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Australian Energy Technology Assessment

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About the Bureau of Resources and Energy Economics

The Bureau of Resources and Energy Economics (BREE) is a professionally independent, economic and statistical research unit within the Australian Government's Resources, Energy and Tourism (RET) portfolio. The Bureau was formed on 1 July 2011 and its creation reflects the importance placed on resources and energy by the Australian Government and the value of these sectors to the Australian economy.

BREE's mission is to support the promotion of the productivity and international competiveness of Australia, the enhancement of the environmental and social sustainability, and Australia's national security within the resources and energy sectors. To this end, BREE uses the best available data sources to deliver forecasts, data research, analysis and strategic advice to the Australian government and to stakeholders in the resources and energy sectors.

The Executive Director/Chief Economist of BREE is Professor Quentin Grafton. He is supported by a dedicated team of resource and energy economists as well as an advisory board. The board is chaired by Drew Clarke, the Secretary of the Department of Resources, Energy and Tourism, and includes prominent Australian experts from both the private and public sectors.

For more information on BREE and its outputs, please visit www.bree.gov.au or contact BREE by mail, telephone or email.

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Foreword

Over the coming decades, the Australian electricity sector will need to adjust to unprecedented changes in the relative cost of electricity generation technologies from technological innovation, movements in the fuel prices and climate change policies.

If planners and investors in the electricity sector are to effectively manage and adapt to this energy transformation, up-to-date and rigorous estimates of the cost of various electricity generation technologies are required.

The *Australian Energy Technology Assessment* (AETA) 2012 provides the best available and most up-to-date cost estimates for 40 electricity generation technologies under Australian conditions. These costs, detailed in this report and in an accompanying model, are provided by key cost component and include a levelised cost of electricity (LCOE) that allows for cross-technology and over time comparisons. The AETA has been developed in close consultation with a project steering committee whose members were selected on the basis of their high-level of technical expertise and also a stakeholder reference group drawn from industry and research/academic organisations with interests and knowledge in a diverse range of electricity generation technologies.

The AETA provides a high level of transparency. Comprehensive details of the underlying methodology, assumptions, parameter values and component costs are provided in the report and/or AETA model. AETA parameters and costs will be invaluable to energy companies, regulators and operators who need detailed cost comparisons across energy technologies and for planning purposes.

An integral component of the AETA that complements the AETA report is the AETA model that was developed to generate LCOE by state, by year and by technology. The AETA model is free to download from www.bree.gov.au and allows users to change many of the principal model parameters such as the capacity factor, the carbon price and discount rate.

The AETA model is the only one of its kind that is provided free of charge and enables users to apply their particular assumptions to construct their own LCOE based on Australian conditions. It will be essential to energy modellers and, indeed, anyone interested in exploring different scenarios and energy futures.

To ensure the cost estimates are the most recent and account for the latest technical and commercial developments, parameters of the AETA model will be updated, as required, biannually with assistance from the AETA stakeholder reference group. A fully updated AETA report and model is expected biennially.

The AETA 2012 provides many important insights including the finding that Australia's electricity generation mix out to 2050 is likely to be very different to its current state. The policy implications of this expected energy transformation will be reviewed in the Australian government's *Energy White Paper* due for release later in 2012.

Quentin Grafton
Executive Director/Chief Economist
July 2012

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Acronyms/Abbreviations

AEMO	Australian Energy Market Operator
ASU	Air Separation Unit
AUD	Australian Dollar
BOEMRE US	Bureau of Ocean Management Regulation and Enforcement
BOP	Balance of Plant
BREE	Bureau of Resources and Energy Economics
BSE	BrightSource Energy
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CLFR	Compact Linear Fresnel Technology
CSIRO	Commonwealth Scientific Industrial Research Organisation
CWF	Coal Water Fuel
CWS	Coal Water Storage
CPI	Consumer Price Index
CQ	Central Queensland
DICE	Direct Injection Coal Engine
DOE	US Department of Energy
DRET	Department of Resources Energy and Tourism
EGS	Enhanced Geothermal System
EPC	Engineering, Procurement, Construction
EPRI	Electric Power Research Institute
ESP	Electrical Service Platform
E_t	Electricity generation in the year t
FGR	Flue Gas Recirculation
FOAK	First of a kind plant
FOM	Fixed Operational and Maintenance costs

F_t	Fuel expenditure in the year t
GALLM	Global and Local Learning Model
GDP	Gross Domestic Product
GDP/GSP	Gross Domestic Product/Gross State Product
GJ	Gigajoule
GWh	Gigawatt hour
HSA	Hot Sedimentary Aquifers
HHV	Higher Heating Value
HR	Hot Rock
HRSG	Heat Recovery Steam Generator
IDC	Interest During Construction
IGCC	Integrated Gas Combined Cycle
ISCS	Integrated solar combined cycle
I_t	Investment expenditure in the year t
kW	Kilowatt
LCOE	Levelised Cost of Energy
LRET	Large Scale Renewable Energy Target
MEA	Mono ethaline amine
MRC	Micronised Refined Coal
MRET	Mandatory Renewable Energy Target
MWAC	Megawatt (AC)
MPa	MegaPascal
M_t	Operations and maintenance expenditure in the year t
MW	Megawatt
MWh	Megawatt hours
n	Amortisation Period
NEM	National Electricity Market

NOAK	nth of a kind plant
NQ	North Queensland
NREL	US National Renewable Energy Laboratories
NSW	New South Wales
NTNDP	National Transmission Network Development Plan
OEM	Original Equipment Manufacturer
O&M	Operations and Maintenance
ONCC	Overnight Capital Cost
OCGT	Open Cycle Gas Turbine
P_{50}	Value with a 50 per cent probability of confidence
P_{85}	Value with a 15 per cent probability of confidence
P_{95}	Value with a 5 per cent probability of confidence
p.a.	per annum
PC	Pulverised Coal
PJ	Peta Joule
PV	Photovoltaic
r	Discount Rate
SESAP	Secondary Enhancement of Sedimentary Aquifer Play
SEGS	Steam Electricity Generating Station
SEQ	South East Queensland
SMR	Small Modular Reactors
SRG	Stakeholder Reference Group
SWIS	South West Interconnecter System
USD	US Dollar
VOM	Variable Operational and Maintenance

Glossary

Amortisation Period: the period over which a plant must achieve its economic return.

Auxiliary Load: the internal or parasitic load from the electricity required to sustain the operation of a plant.

Battery Limit: the defined boundary for interfaces between the plant and the external infrastructure.

Capacity Factor: the ratio of the actual output of a power plant over a period of time and its potential output if it had operated at full nameplate capacity the entire time.

Capital Cost: the cost of delivery of a plant, not including the cost of finance.

Clean Energy Future Package: Australian Government Policy regarding pricing of Carbon, effective as of 1 July 2012.

Cost Confidence Level: the P_{95} confidence interval for capital cost estimates.

Direct Cost: the cost associated with all major plant, materials, minor equipment and labour to develop a power plant to the stage of commercial operation.

Discount Rate: the rate at which future values are discounted or converted to a present value.

Dispatchable generation: sources of electricity that can be dispatched at the request of power grid operators.

First-of-a-Kind Plant cost: costs necessary to put a first commercial plant in place and that will not be incurred for subsequent plants. Design and certification costs are examples of such costs.

First Year Available for Construction: the year in which the technology will be available for commercial deployment globally.

Gross Capacity: maximum or rated generation from a power plant without losses and auxiliary loads taken into account.

GT Pro: Thermoflow's specialised software for designing of a combined cycle or gas turbine cogeneration plant.

International Equipment Cost: the cost for internationally sourced equipment associated with the project.

Labour Cost: the component of the delivery cost for a plant associated with local (Australian) labour.

Lead time for Development: the time taken from inception to financial close. This includes permitting, approvals, and engineering design.

Levelised Cost of Energy: the minimum cost of energy at which a generator must sell the produced electricity in order to achieve its desired economic return.

Local Equipment Cost: the cost of locally sourced (Australia) plant and equipment for the project.

Nameplate Capacity: the intended technical full–load sustained output of a power plant.

Net Capacity: the export capacity of a generation plant – i.e. the Gross Capacity less the losses and auxiliary loads of the plant.

Non-Dispatchable Power: Power that is not continuously available due to the availability of the resource, and cannot be dispatched to meet the demand of a power system.

Nth-of-a-kind plant cost: All engineering, equipment, construction, testing, tooling, project management, and other costs that are repetitive in nature and would be incurred if a plant identical to a FOAK plant were built. The NOAK plant is the nth-of-a-kind or equilibrium commercial plant of identical design to the FOAK plant.

Owner's Cost: the costs associated with the development of a project prior to the start of construction.

Peace: Thermoflow's specialised software for the preliminary engineering and cost estimation of plant designed in GTPro and SteamPro.

Sequestration: the process of transport and storage of Carbon Dioxide (CO_2).

SOAPP-CT: Electric Power Research Institute's (EPRI) specialised software providing plant performance, capital and O&M cost estimates.

Steam Pro: Thermoflow's specialised software for designing a conventional (Rankine cycle) steam power plant.

Thermal Efficiency: the ratio between the useful energy output of a generator and the input, in energy terms.

Executive summary

The Bureau of Resources and Energy Economics (BREE) engaged WorleyParsons to develop cost estimates for 40 electricity generation technologies for the Australian Technology Energy Assessment (AETA). The AETA cost estimates were developed with the active collaboration of the Australian Energy Market Operator (AEMO) that has also used some of the AETA cost estimates for its National Transmission Network Development Plan (NTNDP). In addition, the Commonwealth Science and Industry Research Organisation (CSIRO) provided technical advice as part of the AETA project steering committee and the modelling framework for projecting changes in technology costs over time.

AETA cost estimates were developed to provide:

- Design basis and plant characteristics;
- Performance parameters;
- Capital cost estimates;
- Fuel cost estimates;
- O&M cost estimates; and
- Levelised Cost of Electricity (LCOE) estimates.

The cost estimates, available for each of 40 technologies, were generated on a 'bottom up' basis that accounted for the component costs that determine overall long-run marginal cost of electricity generation from a utility-scale and an Nth kind plant. The methods used to build up the cost estimates were applied consistently across all technologies and all the key assumptions used to generate the costs are fully detailed in this report and/or the accompanying AETA model.

Key findings of the AETA 2012 include:

1. Estimated costs of several fossil fuel-based electricity technologies differ from previous studies, primarily as a result of a carbon price and higher projected market fuel prices.
2. Estimated costs of solar photovoltaic technologies have dropped dramatically in the past two to three years as a result of a rapid increase in the global production of photovoltaic modules.
3. Differences in the cost of generating electricity, especially between fossil fuel and renewable electricity generation technologies, are expected to diminish over time.
4. Biogas and Biomass electricity generation technologies in 2012 are some of the most cost competitive forms of electricity generation and are projected to remain cost competitive out to 2050.
5. By 2030 some renewable technologies, such as solar photovoltaic and wind on-shore, are expected to have the lowest LCOE of all of the evaluated technologies.

6. Among the non-renewable technologies, combined cycle gas (and in later years combined with carbon capture and storage) and nuclear power, offer the lowest LCOE over most of the projection period and they both remain cost competitive with the lower cost renewable technologies out to 2050.
7. For some technologies, LCOE is projected to increase over time. This is because of a projected weakening of the Australian-dollar exchange rate from its current historic highs that will increase the cost of imported power plant components in Australian dollar terms and also because of projected increases in labour costs in excess of the consumer price index. In addition, for fossil-fuel technologies that generate CO_2 emissions, increased costs are projected from assumed increases in the carbon price out to 2050.

The results indicate that Australia's energy future is likely to be very different to the present. This has profound implications for electricity networks, how energy is distributed and Australia's ability to meet its targeted greenhouse gas emissions reductions.

1. Introduction

The Australian Energy Technology Assessment (AETA) 2012 provides the best available and most recent cost estimates for generating electricity from a wide variety of technologies under Australian conditions. It contains cost estimates for 40 utility-scale electricity generation technologies which are presently commercially available or at an advanced stage of development. These technologies encompass a diverse range of energy sources including renewable energy (such as wind, solar, geothermal, biomass and wave power), fossil fuels (such as coal and gas), and nuclear power.

The AETA report provides consistent and transparent cost estimates for the 40 chosen technologies and separates equipment costs into their local and international components. The costs are generated from an accompanying AETA model that is free to download from the Bureau of Resources and Energy Economics (BREE) website at www.bree.gov.au.

A key comparative cost across technologies is the Levelised Cost of Electricity (LCOE) that is expressed in real Australian dollars per Megawatt hour of electricity generation ($/MWh). The LCOE is the price at which electricity must be generated from a specific plant to break even, taking into account the costs incurred over the life of the plant (capital cost, cost of capital/financing, operations and maintenance costs, cost of fuel, carbon price and CO_2 sequestration). LCOE is equivalent to a long-run marginal cost of electricity generation. While LCOE is an invaluable tool for comparing technology costs, power generation companies and/or investors who wish to choose a technology to deploy would also need to consider other criteria such as site-specific costs, technology performance characteristics and experience with the technology prior to any final investment decision.

