to 1.2. It should be noted that the higher factors associated with union work are not a reflection of the worker's capabilities or skill level; rather, they reflect the impact of union work rules.

The experience-based productivity factors presented in this report are not inconsistent with the published information. Richardson indicates average productivity factors versus the USGC of 1.3 each for Melbourne, Sydney and Perth. The comparable factor for Victoria (see Section 19.8) is identical at 1.3; the factors for the Hunter Valley and Western Australia are only slightly higher at 1.4. The Queensland factor is significantly higher at 1.7; however, this is the most remote location and requires the greatest percentage of travellers (non-local labour).

Compass provides productivity factor ranges. The factors for Australia versus the USGC range from 1.05 for 'good' to 1.5 for 'poor'; the average is 1.2. For international power projects, WorleyParsons generally expects the average productivity factor to be somewhat greater than the published average values.

19.6.2 Crew rates

Richardson also provides average crew rates for a number of cities in the US and around the globe, along with a US average. Note that the average crew rates represent a straight average of the individual rates for a number of typical project crews, rather than a weighted average based on a distribution of hours by crew. The rates are also not as comprehensive as the rates developed for WorleyParsons' analysis. However, the Richardson average rates are developed on a consistent basis and so are good for estimating relative cost ratios.

Richardson does not include a specific rate for the USGC. For this comparison, WorleyParsons used the average of the rates for Houston and New Orleans to approximate a Gulf Coast cities value.

Table 95 presents a comparison of the Richardson and Hunter Valley crew rate factors using both the Gulf Coast and the Richardson US average as a base. The comparison to the US average has been included to highlight the large variance between it and the USGC. Note that the information for Sydney has been adjusted to be consistent with the exchange rate of A$1.30:US$1.00 used as the basis for this report.

Table 95: Regional sensitivities—Gulf Coast versus US average

Crew rate factors	vs. Gulf Coast cities	vs. US average
Gulf Coast cities	1.00	0.51
US average	1.96	1.00
Sydney	1.84	0.94
Hunter Valley (see Section 19.8)	1.73	0.88

As shown Table 95, the weighted average crew rate factor for the Hunter Valley compares reasonably with that for Sydney. A similar analysis of the crew rate factors for Melbourne and Perth versus the Gulf Coast found them to also compare favourably with the weighted average factors for Melbourne and Western Australia as presented in Section 19.8.

WorleyParsons did a further analysis to compare wage rates (payroll rates plus fringe benefits only). For this comparison, WorleyParsons referenced RS Means (2015), *Labor rates for the construction industry*, 42nd annual edition, 2015 ('Means'). Means publishes union wage rates for numerous cities throughout the United States, as well a set of wage rates representing the average of 30 major US cities.

The analysis was performed in US$ and was prepared using the same distribution of man-hours by crew as was used to generate the weighted average crew rate factors presented in Section 19.8.

The results showed that the weighted average wage rate for the Hunter Valley compares very closely, within approximately 3%, to that estimated using the Means US 30-city average wage rates for union construction. Also, the wage rate factor for the Hunter Valley versus the USGC is very close to the crew rate factor.

Note that union wage rates for cities along the Gulf Coast are generally higher than the merit shop rates for the same locations. This is due mostly to more costly fringe benefit packages.

19.7 General

It is common for estimates to be developed by applying conversion factors to a reference estimate. However, estimate factors have some limitations and it is important to recognise that using this approach generally results in a slight degradation of overall estimate accuracy.

Factors developed for estimate conversion purposes are considered to be 'point factors'; that is, they represent a specific point in time. These factors can change quickly and markedly based on both worldwide and local market conditions, such as supply and demand, fluctuations in international commodity pricing, fluctuations in exchange rates, political unrest, project-specific equipment/material sourcing requirements, and so on. Users of this report should consider these elements and make the appropriate adjustments or add the appropriate qualifiers to the factored estimate.

Consideration must be given to the basis of the reference estimate used for conversion to ensure that no material differences exist between its basis and the basis used to develop the cost factors.

A good example of the potential volatility of conversion factors would be the construction boom that occurred in Australia, but which has since subsided. During that time, the large volume of construction projects resulted in labour shortages, necessitating the implementation of 60-hour working weeks simply to attract craft labour. In addition, during the 2011–2012 time frame, the Australian dollar had grown stronger than the US dollar. Either of those events alone would have resulted in an increase in the cost factors relative to the USGC; compounding their effects increased the impact even further. Using the cost factors developed to evaluate the project costs during this boom period would have resulted in the US dollar costs being significantly understated. Likewise, using cost factors reflective of market conditions in effect during the boom period to evaluate costs in today's environment would result in an overstatement of the US dollar costs.

19.8 Comparative data

Table 96: US Gulf Coast versus Australian regions comparative table

	vs. USGC			
Factor	**Hunter Valley**	**Queensland**	**Victoria**	**Western Australia (southwest)**
Labour productivity	1.40	1.70	1.30	1.40
Crew rate factors				
Civil	1.49	1.36	1.61	1.28
Electrical bulks	1.52	1.42	1.63	1.41
Electrical equipment	1.70	1.58	1.83	1.57
Insulation	1.65	1.50	1.79	1.44
Instrumentation and controls	1.70	1.58	1.81	1.55
Mechanical equipment	1.87	1.74	1.99	1.67
Piping and valves	1.80	1.66	1.92	1.58
Concrete	1.50	1.35	1.60	1.27
Structural steel	1.55	1.42	1.65	1.36
Weighted average crew rate	1.73	1.59	1.84	1.53

Table 97: Hunter Valley versus other regions comparative table

	vs. Hunter Valley			
Factor	**Hunter Valley**	**Queensland**	**Victoria**	**Western Australia (southwest)**
Labour productivity	1.00	1.21	0.93	1.00
Crew rate factors				
Civil	1.00	0.91	1.08	0.85
Electrical bulks	1.00	0.93	1.07	0.92
Electrical equipment	1.00	0.93	1.07	0.92
Insulation	1.00	0.91	1.09	0.88
Instrumentation and controls	1.00	0.93	1.06	0.91
Mechanical equipment	1.00	0.93	1.06	0.89
Piping and valves	1.00	0.92	1.07	0.88
Concrete	1.00	0.9	1.07	0.85
Structural steel	1.00	0.92	1.06	0.88
Weighted average crew rate	1.00	0.92	1.07	0.89

20
CO_2 TRANSPORT AND STORAGE CASE STUDIES

The authors of this chapter are Professor Dianne Wiley, Dr Peter Neal, Dr Minh Ho and Dr Gustavo Fimbres Weihs from UNSW Engineering.

The authors thank CarbonNet, Coal Innovation NSW, CTSCo, the Western Australian Department of Mines and Petroleum and Dr Charles Jenkins for invaluable input to this chapter. They also thank Anggit Raksajati and Zikai Wang for assistance with calculations.

CO_2 transport and storage case studies—highlights:

- The total plant cost (excluding owner's and risk-adjusted costs) for CO_2 transport, injection and monitoring is likely:
  - to vary between $5/t and 14/t injected for cases involving short transport distances to storage formations with good characteristics
  - to approach $70/t injected for cases involving transporting small volumes of CO_2 over long distances to storage formations with poorer characteristics.
- Variations in injection performance and materials costs can have a significant impact on costs. By optimising capture, transport and injection together, it may be possible to achieve lower costs.
- Depending on the split between injection and transport costs, projects may be more sensitive to geological or economic uncertainties.

20.1 Introduction

This chapter provides estimates of the costs of CO_2 transport and injection for a selection of possible projects in Australia, as developed in conjunction with stakeholders. As this is a scoping study, the design of the projects has not been evaluated or optimised in detail, as would be required for a full feasibility study. The costs presented are total plant costs and do not reflect the total project costs, which include additional owner's and contingency costs for proving up storage sites, undertaking the required front-end engineering and obtaining project approvals (see Chapter 17 for more details on this). The total project costs may also include extra risk-adjusted costs.

The emission sources are assumed to be hubs where high-purity CO_2 has been collected from power plants and compressed to a maximum of 15 MPa ready for introduction to the pipeline for transport. The cost estimates therefore exclude the costs of CO_2 capture and compression.

Source hubs and storage sites included in this evaluation are listed in Table 98, while Figure 135 and Figure 136 show maps of the sources, the approximate pipeline routes and the storage sites for the east and west coasts, respectively.

Table 114 (in Chapter 21) provides the data used for the case studies, including source hub locations and the flow-rate of CO_2 to be injected in Mt/y, storage site characteristics and lengths of onshore and offshore transport pipelines. For most storage sites, a number of different injection horizons have been evaluated. The cases consider both transporting from a single hub to a single storage site (single-source cases) and combining CO_2 from two hubs before injection (multiple-source cases). In the multiple-source cases, the performance and cost calculations cover taking CO_2 from the two sources to a junction point and then from the junction point to the storage site.

Figure 137 plots the permeability and thickness of the storage sites considered in this study, along with data from various existing storage projects. This plot estimates the expected injectivities and has been proposed as a screening tool for storage sites.[1] The figure is divided according to the product of permeability and thickness into three regions:

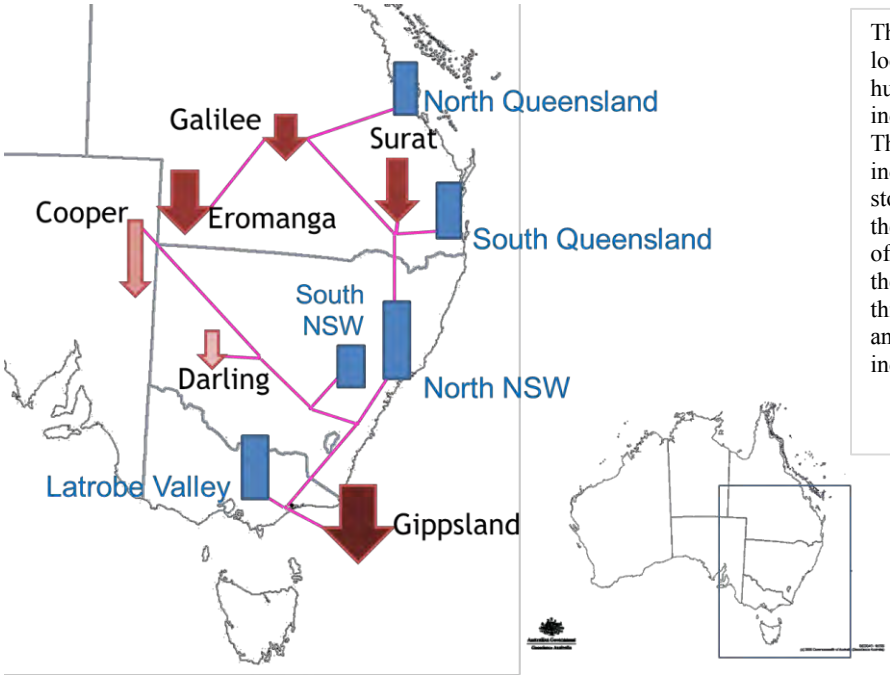
- Type 1 sites have very high injectivities (greater than 10 Mt/y per well).
- Type 2 site have injectivities in the order of 1 Mt/y per well.
- Type 3 sites have injectivities less than 1 Mt/y per well.

The figure indicates that almost all of the storage sites considered are in the Type 1 or 2 regions. However, as discussed in Section 10.3.2, consideration must also be given to parameters such as formation pressure, fracture pressure, porosity and areal extent before determining a final estimate of injectivity.

Table 98: Source hubs and storage sites for case studies

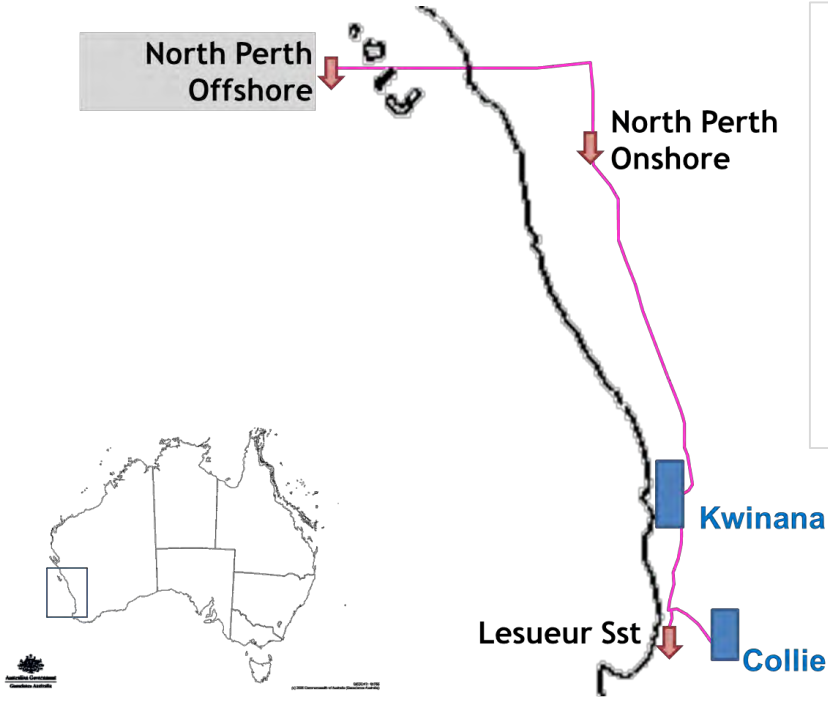
Source hubs	Storage sites
• Latrobe Valley, Victoria • East Victoria • South Qld (East Surat) • North Qld (Gladstone–Rockhampton) • North NSW (Hunter Valley–Newcastle) • South NSW (NSW West–Lithgow) • Southwest WA (Collie) • Kwinana WA	• Gippsland (nearshore, intermediate and basin centre) • Surat (shallow, mid-depth and deep) • Eromanga (shallow, mid-depth and deep) • Galilee (shallow, mid-depth and deep) • Darling (Pondie Range average core and average mini-DST) • Cooper (shallow, mid-depth and deep) • North Perth Offshore (shallow, mid-depth and deep) • North Perth Onshore (shallow, mid-depth and deep) • Lesueur Sandstone (shallow, mid-depth and deep)

[1] N Hoffman, G Carman, M Bagheri, T Goebel (2015), *Site characterisation for carbon sequestration in the near shore Gippsland Basin*, Victorian Department of Economic Development, Jobs, Transport and Resources, Melbourne, Australia.



The blue bars show indicative locations for the emissions hubs. The height of the bar indicates the emission size. The red arrows show indicative locations for storage sites. The length of the arrow indicates the depth of the formation; the width of the arrow indicates the thickness of the formation; and the intensity of colour indicates the permeability.

Figure 135: East coast emissions, storage basins and pipelines evaluated



The blue bars show indicative locations for the emission hubs. The height of the bar indicates the emission size. The red arrows show indicative locations for storage sites. The length of the arrow indicates the depth of the formation; the width of the arrow indicates the thickness of the formation; and the intensity of colour indicates the permeability.

Figure 136: West coast emissions, storage basins and pipelines evaluated

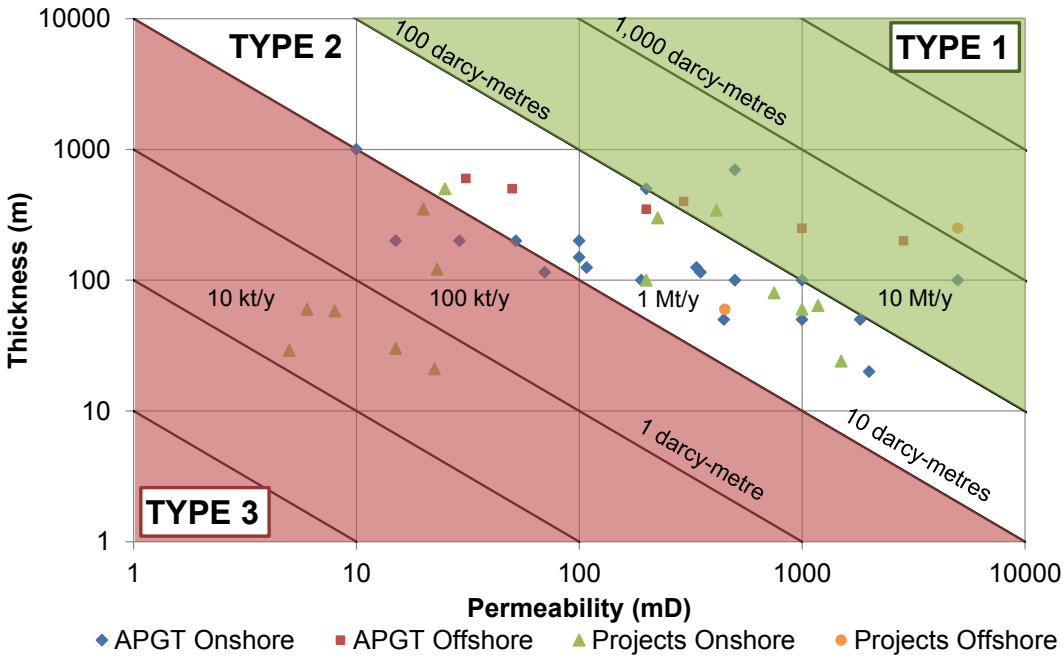


Figure 137: Thickness–permeability cross-plot for storage horizons considered in this study, along with existing projects under development and operation

Source: Adapted from NG Hoffman, G Carman, M Bagheri, T Goebel (2015), *Site characterisation for carbon sequestration in the near shore Gippsland Basin*, Victorian Department of Economic Development, Jobs, Transport and Resources, Melbourne.

20.1.1 Performance data assumptions and methodology

The key transport and storage performance data required for cost estimates include the booster pump duty along the pipeline, the number of injection wells, the flow-rate of CO_2 and the amount of CO_2 emissions avoided.

The booster pump duty for the case studies is calculated using Figure 107, where the duty is a function of the discharge pressure and CO_2 flow-rate. The discharge pressure is the same as the pipeline inlet pressure and is calculated in the same way as in Figure 103. In general, because the CO_2 is assumed to be delivered by the capture plant at a pressure of 15 MPa, initial boosting is not required. In some cases, the required inlet pressure for transport and injection is less than the delivery pressure. In practice, for those cases, the delivery pressure from the capture and compression plant would therefore be reduced.

As mentioned in Section 10.3.1, the cost of supplying energy for the booster pumps in remote areas will be more than the cost in built-up areas or close to electricity grids. Therefore, in the case studies, booster pumps have not been used off shore and have been used as little as possible on shore.

Well numbers are estimated using MonteCarbon (as described in Section 10.3.2). The estimates are based on the best knowledge at this point in time from stakeholders and the literature. On the advice of stakeholders, the maximum injection rate for each well is set at 2 Mt CO_2/year. For storage sites with small areal extents (such as Gippsland Inshore), the restriction of injection to 25% of areal extent (see Section 10.3.2) is overridden and wells are placed over the entire area. Without this, the number of wells may be significantly overestimated. This approach is appropriate because the 25% assumption applies more properly to basin-scale assessments of injection rather than those targeting individual sinks.

In line with published estimates,[2] each of the storage sites is assumed to have enough capacity for injection at the selected rates over 30 years. As these are high-level estimates, more detailed modelling and reservoir characterisation would be needed to estimate capacity at a level suitable for a FEED study or FID. Although our approach determines the maximum injection rates on the basis of injection pressure constraints, the available pore volume is factored into the calculations. This is because the pore volume (and thus the volumetric capacity) is a function of the thickness, areal extent and porosity, all of which are also important to the estimation of injection rates.

The pipeline diameters have been chosen to minimise the total cost of transport and storage per tonne of CO_2 avoided for the given number of wells and a maximum pipeline pressure of 15 MPa. It may be possible to obtain lower costs than are presented here by optimising the entire CCS chain from capture to injection and increasing the maximum working pressure to 18 MPa or 25 MPa within the maximum allowable working pressure of the 1500 lb flange.

The flow-rate of CO_2 from each of the hubs (see Section 21.6) has been chosen in consultation with stakeholders and reflects current projections of the amounts of CO_2 to be captured from those regions and stored. For the case studies, the flow-rate has been assumed to be constant over the life of the project. If the CO_2 flow-rate were not constant but increased over time, the underutilisation of the pipeline in the early years of the project would increase the cost per tonne of CO_2 injected.

To determine the amount of CO_2 avoided, the emissions from the energy required for all transport and injection operations (primarily recompression) is assumed to come from the electricity grid: the NEM for the east coast and the stand-alone WEM for the west coast. The average CO_2 emissions from the grid was assumed to be 0.894 t/MWh.[3]

Thus, the amount of CO_2 avoided is calculated using

$$CO_2 \text{ avoided (Mt/y)} = CO_2 \text{ injected (Mt/y)} - CO_2 \text{ emitted due to energy usage (Mt/y)}$$

For the case studies, the difference between the amount of CO_2 injected and CO_2 avoided is small (less than 1%). This is because the only emissions are from the energy required for the booster pumps (if they are needed) and the booster pump duties are small. If the energy required for the capture and compression of CO_2 were included, the difference between the amount of CO_2 injected and CO_2 avoided would be significant.