Section 2 of the AETA report lists the 40 technologies and outlines, the methods and also the macroeconomic and technical assumptions used to generate cost estimates. Section 3 provides all the core component costs by technology in the following categories: coal-based; gas-based; solar-thermal; solar thermal-hybrid; photovoltaic; wind; wave; biomass; geothermal; and nuclear technologies. The projected LCOE by technology out to 2050 are given in Section 4. A relative ranking of the technologies and comparisons of the capital costs and LCOE estimates to previous Australian and international studies, are provided in Section 5. Section 6 offers concluding remarks.

2. Methods and Assumptions

Key points

Generation Technologies

- 40 utility-scale generation technologies, including both fossil fuel based and renewables, are evaluated.

Macro assumptions

- Key macroeconomic assumptions are consistent with those detailed by the Australian Energy Market Operator in its National Transmission Network Development Plan and by the Australian Treasury.

Technical assumptions

- All technologies are costed on a consistent and transparent basis, with itemisation of component costs.
- Capital costs include direct (e.g. engineering, procurement and construction) and indirect (e.g. owners) costs, but exclude transmission and decommissioning costs.
- Future cost estimates include assumptions about the exchange rate, productivity variation, commodity variation and technology improvements.
- Fuel cost estimates are based on ACIL Tasman projections.
- Projected growth rates for future operating and maintenance costs are provided.

Levelised cost of energy (LCOE)

LCOE can be interpreted as the long-run marginal cost of electricity generation. Key factors used to calculate LCOE by technology include: amortisation period, discount rate, capacity factor, CO_2 emissions factor, CO_2 capture rate, CO_2 emission price, CO_2 storage cost, fuel cost, variable and fixed O&M cost, and the capital cost.

2.1 Electricity Generation Technologies

The 40 AETA electricity generation technologies are:

1. Integrated Gasification and Combined Cycle (IGCC) plant based on brown coal
2. IGCC plant with Carbon Capture and Sequestration (CCS) based on brown coal
3. IGCC plant based on bituminous coal
4. IGCC plant with CCS based on bituminous coal
5. Direct injection coal engine (clean lignite, e.g. brown coal technology)
6. Pulverised coal supercritical plant based on brown coal
7. Pulverised coal supercritical plant with post combustion CCS based on brown coal
8. Pulverised coal subcritical plant with post combustion CCS based on brown coal (retrofit)

9. Pulverised coal supercritical plant based on bituminous coal
10. Pulverised coal supercritical plant based on bituminous coal - SWIS relevant scale
11. Pulverised coal supercritical plant with CCS based on bituminous coal
12. Pulverised coal subcritical plant with post combustion CCS based on bituminous coal (retrofit)
13. Adding CCS to existing Combined Cycle Gas Turbine (CCGT) power plants (retrofitting)
14. Oxy combustion pulverised coal supercritical plant based on bituminous coal
15. Oxy combustion pulverised coal supercritical plant with CCS based on bituminous coal
16. Combined cycle plant burning natural gas
17. Combined cycle plant burning natural gas - SWIS relevant scale
18. Combined cycle plant with post combustion CCS
19. Open cycle plant burning natural gas
20. Solar thermal plant using compact linear fresnal reflector technology w/o storage
21. Solar thermal plant using parabolic trough technology w/o storage
22. Solar thermal plant using parabolic trough technology with storage
23. Solar thermal plant using compact linear fresnal reflector technology with storage
24. Solar thermal plant using central receiver technology w/o storage
25. Solar thermal plant using central receiver technology with storage
26. Solar photovoltaic (PV) - non-tracking
27. Solar photovoltaic (PV) - single axis tracking
28. Solar photovoltaic (PV) - dual axis tracking
29. Wind (on-shore)
30. Wind (off-shore)
31. Wave/Ocean
32. Geothermal - hot sedimentary aquifer (HSA)
33. Geothermal - enhances geothermal system (EGS)
34. Landfill gas power plant
35. Sugar cane waste power plant
36. Other biomass waste power plant (e.g. wood)
37. Nuclear; Gen 3+
38. Nuclear; Small Modular Reactors (SMR)
39. Solar/coal hybrid
40. Integrated solar combined cycle (ISCS) – parabolic trough with combined cycle gas.

AETA cost estimates were developed to provide:

- Design basis and plant characteristics;
- Performance parameters;
- Capital cost estimates;
- Fuel cost estimates;
- O&M cost estimates; and
- Levelised Cost of Electricity (LCOE) estimates.

Technology cost estimates were calculated for the years 2012, 2020, 2025, 2030, 2040 and 2050. A LCOE in a given year is only provided for those technologies that are considerd commercially deployable at that point in time.

Regional impacts on capital and operating costs have been incorporated in the analysis. These regions include:

- Victoria
- New South Wales (including ACT)
- South Queensland (incorporating the South East Queensland, and Central Queensland AEMO regions)
- North Queensland (incorporating the North Queensland AEMO region)
- Northern Territory
- North WA (Pilbara region)
- South WA (the South West Interconnected System region)
- South Australia
- Tasmania

Details of the general assumptions used for calculating the LCOE are outlined in sections 2.2 and 2.3. Section 2.4 explain how the LCOE is calculated. Specific assumptions and cost estimates associated with each technology are outlined in Section 3.

2.2 Macroeconomic assumptions

The AETA was developed to be consistent with the Australian Energy Market Operator's (AEMO) National Transmission Network Development Plan (NTNDP), and its 'planning scenario'. This planning scenario includes the Australian government's macroeconomic assumptions in terms of future carbon prices that are part of the 'Core and Government Policy' models developed by Treasury. The drivers underlying the NTNDP, and the corresponding components of the AETA, are listed in Table 2.2.1.

Table 2.2.1: Macroeconomic assumptions

Factor	AEMO planning scenario prediction	Variable used in this study	Impacted capital cost components
National economic growth	Medium estimate consistent with current growth.	Assume 2.5% average annual growth (drawn from the Treasury assumptions)	Commodity/construction and equipment.
Exchange rate	ACIL Tasman assumptions used in AEMO NTDNP analysis	As per ACIL Tasman assumptions.	AUD moving to peak of 1.13 USD/AUD by 2016–17 and low of 0.86 USD/AUD by 2031–32.
Global economic growth	Moderate global recovery continues with ongoing growth in demand for Australian commodities.	Major equipment supplier countries average GDP growth of 2.5%.	Equipment (50% sensitivity).
Population growth	Moderate Growth	GDP and specific labour productivity (output/ hours worked).	Commodity/construction as per economic growth, and labour productivity (0.8% p.a.)
Carbon price	Initially \$23/tonne CO_2-e leading to a 5% reduction in CO_2 by 2020, and 80% by 2050.	\$23/tonne CO_2-e leading to a 5% reduction in CO_2 by 2020, and 80% by 2050.	Commodity (5% weighted average price sensitivity) and major equipment (1% sensitivity).
Renewable energy target	LRET[1] remains in place to 2030 without significant changes. SRES[2] remains in place to 2030 with currently announced changes to solar credits.	Technology-specific development, cost reduction curves (for renewables and non-renewables from CSIRO).	Technology-specific cost reduction curves.
East Coast LNG exports	Commencing 2014 and reaching approximately 1200 PJ p.a. by 2016.	Affects fuel input via gas prices, some sensitivity for commodity prices.	See domestic gas prices.
Domestic gas prices	ACIL Tasman fuel prices	Affects fuel input via gas prices, some sensitivity for commodity prices.	2% commodity sensitivity.
Global technology R&D	Moderate	Technology-specific development, cost reduction curves.	Technology-specific cost reduction curves and efficiency improvements.
Demand side response	Moderate	Affects regional build but not capital costs.	No impact.
Electric vehicle penetration	Moderate	Affects regional build but not capital costs.	No impact.

1. LRET: Large-scale Renewable Energy Target.

2. SRES: Small-scale Renewable Energy Target.

The inputs from the planning scenario detailed in Table 2.2.1 provide the basis for calculating future increases in local equipment, international equipment and labour. Labour rates are influenced through both an increase in overall O&M costs, and increased productivity (resulting in a decrease in labour costs for plant delivery).

A summary of the economic factors affecting costs over the forecast period is provided in Table 2.2.2.

Table 2.2.2: Summary of economic factors

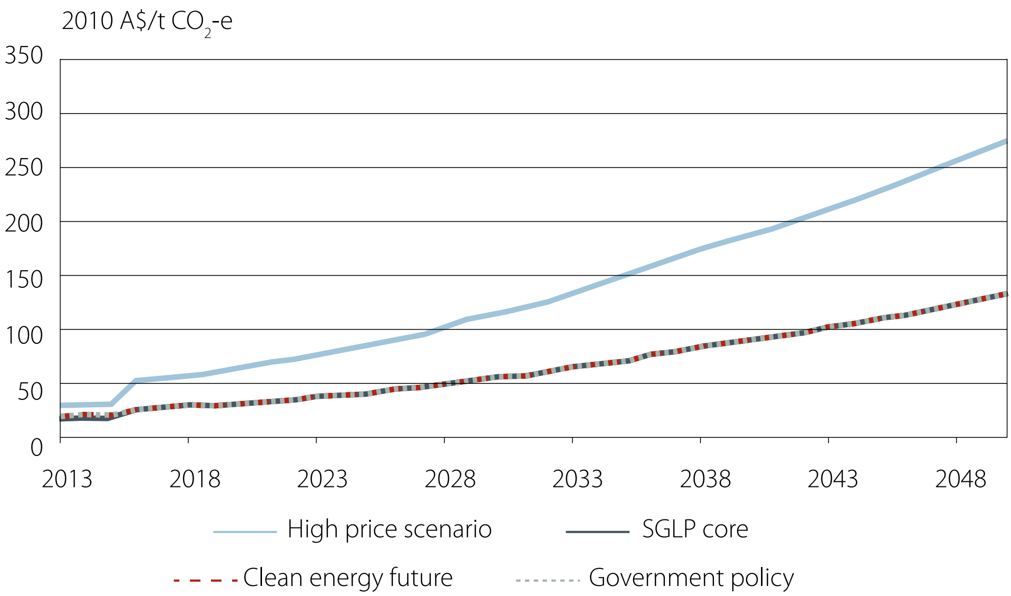
Summary	2020	2025	2030	2040	2050
Local Equipment Escalation rate	4.8%	7.9%	11.0%	16.7%	22.7%
International Equipment Escalation Rate	4.1%	6.8%	9.7%	15.4%	21.4%
Labour Improvement Rate (0.8%)	(6.2%)	(10.0%)	(13.5%)	(20.0%)	(24.3%)
O&M Escalation	7.6%	12.4%	17.1%	26.6%	36.1%

The overall impact of the economic factors is an escalation of both the capital and operating cost for a plant over time. The extent of this escalation is dependent on the characteristics of the individuals technologies.

Carbon Price Assumptions

The carbon prices included in this assessment are based on the Government Policy scenario included in Treasury analysis for the Clean Energy Future package. The projected future carbon price, depicted in the Figure 2.2.1 shows the similarity between SGLP[1] Core and Government Policy scenarios.

Figure 2.2.1: Carbon prices, 2013 to 2050



Source: Treasury estimates from MMRF model, 2011.

1 SGLP: Strong Growth, Low Pollution refers to Treasury modelling of a carbon price in the Australian economy.

2.3 Technical Assumptions

Capital Cost Estimates

The AETA ensures that capital cost estimates are derived consistently for each electricity generation technology. Capital costs are provided on the basis of an N^{th}-of-a-kind (NOAK) plant in Australia and, thus, do not attract the cost premiums of the delivery of a first-of-a-kind plant (FOAK).

The capital costs to be considered as part of each generation project includes plant and equipment costs, typical electrical and site preparation costs and fuel and cooling costs inside the nominal 'project fence' that delineates the separation between the project and the grid. External factors such as electrical connection, fuel pipelines or delivery handling systems, CO_2 transport and storage facilities are excluded from capital costs, but the latter costs are included in the LCOE calculations.

For commercially established technologies and technologies that will be deployed in the near future, the cost of construction for a new generation technology has been developed, where possible, from a bottom-up approach. The cost estimating methodology used to assess current costs for each generation technology include benchmarking against recent project costs in WorleyParsons' database and comparison with forward estimates from various industry sources.

For technologies that are earlier in the commercialisation cycle, information from industry sources, as well as WorleyParsons' internal experience have been applied to establish plant costs and key operating parameters. The elements that make up these costs are broadly identified by international and domestic content. These factors are separated such that assumptions affecting overall cost can be independently varied.