20.1.2 Cost data assumptions and methodology

Table 99 lists the economic assumptions used to calculate the total plant costs for transport and storage, averaged over the 30-year project lifetime, and is consistent with the methodology described in Chapter 17.

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[2] BE Bradshaw, LK Spencer, AC Lahtinen, K Khider, DJ Ryan, JB Colwell, A Chirinos, J Bradshaw (2009), *Queensland Carbon Dioxide Geological Storage Atlas*, Geological Survey of Queensland, Indooroopilly, Queensland, Australia; Carbon Storage Taskforce 2009, *Basin montages*, Department of Resources, Energy and Tourism, Canberra, Australia.

[3] http://www.aemo.com.au/Electricity/Settlements/Carbon-Dioxide-Equivalent-Intensity-Index (accessed October 2015).

The costs for the case studies are broken down along the same lines as the building blocks in Chapter 10:

- transport (bare erected costs for pipelines and booster pumps)
- injection (bare erected costs for wells and facilities)
- on-costs (design, engineering, environmental assessment, site/project supervision/management/logistics fees and equipment/project contingencies)
- monitoring and verification
- energy costs for powering the booster pumps

The average cost per tonne of CO_2 injected or per tonne of CO_2 avoided for the 30-year project is calculated using:

$$\text{Unitised building block cost (\$/tonne } CO_2 \text{ injected or avoided)} = \frac{\text{CCR x TPC} + \text{FOM}}{CO_2 \text{ injected or avoided}}$$

$$\text{Unitised on–costs (\$/tonne } CO_2 \text{ injected or avoided)} = \frac{\text{CCR x On–cost}}{CO_2 \text{ injected or avoided}}$$

$$\text{Unitised MMV cost (\$/tonne } CO_2 \text{ injected or avoided)} = \frac{\text{MMV cost}}{CO_2 \text{ injected or avoided}}$$

$$\text{Unitised energy cost (\$/tonne } CO_2 \text{ injected or avoided)} = \frac{\text{Energy cost}}{CO_2 \text{ injected or avoided}}$$

Total unitised transport and storage cost (\$/tonne CO_2 injected or avoided)
= Total unitised building block costs (pipelines, booster pumps, wells, facilities)
+unitised on– costs + unitised MMV cost + unitised energy cost

where,

Unitised building block cost = unitised overnight cost of pipeline, booster, wells or storage facilities

CCR = capital charge rate (%)

TPC = total plant cost ($) = BEC + decom + interest

BEC = overnight bare erected cost for pipeline, booster, wells or facilities ($/y)

Decom = decommissioning cost ($)

Interest = interest paid during construction ($)

FOM = annual fixed operating and maintenance cost ($/y)

MMV cost = annual monitoring and verification cost ($/y)

Energy cost = annual energy cost ($/y)

CO_2 avoided = annual amount of CO_2 avoided (CO_2 avoided/y)

CO_2 injected = annual amount of CO_2 injected (CO_2 avoided/y)

Table 99: Economic assumptions for the transport and storage case studies

Parameter	Units	Values
Nominal cost of equity	% p.a.	11.5
Nominal cost of debt	% p.a.	8.0
Percentage debt	% p.a.	70.0
Inflation	% p.a.	2.5
Company tax rate	% p.a.	30.0
Property tax / insurance	% p.a.	2.0
Analysis year		2015
Currency		A$
Asset book life	y	30
Asset tax life	y	30
Cost of carbon	$/t CO_2 e	0
Real equity	% p.a.	8.8
Real debt	% p.a.	5.4
Nominal before tax WACC	% p.a.	9.1
Nominal after tax WACC	% p.a.	7.4
Real before tax WACC	% p.a.	6.4
Real after tax WACC	% p.a.	4.8
Total capital requirement	$	1.00
Grid power cost (weighted NEM average)	$/MWh	42.5
CO_2 emission intensity (weighted NEM average)	t/MWh	0.894
Capacity factor	%	85
Load factor	hours	7,446
Real capital charge rate (CCR)	%	9.57
On-cost	$million	40% of the bare erected cost
Construction period	years	2

Construction is spread over 2 years before the commencement of project operations. The annual capital expenditure is calculated as the annuity of the costs.

Decommissioning costs are estimated as 25% of the total capital for each building block. It is assumed that decommissioning occurs in the 2 years following the end of the project and may include costs for site remediation and equipment dismantling. The annual decommissioning cost is calculated as the annuity of the present value of the total decommissioning costs.

The fixed O&M cost is calculated as a fixed percentage value of the total bare erected cost for each transport and storage building block. It is assumed that the annual fixed O&M cost is 1% for pipelines, 2% for wells and 4% for the booster pumps and storage facilities. The energy cost is calculated assuming that all the energy/electricity required for the booster pumps comes from the electricity grid at a price of $42.5/MWh.[4] In practice, the energy for booster pumps in remote locations may come from purpose-built facilities with higher costs.

Monitoring and verification include using seismic and VSP; the seismic monitoring is assumed to occur every 5 years, and the monitoring and verification program is assumed to continue for 11 years after the project is decommissioned. The annual monitoring and verification cost is calculated as the annuity of the present value of the total MMV costs.

The cost estimates do not include owner's costs and risk-adjusted costs. Owner's costs may include the costs of storage site exploration and appraisal, field development planning, front-end engineering, approvals, licensing, design work, equipment procurement, contract management, land acquisition and working capital. In general, owner's costs can range from 15% to more than 40% of the total capital cost.[5]

For projects involving CO_2 storage, the costs of exploration and appraisal may be a significant component in their own right. They might increase the transport and storage project costs by amounts ranging from 14%[6] to 25%.[7]

20.1.3 Case study results

Figure 138 and Figure 139 show the cost in average $/t CO_2 injected (at 2015 A$ values) over the 30 years for the single-source to single-sink cases and the multiple-source to single-sink cases, respectively. The cost of each case in terms of $/t CO_2 avoided is shown in Figure 140. Table 115 provides the estimated CO_2 avoided, pipeline inlet and top-hole pressures, booster pump duty, pipeline wall thickness, nominal pipeline diameter and the number of wells required for injection for each case study. The breakdown of total plant and decommissioning costs, the annualised costs, as well as the cost per tonne of CO_2 injected and per tonne of CO_2 avoided are in Section 21.6.

The results show that the transport and storage unitised costs for the single-source to single-sink cases range from less than $10/t to almost $80/t, while the multiple-source to single-sink cases have unit costs in the range of about $15/t to $40/t. For all cases, costs for booster pumps, monitoring and verification, and energy are almost negligible.

These costs (in $/t CO_2 injected) are semi-optimised for the transport and storage of a fixed annual amount of CO_2 over the 30-year project lifetime, assuming that the maximum injection rate per well is 2 Mt/y and recompression is eliminated wherever possible. This is not necessarily the minimum possible cost for each case.

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[4] www.aemo.com.au/Electricity/Settlements/Carbon-Dioxide-Equivalent-Intensity-Index (accessed October 2015).

[5] National Energy Technology Laboratory (NETL) (2011), *Cost estimation methodology for NETL assessment of power plant performance*, NETL; MS Peters, KD Timmerhaus, RS West (2003), *Plant design and economics for chemical engineers*, McGraw-Hill, New York.

[6] PR Neal, W Hou, WG Allinson, Y Cinar (2010), 'Costs of CO_2 transport and injection in Australia', *SPE Asia Pacific Oil and Gas Conference Exhibition*, 3:1490–1502.

[7] W Hou, G Allinson, I MacGill, PR Neal, MT Ho (2014), 'Cost comparison of major low-carbon electricity generation options: an Australian case study', *Sustainable Energy Technologies and Assessments*, 8:131–148.

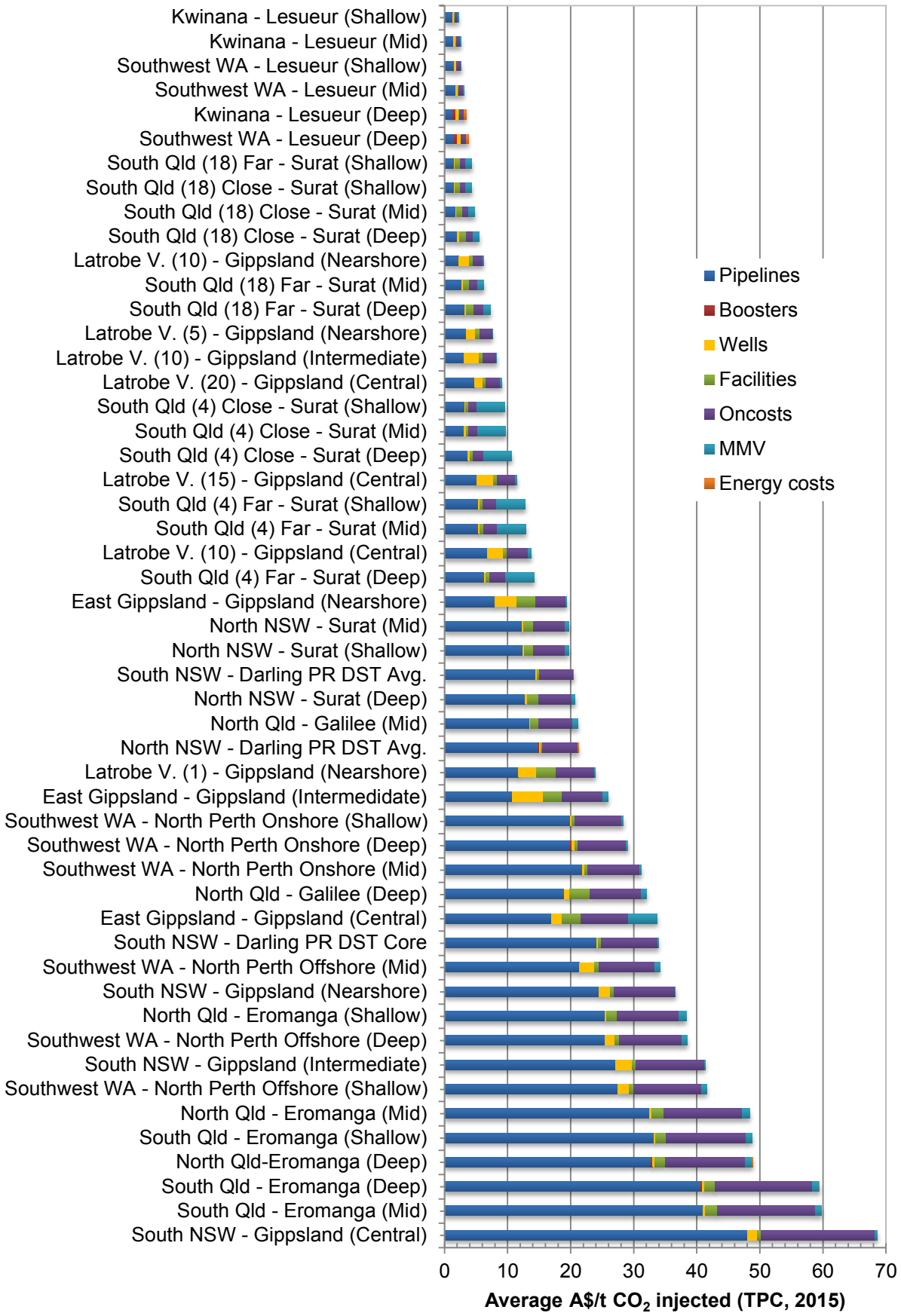


Figure 138: Average total plant cost over 30 years for single-source to single-sink cases

The case studies with the lowest unit costs (less than $15/t) involve taking CO_2 from the Latrobe Valley to the nearshore Gippsland Basin, from south Queensland to the Surat Basin and from Kwinana or south-west Western Australia to the Lesueur Basin (assuming the residual trapping mechanism proposed for this basin can contain the CO2). These cases have low transport costs due to the short distances involved, coupled with low storage costs due to the high injectivity of the formations at the required injection rates of 5–10 Mt/y. Reducing the injection rate to 1 Mt/y for the Latrobe Valley–Gippsland (nearshore) case more than doubles the unit cost of transport and storage.

The most expensive cases (more than $40/t) generally involve very long transport distances and storage in formations with moderate injectivities. These cases include transporting from north Queensland, south Queensland or north New South Wales to the Eromanga Basin and from south-west Western Australia to the North Perth Basin.

For north Queensland, the mid-depth of the Galilee Basin gives the lowest unit cost ($21/t).

For south Queensland, the shallow horizon in the Surat Basin gives the lowest unit cost ($5/t), while for north New South Wales the mid-depth option is the best match ($20/t). Both of these options combine relatively short transport distances and good formation properties. The reason the mid-depth horizon provides a better match for north New South Wales than the shallow horizon is because the greater depth allows for higher injection pressures to accommodate the higher flow-rate from north New South Wales.

For south New South Wales, the Darling site has the lowest unit cost (about $20/t based on the DST average value or nearly $34/t based on the core average), reflecting the high permeability and large injection pressure differential for the formation. When all the emissions from New South Wales are combined, the lowest unit cost ($14/t) is for injection into the deep horizon of the Surat Basin. When the emissions from south New South Wales are combined with those from the Latrobe Valley, the Central Gippsland Basin's higher formation thickness, large areal extent and greater injection depth make it the most attractive horizon at a unit cost of about $18/t.

For the Perth region (south-west Western Australia and Kwinana), the lowest unit cost option in the Lesueur Sandstone is for the mid-depth horizon ($2–3/t). However, there is still work needed to demonstrate that the residual trapping mechanism proposed for the Lesueur can contain the CO_2.

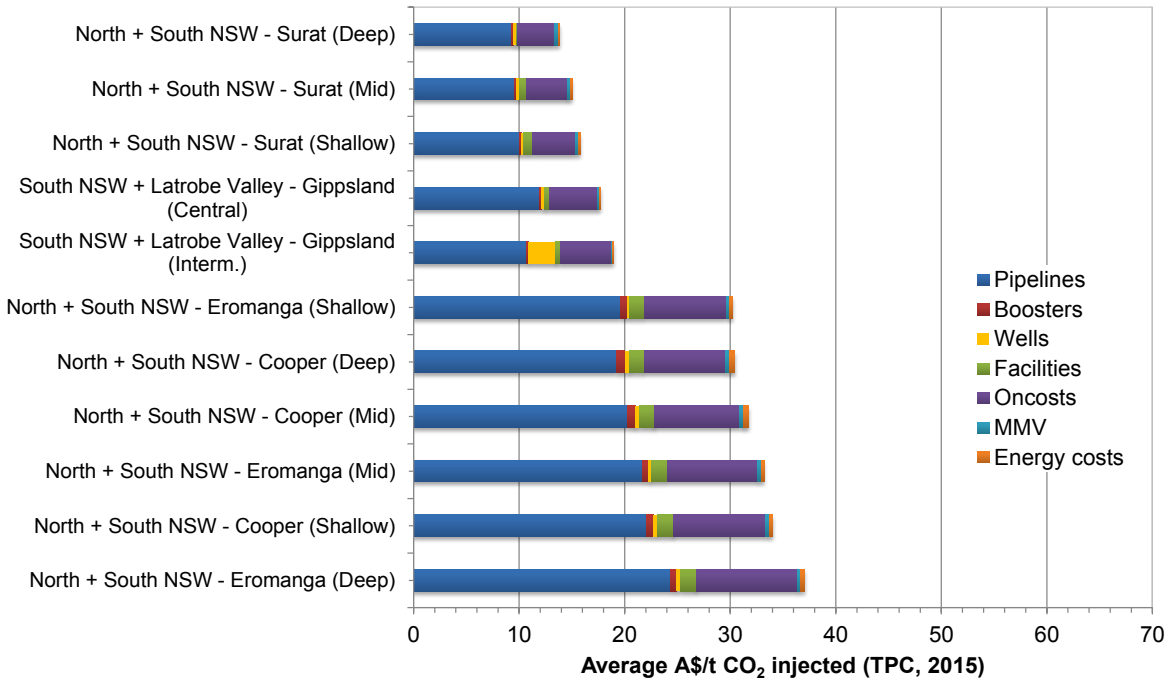


Figure 139: Average total plant cost over 30 years for multiple-source to single-sink cases

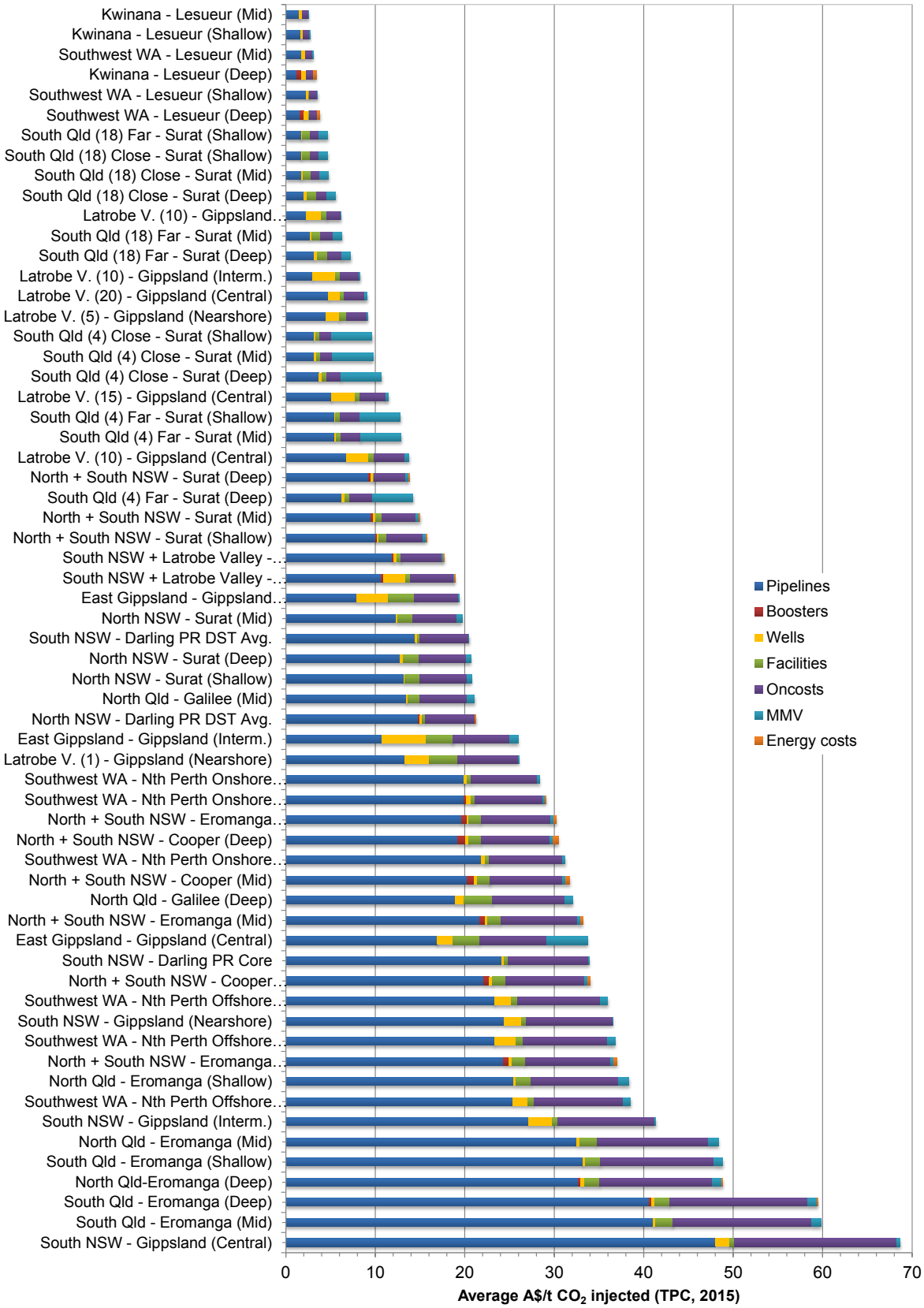


Figure 140: Average total plant cost over 30 years for all case studies

Trade-offs in case study results

Trade-offs between the total compression duty (including the initial compression), pipeline diameter and the number of wells have not been considered in the data presented so far. More detailed evaluation of such trade-offs may lead to lower cost options for each source-to-sink combination.

For example, under the baseline assumptions, injecting 12.9 Mt/y from south New South Wales into the Darling Pondie Range (core) storage horizon using seven wells requires a top-hole pressure of 14 MPa and a 1,350 mm pipeline to keep within the maximum pipeline pressure of 15 MPa. On the other hand, if the number of wells is increased to 14, the top-hole pressure drops to 12 MPa and the pipeline diameter decreases to 1,000 mm. By increasing the number of wells and reducing the pipeline diameter, the total plant cost declines by 33%. As shown in Figure 141, as the number of wells increases, the flow-rate per well decreases, leading to a reduction in top-hole pressure. As the top-hole pressure decreases, smaller diameter pipelines can be used while keeping the pipeline pressure under 15 MPa. The combination of these effects leads to a reduction in the total plant cost until the pipe diameter becomes constant. At that point, the total plant cost begins to slowly increase with the increasing well costs.

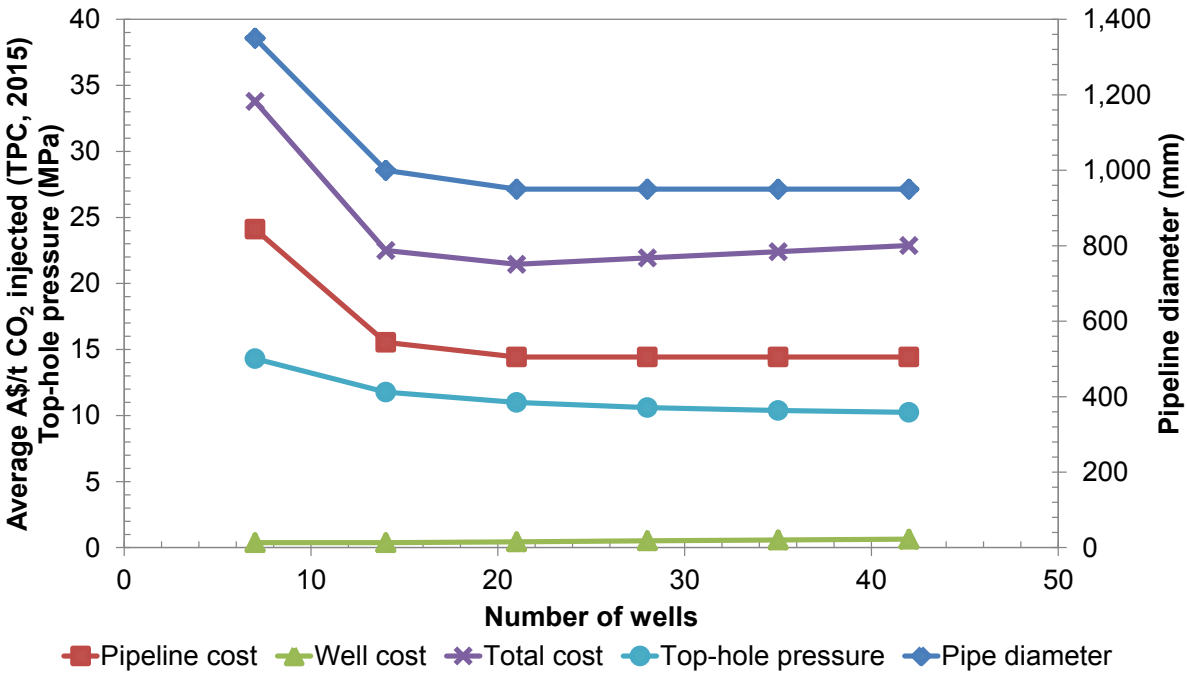


Figure 141: Effects of trade-offs between pipeline diameter and number of wells on the average total plant cost over 30 years for the south NSW to Darling Pondie Range (core) case

The metric of average dollars per tonne of CO_2 injected used in Figure 138 to Figure 140 inherently trades off the total plant costs against the amount of CO_2 transported and stored. This means that cases that are very different in terms of absolute capital costs can have similar unitised costs. For example, the south New South Wales to Darling Pondie Range (DST avg) and north New South Wales to Surat (deep) differ by less than 1% on a $/t injected basis, even though the south New South Wales case is more than $4 billion cheaper in terms of total plant costs (see data in Table 114 through to Table 117 in Chapter 21). This arises because the CO_2 flow-rate from north New South Wales is almost three times that for the south New South Wales case. As a consequence, the south New South Wales case requires a larger pipeline diameter to avoid breaching the fixed 15 MPa MAWP and has more wells injecting more CO_2. These combine to give the north New South Wales case about the same $/t injected cost as the south New South Wales case.

These cases, along with the results of the sensitivity analysis described in Section 20.1.4, show that the total plant cost and the rankings of cases are likely to change if assumptions used in the case studies change. For this reason, it is better to consider groups of ranked cases when analysing case differences, rather than making one-on-one comparisons.

Constraints on injectivity

Of the cases considered, there are a few where the estimated number of wells is very large and cost results are not provided (see data in Table 114 through to Table 117). These cases are north Queensland to Shallow Galilee, north New South Wales to Darling Pondie Range (Core), south New South Wales plus Latrobe Valley to Gippsland (Nearshore), as well as south New South Wales plus north New South Wales to both Darling Pondie Range horizons:

- Based on the assumptions used here, the north Queensland to Shallow Galilee case is found to require very large numbers of wells. This horizon is assumed to be thin (20 m) and shallow (800 m). Thin formations require high injection fluxes (flow-rate per unit perforated area) than thicker formations. Because the formation and fracture pressures diverge with depth, shallow depths have only a small range of allowable pressure. This means that a large number of wells is needed to keep the injection pressures within the allowable limits.
- For the other cases, large injection rates (30–50 Mt/y) combined with small areal extents (200–1,500 km²) result in very high well interference and therefore very large numbers of wells. Although these sites may be suitable for small to large injection operations (1–15 Mt/y), the results suggest that they appear to be unsuitable for very large injection operations. Further detailed studies would be needed to confirm these findings.

Apart from limitations due to injection rates, storage formations may also be subject to geomechanical or geochemical issues, seal integrity issues or total capacity limits. Capacity limits were not imposed in this assessment but are an important consideration for real projects and may place practical limitations on long-term injection in some of the options shown, which have very high injection rates. A consideration of long-term needs requires the evaluation of options such as initially using a smaller capacity site close by and then transferring injection to a more distant, larger capacity site at a later date. Such an assessment would require not only more detailed reservoir modelling but also more detailed modelling of the trade-offs in pipeline routing and compression/recompression requirements to maximise the use of pipeline infrastructure over time.

20.1.4 Sensitivity analysis

The above cost estimates for the case studies are based on fixed assumptions. Changes in the process data, economic assumptions or both will affect the estimates. A sensitivity analysis for variation in the well numbers, capital cost and on-costs is presented here:

- Injectivity is variable across storage formations because they are heterogeneous. Further, there are generally significant uncertainties in the estimate of formation properties. Therefore, well numbers may change as more information is gained about formation properties and as more detailed reservoir storage modelling is completed. To assess the impact of these factors, the case studies are assessed for additional maximum injection rates of 0.5 and 1 Mt CO_2 per year per well.
- The capital costs are varied from the baseline by 30%. Variation in capital costs can arise due to changes in the cost of individual equipment items, the exchange rate, debt-to-equity ratios, final equipment numbers (for example, the number of booster pumps), equipment performance (for example, pipeline thickness), or any combination of these factors.
- The on-cost is varied from the baseline value of 40% of BEC. Values of 5% (representative of very mature technologies and project processes), 25% (representative of less mature technologies and project processes) and 60% (representative of increased contingency and project risk costs). The on-cost reflects the costs for engineering, management and construction in addition to the cost of the equipment. The baseline value of 40% represents the relatively immature stage of development of the CCS industry, despite the relatively mature stage of development of the underlying technology components. As the CCS industry matures, standard engineering design methods and management processes will emerge, and more suppliers, contractors and consultants are likely to enter the marketplace, so on-costs should decrease over time because of greater knowledge, experience and competitive market forces.

The results of the sensitivity analysis are shown in Figure 142 for the single-source to sink cases transporting CO_2 from the Latrobe Valley to the Gippsland Basin and from north New South Wales to the Surat Basin (shallow, mid and deep).

The results indicate that, for the Gippsland Basin cases, the most sensitive factor is the number of wells. This can be attributed to the relatively low baseline number of wells and the relatively high cost of offshore wells. As shown in Figure 138, the cost of wells accounts for about a quarter of the total cost. These cases are therefore approximately one order of magnitude less sensitive to the effects of changes in capital costs and on-costs. On the other hand, the Surat Basin cases show greater sensitivity to the effect of changes in capital cost, followed by the effect of changes in on-costs. This is caused by the large relative component of pipeline costs in the total cost (the pipelines account for around half of the total cost) (Figure 138).

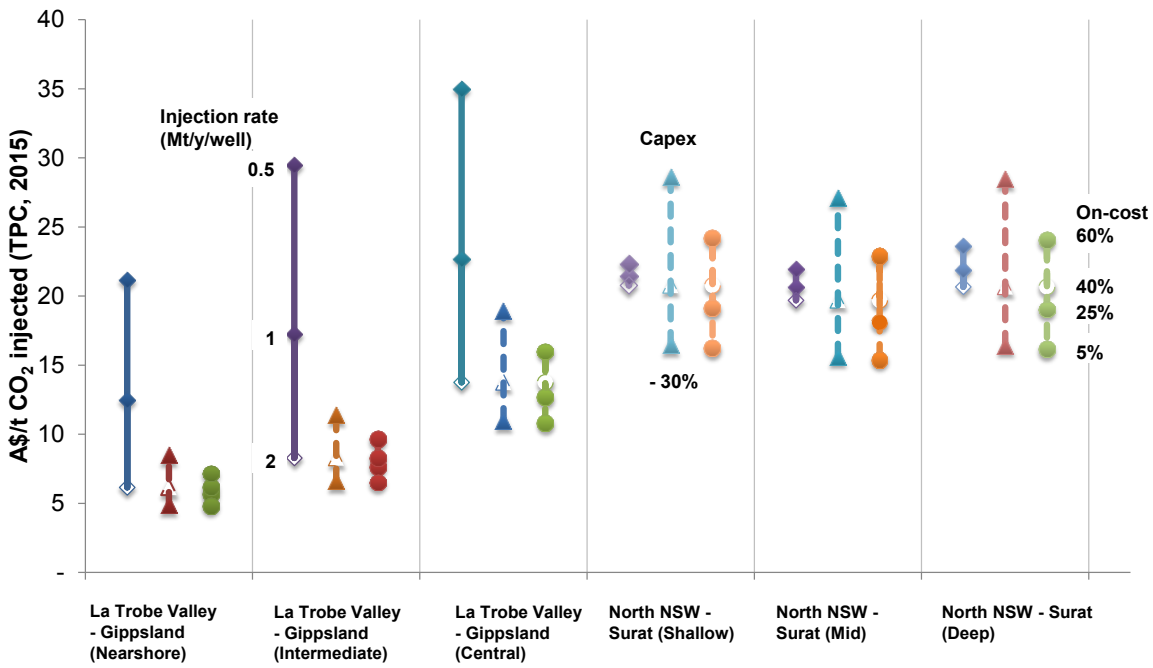


Figure 142: Changes in the average total plant cost over 30 years due to variations in the number of wells, capital costs and on-costs

Note: The diamonds represent the sensitivity values for changes in injection rate, the triangles for changes in capital cost and the circles for changes due to variations in on-costs. The open symbols show the baseline values for each case.

20.2 Conclusions

The data for total plant costs show that cases that combine small transport distances with good injection properties are generally the cheapest. The most expensive practical cases involve large transport distances.

Some of the cases demonstrate that formations will have different maximum injection rates; as injection rates increase, the number of wells needed may become very large.

The sensitivity analysis shows that, depending on the split between injection and transport costs, projects may be more sensitive to geological or economic uncertainties.

The overall design of a transport and storage network needs to consider trade-offs in pipeline and injection design and operation, as well as the interaction with capture.

21

CO_2 TRANSPORT AND STORAGE—ADDITIONAL DATASETS

21.1 Pipelines

This section contains tables of data and equation coefficients for the CO_2 pipeline building blocks.

Table 100: Data and equation coefficients for pipeline diameter as a function of distance and flow-rate for steel grade X70 and flange-class CL1500, as shown in Figure 102

Nominal diameter (mm)		CO_2 flow-rate (Mt/y)									
		1	**3**	**5**	**10**	**15**	**20**	**25**	**30**	**35**	**40**
Pipeline length (km)	17	150	250	300	400	450	500	550	600	650	700
	50	200	300	400	500	550	650	700	750	800	850
	100	200	350	450	550	650	750	800	850	900	950
	200	250	400	500	650	750	850	900	1,000	1,050	1,100
	400	300	450	550	750	850	950	1,050	1,100	1,200	1,250
	600	300	500	600	800	900	1,050	1,150	1,200	1,300	1,350
	800	350	550	650	850	1,000	1,100	1,200	1,300	1,350	1,450
	1,000	350	550	650	850	1,000	1,150	1,250	1,350	1,400	1,500
	1,200	400	550	700	900	1,050	1,200	1,300	1,400	1,450	n/a
	1,400	400	600	700	950	1,100	1,200	1,350	1,450	1,500	n/a
	a	79.3	141	187	233	255	296	315	344	380	406
	b	0.2194	0.197	0.184	0.192	0.201	0.197	0.200	0.198	0.190	0.189
	R^2	0.976	0.994	0.990	0.996	0.997	0.996	0.999	0.998	0.999	0.999

Note: The data in this table have been correlated as a power-law equation of the form $D = aL^b$ where D is the nominal diameter in mm and L is the pipeline length in km.

Table 101: Data and equation coefficients for pipeline pressure gradient as a function of distance and flow-rate for steel grade X70 and flange-class CL1500,

as shown in Figure 103

Pressure drop (MPa/km)		CO_2 flow-rate (Mt/y)									
		1	3	5	10	15	20	25	30	35	40
Pipeline diameter (mm)	200	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	250	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	300	6.69E-02	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	350	2.26E-02	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	400	9.49E-03	8.51E-02	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	450	5.94E-03	5.28E-02	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	500	3.10E-03	2.71E-02	7.61E-02	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	550	1.77E-03	1.50E-02	4.22E-02	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	600	1.06E-03	8.93E-03	2.47E-02	9.72E-02	n/a	n/a	n/a	n/a	n/a	n/a
	650	6.66E-04	5.54E-03	1.52E-02	5.99E-02	1.32E-01	n/a	n/a	n/a	n/a	n/a
	700	4.34E-04	3.61E-03	9.86E-03	4.00E-02	8.84E-02	n/a	n/a	n/a	n/a	n/a
	750	2.92E-04	2.47E-03	6.57E-03	2.64E-02	5.84E-02	1.04E-01	n/a	n/a	n/a	n/a
	800	2.02E-04	1.74E-03	4.55E-03	1.87E-02	4.14E-02	7.36E-02	1.11E-01	n/a	n/a	n/a
	850	1.43E-04	1.24E-03	3.30E-03	1.30E-02	2.88E-02	5.13E-02	8.07E-02	1.13E-01	n/a	n/a
	900	1.04E-04	9.09E-04	2.43E-03	9.36E-03	2.13E-02	3.80E-02	5.74E-02	8.39E-02	1.11E-01	n/a
	950	7.66E-05	6.76E-04	1.82E-03	6.83E-03	1.54E-02	2.74E-02	4.33E-02	6.07E-02	8.42E-02	1.08E-01
	1,000	5.75E-05	5.10E-04	1.38E-03	5.17E-03	1.15E-02	2.10E-02	3.18E-02	4.66E-02	6.19E-02	8.27E-02
	1,050	4.39E-05	3.90E-04	1.06E-03	3.98E-03	8.93E-03	1.56E-02	2.47E-02	3.62E-02	4.82E-02	6.17E-02
	1,100	3.40E-05	3.03E-04	8.27E-04	3.13E-03	6.81E-03	1.23E-02	1.95E-02	2.73E-02	3.80E-02	4.87E-02
	1,150	2.66E-05	2.38E-04	6.51E-04	2.48E-03	5.36E-03	9.57E-03	1.48E-02	2.18E-02	2.90E-02	3.88E-02
	1,200	2.11E-05	1.89E-04	5.18E-04	1.99E-03	4.27E-03	7.56E-03	1.20E-02	1.68E-02	2.34E-02	2.99E-02
	1,250	1.69E-05	1.51E-04	4.16E-04	1.61E-03	3.47E-03	6.06E-03	9.48E-03	1.36E-02	1.90E-02	2.43E-02
	1,300	1.36E-05	1.22E-04	3.37E-04	1.31E-03	2.84E-03	4.86E-03	7.64E-03	1.09E-02	1.49E-02	2.00E-02
	1,350	1.11E-05	9.97E-05	2.75E-04	1.07E-03	2.34E-03	4.02E-03	6.23E-03	9.03E-03	1.23E-02	1.58E-02
	1,400	9.13E-06	8.20E-05	2.27E-04	8.88E-04	1.94E-03	3.35E-03	5.13E-03	7.39E-03	1.00E-02	1.32E-02
	1,450	7.57E-06	6.79E-05	1.88E-04	7.38E-04	1.62E-03	2.80E-03	4.26E-03	6.11E-03	8.25E-03	1.08E-02
	1,500	6.31E-06	5.66E-05	1.57E-04	6.18E-04	1.36E-03	2.36E-03	3.59E-03	5.10E-03	6.86E-03	9.09E-03
a		9.48E9	1.18E11	4.37E11	1.65E12	3.91E12	8.87E12	1.50E13	2.43E13	3.65E13	4.40E13
b		-4.82	-4.87	-4.91	-4.91	-4.92	-4.95	-4.97	-4.98	-5.00	-4.99
R^2		0.999	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

Note: The data in this table have been correlated as a power-law equation of the form $\frac{dP}{dL} = aD^b$ where $\frac{dP}{dL}$ is the pipeline pressure gradient in in MPa/km and D is the nominal diameter in mm.

Table 102: Data and equation coefficients for onshore pipeline capital cost (BEC in 2015) as a function of flow-rate for transport, as shown in Figure 104(a)

Pipeline capex (A$m)		CO_2 flow-rate (Mt/y)									
		1	3	5	10	15	20	25	30	35	40
Pipeline length (km)	17	5.2	8.7	11.0	15.2	17.9	20.6	23.5	26.5	29.7	33.0
	50	19.8	32.3	44.8	60.7	69.2	87.4	97.0	107.0	117.3	128.0
	100	39.6	75.1	105	138	175	214	235	256	278	301
	200	103	179	243	349	428	512	556	648	696	744
	400	258	420	553	856	1,020	1,200	1,390	1,490	1,690	1,800
	600	387	728	937	1,410	1,670	2,090	2,380	2,540	2,850	3,020
	800	601	1,110	1,400	2,050	2,590	2,980	3,380	3,800	4,020	4,460
	1,000	751	1,380	1,750	2,560	3,240	3,970	4,490	5,020	5,300	5,870
	1,200	1,080	1,660	2,330	3,340	4,170	5,070	5,700	6,360	6,700	n/a
	1,400	1,260	2,190	2,720	4,210	5,210	5,920	7,030	7,810	8,210	n/a
a		0.144	0.243	0.333	0.417	0.466	0.568	0.617	0.693	0.799	0.875
b		1.25	1.25	1.24	1.27	1.29	1.28	1.29	1.29	1.28	1.27
R^2		0.999	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

Note: The data in this table have been correlated as a power-law equation of the form $C = aL^b$ where C is the pipeline capital cost in A$m (2015) and L is the pipeline length in km.

Table 103: Data and equation coefficients for offshore pipeline capital cost (BEC in 2015) as a function of flow-rate for transport, as shown in Figure 104(c).

Pipeline capex (A$m)		CO_2 flow-rate (Mt/y)									
		1	3	5	10	15	20	25	30	35	40
Pipeline length (km)	15	59.4	64.6	67.2	71.8	74.2	76.7	80.0	59.4	64.6	67.2
	25	71.4	75.2	78.9	89.2	92.8	97.7	103	71.4	75.2	78.9
	50	94.7	108	120	133	142	161	171	94.7	108	120
	75	128	145	155	186	200	229	245	128	145	155
	100	155	177	201	231	268	307	328	155	177	201
	125	181	224	238	297	345	370	422	181	224	238
	150	207	258	276	346	403	464	495	207	258	276
A		1.104	1.10	1.45	1.57	2.05	2.48	2.83	3.13	3.35	3.74
b		42.92	42.9	38.6	41.3	35.7	26.8	25.0	22.2	21.8	13.7
R^2		0.999	0.997	0.999	0.997	0.995	0.996	0.997	0.997	0.993	0.994

Note: The data in this table have been correlated as a linear equation of the form $C = AL + b$ where, C is the pipeline capital cost in A$m (2015) and L is the pipeline length in km.

21.2 Recompression

This section contains tables of data and equation coefficients for the recompression building blocks.

Table 104: Data and equation coefficients for recompression capital cost (BEC in 2015) as a function of flow-rate, as shown in Figure 106.

CO_2 flow-rate (Mt/y)	Recompression capex (A$m)
1	6.10
3	11.2
5	11.2
10	14.0
15	28.1
20	28.1
25	42.1
30	42.1
35	56.1
40	56.1
a	1.34
b	4.82
R^2	0.971

Note: The data in this table have been correlated as a linear equation of the form $C = aQ + b$ where, C is the pipeline capital cost in A$m (2015) and Q is the CO_2 flow rate in Mt/y.