For thermal technologies such as Integrated Gasification Combined Cycle, Supercritical Pulverised Coal, Open and Combined Cycle Gas Turbines, and Biomass, the respective cost estimates are sourced from relevant databases contained in standard software such as Thermoflow's GTPro, SteamPro and Peace. These software model plant performance and provide Engineering/Procurement/Construction (EPC) and total project cost data. All cost estimates derived using such software were based on current Australian conditions such as exchange rate, materials and labour cost. The SOAPP-CT O&M Cost Estimator software was used to develop a number of fixed and variable operations and maintenance cost estimates for gas turbine based plant configurations.

For renewable technologies such as solar, geothermal, wind and wave, the cost estimates are based on WorleyParsons' direct experience in projects, surveys of vendors' products, access to industry association papers and public domain material. These estimates were further evaluated by the AETA Stakeholder Reference Group members.

The information on cost reductions for most technologies is based on CSIRO developed learning rates (capital cost de-escalation) from 2012 to 2050. This data was also evaluated by the AETA Stakeholder Reference Group members. In general, data on future trends were verified against the Original Equipment Manufacturer (OEM) information, industry body and industry analysis papers as well as WorleyParsons' internal data.

All costs are developed at a 'high level' as well as the relevant regional factors. The level of uncertainty for the cost estimates is provided for each technology. A breakdown of capital costs is provided for each technology based on imported and local equipment installation costs and owner's costs.

(a) Direct and Indirect Costs

The total capital cost estimates for each technology include direct and indirect cost components. Cost curves are expressed as A$/kW for net power sent out.

The following items are excluded from the direct and indirect capital costs:

- Escalation throughout the period-of-performance;
- All taxes;
- Site specific considerations including, but not limited to, such items as seismic zone, accessibility, local regulatory requirements, excessive rock, piles, lay down space, etc.;
- For CCS cases, the cost associated with CO_2 injection wells, pipelines to deliver the CO_2 from the power plant to the storage facility and all administration supervision and control costs for the facility;
- Import tariffs that may be charged for importing equipment to Australia or shipping charges for this equipment; and
- Interest during construction (IDC) and financing costs.

Cost items such as IDC and, where relevant, CO_2 transport and storage costs are excluded from the capital cost estimates, but these costs are included as part of the total cost of generation, and are considered when estimating the LCOE.

(b) Decommissioning Costs

Costs associated with plant decommissioning have *not* been included in the calculation of LCOE. Decommissioning costs are discussed in individual technology sections where they may be significant.

(c) Contracting Strategy

The estimates are based on an Engineering/Procurement/Construction (EPC) approach that utilises a main contractor and multiple subcontracts. This approach provides the owner with greater certainty of costs associated with the facility, but attracts risk premiums that are typically included in an EPC contract price.

(d) Estimated Scope

The estimates relate to a complete power plant on a generic site. Site-specific considerations such as soil conditions, seismic zone requirements, accessibility, and local regulatory requirements are *not* considered in the cost estimates.

Labour costs are based on 2012 Australian rates and productivities, in a competitive bidding environment. Estimates for labour productivity growth are included in future costs.

(e) Direct Cost Estimate

Each technology's direct cost estimate includes costs associated with all major plant, materials, minor equipment and labour work to develop the respective power plant to commercial operation.

(f) Owner's Cost Estimate

Development costs necessary to cover expenses prior to the start of construction and non-EPC costs are included. Specific development cost items that are included are listed below:

- Studies and project development;
- Site acquisition;
- Project support team;
- Development approvals;
- Duties and taxes;
- Operator training;
- Commissioning fuel; and
- Commissioning and testing.

Forward Curve Assumptions

The method used to produce forward-cost curves is based on two tiers of analysis. The first tier includes the effects of changes associated with:

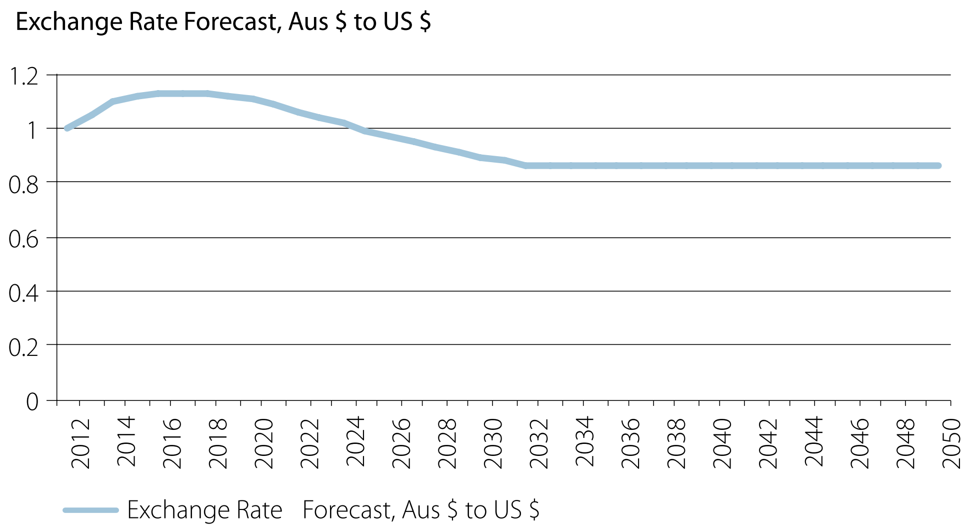
- Projected exchange rate variation over the period 2012 to 2050;
- Productivity variations over the applicable timeframe; and,
- Commodity index/variation over the applicable timeframe.

The second tier of analysis assumes the technological improvement factor that is applied on a year-by-year basis over the period 2012 to 2050.

(a) Exchange Rate Variation

To facilitate cost estimate forecast compatibility, the same foreign exchange forecast curves were applied as those used in the ACIL Tasman AETA fuel price study (Figure 2.3.1).

Figure 2.3.1: ACIL Tasman exchange rate forecast



(b) Productivity Rate Variation

Labour productivity growth (worker output per hour worked) was used to modify the labour component of the capital cost estimates for each technology. A baseline of 0.8 per cent per annum improvement in output per hour was assumed.

(c) Commodity Variation

Commodity variation was assumed to fluctuate in line with the GDP growth rate. The value and profile for commodity variation was linked to the average GDP/GSP (Gross State Product) profile for Australia over the period 2012 to 2050. This, in turn, is based on the assumptions made in AEMO's 2011 NTNDP analysis.

(d) Technological Improvement or Learning Rates

Technological improvement and reductions in the cost of plant equipment and operation are likely to have the largest influence on pricing trends for generating technologies over the period 2012 to 2050. These learning rates incorporated into the AETA are primarily based on the Global Local Learning Model (GALLM) model developed by CSIRO's Energy Transformed Flagship Group (see Annex C).[2]

The GALLM model assesses a number of factors to establish the learning rate for each technology based on:

- technology maturity (i.e. its progression on the learning curve);
- expected rate of technology deployment; and
- rate of cost reduction (with deployment).

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2 A paper outlining the GALLM model and its applications to energy cost projections is available at: http://www.csiro.au/Organisation-Structure/Divisions/Energy-Technology/GALLM-report.aspx

WorleyParsons utilised the results from the GALLM model and, where relevant its own assumptions, to estimate learning rates for technologies that have a similar basis or characteristics to those analysed

Fuel Cost Estimates

ACIL Tasman provided fuel cost estimates for each of the target years out to 2050 (Table 2.3.1, and Annex B). The estimates include the cost of bringing new resource fields to market and the costs of new production facilities and pipelines.

Discrete fuel costs have been forecast for each of the target years 2012, 2020, 2025, 2030, 2040 and 2050. Costs for the intervening years have been linearly extrapolated. Fuel costs beyond 2050 are assumed to remain constant at real 2050 levels.

Fuel cost estimates are developed based on the projected lifetime operation of the power plant for the period 2012 to 2032. The analysis includes all factors that affect the price of fuel, with the exclusion of a carbon price that is applied separately.

Table 2.3.1: ACIL Tasman estimates for fuel prices, 2012 to 2050.

Cost of Brown Coal ($G/GJ)	Year					
Region	**2012**	**2020**	**2025**	**2030**	**2040**	**2050**
North Queensland (NQ, NTNDP Zone)	n/a	n/a	n/a	n/a	n/a	n/a
South Queensland (CQ, WQ, SEQ, NTNDP Zones)	n/a	n/a	n/a	n/a	n/a	n/a
NSW (including ACT)	n/a	n/a	n/a	n/a	n/a	n/a
Vic	0.67	0.65		0.64	0.62	0.61
Tas	n/a	n/a	n/a	n/a	n/a	n/a
SA	n/a	n/a	n/a	n/a	n/a	n/a
Northern Territory	n/a	n/a	n/a	n/a	n/a	n/a
SWIS (WA)	n/a	n/a	n/a	n/a	n/a	n/a
Pilbara (WA)	n/a	n/a	n/a	n/a	n/a	n/a

Cost of Black Coal ($G/GJ)	Year					
Region	**2012**	**2020**	**2025**	**2030**	**2040**	**2050**
North Queensland (NQ, NTNDP Zone)	2.43	2.38		2.31	2.31	2.31
South Queensland (CQ, WQ, SEQ, NTNDP Zones)	2.16	1.66		1.59	1.59	1.59
NSW (including ACT)	2.14	1.73		1.68	1.68	1.68
Vic	n/a	n/a	n/a	n/a	n/a	n/a
Tas	n/a	n/a	n/a	n/a	n/a	n/a
SA	n/a	n/a	n/a	n/a	n/a	n/a
Northern Territory	n/a	n/a	n/a	n/a	n/a	n/a
SWIS (WA)	2.50	2.75		2.75	2.75	2.75
Pilbara (WA)	n/a	n/a	n/a	n/a	n/a	n/a

Cost of Natural Gas ($G/GJ)			Year			
Region	2012	2020	2025	2030	2040	2050
North Queensland (NQ, NTNDP Zone)	6.41	9.33		12.01	12.01	12.01
South Queensland (CQ, WQ, SEQ, NTNDP Zones)	6.76	9.37		11.94	11.94	11.94
NSW (including ACT)	6.36	8.57		11.71	11.71	11.71
Vic	5.36	7.69		10.99	10.99	10.99
Tas	5.82	8.15		11.48	11.48	11.48
SA	6.42	8.70		11.78	11.78	11.78
Northern Territory	11.00	11.00		11.00	11.00	11.00
SWIS (WA)	11.68	13.87		12.30	12.30	12.30
Pilbara (WA)	10.64	12.88		11.29	11.29	11.29

Cost of Bagasse ($G/GJ)			Year			
Region	2012	2020	2025	2030	2040	2050
North Queensland (NQ, NTNDP Zone)	0.83	0.83	0.83	0.83	0.83	0.83
South Queensland (CQ, WQ, SEQ, NTNDP Zones)	0.83	0.83	0.83	0.83	0.83	0.83
NSW (including ACT)	0.83	0.83	0.83	0.83	0.83	0.83
Vic	n/a	n/a	n/a	n/a	n/a	n/a
Tas	n/a	n/a	n/a	n/a	n/a	n/a
SA	n/a	n/a	n/a	n/a	n/a	n/a
Northern Territory	n/a	n/a	n/a	n/a	n/a	n/a
SWIS (WA)	n/a	n/a	n/a	n/a	n/a	n/a
Pilbara (WA)	n/a	n/a	n/a	n/a	n/a	n/a

Cost of Biomass ($G/GJ)			Year			
Region	2012	2020	2025	2030	2040	2050
North Queensland (NQ, NTNDP Zone)	1.50	1.50	1.50	1.50	1.50	1.50
South Queensland (CQ, WQ, SEQ, NTNDP Zones)	1.50	1.50	1.50	1.50	1.50	1.50
NSW (including ACT)	1.50	1.50	1.50	1.50	1.50	1.50
Vic	1.50	1.50	1.50	1.50	1.50	1.50
Tas	1.50	1.50	1.50	1.50	1.50	1.50
SA	1.50	1.50	1.50	1.50	1.50	1.50
Northern Territory	1.50	1.50	1.50	1.50	1.50	1.50
SWIS (WA)	1.50	1.50	1.50	1.50	1.50	1.50
Pilbara (WA)	1.50	1.50	1.50	1.50	1.50	1.50

Cost of Nuclear ($G/GJ)			Year			
Region	2012	2020	2025	2030	2040	2050
North Queensland (NQ, NTNDP Zone)	0.75	0.74		0.72	0.71	0.70
South Queensland (CQ, WQ, SEQ, NTNDP Zones)	0.75	0.74		0.72	0.71	0.70
NSW (including ACT)	0.75	0.74		0.72	0.71	0.70
Vic	0.75	0.74		0.72	0.71	0.70
Tas	0.75	0.74		0.72	0.71	0.70
SA	0.75	0.74		0.72	0.71	0.70
Northern Territory	0.75	0.74		0.72	0.71	0.70
SWIS (WA)	0.75	0.74		0.72	0.71	0.70
Pilbara (WA)	0.75	0.74		0.72	0.71	0.70

Where possible, the fuel price includes a price volume relationship for each fuel source by region. Fuel availability in specific regions is identified, and where restrictions apply, the technology has not been deployed.