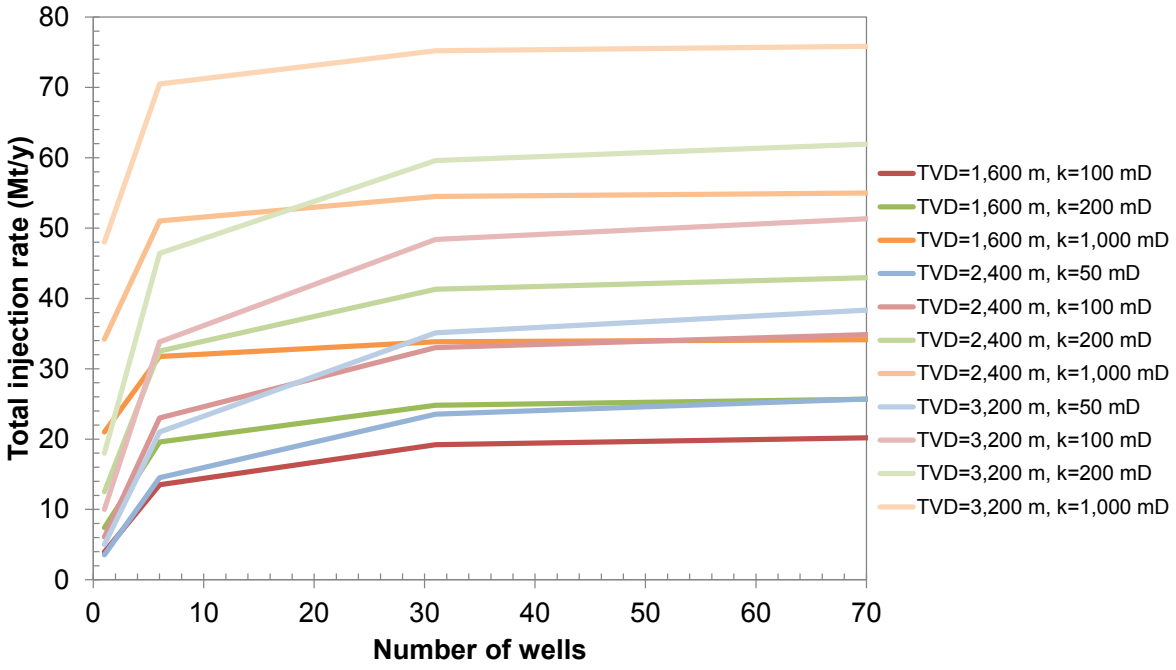
Table 105: Data and equation coefficients for pumping duty as a function of discharge pressure and flow-rate as shown in Figure 107

Pumping duty (MW)		CO_2 flow-rate (Mt/y)									
		1	3	5	10	15	20	25	30	35	40
Discharge Pressure (MPa)	9	0.1	0.3	0.51	1.01	1.52	2.02	2.53	3.03	3.54	4.04
	10	0.15	0.45	0.76	1.51	2.27	3.02	3.78	4.53	5.29	6.05
	11	0.2	0.59	0.99	1.98	2.97	3.95	4.94	5.93	6.92	7.91
	12	0.24	0.72	1.21	2.41	3.62	4.83	6.03	7.24	8.45	9.65
	13	0.28	0.85	1.41	2.82	4.23	5.65	7.06	8.47	9.88	11.29
	14	0.32	0.96	1.61	3.21	4.82	6.42	8.03	9.63	11.24	12.84
	15	0.36	1.07	1.79	3.58	5.37	7.16	8.95	10.74	12.53	14.32
	a	0.503	1.51	2.51	5.03	7.54	10.1	12.6	15.1	17.6	20.1
	b	-1.01	-3.02	-5.03	-10.1	-15.1	-20.1	-25.2	-30.2	-35.2	-40.3
	R^2	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

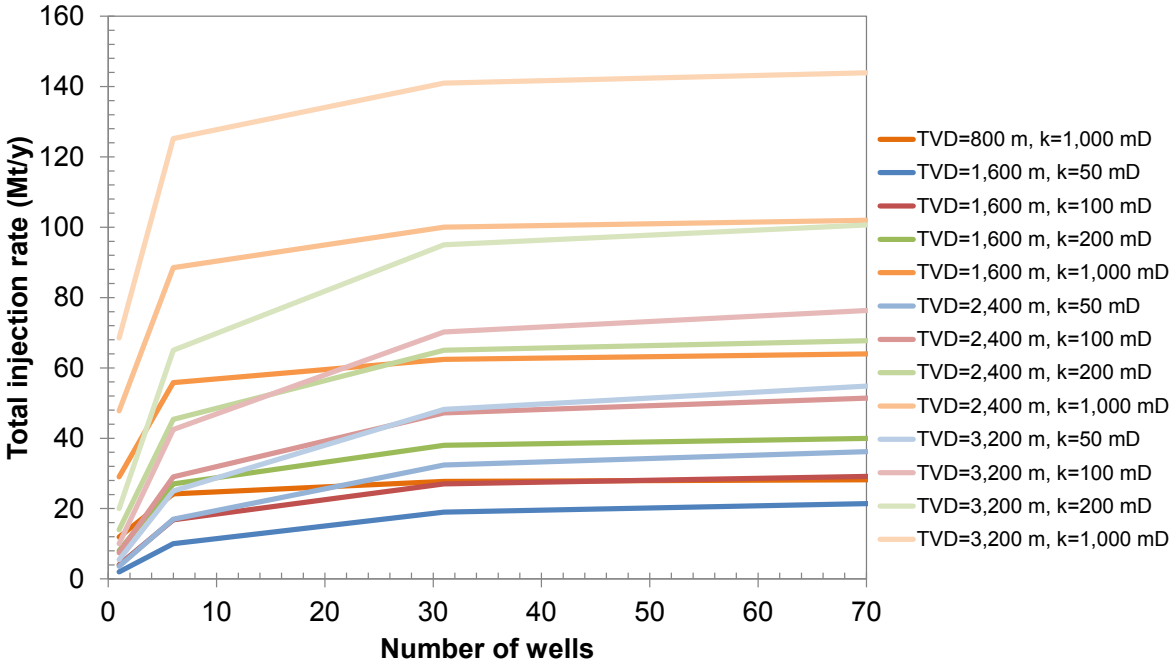
NOTE: The data in this table have been correlated as a linear equation of the form $\dot{W} = a \ln P_d + b$ where $\dot{W}$ is the pumping duty in MW and P_d is the discharge pressure in MPa.
The data can be further correlated as follows: $\dot{W} = (0.503 \ln P_d - 1.01)Q$ where Q is the flow-rate in Mt/y.

21.3 Wells

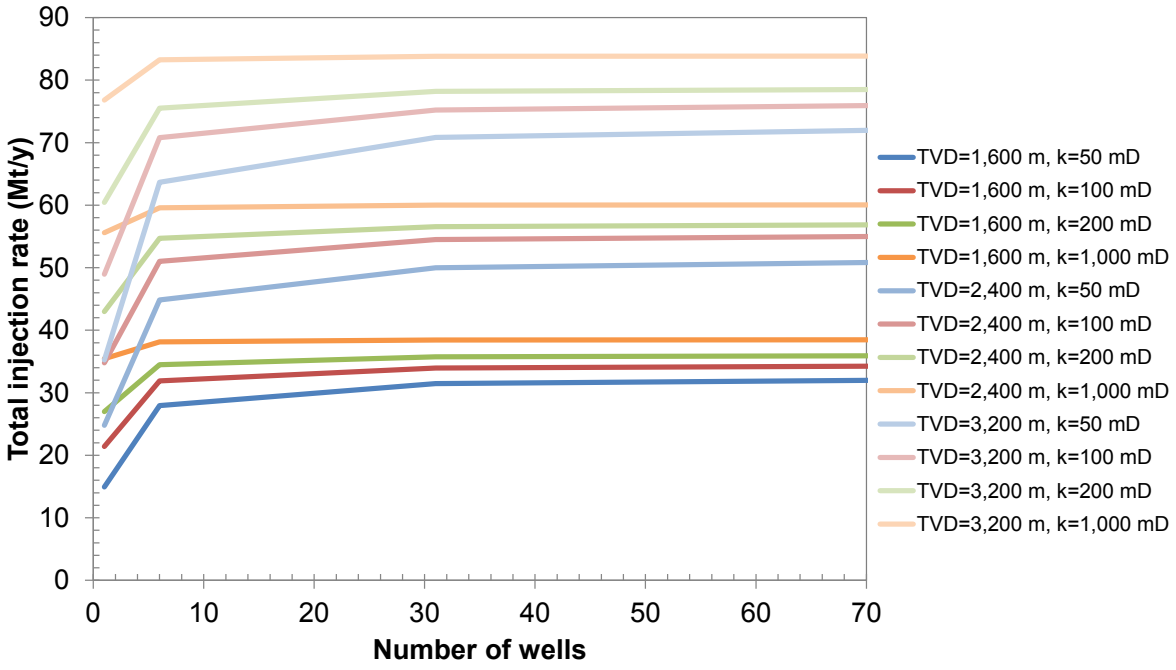
This section contains a full set of figures as well as tables of data and equation coefficients for the well building blocks.



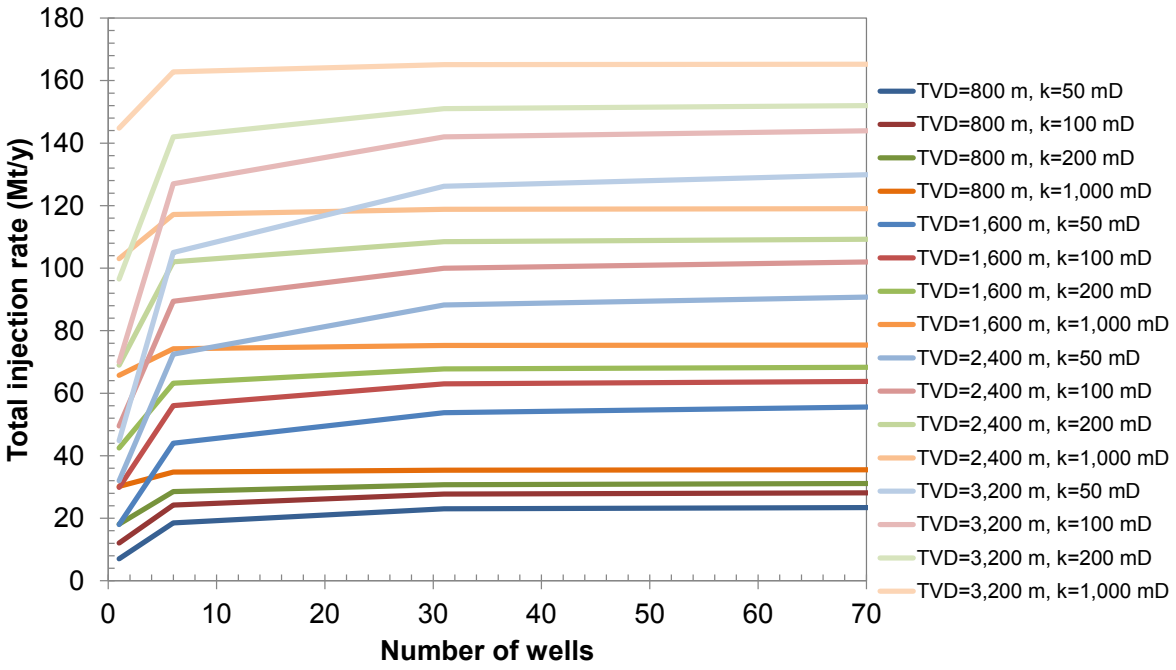
(a) A = 10,000 km^2, h = 100 m and ϕ = 20%



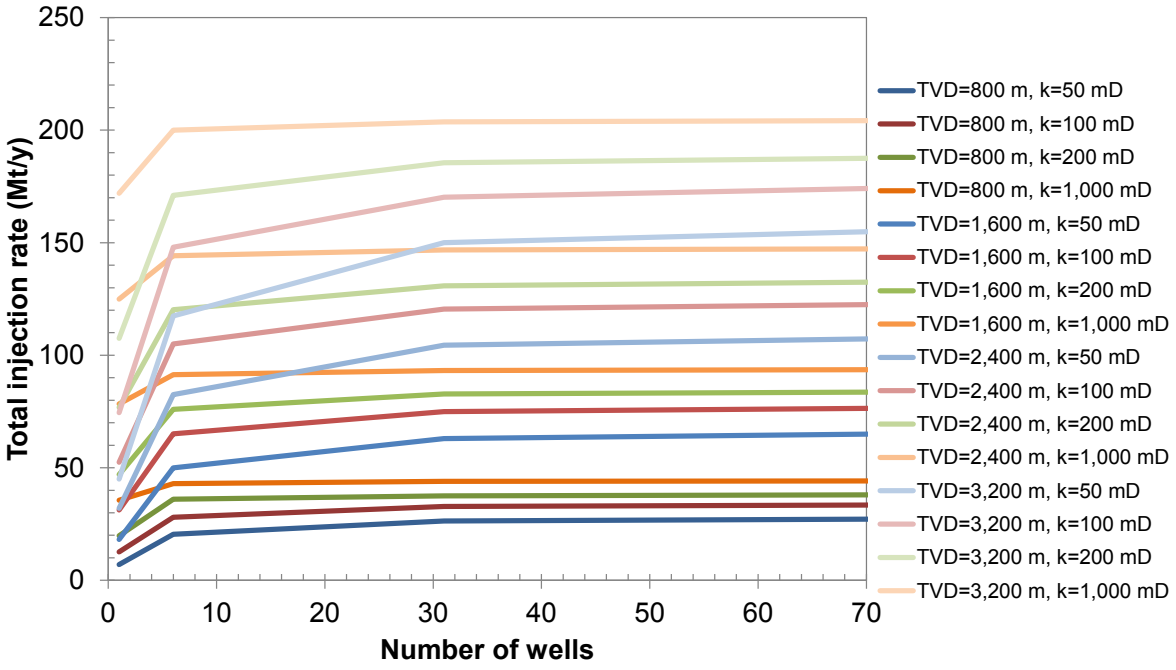
(b) A = 10,000 km^2, h = 100 m and ϕ = 40%



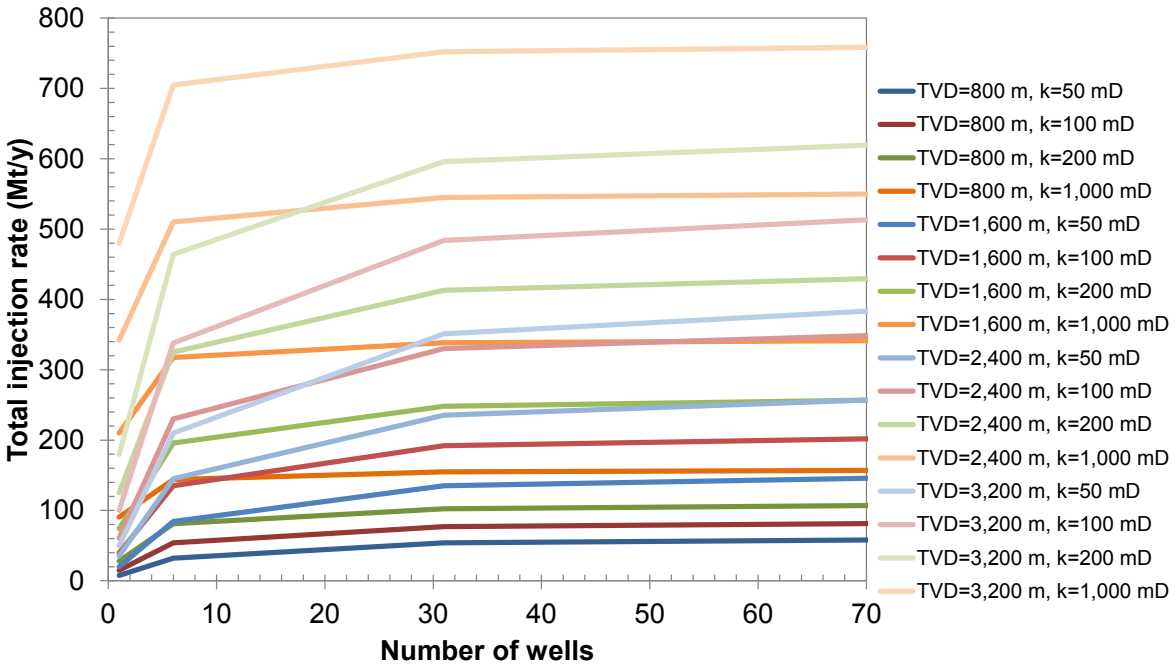
(c) A = 1,000 km^2, h = 1,000 m and ϕ = 20%



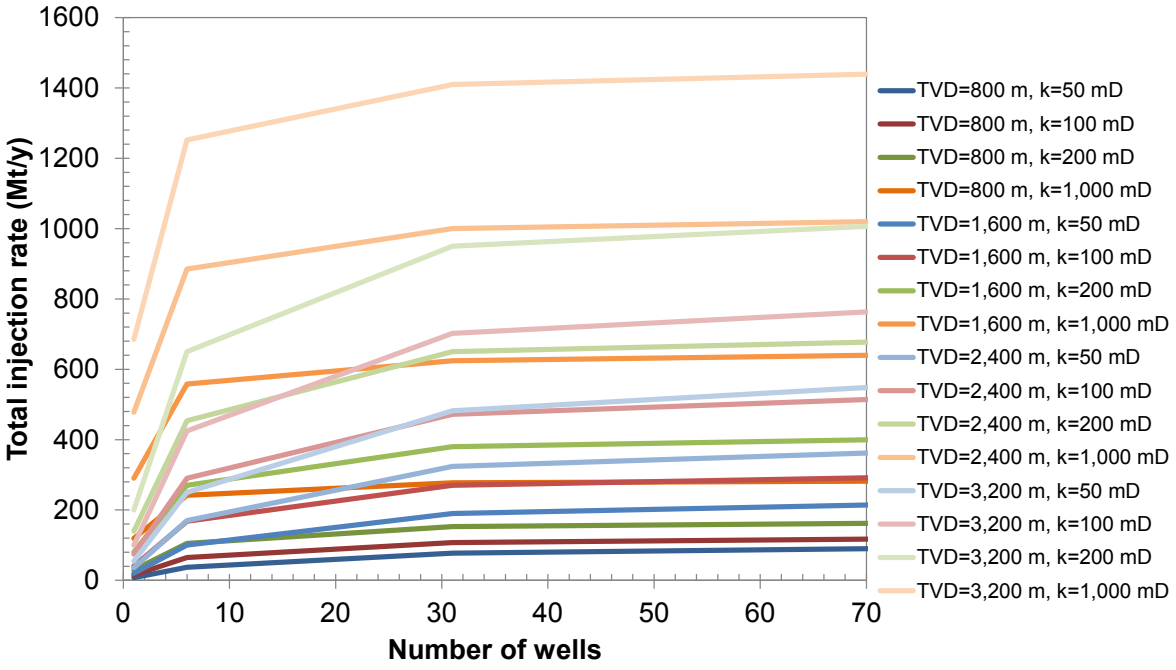
(d) A = 1,000 km^2, h = 1,000 m and ϕ = 40%



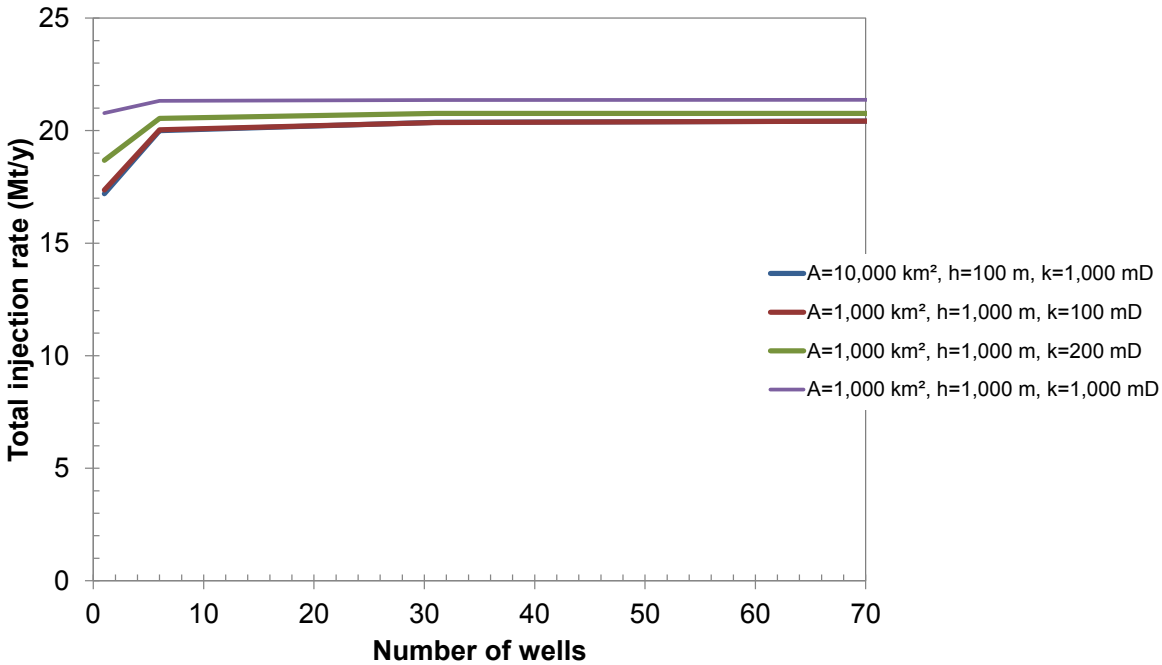
(e) A = 10,000 km^2, h = 1,000 m and ϕ = 5%



(f) A = 10,000 km^2, h = 1,000 m and ϕ = 20%



(g) A = 10,000 km², h = 1,000 m and ϕ = 40%



(h) d = 3,200 m and ϕ = 5%

Figure 143: Total injection rate as a function of numbers of wells for various combinations of permeability (k), injection depth (d), areal extent (A), thickness (h) and porosity (ϕ)

Table 106: Total injection rate as a function of numbers of wells for various combinations of permeability (k), injection depth (d), areal extent (A), thickness (h) and

porosity (ϕ), as shown in Figure 108 and Figure 143

Formation properties					Total CO_2 injection rate (Mt/y) with different number of wells				
h (m)	A (km^2)	Φ (%)	d (m)	k (mD)	1 well	6 wells	31 wells	71 wells	121 wells
100	10,000	5%	3,200	1,000	17.2	20.0	20.4	20.4	20.4
100	10,000	20%	1,600	100	3.95	13.5	19.2	20.2	20.6
100	10,000	20%	1,600	200	7.40	19.6	24.8	25.7	26.0
100	10,000	20%	1,600	1,000	21.0	31.8	33.9	34.2	34.3
100	10,000	20%	2,400	50	3.55	14.5	23.6	25.8	26.3
100	10,000	20%	2,400	100	6.09	23.0	33.0	34.9	35.6
100	10,000	20%	2,400	200	12.5	32.5	41.3	43.0	43.4
100	10,000	20%	2,400	1,000	34.2	51.0	54.5	55.0	55.0
100	10,000	20%	3,200	50	5.02	21.0	35.1	38.4	39.5
100	10,000	20%	3,200	100	10.0	33.8	48.4	51.4	52.1
100	10,000	20%	3,200	200	18.0	46.4	59.6	62.0	62.4
100	10,000	20%	3,200	1,000	48.0	70.5	75.2	75.9	76.0
100	10,000	40%	800	1,000	11.9	24.2	27.7	28.2	28.3
100	10,000	40%	1,600	50	2.00	10.0	19.0	21.5	22.4
100	10,000	40%	1,600	100	4.00	16.8	27.0	29.2	30.1
100	10,000	40%	1,600	200	8.00	27.0	38.0	40.0	42.0
100	10,000	40%	1,600	1,000	29.0	55.8	62.4	64.0	64.2
100	10,000	40%	2,400	50	3.60	17.0	32.4	36.3	38.2
100	10,000	40%	2,400	100	7.40	29.0	47.2	51.5	52.4
100	10,000	40%	2,400	200	14.0	45.4	65.0	67.8	70.0
100	10,000	40%	2,400	1,000	47.8	88.5	100	102	102
100	10,000	40%	3,200	50	5.50	25.0	48.2	55.0	57.3
100	10,000	40%	3,200	100	10.0	42.5	70.2	76.5	78.5
100	10,000	40%	3,200	200	20.0	65.0	95.0	101	103
100	10,000	40%	3,200	1,000	68.5	125.0	141	144	145
1000	1,000	5%	3,200	100	17.4	20.0	20.4	20.4	20.4
1000	1,000	5%	3,200	200	18.7	20.5	20.8	20.8	20.8
1000	1,000	5%	3,200	1,000	20.8	21.3	21.4	21.4	21.4
1000	1,000	20%	1,600	50	15.0	28.0	31.5	32.0	32.1
1000	1,000	20%	1,600	100	21.4	31.9	34.0	34.3	34.4
1000	1,000	20%	1,600	200	27.0	34.5	35.8	35.9	36.0
1000	1,000	20%	1,600	1,000	35.4	38.1	38.4	38.5	38.5
1000	1,000	20%	2,400	50	24.8	44.9	50.0	50.9	50.9
1000	1,000	20%	2,400	100	34.8	51	54.5	55.0	55.1

Formation properties					Total CO_2 injection rate (Mt/y) with different number of wells				
h (m)	A (km^2)	Φ (%)	d (m)	k (mD)	1 well	6 wells	31 wells	71 wells	121 wells
1000	1,000	20%	2,400	200	43.0	54.7	56.6	56.9	57.0
1000	1,000	20%	2,400	1,000	55.6	59.6	60.0	60.0	60.0
1000	1,000	20%	3,200	50	35.3	63.7	70.8	72.0	72.0
1000	1,000	20%	3,200	100	49.0	70.8	75.2	76.0	76.0
1000	1,000	20%	3,200	200	60.5	75.5	78.2	78.5	78.8
1000	1,000	20%	3,200	1,000	76.8	83.3	83.8	83.9	83.9
1000	1,000	40%	800	50	7.00	18.5	23.0	23.5	23.8
1000	1,000	40%	800	100	12.1	24.3	27.8	28.2	28.2
1000	1,000	40%	800	200	18.1	28.5	30.7	31.1	31.3
1000	1,000	40%	800	1,000	30.2	34.8	35.4	35.5	35.5
1000	1,000	40%	1,600	50	18.0	44.0	53.8	55.6	55.9
1000	1,000	40%	1,600	100	29.9	56.0	63.0	63.8	63.4
1000	1,000	40%	1,600	200	42.5	63.2	67.8	68.3	68.5
1000	1,000	40%	1,600	1,000	65.8	74.2	75.3	75.4	75.5
1000	1,000	40%	2,400	50	32.0	72.5	88.2	90.8	92.0
1000	1,000	40%	2,400	100	49.5	89.4	100	102	103
1000	1,000	40%	2,400	200	69.0	102	109	109	110
1000	1,000	40%	2,400	1,000	103	117	119	119	119
1000	1,000	40%	3,200	50	44.8	105	126	130	131
1000	1,000	40%	3,200	100	70.0	127	142	144	145
1000	1,000	40%	3,200	200	96.5	142	151	152	155
1000	1,000	40%	3,200	1,000	145	163	165	165	168
1000	10,000	5%	800	50	7.00	20.5	26.4	27.2	27.6
1000	10,000	5%	800	100	12.6	28.0	32.9	33.5	33.8
1000	10,000	5%	800	200	19.9	36.0	37.5	38.0	38.1
1000	10,000	5%	800	1,000	35.6	43.0	44.0	44.2	44.2
1000	10,000	5%	1,600	50	18.2	50.0	63.0	65.0	65.8
1000	10,000	5%	1,600	100	31.3	65.1	75.0	76.4	77.0
1000	10,000	5%	1,600	200	47.0	76.0	82.8	83.6	84.0
1000	10,000	5%	1,600	1,000	78.4	91.4	93.2	93.6	93.6
1000	10,000	5%	2,400	50	32.0	82.5	105	107	108
1000	10,000	5%	2,400	100	52.5	105	121	123	124
1000	10,000	5%	2,400	200	76.8	120	131	133	133
1000	10,000	5%	2,400	1,000	125	144	147	147	147
1000	10,000	5%	3,200	50	45.0	118	150	155	158
1000	10,000	5%	3,200	100	74.5	148	170	174	175

Formation properties					Total CO_2 injection rate (Mt/y) with different number of wells				
h (m)	A (km^2)	Φ (%)	d (m)	k (mD)	1 well	6 wells	31 wells	71 wells	121 wells
1000	10,000	5%	3,200	200	108	171	186	188	188
1000	10,000	5%	3,200	1,000	172	200	204	204	204
1000	10,000	20%	800	50	7.50	32.0	54.0	58.0	60.5
1000	10,000	20%	800	100	15.0	54.0	77.0	81.5	82.5
1000	10,000	20%	800	200	28.0	81.1	103	107	110
1000	10,000	20%	800	1,000	90.5	144	155	157	157
1000	10,000	20%	1,600	50	20.0	84.5	135	146	150
1000	10,000	20%	1,600	100	39.5	135	192	202	206
1000	10,000	20%	1,600	200	74.0	196	248	257	260
1000	10,000	20%	1,600	1,000	210	318	339	342	343
1000	10,000	20%	2,400	50	35.5	145	236	258	263
1000	10,000	20%	2,400	100	60.9	230	330	349	356
1000	10,000	20%	2,400	200	125	325	413	430	434
1000	10,000	20%	2,400	1,000	342	510	545	550	550
1000	10,000	20%	3,200	50	50.2	210	351	384	395
1000	10,000	20%	3,200	100	100	338	484	514	521
1000	10,000	20%	3,200	200	180	464	596	620	624
1000	10,000	20%	3,200	1,000	480	705	752	759	760
1000	10,000	40%	800	50	7.50	37.0	77.2	90.0	94.5
1000	10,000	40%	800	100	15.0	65.0	108	118	121
1000	10,000	40%	800	200	29.5	105	153	162	165
1000	10,000	40%	800	1,000	119	242	277	282	283
1000	10,000	40%	1,600	50	20.0	100	190	215	224
1000	10,000	40%	1,600	100	40.0	168	270	292	301
1000	10,000	40%	1,600	200	80.0	270	380	400	410
1000	10,000	40%	1,600	1,000	290	558	624	640	642
1000	10,000	40%	2,400	50	36.0	170	324	363	382
1000	10,000	40%	2,400	100	74.0	290	472	515	524
1000	10,000	40%	2,400	200	140	454	650	678	700
1000	10,000	40%	2,400	1,000	478	885	1000	1020	1020
1000	10,000	40%	3,200	50	55.0	250	482	550	573
1000	10,000	40%	3,200	100	100	425	702	765	785
1000	10,000	40%	3,200	200	200	650	950	1010	1030
1000	10,000	40%	3,200	1,000	685	1250	1410	1440	1450

Table 107: Top-hole pressures as a function of total vertical depth and bottom-hole

pressure gradient, as shown in Figure 109

Top-hole pressure (MPa)		Bottom-hole pressure gradient (MPa/km)				
		12	14	16	18	20
Injection depth (m)	800	9.60	11.2	12.8	14.4	16.0
	1,200	14.4	16.8	19.2	21.6	24.0
	1,600	19.2	22.4	25.6	28.8	32.0
	2,000	24.0	28.0	32.0	36.0	40.0
	2,400	28.8	33.6	38.4	43.2	48.0
	2,800	33.6	39.2	44.8	50.4	56.0
	3,200	38.4	44.8	51.2	57.6	64.0

Note: The data in this table have been correlated as a linear equation of the form $THP = 0.001 * \nabla BHP * d$ where THP is the top-hole pressure, ∇BHP is the bottom-hole pressure gradient and d is the injection depth.

Table 108: Onshore vertical well bare erected costs ($/well in 2015) for oil prices of US$50/bbl and US$100/bbl and as a function of injection depth, as shown in Figure 110(a)

Well capex (A$m/well)		Well only		Well plus logging and coring	
		$50/bbl	$100/bbl	$50/bbl	$100/bbl
Well depth (m)	800	2.31	3.60	3.23	4.85
	800	2.31	3.60	3.24	4.85
	900	2.41	3.90	3.34	5.15
	1,000	2.60	4.10	3.53	5.35
	1,080	2.89	4.40	3.82	5.65
	1,100	3.37	4.90	4.23	6.15
	1,200	3.08	4.90	4.01	6.15
	1,200	3.08	4.90	4.01	6.15
	1,250	2.89	4.40	3.82	5.65
	1,300	3.27	5.20	4.20	6.45
	1,360	3.37	5.40	4.30	6.65
	1,450	3.37	5.40	4.30	6.65
	1,500	3.56	5.80	4.49	7.05
	1,500	3.66	5.80	4.59	7.05
	1,500	3.83	6.07	4.76	7.33
	1,700	4.04	6.40	4.97	7.65
	1,700	4.04	6.40	4.97	7.65
	1,800	4.23	6.70	5.16	7.95
	1,950	4.52	7.20	5.45	8.45
	2,000	4.81	7.70	5.74	8.95
	2,000	4.62	7.40	5.55	8.65
	2,000	5.00	8.01	5.93	9.26
	2,200	5.00	8.00	5.93	9.25
	2,250	5.39	8.60	6.32	9.85
	2,400	6.25	10.10	7.18	11.30
	2,500	6.25	10.10	7.18	11.40
	2,500	5.13	8.22	6.06	9.47
	2,500	6.38	10.30	7.31	11.50
	2,600	5.77	9.30	6.70	10.60
	2,945	7.82	12.70	8.75	13.90
a		2.26	3.73	2.26	3.73
b		331	312	1,260	1,560
R^2		0.948	0.950	0.948	0.950

Note: The data in this table have been correlated as a linear equation of the form $C = ad + b$ where C is the well capital cost in A$m (2015) and d is the well depth in m.

Table 109: Offshore vertical well bare erected costs ($/well in 2015) for oil prices of US$50/bbl and US$100/bbl and as a function of injection depth, as shown in Figure 110(b)

Well capex (A$m/well)		Well only		Well plus logging and coring	
		$50/bbl	$100/bbl	$50/bbl	$100/bbl
Well depth (m)	1,100	18.4	21.5	19.3	22.8
	1,350	19.3	44.3	20.2	45.5
	1,500	21.7	26.4	22.7	27.7
	1,800	24.4	30.6	25.3	31.9
	1,800	24.4	30.6	25.3	31.9
	1,800	24.4	27.0	25.3	28.2
	2,100	27.6	35.0	28.5	36.3
	2,130	39.2	46.7	40.2	48.0
	2,500	32.3	41.8	33.3	43.1
	2,630	48.2	59.5	49.1	60.8
	2,650	34.2	44.6	35.1	45.9
	2,700	34.7	45.3	35.6	46.6
	3,000	38.9	51.3	39.8	52.5
	3,000	32.1	57.1	33.1	58.4
	3,300	43.3	57.6	44.2	58.8
a		11.4	15.4	11.4	15.4
b		5,510	7,100	6,44	8,350
R^2		0.707	0.690	0.707	0.690

Note: The data in this table have been correlated as a linear equation of the form $C = ad + b$ where, C is the well capital cost in A$m (2015) and d is the well depth in m.

21.4 Storage facilities

This section contains tables of data and equation coefficients for the storage facilities building blocks.

Table 110: Onshore distribution capital costs (A$ bare erected cost in 2015) as a function of number of wells or flow-rate for onshore injection, as shown in Figure 111

Distribution capex (A$m/km of well spacing)		CO_2 flow rate (Mt/y)									
		1	3	5	10	15	20	25	30	35	40
Number of wells	1	0	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
	2	0.137	0.288	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
	3	0.274	0.507	0.962	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
	7	0.821	1.32	1.73	3.14	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
	10	1.23	1.98	2.59	3.96	6.35	n.a.	n.a.	n.a.	n.a.	n.a.
	20	2.60	4.19	5.47	7.59	9.95	12.5	15.3	19.2	n.a.	n.a.
	30	3.97	6.39	8.35	11.6	15.2	17.8	20.5	23.3	27.8	30.9
	70	9.44	15.2	19.9	27.6	36.1	39.1	45.4	52	55.4	62.4
	100	13.5	21.8	28.5	39.6	47.6	56.2	65.2	74.6	79.5	84.5
	200	27.2	43.9	57.3	79.5	95.7	113	131	150	160	170
	A	0.137	0.220	0.287	0.398	0.472	0.559	0.646	0.735	0.783	0.820
	b	-0.137	-0.197	-0.205	-0.113	1.311	0.766	1.169	2.070	2.292	4.945
	R^2	1.00	1.00	1.00	1.00	0.999	1.000	1.000	0.999	0.999	0.999

NOTE: The data in this table have been correlated as an equation of the form $C = AN + b$ where C is the well capital cost in A$m/km of well spacing (2015) and N is the number of wells.

Table 111: Offshore platform capital costs as a function of number of wells for offshore injection (A$ million bare erected cost in 2015), as shown in Figure 112

Number of wells	Platform capex (A$m)
3	23.2
4	29.8
4	39.7
5	47.2
5	47.5
5	47.3
5	43.9
5	48.2
5	36.1
6	92.5
8	49.5
13	74.3
21	113
21	111
22	114
22	120
22	116
26	134
30	151
36	177
a	4.64
b	14.2
R^2	0.946

Note: The data in this table have been correlated as a linear equation of the form $C = aN + b$ where C is the platform capital cost in A$m (2015) and N is the number of wells.

21.5 Monitoring

This section contains tables of data and equation coefficients for the monitoring building blocks.

Table 112: The cost of onshore and offshore 3D seismic surveys (A$ million in 2015), as shown in Figure 113 and Figure 114

The cost of 3D seismic surveys (A$m)		Onshore 3D seismic survey		Offshore 3D seismic survey	
		Low cost	High cost	Low cost	High cost
Areal extent (km^2)	500	2.50	6.25	3.50	12.5
	1,000	5.00	12.5	7.00	25.0
	2,000	10.0	25.0	14.0	50.0
	5,000	25.0	62.5	35.0	125
	10,000	50.0	125	70.0	250
	20,000	100	250	140	500
	50,000	250	625	350	1250
	100,000	500	1250	700	2500
m		5.00	12.5	7.00	25.0
R^2		1.00	1.00	1.00	1.00

Note: The data in this table have been correlated as equations of the form $C = mA/1000$ where C is the cost of seismic survey in A$m (2015) and A is the areal extent

Table 113: The cost of vertical seismic profiling logs and well depth (A$m in 2015), as shown in Figure 115

Well depth (m)	VSP cost (A$m/log)
800	0.040
1,200	0.060
2,000	0.100
2,200	0.110
2,800	0.140
3,200	0.160
3,600	0.180
4,000	0.200
a	0.000 050
R^2	1.00

Note: The data in this table have been correlated as equations of the form $C = ad$ where C is the cost of the VSP log in A$m (2015) and d is the well depth (m)

21.6 Case studies

Table 114: Transport and storage data for case studies

Source hub	Storage basin (horizon)	Flow-rate (Mt/y)	Onshore distance (km)	Offshore distance (km)	Total distance (km)	Areal extent (km^2)	Fm thick. (m)	Injection depth (m)	Porosity (%)	Perm. (mD)	Fracture gradient (MPa/km)
Latrobe Valley, Victoria	Gippsland (Nearshore)	1	85	20	105	200	250	1,350	25%	1,000	20.8
Latrobe Valley, Victoria	Gippsland (Nearshore)	5	85	20	105	200	250	1,350	25%	1,000	20.8
Latrobe Valley, Victoria	Gippsland (Nearshore)	10	85	20	105	200	250	1,350	25%	1,000	20.8
Latrobe Valley, Victoria	Gippsland (Intermediate)	10	85	48	133	2,000	350	2,000	22%	200	20.8
Latrobe Valley, Victoria	Gippsland (Central)	10	85	82	167	10,000	500	3,000	19%	50	20.8
Latrobe Valley, Victoria	Gippsland (Central)	15	85	82	167	10,000	500	3,000	19%	50	20.8
Latrobe Valley, Victoria	Gippsland (Central)	20	85	82	167	10,000	500	3,000	19%	50	20.8
Eastern Victoria	Gippsland (Nearshore)	1	17	20	37	200	250	1,350	25%	1,000	20.8
Eastern Victoria	Gippsland (Intermediate)	1	17	48	65	2,000	350	2,000	22%	200	20.8
Eastern Victoria	Gippsland (Central)	1	17	82	99	10,000	500	3,000	19%	50	20.8
South Qld—Single (East Surat) Close	Surat (Shallow)	4	130	–	130	40,000	100	800	20%	5,000	16.6
South Qld—Single (East Surat) Close	Surat (Mid)	4	130	–	130	40,000	100	1,400	15%	1,000	16.6
South Qld—Single (East Surat) Close	Surat (Deep)	4	130	–	130	40,000	200	2,000	21%	100	16.6
South Qld—Single (East Surat) Far	Surat (Shallow)	4	190	–	190	40,000	100	800	20%	5,000	16.6
South Qld—Single (East Surat) Far	Surat (Mid)	4	190	–	190	40,000	100	1,400	15%	1,000	16.6
South Qld—Single (East Surat) Far	Surat (Deep)	4	190	–	190	40,000	200	2,000	21%	100	16.6
South Qld—Hub (East Surat) Close	Surat (Shallow)	18	130	–	130	40,000	100	800	20%	5,000	16.6