Fuel prices were developed using the forecast economic scenario conditions and includes upper and lower confidence bands and are expressed in 2012 dollars.

Operating and Maintenance Cost Estimates

Costs for fixed and variable operating and maintenance (O&M) expenses are provided as high-level estimates based on WorleyParsons' in house data, public domain information and industry-based software for fossil technology.

Operating costs exclude fuel costs, carbon price, and carbon storage. These costs are evaluated separately in the calculation of LCOE.

The following costs are included in the fixed O&M (FO&M) cost estimates as an annual cost per MW capacity:

- Direct and home office labour and associated support costs;
- Fixed service provider costs;
- Minor spares and fixed operating consumables; and
- Fixed inspection, diagnostic and repair maintenance services.

The following costs are included in the variable O&M (VO&M) costs as a cost rate per MWh of sent out energy:

- Chemicals and operating consumables that are generation dependent – e.g. raw water, and water treatment chemicals;
- Scheduled maintenance for entire plant including balance of plant; and
- Unplanned maintenance.

The escalation rates estimated in Table 2.3.2 represent the trend that power station labour costs (both in-house and service provider) increase at rates in excess of the consumer price index (CPI). An escalation rate of 100 per cent implies costs increase at the *same* rate. Spare parts typically escalate at a mix of the metals index and labour rate increases. The escalation rate is assumed to be common for all technologies.

Table 2.3.2: Operations and maintenance escalation rates

FO&M Escalation Rate (% of CPI)	VO&M Escalation Rate (% of CPI)
150	150

2.4 Levelised Cost of Energy (LCOE)

LCOE is the most commonly used tool for measuring and comparing electric power generation costs. It reflects the minimum cost of energy at which a generator must sell the produced electricity in order to breakeven. It is equivalent to the long-run marginal cost of electricity at a given point in time because it measures the cost of producing one extra unit of electricity with a newly constructed electricity generation plant.

The calculation of LCOE requires a significant number of inputs and assumptions. The formula for calculating LCOE and its component parts are defined below.

$$LCOE = \frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

Where:

- LCOE = Average lifetime levelised electricity generation cost
- I_t = Investment expenditure in the year t
- M_t = Operations and maintenance expenditure in the year t (in calculations, other costs (such as a carbon price) may be added in to this variable or separately)
- F_t = Fuel expenditure in the year t
- E_t = Electricity generation in the year t
- r = Discount rate
- n = Amortisation period

and

$$I_t = Capital\ Cost \times Net\ Plant\ Output \times 1000$$

$$M_t = Fixed\ O\&M \times Net\ Plant\ Output + Variable\ O\&M \times Net\ Plant\ Output \times hours\ in\ year \times \frac{Capacity\ Factor}{100} + Carbon\ Price \times \frac{Emissions}{1000} \times Net\ Plant\ Output \times hours\ in\ year \times \frac{Capacity\ Factor}{100}$$
$$+ Sequestration\ Costs \times \left(\frac{\frac{Emissions}{1000}}{\left(1 - \frac{Emissions\ Captured}{100}\right)} - \frac{Emissions}{1000} \right) \times Net\ Plant\ Output \times hours\ in\ year \times \frac{Capacity\ Factor}{100}$$

$$F_t = Fuel\ Cost \times \frac{Net\ Plant\ Output}{\frac{Thermal\ Efficiency}{100}} \times hours\ in\ year \times \frac{Capacity\ Factor}{100}$$

$$E_t = Net\ Plant\ Output \times hours\ in\ year \times \frac{Capacity\ Factor}{100}$$

LCOE Key Inputs

Key inputs and sensitivities affecting the LCOE calculation are:

(a) Amortisation period

(b) Discount rate

(c) Capacity factor

(d) Emissions factor

(e) CO_2 capture rate

(f) CO_2 emission cost (carbon price)

(g) CO_2 storage cost

(h) Fuel cost

(i) VO&M

(j) FO&M

(k) Capital

(l) Exclusions

All components costs and factors are converted into common units to develop the LCOE in terms of $/MWh.

LCOE numbers are only generated for technologies where it is expected that the technology is commercially available.[3] While LCOE figures have been produced for technologies that are or may be commercially deployed in a specific year, there may be a time delay to facilitate deployment in Australia. An anticipated lead time for development of specific technologies is provided in Section 3.

The key variables used to calculate LCOE are detailed below:

(a) Amortisation Period

The amortisation period defines the period of time over which the LCOE is calculated. This period can be determined by the life of the plant – an estimate of the operating life of a particular technology prior to repowering or decommissioning – or by the finance term the expected amortisation period for finance for a project.

For consistency, when in comparing technologies, a uniform amortisation period of 30 years from the commencement of construction has been adopted.

(b) Discount Rate

To ensure consistency in the comparison between technologies, and as a result of consultations with the Stakeholder Reference Group, a discount rate of 10 per cent has been applied to all technologies.

(c) Capacity Factor

A generation plant's capacity factor is dependent on both the physical limitations of the plant to operate, and the market and operating regime it faces. To ensure consistency in the comparisons across technologies, the capacity factor applied in calculating the LCOE is based only on the physical operating constraints of the plant, consistent under Australian operating conditions.

The capacity factor is stated on a case-by-case basis and detailed in Section 3.

(d) Emissions Factor

An annual estimate of the CO_2 emissions intensity per MWh is calculated and presented for each technology. This allows for the calculation of the costs of carbon emissions associated with a carbon price.

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3 Where required, costs and economic indicators beyond 2050 are used as inputs into the LCOE calculation. In this case, the value of the indicator or input in 2050 is assumed to remain constant in real terms for future years.

(e) CO_2 Capture Rate

The CO_2 capture rate provides an estimate of the proportion of carbon emissions captured under each technology. In addition to the emissions factor, the carbon capture rate determines the amount of green house gases (GHG) per annum that is separated, compressed and sequestered, as well as the balance that is emitted from the plant.

(f) CO_2 Emissions Cost

The carbon price is based on the Australian Government policy assumptions included in Treasury carbon price modelling analysis (2011). A price for emissions has not been applied to biomass projects as it is assumed that the greenhouse gases emitted during the generation of electricity is equivalent to the uptake of these gases during the biomass growing phase.

(g) CO_2 Transport Storage Cost

It is assumed that the capital costs of the plant include all components and associated operations up to the outlet flange of the CO_2 compressor. It is assumed that infrastructure associated with CO_2 transport and storage, including all infrastructure, operating and insurance costs, is *external* to the plant. Costs associated with transport and sequestration are, thus, levied through a per tonne charge.

There are currently no commercial CO_2 geo-sequestration operations in Australia, and much of the operation and costing information is at an early stage of development. The CO_2CRC along with the University of NSW has carried out an assessment of the opportunities and costs associated with CO_2 transport and storage for different regions in Australia (Allinson, Cinar, Hou, & Neal, 2009). This has been used as the basis for storage and transport costs in this report, and is listed in Table 2.4.1.

Table 2.4.1: Adopted CO_2 sequestration values

Region	Cost of Sequestration ($/t CO_2)
North Queensland	40
South Queensland	23
NSW	72
Victoria	22
SWIS	14
Pilbara	19

The cost estimates for CO_2 geo-sequestration assume an average value for each region. Some specific projects within a region may be able to achieve lower sequestration costs than the regional average.

Sequestration costs are not projected to substantially decrease over time because the majority of the technology for transport and drilling is relatively mature. Sequestration rates are thus kept at (real) 2012 levels over the forecast period.

(h) Fuel cost

Previously outlined in *fuel cost estimates* in section.

(i) VO&M

Previously outlined in *operating and maintenance cost estimates* in section 2.3.

(j) FO&M

Previously outlined in *operating and maintenance cost estimates* in section 2.3.

(k) Capital

Previously outlined in *capital cost estimates* in section 2.3.

(l) Exclusions from LCOE:

- The effects of taxation;
- Degradation effects for output from each technology;
- Plant decommissioning costs; and
- Plant residual cost.

Caveats on the use of LCOE

LCOE provides a generalised cost estimate and does not account for site specific factors that would be encountered when constructing an actual power plant. As a result, the costs associated with integrating a particular technology in a specific location to a specific electricity network are not considered.

Technologies with an established track record during the phases of both construction and operation, and with relatively stable costs during their lifetime may be regarded as less 'risky'. To the extent that a long term, stable income can be assured over a project's life, risk is further reduced. By contrast, technologies with historical cost overruns, costly delays during construction, and fuel cost volatility generate additional risks, real or perceived. Higher perceived risks will in turn demand higher rates of return on investment. Typically, the discount rate can be used to account for some of these differences in risk with a higher discount rate applied to the 'riskier' projects. For ease of comparison, however, a common discount rate of 10 per cent is applied for all technologies.

Projected LCOE does not necessarily provide a reliable indicator of the relative market value of generation technologies because of differences in the role of technologies in a wholesale electricity market. The value of variable (or intermittent) power plants (such as wind, and solar) will depend upon the extent to which such plants generate electricity during peak periods and the impact these plants have on the reliability of the electricity system. Unlike dispatchable power plants (such as coal, natural gas, biomass, and hydroelectric) – which are reliant on some form of stored energy (e.g. fuels, water storage) – wind and photovoltaic power plants do not, typically, include energy storage.

To cater for sudden, unpredictable, changes in the output of variable power plants, it is necessary to operate responsive, dispatchable power plants (e.g. hydro, open-cycle gas turbines) in a back-up role to maintain the overall reliability of the electricity system. As a result, LCOE by technology is not the only factor considered when deciding what type of electricity generation plant to construct.

The AETA LCOEs are restricted to only utility-scale or large scale technologies. Consequently, small-scale technologies (e.g. non-tracking photovoltaics, fuel cells, co-generation, and trigeneration) that may be relevant to distributed generation are not include in the AETA 2012 analysis, LCOE cost estimates associated with distributed photovoltaics are likely to differ substantially from utility-scale photovoltaic systems as a result of differences in component costs (e.g. capital costs, operating and maintenance costs) and performance characteristics (e.g. capacity factor).

Future updates

The next fully updated AETA report is scheduled for completion in 2014. To ensure that cost estimates for electricity generation technologies are current, and take into consideration the latest developments, parameter estimates for the 40 technologies will be updated, where appropriate, every six months in a manner consistent with the methods outlined in this report and in consultation with the stakeholder reference group.

3. Technology Assessments

Key points

- 40 utility-scale generation technologies are considered and cost estimates are developed at a regional scale to account for Australian conditions.
- Key assumptions regarding capital cost, development time, carbon emissions, capacity factors and efficiency rates are listed for each technology.

This section provides the design characteristics, performance parameters, and cost estimates for each of the 40 technologies assessed in this study. For ease of comparison, the technology options are grouped into the following technology classes: coal (Tables 3.1.1, 3.1.2, 3.1.3, and 3.1.4), gas (Table 3.2.1), solar thermal (Tables 3.3.1 and 3.3.2), solar thermal hybrid (Tables 3.41, 3.4.2, and 3.4.3), photovoltaics (Tables 3.5.1, and 3.5.2), wind (Table 3.6.1), wave (Table 3.7.1), biomass (Table 3.8.1, and 3.8.2, and 3.8.3), geothermal (Table 3.9.1), and nuclear (Table 3.10.1).

3.1 Coal-based technology options

Fourteen coal-based technology options are examined encompassing different fuels (brown, and bituminous), different combustion technologies (pulverised coal, IGCC, and direct injection coal engine), options for carbon capture (post-combustion, oxy combustion; new, retrofit) and different power plant scales (NEM, SWIS).

Pulverised coal

The major components included in the cost for a pulverised coal (PC) plant include coal-handling equipment, boiler or steam generator island, turbine generator island and all balance of plant equipment, bottom and fly ash handling systems as well as emission control equipment. Particulate emissions are typically controlled using fabric filter or electrostatic precipitator systems.

Subcritical pressure units generate steam at pressures of at least 19.0 MegaPascals (MPa) with steam temperatures of 535–560°C. Subcritical black and brown coal fired power stations are common in Australia. Retrofitting these existing power plants with carbon capture equipment represents an option for mitigating CO_2 emissions.

Supercritical pressure units generate steam at pressures of at least 24.8 MPa with steam temperatures of 565–593°C. Supercritical units operate at about two percentage points higher efficiency than subcritical units (i.e. increasing from 36.5 to 38.5 per cent efficiency on a higher heating value basis for plants with wet cooling towers).

In an oxy combustion pulverised coal supercritical plant, the fuel is combusted in a blend of oxygen and recycled flue gas which is rich in CO_2. Recycling is achieved by looping the exhaust duct prior to the stack and redirecting the flue gas back to the boiler where it is mixed with a blend of oxygen and pulverised fuel. The oxygen stream is produced in an air separation unit (ASU), which consumes a considerable amount of electricity.