Source hub	Storage basin (horizon)	Flow-rate (Mt/y)	Onshore distance (km)	Offshore distance (km)	Total distance (km)	Areal extent (km²)	Fm thick. (m)	Injection depth (m)	Porosity (%)	Perm. (mD)	Fracture gradient (MPa/km)
South Qld—Hub (East Surat) Close	Surat (Mid)	18	130	–	130	40,000	100	1,400	15%	1,000	16.6
South Qld—Hub (East Surat) Close	Surat (Deep)	18	130	–	130	40,000	200	2,000	21%	100	16.6
South Qld—Hub (East Surat) Far	Surat (Shallow)	18	190	–	190	40,000	100	800	20%	5,000	16.6
South Qld—Hub (East Surat) Far	Surat (Mid)	18	190	–	190	40,000	100	1,400	15%	1,000	16.6
South Qld—Hub (East Surat) Far	Surat (Deep)	18	190	–	190	40,000	200	2,000	21%	100	16.6
South Qld (East Surat)	Eromanga (Shallow)	18	1,312	–	1,312	40,000	50	1,200	22%	1,000	16.5
South Qld (East Surat)	Eromanga (Mid)	18	1,440	–	1,440	40,000	100	1,700	18%	500	16.5
South Qld (East Surat)	Eromanga (Deep)	18	1,605	–	1,605	40,000	150	2,000	16%	100	16.5
North Qld (Gladstone/Rockhampton)	Galilee (Shallow)	16.1	615	–	615	30,000	20	800	22%	2,000	16.6
North Qld (Gladstone/Rockhampton)	Galilee (Mid)	16.1	618	–	618	30,000	100	1,080	19%	190	16.6
North Qld (Gladstone/Rockhampton)	Galilee (Deep)	16.1	711	–	711	30,000	200	1,360	16%	15	16.6
North Qld (Gladstone/Rockhampton)	Eromanga (Shallow)	16.1	1,020	–	1,020	40,000	50	1,200	22%	1,000	16.5
North Qld (Gladstone/Rockhampton)	Eromanga (Mid)	16.1	1,148	–	1,148	40,000	100	1,700	18%	500	16.5
North Qld (Gladstone/Rockhampton)	Eromanga (Deep)	16.1	1,313	–	1,313	40,000	150	2,000	16%	100	16.5
North NSW (Hunter Valley & Newcastle)	Surat (Shallow)	33.5	813	–	813	40,000	100	800	20%	5,000	16.6
North NSW (Hunter Valley & Newcastle)	Surat (Mid)	33.5	759	–	759	40,000	100	1,400	15%	1,000	16.6

Source hub	Storage basin (horizon)	Flow-rate (Mt/y)	Onshore distance (km)	Offshore distance (km)	Total distance (km)	Areal extent (km²)	Fm thick. (m)	Injection depth (m)	Porosity (%)	Perm. (mD)	Fracture gradient (MPa/km)
North NSW (Hunter Valley & Newcastle)	Surat (Deep)	33.5	710	–	710	40,000	200	2,000	21%	100	16.6
South NSW (NSW West & Lithgow)	Gippsland (Nearshore)	12.9	930	20	950	200	250	1,350	25%	1,000	21
South NSW (NSW West & Lithgow)	Gippsland (Intermediate)	12.9	930	48	978	2,000	350	2,000	22%	200	21
South NSW (NSW West & Lithgow)	Gippsland (Central)	12.9	930	82	1,012	10,000	500	3,000	19%	50	21
North NSW (Hunter Valley & Newcastle)	Darling—Core (Pondie Range)	33.5	915	–	915	1,300	115	1,640	12%	70	24.5
North NSW (Hunter Valley & Newcastle)	Darling—DST avg (Pondie Range) (Watson et al. 2015)	33.5	915	–	915	1,300	115	1,640	12%	350	24.5
South NSW (NSW West & Lithgow)	Darling—Core (Pondie Range)(Watson et al. 2015)	12.9	574	–	574	1,300	115	1,640	12%	70	24.5
South NSW (NSW West & Lithgow)	Darling—DST avg (Pondie Range)	12.9	574	–	574	1,300	115	1,640	12%	350	24.5
Southwest WA (Coolimba to Collie)	North Perth Offshore (Shallow)	8.4	635	100	735	15,500	200	1,000	26%	2,857	14.9
Southwest WA (Coolimba to Collie)	North Perth Offshore (Mid)	8.4	635	100	735	15,500	400	1,700	22%	294	14.9
Southwest WA (Coolimba to Collie)	North Perth Offshore (Deep)	8.4	635	100	735	15,500	600	2,400	18%	31	14.9
Southwest WA (Coolimba to Collie)	North Perth Onshore (Shallow)	8.4	725	–	725	4,400	50	1,500	27%	1,825	14.9
Southwest WA (Coolimba to Collie)	North Perth Onshore (Mid)	8.4	725	–	725	4,400	125	2,250	22%	336	14.9
Southwest WA (Coolimba to Collie)	North Perth Onshore (Deep)	8.4	725	–	725	4,400	200	3,000	18%	52	14.9
Southwest WA (Coolimba to Collie)	Lesueur Sst (Shallow)	8.4	80	–	80	150	700	1,380	23%	500	14.9
Southwest WA (Coolimba to Collie)	Lesueur Sst (Mid)	8.4	80	–	80	150	500	1,965	14%	200	20.0

Source hub	Storage basin (horizon)	Flow-rate (Mt/y)	Onshore distance (km)	Offshore distance (km)	Total distance (km)	Areal extent (km²)	Fm thick. (m)	Injection depth (m)	Porosity (%)	Perm. (mD)	Fracture gradient (MPa/km)
Southwest WA (Coolimba to Collie)	Lesueur Sst (Deep)	8.4	80	–	80	150	1,000	2,965	8%	10	20.0
Kwinana	Lesueur Sst (Shallow)	8.4	100		100	150	700	1,380	23%	500	14.9
Kwinana	Lesueur Sst (Mid)	8.4	100		100	150	500	1,965	14%	200	20
Kwinana	Lesueur Sst (Deep)	8.4	100		100	150	1,000	2,965	8%	10	20
South NSW & Latrobe Valley	Gippsland (Nearshore)	31.2	990	20	1,010	200	250	1,350	0.25	1,000	21
South NSW & Latrobe Valley	Gippsland (Intermediate)	31.2	990	48	1,038	2,000	350	2,000	0.22	200	21
South NSW & Latrobe Valley	Gippsland (Central)	31.2	990	82	1,072	10,000	500	3,000	0.19	50	21
South Qld and North NSW	Surat (Shallow)	51.5	1,189	–	1,189	40,000	100	800	20%	5,000	16.6
South Qld and North NSW	Surat (Mid)	51.5	1,135	–	1,135	40,000	100	1,400	15%	1,000	16.6
South Qld and North NSW	Surat (Deep)	51.5	1,086	–	1,086	40,000	200	2,000	21%	100	16.6
South Qld and North NSW	Eromanga (Shallow)	51.5	2,022	–	2,022	40,000	50	1,200	22%	1,000	17
South Qld and North NSW	Eromanga (Mid)	51.5	2,150	–	2,150	40,000	100	1,700	18%	500	17
South Qld and North NSW	Eromanga (Deep)	51.5	2,315	–	2,315	40,000	150	2,000	16%	100	17
South and North NSW	Darling—Core (Pondie Range)	46.4	1,120	–	1,120	1,300	115	1,640	12%	70	24.5
South and North NSW	Darling—DST avg (Pondie Range)	46.4	1,409	–	1,409	1,300	115	1,640	12%	350	24.5
South and North NSW	Cooper (Shallow)	46.4	1,944	–	1,944	35,000	50	1,950	17%	446	16.5
South and North NSW	Cooper (Mid)	46.4	1,855	–	1,855	35,000	125	2,250	15%	108	16.5
South and North NSW	Cooper (Deep)	46.4	1,771	–	1,771	35,000	200	2,500	13%	29	16.5

Table 115: Performance results for all transport and storage cases

	CO_2 avoided (Mt/yr)	Pipeline inlet pressure (MPa)	Top hole pressure (MPa)	Boost duty (MW)	Pipe. wall thick. (mm)	Nom. pipe. outer diam. (mm)	No. of wells
Latrobe Valley (1)—Gippsland (Nearshore)	1.0	11.6	9.2	–	7.3	250.0	1
Latrobe Valley (5)—Gippsland (Nearshore)	5.0	14.3	12.7	–	14.0	550.0	3
Latrobe Valley (10)—Gippsland (Nearshore)	10.0	14.6	8.4	–	14.0	550.0	5
Latrobe Valley (10)—Gippsland (Intermediate)	10.0	14.8	9.8	–	15.2	600.0	5
Latrobe Valley (10)—Gippsland (Central)	10.0	14.9	14.4	–	24.6	1,000.0	5
Latrobe Valley (15)—Gippsland (Central)	15.0	14.9	14.3	–	27.0	1,100.0	8
Latrobe Valley (20)—Gippsland (Central)	20.0	14.9	14.4	–	31.7	1,300.0	10
East Gippsland—Gippsland (Nearshore)	1.0	12.2	9.2	–	6.4	200.0	1
East Gippsland—Gippsland (Intermediate)	1.0	14.7	9.3	–	6.4	200.0	1
East Gippsland—Gippsland (Central)	1.0	14.3	13.4	–	8.5	300.0	1
South Qld (4) Close—Surat (Shallow)	4.0	14.5	8.2	–	10.4	400.0	2
South Qld (4) Close—Surat (Mid)	4.0	14.4	8.2	–	10.4	400.0	2
South Qld (4) Close—Surat (Deep)	4.0	14.6	11.3	–	11.6	450.0	2
South Qld (4) Far—Surat (Shallow)	4.0	13.3	8.2	–	11.6	450.0	2
South Qld (4) Far—Surat (Mid)	4.0	13.3	8.2	–	11.6	450.0	2
South Qld (4) Far—Surat (Deep)	4.0	14.2	11.3	–	12.8	500.0	2
South Qld (18) Close—Surat (Shallow)	18.0	13.7	8.2	–	18.7	750.0	9
South Qld (18) Close—Surat (Mid)	18.0	13.6	8.2	–	18.7	750.0	9
South Qld (18) Close—Surat (Deep)	18.0	14.1	11.3	–	21.1	850.0	9
South Qld (18) Far—Surat (Shallow)	18.0	13.7	8.2	–	18.7	750.0	9
South Qld (18) Far—Surat (Mid)	18.0	13.9	8.2	–	19.9	800.0	9
South Qld (18) Far—Surat (Deep)	18.0	14.4	11.3	–	22.3	900.0	9
South Qld—Eromanga (Shallow)	18.0	14.9	9.9	–	29.3	1,200.0	9
South Qld—Eromanga (Mid)	18.0	14.8	11.1	–	31.7	1,300.0	9
South Qld—Eromanga (Deep)	18.0	14.4	14.2	5.9	29.3	1,200.0	9
North Qld—Galilee (Shallow)							3,341
North Qld—Galilee (Mid)	16.1	14.6	9.9	–	24.6	1,000.0	9
North Qld—Galilee (Deep)	16.1	14.6	11.9	–	28.2	1,150.0	23
North Qld—Eromanga (Shallow)	16.1	14.6	9.7	–	27.0	1,100.0	9

	CO_2 avoided (Mt/yr)	Pipeline inlet pressure (MPa)	Top hole pressure (MPa)	Boost duty (MW)	Pipe. wall thick. (mm)	Nom. pipe. outer diam. (mm)	No. of wells
North Qld—Eromanga (Mid)	16.1	14.4	10.9	–	29.3	1,200.0	9
North Qld—Eromanga (Deep)	16.1	14.4	13.8	5.0	27.0	1,100.0	9
North NSW—Surat (Shallow)	33.5	14.3	8.2	–	32.9	1,350.0	17
North NSW—Surat (Mid)	33.5	14.0	8.2	–	32.9	1,350.0	17
North NSW—Surat (Deep)	33.5	14.9	11.3	–	35.2	1,450.0	17
South NSW—Gippsland (Nearshore)	12.9	14.4	8.2	–	23.4	950.0	7
South NSW—Gippsland (Intermediate)	12.9	14.6	9.8	–	24.6	1,000.0	7
South NSW—Gippsland Central)	12.9	15.0	14.2	–	35.2	1,450.0	7
North NSW—Darling PR Core							24,421
North NSW—Darling PR DST avg.	33.5	14.9	11.3	7.0	32.9	1,350.0	17
South NSW—Darling PR Core	12.9	14.9	14.3	–	32.9	1,350.0	7
South NSW—Darling PR DST avg.	12.9	13.9	10.2	–	23.4	950.0	7
South NSW + Latrobe Valley—Gippsland (Nearshore)							35,154
South NSW + Latrobe Valley—Gippsland (Intermediate)	31.1	14.1	10.0	10.1	21.1	850.0	16
South NSW + Latrobe Valley—Gippsland (Central)	31.1	14.9	14.4	11.1	32.9	1,350.0	16
North + South NSW—Surat (Shallow)	51.4	14.7	8.2	17.8	25.8	1,050.0	26
North + South NSW—Surat (Mid)	51.4	14.9	8.2	18.2	22.3	900.0	26
North + South NSW—Surat (Deep)	51.4	11.3	11.3	10.8	6.4	100.0	26
North + South NSW—Eromanga (Shallow)	51.2	14.9	9.9	44.3	34.1	1,400.0	26
North + South NSW—Eromanga (Mid)	51.2	14.6	11.1	46.0	35.2	1,450.0	26
North + South NSW—Eromanga (Deep)	51.2	14.5	14.1	51.8	36.4	1,500.0	26
North + South NSW—Darling PR DST Core							38,754
North + South NSW—Darling PR DST avg.							29,362
North + South NSW—Cooper (Shallow)	46.1	14.1	12.8	42.9	35.2	1,450.0	26
North + South NSW—Cooper (Mid)	46.0	14.7	15.5	67.0	34.1	1,400.0	24
North + South NSW—Cooper (Deep)	45.9	14.2	20.7	80.5	34.1	1,400.0	24
Southwest WA—North Perth Offshore (Shallow)	8.4	14.2	9.5	–	19.9	800.0	5
Southwest WA—North Perth Offshore (Mid)	8.4	13.6	8.8	–	19.9	800.0	5
Southwest WA—North Perth Offshore (Deep)	8.4	14.7	11.3	–	21.1	850.0	5
Southwest WA—North Perth Onshore (Shallow)	8.4	14.9	8.4	–	18.7	750.0	5

	CO_2 avoided (Mt/yr)	Pipeline inlet pressure (MPa)	Top hole pressure (MPa)	Boost duty (MW)	Pipe. wall thick. (mm)	Nom. pipe. outer diam. (mm)	No. of wells
Southwest WA— North Perth Onshore (Mid)	8.4	15.0	10.3	–	19.9	800.0	5
Southwest WA— North Perth Onshore (Deep)	8.4	14.6	14.9	3.0	18.7	750.0	5
Southwest WA— Lesueur (Shallow)	8.4	14.5	12.7	–	16.3	650.0	5
Southwest WA— Lesueur (Mid)	8.4	15.0	10.8	–	14.0	550.0	5
Southwest WA— Lesueur (Deep)	8.3	14.9	18.3	7.8	12.8	500.0	5
Kwinana— Lesueur (Shallow)	8.4	14.8	12.7	–	15.2	600.0	5
Kwinana— Lesueur (Mid)	8.4	14.2	10.8	–	14.0	550.0	5
Kwinana— Lesueur (Deep)	8.3	13.6	18.3	7.8	12.8	500.0	5

Table 116: Economic results for all transport and storage cases

	Cost in A$m 2015						
	Pipeline	Booster pumps	Wells	Facilities	On-cost	Total plant cost (overnight)	Decommissioning Cost
Latrobe Valley (1)—Gippsland (Nearshore)	114	–	22	22	63	220	55
Latrobe Valley (5)—Gippsland (Nearshore)	206	–	65	28	120	420	105
Latrobe Valley (10)—Gippsland (Nearshore)	206	–	149	44	160	558	140
Latrobe Valley (10)—Gippsland (Intermediate)	280	–	210	44	214	748	187
Latrobe Valley (10)—Gippsland (Central)	628	–	210	44	353	1,236	309
Latrobe Valley (15)—Gippsland (Central)	710	–	337	60	443	1,549	387
Latrobe Valley (20)—Gippsland (Central)	885	–	217	72	470	1,644	411
East Gippsland—Gippsland (Nearshore)	73	–	30	22	50	175	44
East Gippsland—Gippsland (Intermediate)	100	–	42	22	65	229	57
East Gippsland—Gippsland (Central)	157	–	15	22	77	271	68
South Qld (4) Close—Surat (Shallow)	117	–	6	13	54	191	48
South Qld (4) Close—Surat (Mid)	117	–	9	13	56	194	49
South Qld (4) Close—Surat (Deep)	137	–	12	16	66	229	57
South Qld (4) Far—Surat (Shallow)	200	–	6	16	89	310	77
South Qld (4) Far—Surat (Mid)	200	–	9	16	90	314	78
South Qld (4) Far—Surat (Deep)	231	–	12	18	104	364	91
South Qld (18) Close—Surat (Shallow)	278	–	28	117	169	592	148
South Qld (18) Close—Surat (Mid)	278	–	40	117	174	609	152

	Cost in A$m 2015						
	Pipeline	**Booster pumps**	**Wells**	**Facilities**	**On-cost**	**Total plant cost (overnight)**	**Decommissioning Cost**
South Qld (18) Close—Surat (Deep)	333	–	52	140	210	734	184
South Qld (18) Far—Surat (Shallow)	278	–	28	117	169	592	148
South Qld (18) Far—Surat (Mid)	446	–	40	128	246	860	215
South Qld (18) Far—Surat (Deep)	528	–	52	151	293	1,024	256
South Qld—Eromanga (Shallow)	5,546	–	36	228	2,324	8,133	2,033
South Qld—Eromanga (Mid)	6,845	–	46	255	2,858	10,005	2,501
South Qld—Eromanga (Deep)	6,784	28	52	228	2,837	9,929	2,482
North Qld—Galilee (Shallow)	Not assessed						
North Qld—Galilee (Mid)	2,002	–	33	152	875	3,062	765
North Qld—Galilee (Deep)	2,824	–	134	375	1,333	4,666	1,167
North Qld—Eromanga (Shallow)	3,796	–	36	201	1,613	5,646	1,411
North Qld—Eromanga (Mid)	4,853	–	46	228	2,050	7,176	1,794
North Qld—Eromanga (Deep)	4,887	28	52	201	2,067	7,235	1,809
North NSW—Surat (Shallow)	4,085	–	52	392	1,812	6,340	1,585
North NSW—Surat (Mid)	3,813	–	75	392	1,712	5,993	1,498
North NSW—Surat (Deep)	3,962	–	98	434	1,798	6,292	1,573
South NSW—Gippsland (Nearshore)	2,922	–	208	54	1,273	4,457	1,114
South NSW—Gippsland (Intermediate)	3,243	–	295	54	1,437	5,028	1,257
South NSW—Gippsland Central)	5,741	–	177	54	2,389	8,361	2,090

	Cost in A$m 2015						
	Pipeline	**Booster pumps**	**Wells**	**Facilities**	**On-cost**	**Total plant cost (overnight)**	**Decommissioning Cost**
North NSW— Darling PR Core	Not assessed						
North NSW— Darling PR DST avg.	4,597	42	84	71	1,918	6,712	1,678
South NSW— Darling PR Core	2,884	–	35	41	1,184	4,144	1,036
South NSW— Darling PR DST	1,726	–	35	25	714	2,500	625
South NSW + Latrobe Valley— Gippsland (Nearshore)	Not assessed						
South NSW + Latrobe Valley— Gippsland (Intermediate)	3,091	42	673	107	1,565	5,479	1,370
South NSW + Latrobe Valley— Gippsland (Central)	3,439	42	81	107	1,468	5,137	1,284
North + South NSW— Surat (Shallow)	4,778	70	80	346	2,110	7,384	1,846
North + South NSW— Surat (Mid)	4,556	70	115	278	2,008	7,028	1,757
North + South NSW— Surat (Deep)	4,420	70	150	23	1,866	6,529	1,632
North + South NSW— Eromanga (Shallow)	9,381	210	103	522	4,087	14,303	3,576
North + South NSW— Eromanga (Mid)	10,358	210	133	549	4,500	15,749	3,937
North + South NSW— Eromanga (Deep)	11,628	210	150	576	5,026	17,591	4,398
North + South NSW— Darling PR Core	Not assessed						
North + South NSW— Darling PR DST avg.	Not assessed						
North + South NSW— Cooper (Shallow)	9,505	210	147	513	4,151	14,527	3,632
North + South NSW— Cooper (Mid)	8,699	281	152	467	3,840	13,439	3,360
North + South NSW— Cooper (Deep)	8,254	281	166	467	3,667	12,835	3,209
Southwest WA— North Perth Offshore (Shallow)	1,818	–	130	44	797	2,789	697