Pulverised plant configurations with CCS include a post-combustion carbon capture technology such as an amine-based process. Absorption of CO_2 in chemical solvents such as amines is a technology that has an excellent track record in many applications. The reaction between CO_2 and amines can offer a cost-effective solution for directly obtaining high purity CO_2 for a capture efficiency of 90 per cent. 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. The compression pressure is assumed to be of the order of 150 Bar.

Thermoflow software version 21 was used to model and derive the performance parameters for the pulverised coal technologies including the capital costs. The cost factors used for Australian based models are based on the default values provided by the Thermoflow software (1.3 for equipment and commodity and 2.025 for labour). The capital cost allowance for CO_2 capture equipment in the Thermoflow model was based on a report for the Global CCS Institute (WorleyParsons, Schlumberger, 2011).

Table 3.1.1: Key performance parameters and cost estimates for pulverised coal technology options - without CCS

Technology Description	PC Supercritical – Brown Coal	PC Supercritical Black Coal	PC Supercritical Black Coal (SWIS Scale)	PC Oxy Combustion Supercritical
Capital Costs A$/kW net	3,788	3,124	3,381	4,930
Local Equipment/ Construction Costs (includes commodities)	33%	31%	29%	32%
International Equipment Costs	38%	39%	40%	40%
Labour Costs	29%	30%	31%	27%
Engineering Procurement Contractors (EPC) costs	90%	90%	90%	93%
Owners Costs	10%	10%	10%	7%
Construction profile % of capital Cost	Year 1 = 35% Year 2 = 35% Year 3 = 20% Year 4 = 10%	Year 1 = 35% Year 2 = 35% Year 3 = 20% Year 4 = 10%	Year 1 = 35% Year 2 = 35% Year 3 = 20% Year 4 = 10%	Year 1 = 35% Year 2 = 35% Year 3 = 20% Year 4 = 10%
First year available for Construction	2015	2015	2015	2022
Typical new entrant size Gross/Net MW	750/683	750/714	450/425	750/580
Economic Life (years)	50	50	50	50
Lead time for development (years)	4	4	4	10
Average capacity factor	83%	83%	83%	83%
Thermal Efficiency (sent out – HHV)	32.3%	41.9%	41.4%	34%

Technology Description	PC Supercritical – Brown Coal	PC Supercritical Black Coal	PC Supercritical Black Coal (SWIS Scale)	PC Oxy Combustion Supercritical
Thermal Efficiency (sent-out HHV) learning rate (% improvement per annum	0.3%	0.3%	0.3%	0.3%
Auxiliary Load MW/%	67 MW/8.9%	36 MW/4.8%	25 MW/5.6%	170MW (22.6%)
FOM ($/MW/year) for 2012	60,500	50,500	55,500	59,200
VOM ($/MWh sent out) 2012	8	7	8	13
Percentage of emissions captured (%)	0	0	0	0
Emissions rate per $kgCO_2e/MWh$	1024	773	783	977

Table 3.1.2: Key performance parameters and cost estimates for pulverised coal technology options - with CCS

Technology Description	PC Supercritical with CCS – Brown Coal	PC Supercritical with CCS – Bituminous Coal	PC Oxy Combustion Supercritical with CCS	PC Subcritical Brown Coal - Retrofit CCS	PC Subcritical Black Coal - Retrofit CCS
Assumed LCOE of existing subcritical plant A$/MWh				26	30
Capital Costs A$/kW net	7,766	5,434	5,776	3,945	2,244
Local Equipment/ Construction Costs (includes commodities)	36%	36%	32%	40%	40%
International Equipment Costs	35%	35%	35%	30%	30%
Labour Costs	29%	29%	33%	30%	30%
Engineering Procurement Contractors (EPC) costs	91%	91%	93%	91%	91%
Owners Costs	9%	9%	7%	9%	9%
Construction profile % of capital Cost	Year 1 = 35% Year 2 = 35% Year 3 = 20% Year 4 = 10%	Year 1 = 35% Year 2 = 35% Year 3 = 20% Year 4 = 10%	Year 1 = 35% Year 2 = 35% Year 3 = 20% Year 4 = 10%	Year 1 = 25% Year 2 = 60% Year 3 = 15%	Year 1 = 25% Year 2 = 60% Year 3 = 15%
First year available for Construction	2023	2023	2023	2023	2023
Typical new entrant size MW gross/net	750/569	750/ 629	750/554	500/316 (500/464 pre retrofit)	660/474 (660/630 pre retrofit)
Economic Life (years)	50	50	50	30 (dependent on existing coal plant)	
Lead time for development (years)	4	10	10	2 to 3	2 to 3
Average capacity factors	83%	83%	83%	83%	83%
Thermal Efficiency (sent out – HHV)	20.8%	31.4%	32.5%	21.6	30.1
Thermal Efficiency (sent-out HHV) learning rate (% improvement per annum	0.32%	0.32%	0.35%	0.17%	0.17%
Auxiliary Load (%)	181 MW/24%	121 MW/16.1%	196MW/ 26%	36.8%	28.2%
FOM ($/MW/year) for 2012	91,500	73,200	62,000	37,200	31,000
VOM ($/MWh sent out) 2012	15	12	14	8.4	7
Emissions captured (%)	90	90	100	91	90
Emissions rate per $kgCO_2e/MWh$	156	103	0	161	108

The major technical issues with advancing pulverised coal technology are mostly associated with new metal alloys as well as operating flexibility. As the technology further progresses, new materials will be required for higher temperature and pressures. This will require development of high chrome and nickel alloy pressure parts that can reliably operate at temperatures in excess of 700 degrees celcius (ºC).

Internationally, there are plans to build a commercial-scale supercritical pulverised coal facility with main steam temperature of 700ºC by 2016. There are also efforts to develop and test materials needed to achieve main steam conditions of 760ºC and 34.5 MPa in boilers and steam turbines. It is expected and assumed that those conditions will be available in commercial-scale plants by 2030. It is estimated that moving to 760ºC and 34.5 MPa will increase thermal efficiency by at least six percentage points compared to current technology.

Oxy combustion supercritical plants will benefit from the same technological improvement in the steam cycle as other PC coal fired technologies. In addition, improvements to the CO_2 compression systems, as well as more efficient processes to produce oxygen in the ASU will reduce the base plant's auxiliary load, thereby increasing the overall thermal efficiency of the plant. It is anticipated for an oxy combustion plant with CCS that the efficiency will increase by 8 per cent by 2030 (EPRI, 2009).

For brown coal plants, it is expected that new coal drying technologies, using low grade heat, will be used to dry the coal more efficiently. While an increase in thermal efficiency does not directly impact on post-combustion capture processes, it does result in a more efficient power plant which produces less CO_2 per MWh.

A facility fitted with a post combustion CO_2 capture plant will need smaller CO_2 capture systems due to the higher thermal efficiency. This will ultimately result in a decrease in the capital cost of CO_2 capture on a $/kW basis, as well as a decrease in the auxiliary power load of the capture CO_2 system.

In addition to improved Rankine Cycle[4] efficiency by increasing steam temperature and pressure, it is assumed that post-combustion CO_2 capture technology will improve significantly by 2030. The current Mono-Ethanol-Amine (MEA) based system is expected to improve significantly over the next several years and there are likely to be step changes in lower cost and higher efficiency processes for other CCS systems under development.

Advancement in CO_2 compressor technology, with inter-cooling systems, will also lower the overall $/kW cost and reduce the auxiliary loads needed to run the CCS plant.

Integrated Gasification Combined Cycle

An integrated gasification and combined cycle (IGCC) technology uses synthetic gas (syngas) to power the combustion turbine which subsequently produces heat to raise steam in a heat recovery steam generator to power a steam turbine. Brown coal or bituminous coal is converted into syngas – which is composed primarily of CO, H_2, H_20 and CO_2 - using a gasifier.

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4 The Rankine Cycle – named for Scottish Professor William Rankine – is a common process by which heat is converted to work.

Thermoflow software version 21 was used by WorleyParsons to model and derive the performance parameters and the capital costs for IGCC technologies based on brown and bituminous coal. The cost factors used for Australian based models are based on default values provided by the Thermoflow software (1.3 for equipment and commodity, 1.518 for gasification plant and 2.025 for labour). IGCC based on brown coal and bituminous coal plants were modelled using two oxygen-blown, dry-feed, Shell gasifiers with convective cooling of the raw syngas, fuelling GE 9F gas turbines. The General Electric 9FA turbine was selected due to its higher thermal efficiency.

CSIRO's GALLM model projects no reduction in capital cost for IGCC technologies over the forecast period due to its low deployment rate on account of higher capital cost in relation to other coal based technologies. As a result, a separate LCOE scenario was developed for IGCC technologies. The decline in capital costs is based on the predictions for improvements in reliability and flexibility of gasifiers, oxygen separation, and the use of hydrogen-fuelled turbines and fuel cells.

Table 3.1.3: Key performance parameters and cost estimates for IGCC technology options

Technology Description	IGCC - Brown Coal	IGCC – Bituminous Coal	IGCC with CCS – Bituminous Coal	IGCC with CCS – Brown Coal
Capital Costs A$/kW net	6,306	5,346	7,330	8,616
Local Equipment/ Construction Costs	21%	21%	21%	21%
International Equipment Costs	52%	52%	52%	52%
Labour Costs	27%	27%	27%	27%
Engineering Procurement Contractors (EPC) costs	94%	94%	94%	94%
Owners Costs	6%	6%	6%	6%
Construction profile % of capital Cost	Year 1 = 20% Year 2 = 60% Year 3 = 20%	Year 1 = 20% Year 2 = 60% Year 3 = 20%	Year 1 = 20% Year 2 = 60% Year 3 = 20%	Year 1 = 20% Year 2 = 60% Year 3 = 20%
First year available for Construction	2015	2015	2023	2023
Typical new entrant size Gross/Net MW	960/655	854/660	821/557	936/552
Economic Life (years)	>30	>30	>30	>30
Lead time for development (years)	3	3	10	10
Average capacity factor	83%	83%	83%	83%
Thermal Efficiency (sent out – HHV)	33.5%	37.9%	28.9%	25.5%
Thermal Efficiency (sent-out HHV) learning rate (% improvement per annum	0.3%	0.3%	0.3%	0.3%
Auxiliary Load MW/%	305MW/32%	194 MW/23%	263 MW or 32%	384MW/41%
FOM ($/MW/year) for 2012	99,500	79,600	98,700	123,400

Technology Description	IGCC - Brown Coal	IGCC – Bituminous Coal	IGCC with CCS – Bituminous Coal	IGCC with CCS – Brown Coal
VOM ($/MWh sent-out) 2012	9	7	8	10
Percentage of emissions captured (%)	0	0	90	90
Emissions rate per $kgCO_2e$/MWh	1,008	840	127	151

Direct Injection Coal Engine

Although the Direct Injection Coal Engine (DICE) has been subject to development for the past century, it is still a relatively immature and unproven technology. Traditionally, the DICE has been based on a conventional diesel engine with pulverised coal as the fuel source. The focus of development of the DICE over the past 10–20 years, however, has been the development of an engine using coal as a fuel source in a Coal Water Fuel (CWF), Coal Water Slurry, or Micronised Refined Coal (*Wibberley L., 2011*). Brown coal such as that found in Victoria's Latrobe Valley is ideal for use as a CWF in a DICE as it has a low ash content which negates fouling problems often observed in a DICE using pulverised coal.

Estimates on possible cycle efficiencies of a DICE using CWF are similar to low speed fuel oil diesel engines at approximately 50 per cent (HHV[5]) (*Wibberley, Palfreyman, & Scaife, 2008*). The high sent out thermal efficiencies of DICEs make them an attractive option compared to conventional pulverised coal plants, and put them in the same efficiency range as small gas turbines.

Wear in the engine was a large concern for DICE technology early in its development, especially in the fuel injection nozzles where the use of low grade carbon steel led to a nozzle life in the order of a few hours. Research and development to solve wear issues has led to the use of advanced materials. Along with improved injector and nozzle design, the reliability of the DICE engine has increased to the point where it could be scaled up to possible commercial operation.

As DICE with CWF is an immature technology with no commercial plants, there is a low level of confidence associated with the capital cost estimate. The basis for the capital cost is a CSIRO study of a 100MW DICE engine. The capital cost is estimated at 1,600 A$/kW in 2012 for the engine. The balance of capital costs, including local equipment, labour and owners costs increase the total delivered cost to an estimated $2,285 A$/kW.

The expected learning rates for DICE with CWF are mainly driven by the development of the CWF production technology, as the actual DICE engine – that is based on a conventional diesel engine – is well established. CWF production is expected to be the main focus of the development in the near future, with smaller improvements in efficiency towards the end of the study period.

5 HHV is Higher Heating Value, a measure of the latent heat of vaporisation of water.

Table 3.1.4: Key performance parameters and cost estimates DICE technology

Technology Description	Direct Injection Coal Engine
Capital Costs A$/kW net	2,285
Local Equipment/Construction Costs (includes commodities)	22%
International Equipment Costs	70%
Labour Costs	8%
Engineering Procurement Contractors (EPC) Cost	95%
Owners Costs	5%
Construction profile % of capital Cost	100% in year 1
First year available for Construction	2020
Typical new entrant size MW gross/net	300 (3 x 100 generator sets)
Economic Life (years)	25–30
Lead time for development (years)	1
Average capacity factor	83%
Thermal Efficiency (sent out – HHV)	50%
Thermal Efficiency (sent-out HHV) learning rate (% improvement per annum	No Change
Auxiliary Load (%)	5% (assumes no fuel processing)
FOM ($/MW/year) for 2012	150,000
VOM ($/MWh sent out) 2012	10
Percentage of emissions captured (%)	0
Emissions rate per kgCO_2e/MWh	700

3.2 Gas-based technology options

Five gas-based technology options are examined encompassing different combustion technologies (open cycle, combined cycle), different options for carbon capture (new, retrofit) and different power plant scales (NEM, SWIS).

There are various types and categories of gas turbines available in the market today that are suitable for the power generation industry. These include the earlier designed E class and the state-of-the-art heavy-duty F, G and H class turbine models; all of which are suitable for CCGT applications.

The efficiencies of gas turbines depends on several factors such as inlet mass flow, compression ratio and expansion turbine inlet temperature. Recent heavy-duty gas turbine designs have advanced hot gas path materials and coatings, advanced secondary air cooling systems, and enhanced sealing techniques that enable higher compression ratios and turbine inlet temperatures that reach over 1,371°C.

A CCGT plant based on natural gas uses a combination of a natural gas fired turbo-generator system, a Heat Recovery Steam Generator (HRSG) and a steam turbo-generator system to provide power. A CCGT plant with Carbon Capture and Storage (CCS) is based on the same technology as a CCGT plant with the addition of a system post combustion to capture carbon dioxide.

The percentage of emissions captured is claimed by the manufacturers of the technology to be as high as 98 per cent for laboratory conditions. However, based on current experience, a capture rate of 85–90 per cent is a more realistic assumption for power generation applications.

The capital cost and performance of the gas technology options was based on the output of Thermoflow 21 software. While the concentration of CO_2 in the exhaust gas from a CCGT plant is lower than that for a coal fired plant (necessitating a larger CO_2 removal plant per m^3 of flue gas), the volume of CO_2 is significantly lower for a CCGT plant per MW of output. Thus, the overall carbon capture and compression plant is smaller for a CCGT on a per MW sent out basis than for a coal plant.

The capital costs associated with retrofitting CCS to an existing CCGT plant include the cost of the new CCS plant plus additional costs for demolition and modification (tie-ins) to the existing CCGT plant. It was assumed there is adequate space within the plant boundary to place the CCS plant. An allowance of 10 per cent, over the base CCS plant cost, was assumed to cover costs associated with tie-ins to the existing power plant.

Table 3.2.1: Key performance parameters and cost estimates for gas technology options

Technology Description	CCGT	CCGT SWIS Scale	CCGT with CCS	Existing CCGT with retrofit CCS	OCGT
Fuel Type Assumed LCOE of existing CCGT plant A$/MWh				65	
Capital Costs A$/kW net	1062	1111	2772	1547	723
Local Equipment/ Construction Costs (includes commodities)	18%	18%	14%	10%	10%
International Equipment Costs	56%	56%	67%	78%	79%
Labour Costs	26%	26%	19%	12%	11%
Engineering Procurement Contractors (EPC) costs	95%	95%	94%	92%	91%
Owners Costs	5%	5%	6%	8%	9%
Construction profile % of capital Cost	Year 1 = 60% Year 2 = 40%	Year 1 = 60% Year 2= 40%	Year 1 = 60% Year 2 = 40%	Year 1 = 25% Year 2 = 60% Year 3 = 15%	Year 1 = 100%
First year available for Construction	2012	2012	2023	2023	2012
Typical new entrant size MW gross/net	386/374	386/373	361/327	300/500	564/ 558
Economic Life (years)	40	40	40–50	30 (dependent on existing gas plant)	30

Technology Description	CCGT	CCGT SWIS Scale	CCGT with CCS	Existing CCGT with retrofit CCS	OCGT
Lead time for development (years)	2	2	2	2–3	1
Average capacity factors	83%	83%	83%	83%	10%
Thermal Efficiency (sent out – HHV)	49.5%	49.3%	43.1%	43%	35%
Thermal Efficiency (sent-out HHV) learning rate (% improvement per annum	0.35%	0.35%	0.4%	0.17%	0.3 %
Auxiliary Load (%)	3%	3%	10%	10%	1%
FOM ($/MW/year) for 2012	10,000	10,000	17,000	17,000	4,000
VOM ($/MWh sent out) 2012	4	4	9	9	10
Percentage of emissions captured (%)	0	0	85	85	0
Emissions rate per $kgCO_2e/MWh$	357 (Gross)/368 (Net)	358 (Gross)/369 (Net)	55 (Gross)/60 (Net)	55 (Gross)/60 (Net)	509 (Gross)/ 515 (Net)

Improvements in efficiency and reductions in capital costs of gas technology options are not likely to be as marked as for an emerging technology. Future plants will be based on advanced heavy-duty gas turbines which are expected to operate at higher firing temperatures and higher pressure ratios than current models. With these advanced gas turbines, a more efficient reheat steam turbine cycle can be selected for higher efficiency for the bottoming cycle of a combined cycle plant.

CCGT with CCS is still an emerging technology. The current MEA based amine system is expected to improve significantly over the next several years and there are likely to be step changes in lower cost and higher efficiency processes for other CCS systems under development. Advancement in CO_2 compressor technology, with inter-cooling systems, will assist in reducing the overall $/kW capital cost and reducing the auxiliary loads needed to run the CCS plant.

3.3 Solar thermal technology options

The three solar thermal technologies considered are compact linear fresnel, parabolic trough and central receiver tower. These systems are based on the concept of concentrating direct normal radiation to produce steam used in electricity generating steam turbine cycles.

The solar power generating systems in these technologies use mirrors that continuously track the position of the sun and reflect the radiation into a receiver that absorbs the solar radiation energy. The absorbed solar energy can be harnessed and transferred in two ways: directly or indirectly. The direct method circulates water directly through the concentrated solar radiation path to directly produce steam. The indirect method uses a heat transfer fluid which absorbs solar radiation energy and transfers the heat to water by way of a series of solar steam generator heat exchangers, thus indirectly producing steam.

Compact Linear Fresnel Technology (CLFR)

CLFR technology commercialised by AREVA[6] is presently under consideration for the Australian Government's solar thermal solar flagship project. The proposed project is scheduled to commence operation in 2015 following the finalisation of project development and a three-year construction timeframe.

The project is based on direct steam generation in the solar absorbers. The plant has generation capacity of 250 MW (2 x 125 MW) and does not incorporate energy storage. It has been publicly reported that the project has a capital cost of A$1.2 billion (i.e. A$4,800/kW) and a capacity factor of 22 per cent to 24 per cent.

A CLFR technology option including six hours of storage has also been considered in this study. In order to estimate a cost allowance for a CLFR plant with storage it has been assumed that the storage cost would be similar to that for parabolic trough plants with salt storage.

Parabolic Trough Technology

Parabolic trough is the most widely deployed solar thermal technology, with the first plants installed in the 1980s in the US.

A report by the US National Renewable Energy Laboratory (NREL) assessed the cost of a 100MW trough system with 6 hours storage (Turchi, 2010). Based on a water cooled design, with a solar multiplier of 2.0[7], the plant was estimated to cost $8,950 per kW installed (in 2009 US dollars). It is not expected that this estimate will have changed substantially since 2009.

Table 3.3.1: Apportionment of the costs in a solar trough system

Component	Local (%)	International (%)
Solar field	11	22
Allowances	8	8
Storage	6	4
Project management	5	3
Balance of plant	3	6
Civil works	8	
Power block		6
Heat transfer fluid		5
Project development	3	
Miscellaneous	1	1
Total	45	55

6 AREVA is a French multinational the focuses on energy generation.

7 Solar field has twice the capacity of the generation of the plant, with excess heat being to increase the capacity factor of the plant.

A solar trough system without energy storage, and with a solar field multiplier of 1.0[8], is estimated to cost 55 per cent of a plant with 6 hours storage (*Turchi, 2010*) of the above. Thus, a capital cost in the order of $4,920 per MW is expected.

Central Receiver Technology (CRT)

Gemasolar is the first commercial-scale plant in the world to apply central tower receiver and molten salt heat storage technology. The relevance of this plant lies in its technological uniqueness, since it opens up the way for new thermosolar electrical generation technology.

Characteristics of Gemasolar are as follows:

- Rated electrical power: 19.9 MW
- Net electrical production expected: 110 GWh/year
- Solar field: 2,650 heliostats on 185 hectares
- Heat storage system: the molten salt storage tank permits independent electrical generation for up to 15 hours without any solar feed
- Capital Cost: 200M Euro.

For this analysis, six hours storage is required which will reduce the solar field, storage capacity and associated equipment by 40 per cent. It is expected that the capital cost will be some 30 per cent less than Gemasolar on a $/kW basis. A further cost reduction of 20 per cent is expected for subsequent commercial plant based on experience gained from Gemasolar.

The likely preferred technology for CRT without storage is steam generation for use directly in a steam turbine rather than via molten salt technology where an additional heat transfer from salt to steam is required. BrightSource Energy is constructing three power towers known as the Ivanpah Steam Electricity Generating Station (SEGS) located in the Mojave Desert in California, USA. The Ivanpah project has a reported capacity of 392 MW (gross)/370 MW(net) and a total project cost of US$2,180 million.

Table 3.3.2: Key performance parameters and associated cost estimates for each solar thermal technology, with and without thermal energy storage

Technology Description	CLFR	CLFR with storage	Parabolic trough	Parabolic trough with storage	Central Receiver	Central Receiver with storage
Capital Costs A$/kW net	5,220	9,500	4,920	8,950	5,900	8,308
Local Equipment/Construction Costs (includes commodities)	25%	20%	25%	20%	15%	20%

8 Solar field sized to match the maximum generation capacity of the plant.

Technology Description	CLFR	CLFR with storage	Parabolic trough	Parabolic trough with storage	Central Receiver	Central Receiver with storage
International Equipment Costs	55%	55%	55%	55%	55%	55%
Labour Costs	20%	25%	20%	25%	30%	25%
Engineering Procurement Contractors (EPC) costs	90%	92%	92%	92%	92%	92%
Owners Costs	10%	8%	8%	8%	8%	8%
Construction profile % of capital Cost	Year 1 = 50% Year 2 = 30% Year 3 = 20%	Year 1 = 50% Year 2 = 30% Year 3 = 20%	Year 1 = 50% Year 2 = 30% Year 3 = 20%	Year 1 = 50% Year 2 = 30% Year 3 = 20%	Year 1 = 20% Year 2 = 60% Year 3 = 20%	Year 1 = 50% Year 2 = 30% Year 3 = 20%
First year available for Construction	2012	2012	2012	2012	2012	2012
Typical new entrant size	125 MW	125 MW	150 MW	150 MW	130MW (gross)/122 MW (net)	20 MW
Economic Life (years)	40	40	30–40	30–40	30–40	40
Lead time for development (years)	4	4	4	4	5	4
Capacity Factor	22% to 24%	42%	22% to 24%	42%	31%	42%
Auxiliary Load (%)	8%	10%	8%	10%	5.6%	10%
FOM ($/MW/year) for 2012	50,000–70,000	50,000–70,000	60,000	65,000	70,000	60,000
VOM ($/MWh sent out) 2012	0–30	0–30	15	20	1–30	15
Percentage of emissions captured (%)	Not Applicable	Not Applicable	Not Applicable	Not Applicable	Not applicable	Not applicable
Emissions rate per $kgCO_2e/MWh$	Not Applicable	Not Applicable	Not Applicable	Not Applicable	Not Applicable	Not applicable

As concentrating solar power plants increase their share of the utility market and their installed capacity expands, costs are expected to continue to decrease. This is due to the higher production volume of key equipment and increased experience gained by manufacturers and engineers who are planning and building plants. Additionally, it is expected that cheaper heat transfer fluids will become available or that fluids that can handle higher temperatures, and therefore enable increased efficiency, will be used. The cost of storage systems is also expected to be reduced.

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.

3.4 Solar thermal hybrid technology options

The solar thermal hybrid technology options investigated are solar/coal hybrid and integrated solar combined cycle technology.

Solar/coal hybrid

Concentrating solar thermal systems can operate in conjunction with pulverised coal power plants. For this analysis, it is envisaged that a 750 MW supercritical black coal-fired power plant operates in conjunction with a 125 MWt[9] solar field contributing 40 MWe[10] to the plant output. This design was chosen as it is similar to the configuration for the Solar Boost Project which is currently under construction at Kogan Creek Power Station in Queensland.