	Cost in A$m 2015						
	Pipeline	**Booster pumps**	**Wells**	**Facilities**	**On-cost**	**Total plant cost (overnight)**	**Decommissioning Cost**
Southwest WA— North Perth Offshore (Mid)	1,818	–	173	44	814	2,849	712
Southwest WA— North Perth Offshore (Deep)	1,975	–	118	44	855	2,991	748
Southwest WA— North Perth Onshore (Shallow)	1,551	–	23	26	640	2,241	560
Southwest WA— North Perth Onshore (Mid)	1,701	–	32	29	705	2,466	617
Southwest WA— North Perth Onshore (Deep)	1,551	14	40	26	653	2,284	571
Southwest WA— Lesueur (Shallow)	175	–	22	4	80	281	70
Southwest WA— Lesueur (Mid)	138	–	29	3	68	238	60
Southwest WA— Lesueur (Deep)	121	28	40	3	77	269	67
Kwinana— Lesueur (Shallow)	125	–	22	4	60	211	53
Kwinana— Lesueur (Mid)	111	–	29	3	57	199	50
Kwinana— Lesueur (Deep)	97	28	40	3	67	235	59

Table 117: Annualised and average injected or avoided costs for all transport and storage cases over 30 years

	Annualised costs (A$m/year in 2015)									
	Pipelines	Booster pumps	Wells	Facilities	On-costs	Total fixed operating costs	MMV	Energy costs	$/t CO_2 avoided	$/t CO_2 injected
Latrobe Valley (1)—Gippsland (Nearshore)	12.2	–	2.3	2.3	6.7	2.4	0.1	–	26.0	26.0
Latrobe Valley (5)—Gippsland (Nearshore)	20.2	–	6.4	2.7	11.7	4.5	0.1	–	9.1	9.1
Latrobe Valley (10)—Gippsland (Nearshore)	20.2	–	14.6	4.3	15.6	6.8	0.1	–	6.2	6.2
Latrobe Valley (10)—Gippsland (Intermediate)	27.4	–	20.6	4.3	20.9	8.8	0.9	–	8.3	8.3
Latrobe Valley (10)—Gippsland (Central)	61.5	–	20.6	4.3	34.5	12.2	4.5	–	13.8	13.8
Latrobe Valley (15)—Gippsland (Central)	69.4	–	32.9	5.9	43.3	16.2	4.5	–	11.5	11.5
Latrobe Valley (20)—Gippsland (Central)	86.5	–	21.3	7.1	45.9	16.1	4.5	–	9.1	9.1
East Gippsland—Gippsland (Nearshore)	7.2	–	2.9	2.1	4.9	2.2	0.1	–	19.4	19.4
East Gippsland—Gippsland (Intermediate)	9.7	–	4.1	2.1	6.4	2.7	0.9	–	26.0	26.0
East Gippsland—Gippsland (Central)	15.3	–	1.5	2.1	7.6	2.7	4.5	–	33.7	33.7
South Qld (4) Close—Surat (Shallow)	11.4	–	0.6	1.3	5.3	1.8	18.0	–	9.6	9.6
South Qld (4) Close—Surat (Mid)	11.4	–	0.9	1.3	5.4	1.9	18.0	–	9.7	9.7
South Qld (4) Close—Surat (Deep)	13.4	–	1.1	1.5	6.4	2.2	18.0	–	10.7	10.7
South Qld (4) Far—Surat (Shallow)	19.5	–	0.6	1.5	8.7	2.7	18.0	–	12.8	12.8
South Qld (4) Far—Surat (Mid)	19.5	–	0.9	1.5	8.8	2.8	18.0	–	12.9	12.9
South Qld (4) Far—Surat (Deep)	22.5	–	1.1	1.8	10.2	3.3	18.0	–	14.2	14.2
South Qld (18) Close—Surat (Shallow)	27.2	–	2.7	11.5	16.6	8.0	18.0	–	4.7	4.7
South Qld (18) Close—Surat (Mid)	27.2	–	3.9	11.5	17.0	8.3	18.0	–	4.8	4.8

	Annualised costs (A$m/year in 2015)									
	Pipelines	Booster pumps	Wells	Facilities	On-costs	Total fixed operating costs	MMV	Energy costs	$/t CO_2 avoided	$/t CO_2 injected
South Qld (18) Close—Surat (Deep)	32.6	–	5.1	13.7	20.5	10.0	18.0	–	5.5	5.5
South Qld (18) Far—Surat (Shallow)	27.2	–	2.7	11.5	16.6	8.0	18.0	–	4.7	4.7
South Qld (18) Far—Surat (Mid)	43.6	–	3.9	12.5	24.0	10.4	18.0	–	6.2	6.2
South Qld (18) Far—Surat (Deep)	51.7	–	5.1	14.8	28.6	12.4	18.0	–	7.3	7.3
South Qld—Eromanga (Shallow)	542.5	–	3.5	22.3	227.3	65.3	18.0	–	48.8	48.8
South Qld—Eromanga (Mid)	669.6	–	4.5	25.0	279.6	79.6	18.0	–	59.8	59.8
South Qld—Eromanga (Deep)	663.7	2.7	5.1	22.3	277.5	79.1	18.0	1.9	59.6	59.5
North Qld—Galilee (Shallow)	Not assessed					–				
North Qld—Galilee (Mid)	195.8	–	3.3	14.9	85.6	26.8	13.5	–	21.1	21.1
North Qld—Galilee (Deep)	276.2	–	13.1	36.7	130.4	45.9	13.5	–	32.0	32.0
North Qld—Eromanga (Shallow)	371.4	–	3.5	19.7	157.8	46.7	18.0	–	38.3	38.3
North Qld—Eromanga (Mid)	474.7	–	4.5	22.3	200.6	58.5	18.0	–	48.4	48.4
North Qld—Eromanga (Deep)	478.0	2.7	5.1	19.7	202.2	59.1	18.0	1.6	48.9	48.8
North NSW—Surat (Shallow)	399.6	–	5.1	38.4	177.2	57.6	18.0	–	20.8	20.8
North NSW—Surat (Mid)	373.1	–	7.4	38.4	167.5	55.3	18.0	–	19.7	19.7
North NSW—Surat (Deep)	387.6	–	9.6	42.5	175.9	59.0	18.0	–	20.7	20.7
South NSW—Gippsland (Nearshore)	285.8	–	20.4	5.3	124.6	35.5	0.1	–	36.6	36.6
South NSW—Gippsland (Intermediate)	317.3	–	28.8	5.3	140.5	40.5	0.9	–	41.3	41.3

	Annualised costs (A$m/year in 2015)									
	Pipelines	**Booster pumps**	**Wells**	**Facilities**	**On-costs**	**Total fixed operating costs**	**MMV**	**Energy costs**	**$/t CO_2 avoided**	**$/t CO_2 injected**
South NSW—Gippsland Central)	561.6	–	17.3	5.3	233.7	63.1	4.5	–	68.6	68.6
North NSW—Darling PR Core						–				
North NSW—Darling PR DST avg.	449.7	4.1	8.3	6.9	187.6	52.2	0.6	2.2	21.3	21.2
South NSW—Darling PR Core	282.1	–	3.4	4.0	115.8	31.2	0.6	–	33.9	33.9
South NSW—Darling PR DST	168.8	–	3.4	2.4	69.9	19.0	0.6	–	20.5	20.5
South NSW + Latrobe Valley—Gippsland (Nearshore)	Not assessed					–				
South NSW + Latrobe Valley—Gippsland (Intermediate)	302.4	4.1	65.9	10.5	153.1	50.3	0.9	3.2	19.0	18.9
South NSW + Latrobe Valley—Gippsland (Central)	336.4	4.1	8.0	10.5	143.6	42.0	4.5	3.5	17.8	17.7
North + South NSW—Surat (Shallow)	467.5	6.9	7.8	33.8	206.4	66.0	18.0	5.6	15.8	15.8
North + South NSW—Surat (Mid)	445.7	6.9	11.3	27.2	196.4	61.8	18.0	5.8	15.0	15.0
North + South NSW—Surat (Deep)	432.4	6.9	14.7	2.3	182.5	50.9	18.0	3.4	13.8	13.8
North + South NSW—Eromanga (Shallow)	917.7	20.6	10.1	51.1	399.8	125.2	18.0	14.0	30.4	30.2
North + South NSW—Eromanga (Mid)	1,013.3	20.6	13.0	53.7	440.2	136.6	18.0	14.5	33.4	33.2
North + South NSW—Eromanga (Deep)	1,137.6	20.6	14.7	56.4	491.7	150.8	18.0	16.4	37.3	37.0
North + South NSW—Darling PR Core	Not assessed					–				
North + South NSW—Darling PR DST avg.	Not assessed					–				
North + South NSW—Cooper (Shallow)	929.9	20.6	14.4	50.2	406.0	126.9	15.8	13.6	34.2	34.0

	Annualised costs (A$m/year in 2015)									
	Pipelines	Booster pumps	Wells	Facilities	On-costs	Total fixed operating costs	MMV	Energy costs	$/t CO_2 avoided	$/t CO_2 injected
North + South NSW—Cooper (Mid)	851.0	27.4	14.9	45.7	375.6	120.0	15.8	21.2	32.0	31.7
North + South NSW—Cooper (Deep)	807.4	27.4	16.2	45.7	358.7	115.8	15.8	25.5	30.8	30.4
Southwest WA—North Perth Offshore (Shallow)	177.9	–	12.7	4.3	77.9	22.5	7.0	–	36.0	36.0
Southwest WA—North Perth Offshore (Mid)	177.9	–	17.0	4.3	79.6	23.4	7.0	–	36.8	36.8
Southwest WA—North Perth Offshore (Deep)	193.2	–	11.5	4.3	83.6	23.9	7.0	–	38.5	38.5
Southwest WA—North Perth Onshore (Shallow)	151.8	–	2.3	2.6	62.6	17.0	2.0	–	28.4	28.4
Southwest WA—North Perth Onshore (Mid)	166.4	–	3.1	2.8	68.9	18.8	2.0	–	31.2	31.2
Southwest WA—North Perth Onshore (Deep)	151.8	1.4	3.9	2.6	63.8	17.9	2.0	0.9	29.2	29.1
Southwest WA—Lesueur (Shallow)	17.1	–	2.1	0.4	7.8	2.3	0.1	–	3.6	3.6
Southwest WA—Lesueur (Mid)	13.5	–	2.8	0.3	6.7	2.1	0.1	–	3.0	3.0
Southwest WA—Lesueur (Deep)	11.9	2.7	3.9	0.3	7.5	3.2	0.1	2.5	3.8	3.8
Kwinana—Lesueur (Shallow)	12.2	–	2.1	0.3	5.9	1.8	0.1	–	2.7	2.7
Kwinana—Lesueur (Mid)	10.8	–	2.8	0.3	5.6	1.8	0.1	–	2.5	2.5
Kwinana—Lesueur (Deep)	9.5	2.7	3.9	0.3	6.6	3.0	0.1	2.5	3.4	3.4

22
AUSTRALIAN OXYFUEL DEMONSTRATION

This chapter was written by Mr Jim Craigen and Dr Chris Spero

Oxyfuel—highlights:

- The Australian Callide Oxyfuel Project successfully demonstrated the feasibility of oxyfuel combustion for over 10,000 hours in the largest low-emissions coal plant demonstration in Australia.
- Ramp rates equivalent to air-fired operation were demonstrated.
- The operational flexibility of an oxyfuel boiler was tested and a 50% load factor turndown was achieved.
- A greater than 99.9% CO_2 purity offtake was achieved.
- A nearly complete capture of SO_x, NO_x, trace metals and particulates was demonstrated.

22.1 Overview

22.1.1 Objectives

The Callide Oxyfuel Project had two broad goals:

- To demonstrate a complete and integrated process of oxyfuel combustion of pulverised coal in a NEM facility, incorporating oxygen production, oxyfuel combustion and CO_2 processing and liquefaction; and to assess CO_2 transport and geological storage.
- To obtain detailed engineering design and costing data and operational experience to underpin the commercial development and deployment of new and retrofitted oxyfuel boilers for electricity generation.

22.1.2 Scope

Oxyfuel demonstration

The oxyfuel demonstration included the following elements:

- Refurbishment and retrofit of oxyfuel technology to Callide A Unit No. 4 (30 MW_e)
- Installation of 2 × 330 t/day air separation units (ASUs)
- Installation of a 75 t/day CO_2 capture plant treating a 15% sidestream of flue gas.

CO_2 transport and geological storage assessment

This work comprised four main activities:

- Collaboration with ZeroGen to appraise saline aquifers in the Northern Denison Trough

- Collaboration with Origin and Santos to appraise depleted natural gas fields in the Northern Denison Trough
- Collaboration with CTSCo on the development of a CO_2 storage trial in the Surat Basin
- GCCSI-funded studies on CO_2 storage site assessments and appraisal of Surat Basin storage potential.

22.1.3 Project funding and structure

The project funders and their contributions are shown in Table 118.

Table 118: Oxyfuel project funding

Funders	Funding ($m)
Australian coal industry (COAL21 Fund)	76.9
Australian Government	63.0
CS Energy (Queensland Government)	35.0
Glencore	1.0
Japanese Government	20.0
IHI	6.7
JPower	6.7
Mitsui	6.7
Subtotal	**216.0**
Other revenue (power sales, equipment salvage)	26.0
Schlumberger (in-kind)	2.0
Total	**244.0**

The overall structure of the project was an unincorporated joint venture managed by a steering committee made up of one representative of each funding party (Figure 144).

Oxyfuel Technologies Pty Ltd (OTPL) was established as an agent for the unincorporated joint venture. the assets of the project, including intellectual property, are owned by the joint venture participants (through OTPL) as tenants-in-common according to their respective shareholdings.

Callide Oxyfuel Services Pty Ltd (COSPL) was set up as the project management company through which the daily affairs of the project (except funding) are handled. All the contracts signed for the project have been executed through COSPL.

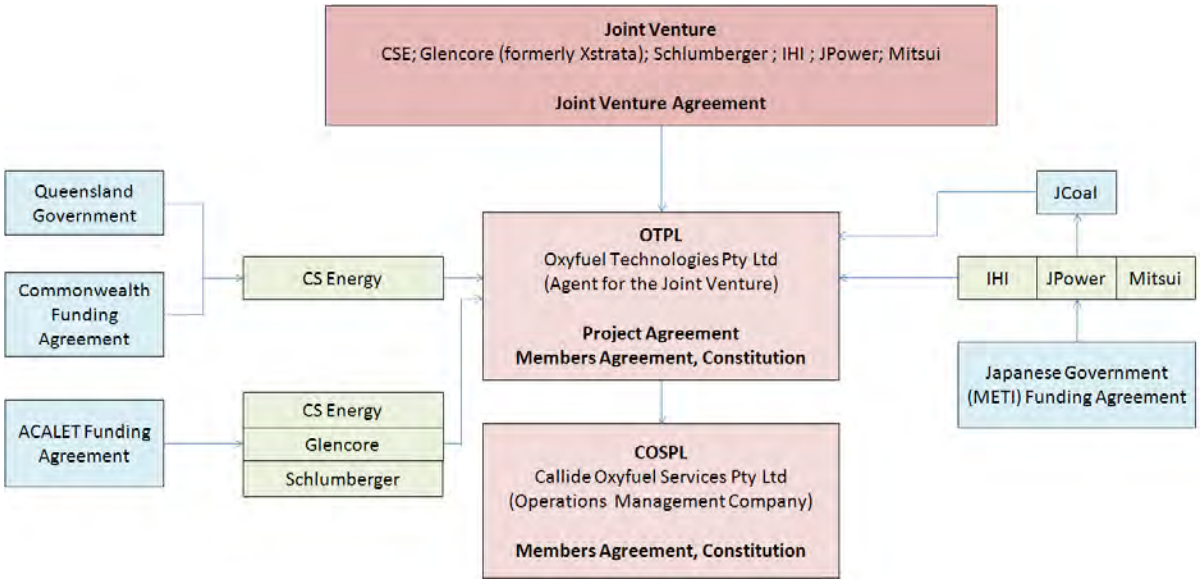


Figure 144: Callide Oxyfuel Project structure

22.2 Technical description

The Callide Oxyfuel Project consisted of:

- 2 x 330 t/day cryogenic air separation units (ASUs)
- an oxyfuel boiler (30 MW_e generating capacity)
- a CO_2 purification unit (CPU).

These components are shown schematically in Figure 145. The CPU comprises a flue gas low-pressure pre-treatment plant (100 t/day), flue gas high-pressure treatment, a CO_2 liquefaction plant (75 t/day) and a CO_2 load-out tank and facilities.

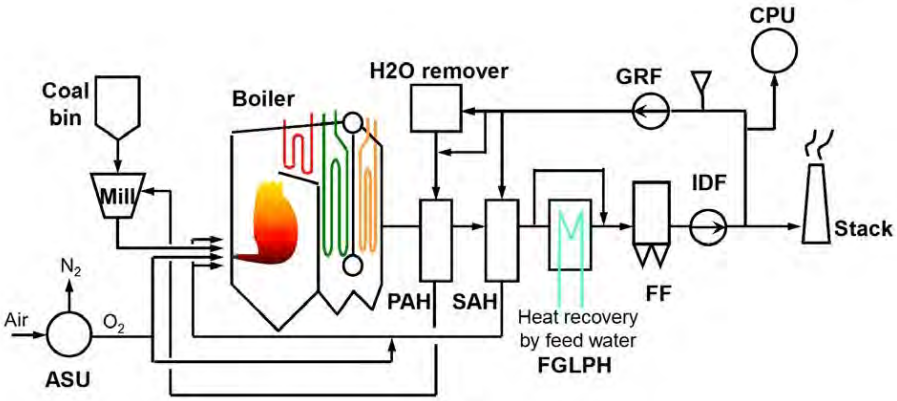


Figure 145: Callide oxyfuel process

ASU = air separation unit; CPU = CO_2 purification unit; FF = fabric filter; FGLPH = flue gas low-pressure heater; GRF = gas recirculation / forced draft fan; IDF = induced draft fan; PAH = primary air heater; SAH = secondary air heater

22.2.1 Air separation unit

The ASUs deliver 98% pure oxygen at 1.8 bar_A. They are a standard commercial design and can turn down to 80% of full load. Oxygen production rates can be modulated (to an extent) to match boiler consumption rates. Each train is fitted with safety shutdown skids to isolate the ASUs from the boiler.

22.2.2 Oxyfuel boiler

The operational intent in oxyfiring mode is to achieve furnace heat absorption similar to that under air-firing conditions. In air-firing mode, the overall oxygen concentration at the boiler inlet (primary air plus secondary air) is 21% by volume. Under oxyfiring conditions, the overall oxygen concentration at the boiler inlet (primary gas plus secondary gas) is maintained within the 24–30% by volume range. The change from air-firing to oxyfiring (and vice versa) is made at 80% load or above and is completed within 90 minutes under full automatic control.

In air-fired mode, as with all boilers, the flue gas oxygen content is controlled by adjusting the airflow to ensure that there is adequate excess air for complete combustion. In oxyfiring mode, the flue gas oxygen content is controlled by adjusting both the amount of oxygen injected into the secondary gas stream and regulating recycled flue gas flow.

The Callide oxyfuel boiler has the following components (see Figure 146):

- 3 pulverising mills, of which 2 are required for full-load operation
- 6 burners (2 per mill), 4 of which are required for normal operation
- a water remover in the primary gas duct to remove sulphur trioxide to prevent corrosion
- a flue gas low-pressure heater cooled against boiler feedwater at the boiler outlet to reduce the temperature of the flue gas before the fabric filter.

Oxygen from the ASUs is mixed with recycled flue gas after the secondary air heater. In addition, a part of the oxygen can be supplied to the burner flame area directly

In oxyfuel operation, flue gas is recycled from the outlet of the induced draft fan by a gas recirculation / forced draft fan.

Figure 146: View of Callide oxyfuel boiler equipment

A = boiler house; B = fabric filter; C = flue gas exit duct; D = recycled flue gas duct)

An important differentiation between air-firing and oxy-firing is the composition of the flue gas (Figure 147). Because nitrogen is removed by the ASUs, the CO_2 produced during combustion is concentrated into about one-quarter of the volume of flue gas that would be present under air-firing conditions. This allows the CO_2 to be purified and separated from the other gases (mainly nitrogen, oxygen and argon) using a physical (cryogenic) process rather than a chemical process.

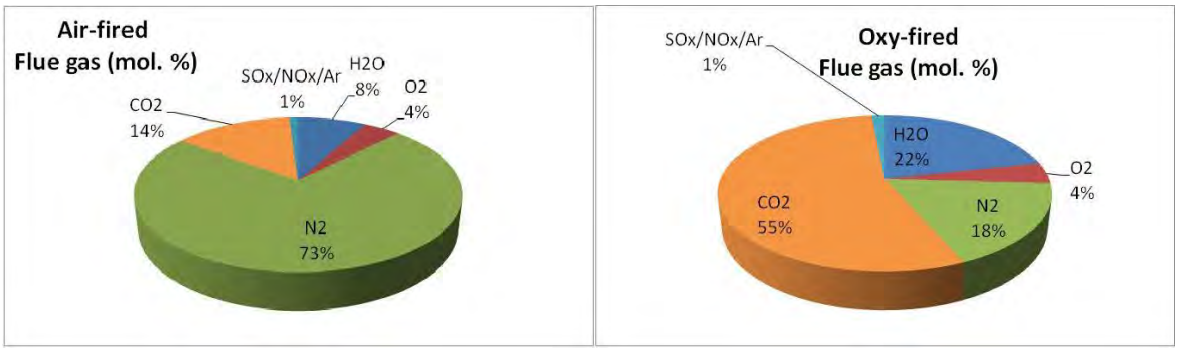


Figure 147: Typical flue gas composition under air-fired and oxy-fired conditions

In the final stages of commissioning of the oxyfuel boiler, attention was given to determining the optimal setpoints for several key variables: balance between primary gas and secondary gas to ensure good burner stability, minimisation of air ingress by mechanical improvements around some parts of the older boiler sections, and tuning of the oxygen mixing valve, which controls the flow of oxygen from the ASUs into the secondary air/gas duct to the boiler windbox.