Feedwater for the solar field is extracted from the inter-stage tapping points on the power station boiler feedwater pumps. The solar field comprises Compact Linear Fresnel Reflector (CLFR) receiver lines that generate superheated steam directly from the supplied feedwater.

Thermoflow software version 21 was used to model and derive the performance parameters for this technology, including the capital costs. The cost factors used for Australian models are based on default values provided by the Thermoflow software (1.3 for equipment and commodity and 2.025 for labour). The capital cost allowance for the solar field has been based on the known cost of the Kogan Creek Solar Boost Project.

To understand the impact on the power station from injecting solar steam, nominal performance data from four cases has been shown below.

Operating Option 1 shows the following two cases:

- Plant performance with boiler firing at 100 per cent and the solar field out of service (e.g. overnight); and
- The impact on plant performance when solar steam is added and the boiler firing rate is maintained at 100 per cent.

Operating Option 2 shows the following two cases:

- Plant performance when solar steam is added with the boiler load reduced in order to maintain the plant gross power; and
- Plant performance with the boiler firing at the reduced load determined above and the solar field out of service.

9 MWt is Mega Watt thermal and refers to thermal power produced.

10 MWe is Mega Watt electrical and refers to electrical power produced.

Table 3.4.1: Plant performance options

Performance Option		Increase Plant Power		Maintain Plant Power	
Case		100% firing No Solar	100% firing 100% Solar	Reduce firing No Solar	Reduce firing 100% Solar
Fuel Type		Hunter Valley Black Coal			
Gross Power	MW	750	790	707	750
Auxiliary Load	MW	37	37	34	35
Net Power	MW	713	753	672	715
Plant Net Efficiency (HHV)	%	41.9	44.2	41.9	44.6
CO_2 Emitted	kg/s	153.3	153.3	144.4	144.4
	ton/MWh	0.773	0.733	0.733	0.727
Fuel Mass Flow	kg/s	58.8	58.8	55.4	55.4
Solar Field Heat to Steam	MWth	0	125	0	125

NB. Performance data is nominal only and should be treated as indicative

For the purposes of the analysis, a plant operating at 750MW gross output is considered, that is, the boiler is turned down to compensate for the input of solar steam.

While Table 3.4.1 outlines the expected impact of full output from the solar component under two plant scenarios, the LCOE has been calculated on the basis of the solar component operating at an average annual capacity factor of 23 per cent.

Integrated Solar Combined Cycle

As with the solar/coal hybrid technology, the integrated solar combined cycle (ISCC) design presents an opportunity to integrate solar thermal technology into conventional plant and optimise the plant configuration for fuel use and equipment utilisation.

For the purposes of the analysis, a 525.7 MW (net) ISCC plant has been modelled. The capital cost was estimated from a plant modeled on a single Alstom GT26 gas turbine with a three pressure reheat HRSG and a nominally sized solar field multiple of 1.2 with no thermal storage.

Feedwater for the solar field has been extracted from the interstage tapping points on the power station HRSG feedwater pumps. The solar field comprises Compact Linear Fresnel Reflector (CLFR) receiver lines that generate superheated steam directly from the supplied feedwater.

To understand the impact on the power station from injecting solar steam, nominal performance data from three cases has been shown in Table 3.4.2.

- Case one presents the performance parameters for the power station on 100 per cent gas, with no solar input.
- Case two presents performance with 100 per cent input from the solar component (i.e. full output from the solar component)
- Case three presents the expected annual performance of the plant with the solar component operating at a capacity factor of 23 per cent on average over the year.

Table 3.4.2: Key performance parameters from the GT Pro model used to size the ISCC plant

		CCGT – no solar	CCGT – solar (100% output)	CCGT – solar (Average)
Plant Output (gross)	MWe	525.7	525.7	525.7
Plant Output (net)	MWe	506.0	502	504.9
Auxiliary	MWe	19.6	23.7	20.7
	%	3.7	4.5	3.9
Fuel		CH_4	CH_4	CH_4
CO2 Intensity (net)	kgCO2/MWhr	362	276	336
Plant net eff (HHV)	%	47.3	62.1	50.7
Solar field heat to steam	MWth	n/a	340.3	340.3 (max)
Solar field price	$	n/a	$618m	$618m
CC Plant Price	$	$419m	$464m	$464m
Total Plant Price	$	$419m	$1,082m	$1,082m

Table 3.4.3: Key performance parameters and associated cost estimates for the solar hybrid technology options

Technology Description	Solar/Coal Hybrid	Integrated Solar Combined Cycle
Capital Costs A$/kW net	3,395	2,150
Local Equipment/Construction Costs (includes commodities)	30%	18%
International Equipment Costs	40%	56%
Labour Costs	30%	26%
Engineering Procurement Contractors (EPC) costs	90%	95%
Owners Costs	10%	5%
Construction profile % of capital cost	Year 1 = 20% Year 2 = 60% Year 3 = 20%	Year 1 = 60% Year 2 = 40%
First year available for Construction	2015	2012
Typical new entrant size	750MW/715MW	500 MW
Economic Life (years)	50	40
Lead time for development (years)	4	5
Capacity factor (%)	83%	83%
Thermal Efficiency (sent out – HHV)	42.5%	62.1% (max), 50.7 (Ave)
Thermal Efficiency (sent-out HHV) learning rate (% improvement per annum	0.30%	0.15%
Auxiliary Load	35MW	23 MW
FOM ($/MW/year) for 2012	72,000	15,000
VOM ($/MWh sent out) 2012	8	10
Percentage of emissions captured (%)	0	0
Emissions rate per kg CO_2e/MWh	762	336

Technological improvement of the plant components (solar and supercritical pulverised coal or CCGT) will be in line with that outlined in previous technology discussions relating to each component. There are likely to be additional opportunities for improvement in the integration and overall operation of the hybrid plant.

3.5 Photovoltaic technology options

Solar photovoltaic (PV) technologies convert sunlight directly into electricity using semiconductor materials that produce electric currents when exposed to light. Semiconductor materials used for PV cells are typically silicon mixed with other elements that have either one more or one less valence electrons to alter the conductivity of the silicon. PV technology can be installed as fixed flat plates on roofs or as a large field and can be mounted on tracking devices that have single axis or dual axis tracking.

There have been significant increases in solar PV installation in recent years with significant price reductions per kW as large scale manufacturing facilities reduce production costs. A number of recent reports were utilised to provide the basis for the sizing and costs associated with the PV fixed plate technology. The reports are USA based and are for recent utility scaled projects based on publically available information together with proposed technology advancement/cost reduction programs.

A Lawrence Berkeley National Laboratory report (2011) provides the following key points:

- There was a wide range of installed cost per MW DC for the 20 utility scale projects investigated. This is due to differing project size, different PV modules (thin film/crystalline), and fixed or tracking configuration;
- Cost typically declines with increasing size;
- Thin film technology is typically lower cost than crystalline technology;
- A number of cited sources have provided installed cost benchmarks in US$ DC power rating of between $3.8 and $4.1 per watt for large scale utility projects; and
- There is project evidence that utility scale costs have reduced significantly over the period of 2008 to 2011.

In 2010, the United States Department of Energy (DoE) implemented a program with the aim of achieving installed solar photovoltaic for $1/Watt by 2017. With the current rate of progress, the cost of utility-sized photovoltaic (PV) systems is predicted to reach $2.20/watt by 2016.

The DoE has identified that PV is unlikely to be able to sustain continued price reductions without significant ongoing investment. The cost reductions are considered across three main areas of utility project development, presented in Table 3.5.1. All costs are in USD.

Table 3.5.1: Cost reductions across three main areas of utility project development

YEAR/GOAL	2010	2016	$1/watt goal
Module ($/kW)	1700	1050	500
Balance of System ($/kW)	910	970	400
Installation ($/kW)	570		
Power Electronics (($/kW)	220	180	100
Total Capital Cost ($/kW)	3400	2200	1000
O&M Cost ($/MWh)	13	9	3

A recent report on the status of the US solar market (*Solar Energy Industries Association, 2012*) demonstrated a reduction in capital costs for installed US Solar PV systems in the order of 23 per cent from 2010 to Q4 2011. While this reduction is affected by the current oversupply of panels in the market, there is not expected to be a significant upward adjustment with a rebalance of supply and demand. Nevertheless, this rate of cost reduction is not expected to continue into the forecast period.

Based on the US information presented above, the cost basis proposed for 2012 is based on the following:

- 2010 cost range midpoint is $3.95/W DC;
- Factor to convert to W AC – based on WorleyParsons project experience, 1.15 W DC installed converts to 1W AC (the solar module field is oversized compared to the inverter AC size);
- Costs do not include step up transformer and switching station typically within plant boundary – allow $0.15/W DC for this cost, based on recent WorleyParsons' experience; and
- Assume A$1 = US$1.

Recent project evidence in Australia has indicated a continued decrease in costs in the order of 30 to 35 per cent from mid-2010 to Q2 2012. This is reinforced with the recent announcement of the AGL- First Solar "Solar Flagships" project, and WorleyParsons experience with 20 to 30MW solar PV projects. In summary, it is estimated that the total installed cost of fixed PV systems is now $3.38/W AC (i.e. $3380/kWnet) in 2012.

Tracking systems have increased capital cost compared to fixed systems. An evaluation by the US Electric Power Research Institute (EPRI) found that, for a C-Si based panel system, the cost of single axis tracking would add $0.48/Wp compared to a fixed tilt system (Black and Veatch, 2010).

Typically, it is expected that single axis trackers will increase annual electricity output from photovoltaic panels by 27 per cent to 32 per cent compared with fixed PV panels. Dual axis tracking will increase annual electricity output by an additional 6 per cent to 10 per cent output compared with single axis trackers.

Table 3.5.2: Key performance parameters and associated cost estimates for fixed and tracking photovoltaic systems

Technology Description	Solar PV fixed	Solar PV single axis tracking	Solar PV dual axis tracking
Capital Costs A$/kW net	3,380	3,860	5,410
Local Equipment/Construction Costs (includes commodities)	15%	15%	15%
International Equipment Costs	70%	70%	70%
Labour Costs	15%	15%	15%
Engineering Procurement Contractors (EPC) costs	93%	93%	93%
Owners Costs	7%	7%	7%
Construction profile % of capital Cost	Year 1 = 70% Year 2 = 30%	Year 1 = 70% Year 2 = 30%	Year 1 = 70% Year 2 = 30%
First year available for Construction	2012	2012	2012
Typical new entrant size MW gross/net	100 MW	100MW	100MW
Economic Life (years)	30–40	30–40	30–40
Lead time for development (years)	3	3	3
Capacity factors (AC output basis)	21%	24%	26%
Thermal Efficiency (sent out – HHV)	Not Applicable	Not Applicable	Not Applicable
Thermal Efficiency (sent-out HHV) learning rate (% improvement per annum	Not Applicable	Not Applicable	Not Applicable
Auxiliary Load (%)	Nil	Nil	Nil
FOM ($/MW/year) for 2012	25,000	38,000	47,000
VOM ($/MWh sent out) 2012	Included in FOM	Included in FOM	Included in FOM
Percentage of emissions captured (%)	Not Applicable	Not Applicable	Not Applicable
Emissions rate per kgCO_2e/MWh (or kgCO_2e/GJ fuel)	Not Applicable	Not Applicable	Not Applicable

The cost of electricity from photovoltaic plants is expected to decrease rapidly in the future, due to expanded manufacturing capacity and process, and cell efficiencies. This is due both to expected reduction in solar panel costs and increased efficiency. The balance of system and inverter costs are also expected to decrease over time. Research continues to develop new PV configurations, such as multi-junction concentrators, that promise to increase cell and module efficiency.

3.6 Wind technology options

On-shore wind generation represents the most mature form of renewable energy generation technology to emerge in the past 30 years. While there are a number of variations on the technology, the vast majority of recent installations globally are of a standard configuration, consisting of a tower mounted with three blades in an upwind turbine design. Utility scale wind farms typically utilise machines in the 1 to 3 MW range with hub heights of 70 to 100m, rotor diameters of 70 to 120m. Wind farms are typically arrays of 50 to 150 turbines.

The trend in turbine design over the past two decades has seen the consistent development of larger turbines, which is likely to continue into the future. Material and construction technique developments enable the use of taller towers and larger diameter rotors, which have the benefit of improving energy capture by accessing stronger and less turbulent wind at higher elevations as well as increasing the energy intercepted from the swept area of the rotor.

There is an increasing trend to develop larger scale on-shore wind projects in Australia, with the recent 400 MW Macarthur Wind Farm being an example. It is expected that 100+ MW wind farms will become more common over the forecast period with an ongoing trend towards deployment of fewer, larger capacity machines.