Combustion efficiency was assessed in terms of unburned carbon in ash (measured as a loss-on-ignition of the fly ash). Overall, oxy-firing produced significantly lower carbon in ash levels than air-firing.

Furnace ash deposition and slagging propensity were evaluated by observation and by using two calculated parameters: temperature of critical viscosity and slagging index. Overall, for coals with higher slagging propensity, oxy-firing reduced ash deposition.

Oxy-firing also significantly reduces NO_x formation. This occurs because there is a reduction in the amount of atmospheric nitrogen involved and hence a reduction in thermal NO_x and because the recycled flue gas reburning in the furnace reduces NO_x back to nitrogen.

SO_x levels are 4–5 times higher than in air-firing because there is no nitrogen dilutant. There is a slightly higher absorption of SO_x by fly ash in oxy-firing. Mass balance calculations indicate that the mass emission rate of SO_x from oxy-firing is about the same or slightly less than in air-firing.

The Callide A facility uses standard fabric filters to control particulate emissions from the boiler via the stack. Test results indicate that particulate mass emission rates are slightly lower with oxy-firing because of the water remover spray-down in the CPU.

22.2.3 Water remover and air heaters

As indicated in Figure 145, the recycled flue gas is split into two streams (primary and secondary), which substitute for primary air and secondary air in air-firing. Initially, the primary stream is cooled directly using process water in the water remover vessels to reduce its moisture content to around 8% and remove sulphur trioxide (this cooler is by-passed in air-firing mode). The cooled gas then enters the primary gas/air heater and is heated to 350°C.

The secondary stream is heated in the secondary air heater to 280°C. Oxygen is mixed with the heated gas and the mix is passed to the windbox through adjustable air/gas registers around the burners to support the combustion of the coal that is entering with the primary stream. For safety and practical reasons, no oxygen is fed with the primary stream.

22.2.4 Flue gas low-pressure heater

Although the oxyfuel boiler was designed to achieve a similar heat flux to air-firing, the flue gas temperature exiting the boiler is higher because the air side of the secondary air heater (usually at 30 °C) is now at 150°C in oxy-combustion mode and requires a flue gas cooler to protect the fabric filter (a bag-house). In oxy-firing, the temperature of the flue gas exiting the secondary air heater is 250°C. The cooler reduces it to 150°C. Boiler feedwater is used for cooling, and the heat added increases generating efficiency by reducing steam extraction to heat the boiler feedwater. During air-firing, the flue gas cooler can be bypassed, as the flue gas is at the required temperature of 150°C.

22.2.5 Gas recirculation / forced-draft and induced-draft fans

The original forced-draft and induced-draft fans were replaced as part of the oxyfuel retrofit to allow for the additional pressure required for the flue gas recirculation system and, in the case of the forced-draft fan, the higher temperature of the recycled flue gas compared to normal intake air temperature. The control systems were also modified to more closely control flow-rates, which is especially important during the air-to-oxygen and oxygen-to-air transitions.

22.2.6 CO_2 purification unit

The cryogenic CPU is designed to deliver a net production of 75 tCO_2/day at 99.9% purity, 16.2 bar and –30°C for transportation in road tankers (Figure 148). The nominal CPU production rate is 100 t/day, but around 25% of the CO_2 product is recycled and used in the process to separate gases and purify the CO_2 product.

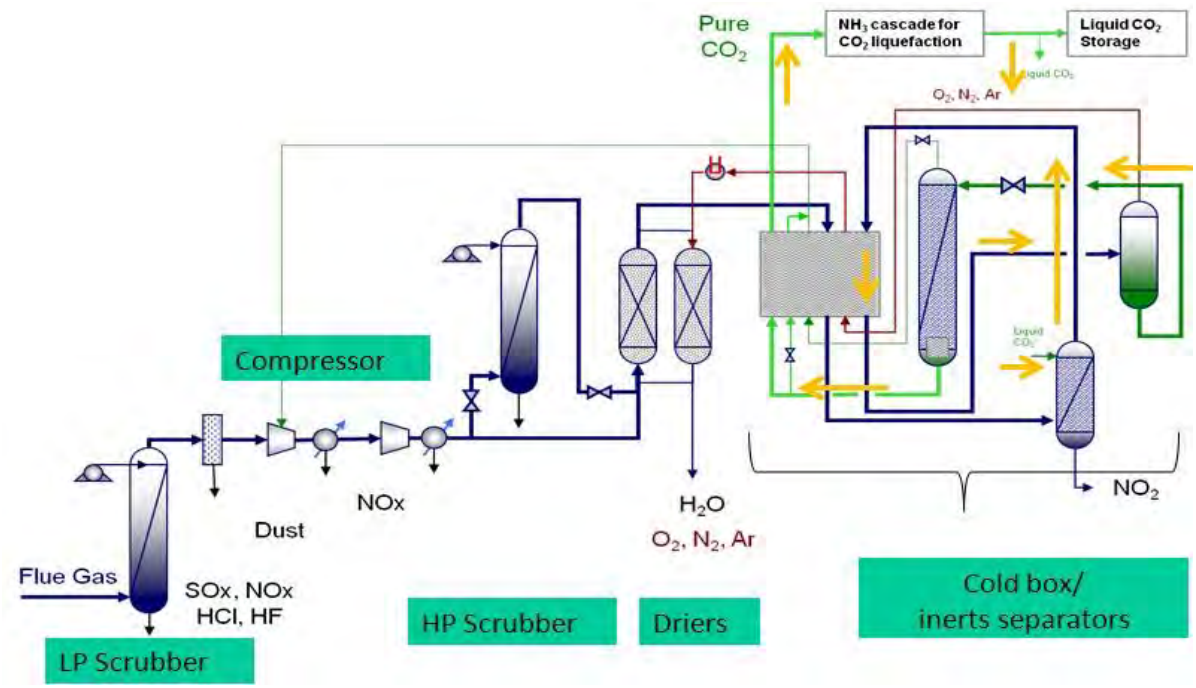


Figure 148: Schematic of Callide A CO_2 capture plant

Source: Air Liquide.

As in all Australian coal-fired boilers, there is no selective catalytic reduction for NO_x control or flue gas desulphurisation. Hence, upstream of the CPU, the flue gas is cooled and neutralised in a low-pressure scrubbing column with a caustic soda and water wash that removes the sulphur dioxide, hydrogen chloride, hydrogen fluoride and nitrogen dioxide. The exiting flue gas is blown through a fabric filter and screen filter to remove any carryover particulates and then enters an Atlas Copco four-stage centrifugal compressor with inter- and after-coolers. The coolers condense additional gaseous contaminants, and the acidic water formed also removes most of the mercury. The flue gas is then further cooled and washed with chilled water in a high-pressure column and then dried in pressure-swing absorption columns that use recycled non-condensable gases (nitrogen, oxygen and argon) separated from the CO_2 upstream in the cryogenic stage for regeneration. The final CO_2 separation involves a cryogenic plant with an ammonia refrigeration circuit and recycled CO_2 to achieve liquefaction of the near-pure CO_2 product.

The CO_2 liquefier is coupled with a standard ammonia refrigeration plant and sits above a 100 t CO_2 storage tank. The final CO_2 product is maintained at 1,450–2,300 kPa and –27°C.

22.3 Overall performance

The CPU has operated reliably, easily exceeding the 4,000 operating hours target and producing CO_2 at purities exceeding 99.9%.

It has also demonstrated almost complete removal of all non-CO_2 emissions (such as SO_x, NO_x, particulates and trace elements) from the flue gas stream, which are then disposed of via the waste ash/condensate streams of the process.

Measurements by Macquarie University indicate that virtually all trace element species in the raw flue gas, including mercury, halogens and halides, are effectively absorbed in the condensate stream.

22.4 CO_2 transport and storage

One of the objectives of the Callide Oxyfuel Project was to facilitate the testing and/or demonstration of CO_2 geological storage. The Queensland Government's Carbon Geo-storage Initiative had previously mapped potential CO_2 storage reservoirs in the state. That work established and ranked the prospectivity of various geological basins in Queensland for CO_2 storage and estimated the storage potential of 'high-prospectivity' areas to be more than 50 billion tonnes (Figure 149).[1]

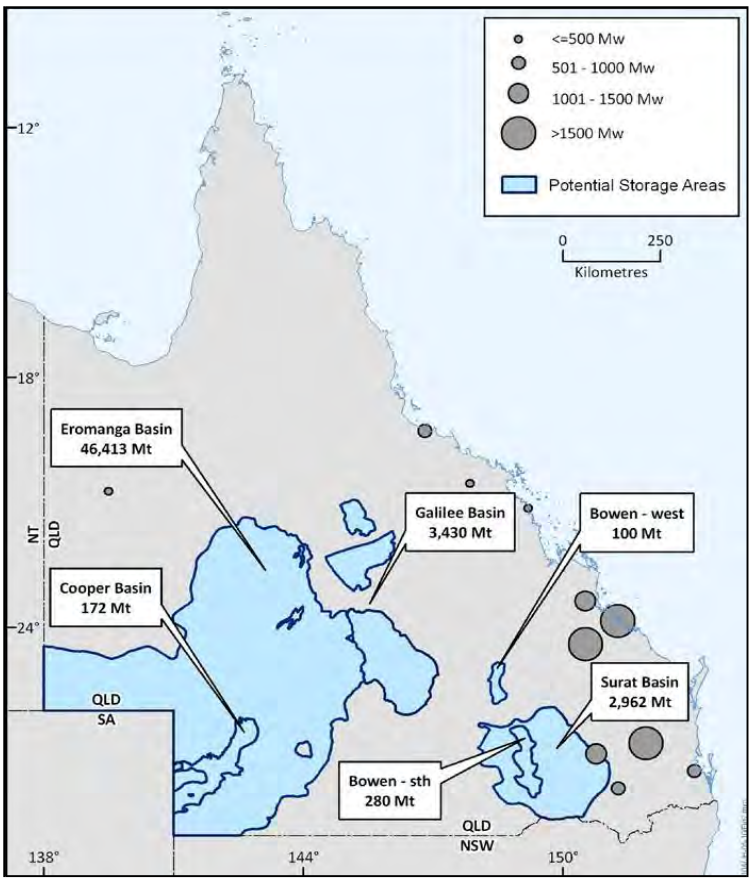


Figure 149: Maximum potential CO_2 storage for high-prospectivity areas in Queensland

Source: BE Bradshaw, LK Spencer, AL Lahtinen, K Khider, DJ Ryan, JB Colwell, A Chirinos, J Bradshaw, JJ Draper, J Hodgkinson, M McKillop (2010), *An assessment of Queensland's CO_2 geological storage prospectivity—The Queensland CO_2 Geological Storage Atlas*, Global CCS Institute, August.

With support from the Global CCS Institute, the Callide Oxyfuel Project conducted an initial appraisal and assessment of a number of CO_2 storage options in the Surat Basin, including for the road transportation of CO_2 from Callide A. The project also carried out a number of other studies related to CO_2 storage, including evaluations of CO_2 product specifications, the storage potential of depleted natural gas fields in the Northern Denison Trough in central Queensland, and the storage potential of sandstone aquifers in the northern and southern Surat Basin in south-east Queensland.

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[1] BE Bradshaw, LK Spencer, AL Lahtinen, K Khider, DJ Ryan, JB Colwell, A Chirinos, J Bradshaw, JJ Draper, J Hodgkinson, M McKillop (2010), *An assessment of Queensland's CO_2 geological storage prospectivity—The Queensland CO2 Geological Storage Atlas*, Global CCS Institute, August.

Subsequently, a detailed appraisal considered the storage potential of gazetted tenements in the northern and southern parts of the Surat Basin. The study concluded that the combined storage potential of five tenements was more than 900 Mt. The appraisal described the assessment methodology and the general geography of the areas, characterised and ranked the sites according to social and environmental factors, and outlined access, infrastructure, injectivity, storage capacity and containment. It also summarised core and bore-hole data in the public domain, including stratigraphic profiles and hydrological data.

A further study was conducted on the environmental and social factors relevant to large-scale geological storage of CO_2, on the basis of a staged development involving:

- road transport of initially small volumes of CO_2 from the Callide A plant for an injection and storage trial
- pipeline transport for a nominal 1 Mt CO_2 per year over 250 km from a large producer of CO_2, such as a coal-fired power station.

The report included:

- a summary and explanation of the important properties of CO_2, including impurities that affect health and safety aspects of CO_2 transport and storage
- a technical review of road and pipeline transport technology
- an appraisal of environmental and social factors, including descriptions of the content of an environmental management plan and a health and safety plan for CO_2 transport and geological storage.

22.5 Permitting

22.5.1 Environmental factors

The permitting of the Callide Oxyfuel Project was done as an extension to the existing Callide A developmental approval through the Queensland Department of Environment and Heritage Protection. It was determined that the additions did not materially affect the scale or the primary purpose of the facility (the production of electricity).

The final licensing arrangements for operations under oxy-firing conditions were developed consultatively with the department. A large number of release points, with specific coordinates and heights, were registered. The Callide plant has managed its environmental obligations successfully.

In future oxyfuel plants, further attention could be given to rationalising the number of gas vents, especially around the CO_2 capture plant, the option of processing and recovering potable water from wastewater streams, and the beneficial use of other waste streams, such as vented nitrogen and argon and nitric acid that is condensed in the flue gas compressor coolers.

22.5.2 Safety factors

A key aspect of the commissioning and operation of the Callide Oxyfuel Project was the identification, assessment and management of potential new workplace health and safety hazards associated with operation of the boiler for oxy-firing and CO_2 capture.

During the design phase, hazard and operability studies (HAZOPs) were conducted on each major section of plant and on the overall system by teams comprising representatives from the original equipment manufacturers or vendors, the operator, the owner and a hazardous operations specialist. Sign-offs were required before the hot commissioning of plant.

Hazardous areas and the controls needed to manage the hazards were identified and assessed. The hazards and their mitigation are outlined in a report available on the GCCSI website

22.6 Communications

A communications plan, including stakeholder engagement guidelines and communications protocols, was developed early in the project and regularly reviewed and updated. Activities included a project website, newsletters, media releases, media tracking, legacy publications, site visits and events to mark the achievement of key milestones.

Public consultation and external stakeholder liaison were an important part of the project. This included:

- displays at trade expos, conferences and the local shopping mall
- presentations to the state and local governments, the regional development authority, environmental groups, service clubs, business groups, school groups and professional organisations
- open days at Callide A for schools and the public
- site tours for university groups and Australian and international research institutions and industry groups.

Overall, the project has kept stakeholders, interested parties and the public well informed about its activities and objectives. Without exception, the response to the Callide Oxyfuel Project has been overwhelmingly positive.

22.7 Project milestones

Table 119 lists milestones for the project.

Table 119: Callide Oxyfuel Project key milestones

Milestone	Date
Project idea conceived	November 2003
Oxyfuel technology included in COAL21 National Action Plan	March 2004
Japan–Australia Feasibility Study; memorandum of understanding signed	September 2004
Australian Government LETDF Program—funding announced	October 2006
Oxy-firing pilot tests completed at IHI facility in Aioi, Japan (3 × 10 t coal tested)	January 2007
Feasibility study completed (published April 2008)	November 2007
Project funding agreements executed	March 2008
Project financial close: plan and budget approved by joint venture	July 2008
Plant supply contracts awarded: Air Liquide, GLP Plant, CBH, Siemens	August 2008
Plant refurbishment completed	January 2009
Site construction works begun	March 2010
Oxyfuel boiler retrofit completed	March 2011
ASU plant construction completed	October 2011
Commissioning works begun	February 2012
Practical completion of ASUs and oxyfuel boiler	June 2012
Practical completion of CPU: commissioning complete	December 2012
Opening ceremony at site; operational phase begun	December 2012
Review of Surat Basin CO2 Storage Options published (GCCSI)	May 2013
Air Liquide 1st performance test (Passenger Test) complete	June 2013
1st industrial operation milestones: oxyfuel boiler 3,600 hours, CPU 900 hours	June 2013
Site visit and collaborative workshop with Futuregen 2.0	August 2013
IHI high-temperature corrosion probes installed	October 2013
In-furnace measurements on oxyfuel boiler	Nov 2013
Oxyfuel boiler turndown tests completed	January 2014
2nd industrial operation milestones: oxyfuel boiler 5,500 hrs, CPU 2,500 hrs	March 2014
Air Liquide 2nd performance test (passenger test) completer	April 2014
Lessons learned report published (GCCSI)	May 2014
4,000 operating hours target for CPU achieved	**August 2014**
Oxyfuel boiler turndown tests completed	August 2014
Oxyfuel boiler load change rate tests completed	Sept 2014
Oxyfuel boiler direct oxygen injection tests completed	Sept 2014
Oxyfuel boiler mode change optimisation completed	October 2014
Otway injection tests completed	December 2014
10,000 operating hours target for oxyfuel boiler achieved	**February 2015**
Operational phase complete: site decommissioning begun	March 2015

22.8 Conclusion

The principal driver for oxy-firing technology development has been CO_2 capture; the secondary driver has been the need to reduce other flue gas emissions.

The Callide Oxyfuel Project has demonstrated the technical viability of oxyfuel technology, exceeding the target operating hours for both the oxyfuel boiler and the CPU.

Oxy-firing and CO_2 capture at Callide A has almost completely removed all toxic gaseous emissions from the flue gas stream and disposed of them via the process's waste ash and condensate streams. It has also improved combustion efficiency, reducing the quantity of furnace ash deposits.

The project has provided a great deal of knowledge and experience to inform future oxyfuel technology development and made a useful contribution to knowledge about the geological storage of CO_2 and the safety and environmental aspects of oxyfuel combustion.

23 ABBREVIATIONS AND ACRONYMS

AC	alternating current
AEMC	Australian Electricity Market Commission
AEMO	Australian Electricity Market Operator
AGR	acid gas removal
AGRU	acid gas removal unit
ASU	air separation unit
BEC	bare erected cost
CCS	carbon capture and storage
CO	carbon monoxide
CPV	concentrating photovoltaic
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CSP	concentrating solar thermal power
D_2O	heavy water
DC	direct current
DKIS	Darwin Katherine Interconnected System
DNI	direct normal irradiation / insolation
EPC	engineering, procurement and construction
EPCM	engineering, procurement, and construction management
EPRI	Electric Power Research Institute, Inc.
FCAS	frequency control ancillary services
FGD	flue gas desulphurisation
HHV	higher heating value
HRSG	heat recovery steam generator
HSIP	highest safe injection pressure
HTR	high-temperature gas-cooled reactor
HV	high voltage
HVDC	high-voltage direct current
IEA	International Energy Agency

IGBT	insulated-gate bipolar transistor
IGBT	insulated-gate bipolar transistor
IGCC	integrated gasification combined cycle
ILR	inverter load ratio
IP	intermediate pressure
LCC	Line commutated converter
LCOE	levelised cost of electricity
LFR	linear Fresnel reflector
LP	low pressure
MAWP	maximum allowable working pressure
MDEA	methyl diethanolamine
MEA	monoethanolamine
MHI	Mitsubishi Heavy Industries
MHI	Mitsubishi Heavy Industry
MPC	market price cap
MTTF	mean time to fail
MTTR	mean time to repair
MV	medium voltage
NEM	National Electricity market
NOx	nitrogen oxide, nitrogen dioxide
NWIS	North West Interconnected System
O&M	operating and maintenance
OECD	Organisation for Economic Co-operation and Development
OEM	Original equipment manufacturer
PC	pulverised coal
PCC	post-combustion capture
PHWR	pressurised heavy water reactor
PV	photovoltaic
R&D	research and development
RET	Renewable Energy Target

SAT	single-axis tracking
SCA	solar collector assembly
SCADA	supervisory control and data acquisition
SCR	selective catalytic reduction
SWER	single-wire earth return
SWIS	South West Interconnected System
T&S	transportation and sequestration
TPC	total plant cost
TRL	technical readiness level
US	United States
USE	unserved energy
USGC	US Gulf Coast
VAR	Volt amp reactive
VSC	voltage source converter
VSP	vertical seismic profiling
WACC	weighted average cost of capital
WEM	Wholesale Electricity Market

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