Due to the relative infancy of the wind energy industry, there are only a few turbines that have reached their life expectancy. These turbines are also much smaller than those currently available on the market. Nevertheless, based on experiences in Germany, the UK and USA, O&M costs are generally estimated to be around 1.2 to 1.5 euro cents (c€) per kWh of wind power produced over the total lifetime of a turbine (EWEA, 2009).

Turbines utilised for off-shore application, typically, have a power rating greater than those use for on-shore use. The current range of off-shore machines have power outputs between 2 MW to 6 MW (80m to 130m rotor diameters) with turbines up to 10MW (250m + rotor diameter) under development. The scale of machines utilised off-shore is generally larger for a number of reasons:

- There are fewer constraints on the transportation associated with both the generation and erection equipment;
- There is a drive to minimise the number of machines due to the high cost associated with sub-sea foundation installation; and
- O&M costs can be optimised with fewer machines.

Sub-sea structures and foundations for off-shore facilities vary considerably from on shore wind facilities. There are a range of technologies utilised for foundations, the selection being dependent both on the sub-sea conditions and the depth of water. The most common foundation design is a monopole foundation – a large steel tube with a diameter up to 6m, with typical embedment depths of 25 to 30m, and application in water depths up to 30m. Gravity based foundation systems are also common. While they have the benefit of avoiding some of the specialised piling equipment required for monopole foundations, a significant amount of seabed preparation is required, and application is limited to regions where there is a firm soil substrate and relatively shallow water.

The electrical distribution system deployed for an off-shore wind facility is necessarily more complex than that for an on-shore facility. A typical arrangement includes a step-up transformer at each turbine to increase the voltage to that of the collection network (typically 34kV). A distribution system then collects the power from each turbine and supplies it to a common electrical collection point.

The capital cost of off-shore wind facilities is dependent on a number of factors. Key site criteria that will influence the cost on a per MW installed basis are:

- Depth of water for installation
- Distance of the facility off-shore
- Capacity of the facility

To date, there have been no off-shore wind farm developments in Australia. However, cost data is available for a number of international facilities. A report by the US National Renewable Energy Laboratories (NREL, 2010) investigated published information regarding both delivered project costs and forecast projects costs and this has been used for generating costs estimates for the AETA.

Operations and maintenance for off-shore wind facilities presents a number of challenges not associated with the O&M of on-shore wind farms. O&M costs are two to three times higher than on shore systems, with costs increasing with distance of the facility from shore (Ernst and Young, 2009).

Table 3.6.1: Key performance parameters and associated cost estimates for on-shore and off-shore wind facilities.

Technology Description	On-shore Wind Farm	Off-shore Wind Farm
Capital Costs A$/kW net	$2,530	$4,451
Local Equipment/Construction Costs (includes commodities)	13%	24%
International Equipment Costs	72%	61%
Labour Costs	15%	15%
Engineering Procurement Contractors (EPC) costs	95%	93%
Owners Costs	5%	7%
Construction profile % of capital Cost	Year 1 = 80% Year 2 = 20%	Year 1 = 30% Year 2 = 50% Year 3 = 20%
First year available for Construction	2012	2012
Typical new entrant size MW gross/net	100 MW	100 MW
Economic Life (years)	20–30	20–30
Lead time for development (years)	4 to 7	4 to 7
Average capacity factors	38%	40%
Thermal Efficiency (sent out – HHV)	Not Applicable	Not Applicable
Thermal Efficiency (sent-out HHV) learning rate (% improvement per annum	Not Applicable	Not Applicable
Auxiliary Load (%)	Approximately 0.5%	Approximately 0.5%
FOM ($/MW/year) for 2012	40,000	80,000
VOM ($/MWh sent out) 2012	12	12
Percentage of emissions captured (%)	Not Applicable	Not Applicable
Emissions rate per kgCO_2e/MWh (or kgCO_2e/GJ fuel)	Not Applicable	Not Applicable

It is expected that advances in a number of areas will continue to drive the capital cost of wind facilities down through the forecast period. The IEA projections incorporate a learning rate of 7 per cent, while the European Wind Energy Association (EWEA, 2009) are forecasting a 10 per cent learning rate consistent with that observed historically. EWEA forecasts that the installed capacity should double every three years over the forecast period. A shorter term reduction in capital as a result of the increase in market share of Chinese imported turbines has also been included.

The principal areas of development of technology that result in increased output efficiency are expected to include:

- Stronger and lighter materials that are expected to allow the development of larger and lighter blades; and
- Increases in electrical efficiency due to the introduction of superconductor materials.

While off-shore wind has been deployed commercially for a number of years, it remains relatively immature in comparison to on-shore wind. There is a continuing trend to develop larger off-shore machines, with a number of manufacturers currently developing machines of 10 MW plus capacity. One of the primary technological limitations for the development of such large scale technology is the range of current material available. Physically scaling up existing components has a number of material limitations, thus new composite materials and manufacturing methods for components such as bearings, rotors, gearboxes and drive trains are required to achieve the desired capacities.

Reliability of off-shore machines is also critical to reducing the delivered cost of energy. Maintenance of off-shore equipment is significantly more complex and costly than that of on-shore facilities, and cannot always be carried out at the time of failure due to weather or equipment availability. The drive toward greater reliability is likely to develop a combination of system design, built in redundancy, improved quality control, and greater and more sophisticated condition monitoring.

Sub-structure technology for off-shore facilities is also developing to enable deployment of machines in a greater variety of sea-bed conditions. The existing sub-sea monopole or gravity foundations are suitable for deployment only in a limited range of sea depths (typically up to 30m), which limits the area for deployment of off-shore facilities. Equipment such as tripods, jackets and trusses may be suitable for transitional depths (typically water depths up to 30 to 60m), with floating structures for depths in excess of 60m (the first trial unit was deployed in 2009).

3.7 Wave technology

Wave energy extraction refers to technologies dealing with harnessing the motion of ocean waves, and converting that motion into electrical energy. Wave technologies have been designed to be installed in near-shore, off-shore, and far off-shore locations. While all wave energy technologies are intended to be installed at or near the water's surface they differ in their orientation to the waves with which they are interacting and in the manner in which they convert the wave's energy, usually to electricity.

The global wave power industry is still immature. Thus, commercial production of wave energy is very limited. However, there are several prototype wave energy generators that have been tested in various locations around the world. They include point absorbers (buoys), terminator devices (such as Salter's duck), oscillating water columns, attenuators (such as Pelami), overtopping devices and surging devices.

The generating costs of the first wave energy devices are high due to the high fixed costs associated with a wave energy scheme being defrayed against the output of a single device.

For the purposes of this study, a commercial deployment of a reaction point absorber system has been assumed. With indirect costs included and assuming a median price in the range of technologies, a capital cost of $5,900 has been adopted as an indicative cost for a commercial point absorber system. Performance indicators are provided in Table 3.7.1.

As with other technologies currently in the research stage, costs are based on the commercial deployment of generation, and not the current pricing exhibited for research and development scale projects.

Table 3.7.1: Key performance parameters and associated cost estimates for a wave power facility

Technology Description	Ocean/Wave
Capital Costs A$/kW net	5,900
Local Equipment/Construction Costs (includes commodities)	30%
International Equipment Costs	40%
Labour Costs	30%
Engineering Procurement Contractors (EPC) costs	91%
Owners Costs	9%
Construction profile % of capital Cost	Year 1 = 60% Year 2 = 40%
First year available for Construction	2020
Typical new entrant size Gross/Net MW	50
Economic Life (years)	25
Lead time for development (years)	5
Average capacity factor	35%
Thermal Efficiency (sent out – HHV)	n/a
Thermal Efficiency (sent-out HHV) learning rate (% improvement per annum	n/a

Technology Description	Ocean/Wave
Auxiliary Load MW/%	
FOM ($/MW/year) for 2012	190,000
VOM ($/MWh sent out) 2012	0
Percentage of emissions captured (%)	n/a
Emissions rate per kgCO_2e/MWh	0

Given the broad range of technologies that are currently under development, it is anticipated that a smaller number of cost effective options will emerge over the coming years. Increased deployment will also see the costs of the technology decline.

3.8 Biomass technology options

Three biomass technology options are examined: landfill gas; sugar cane waste; and other biomass waste.

Landfill gas

Landfill gas (LFG) is the gas produced as organic wastes in landfill deposits break down over time and is primarily a mixture of methane and carbon dioxide. The gas is produced by chemical reactions and microbes acting on putrescible material in landfill. The rate of production is affected by a number of factors, including waste composition, landfill geometry, chemical make-up, leachate treatment of the bed, thermal characteristics, moisture entry, bed temperature and escape of gas.

When landfill gas is used for power generation, a gas collection system needs to be put in place. The gas is extracted from the landfill by a series of wells using a blower or vacuum system. This collection system directs the gas via an array of pipes to a central point where it can be processed. Because of the presence of contaminants, treatment of the gas prior to being delivered to the power generating plant is an important element of this process. Some landfills employ bioreactor technology which aims to achieve enhanced gas generation.

Australia has over fifty existing landfill gas power generation sites, ranging in capacity from less than 1 MW to the Woodlawn bioreactor site which has the potential to generate up to 20 MW. By 2020, it is expected that approximately 1900 GWh will be generated from landfill gas (Clean Energy Council, 2010a).

Indicative performance figures and cost estimates for various sizes of landfill gas plants utilising reciprocating gas engines are outlined in Table 3.8.1 (American Chemical Society, 2010).

Table 3.8.1: Indicative performance figures and cost estimates for various sizes of landfill gas plants utilising reciprocating gas engines

Plant capacity (kW)	100	300	1000	3000	5000
HHV efficiency (%)	30.6	31.1	33.3	36	39
Capital cost ($/kW)	4500	3600	3000	2700	2700
O&M cost ($/MWh)	54	39	30	27	27

Sugar cane waste

In all Australian sugar mills, the fibrous residue of the sugar cane milling process (bagasse) is the primary energy source for operation of the mill. At each mill, bagasse is fired in a number of boilers to generate steam. Some steam is used as part of the sugar production process and some is delivered to steam turbine generator(s) for power generation.

In the past, Australian sugar mills were normally configured to achieve an energy balance between the amount of bagasse fuel produced by milling operations and the energy requirement of the mill. Achieving this balance often meant that power plants operated at low efficiency. In recent years, some mills have developed power plants which operate at high efficiency, with power generated that is in excess of the mill's requirements exported into the utility power grid.

The Australian sugar milling operation is seasonal, with cane harvesting typically taking place between June and November. To improve power generation economics, some of the newly developed bagasse fired power plants operate with alternative biomass fuels for the slack (non-milling season), while others accumulate bagasse during the milling season to enable them to continue power generation into the slack season. The total generating capacity for all Australian sugar mills is around 470 MW (Sustainable energy in Australia, 2011) and in recent years, total generation from all Australian sugar mills has been around 1,200 GWh per year

The Australian sugar industry generates approximately 5 Mt/year of bagasse and about 4 Mt/year of trash such as cane tops, leaves, etc. (Clean Energy Council, 2010). Some sugar mills still have cane burnt off in the field before harvesting and some leave the trash in the field. Very little trash currently finds its way to the mill. In theory, the potential exists for the generation of around 4,600 GWh per year of electrical energy from the combined bagasse and trash supplies. The sugar industry has assessed that there is potential for three to five large regional cogeneration projects by 2020 (*Australian Sugar Milling Industry, 2009*). Assuming five of these projects were constructed with a capacity similar to the reference plant discussed above, the additional generation achieved would be around 1,500 GWh per year, making a total of about 2,700 GWh/year.

Because many of the elements of a particular sugar cane waste power plant are specific to the individual sugar mill, it is not possible to specify a typical sugar cane waste fired power plant. For the purposes of comparison, a 'reference' plant is specified, against which performance data and costings are provided. The 'reference' unit is a stand-alone power plant, generating 36 MW firing bagasse. It employs a high pressure boiler and condensing steam turbine generator. No steam is extracted from the turbine for sugar mill process use. The power plant operates year round, firing stored bagasse during periods when the associated sugar mill is not crushing.

Other biomass waste

The most common form of power generation from biomass crops is by direct firing in a boiler to raise steam which is fed to a steam turbine generator. As well as electrical power generation, these systems can provide process heat, in which case they are referred to as cogeneration or combined heat and power (CHP) plants. In cogeneration or CHP plants, steam can be extracted from the turbine at the pressure required by an industrial process, or at the exhaust of a back pressure (non-condensing) turbine. Direct fired boilers are normally fixed bed stoker or fluidised bed type.

Solid biomass such as wood can also be co-fired with coal in existing power generation plants. This configuration can utilise infrastructure already developed for generating electricity from coal and can normally be developed at a relatively low cost.

Australia currently has about 73 MW of dedicated wood waste fired power plants, generating approximately 400 GWh of electricity per year. Most of these plants are relatively small, typically less than 20 MW capacity. The potential exists for another 330 MW of power generating capacity from these sources by 2020, generating about 2,500 GWh per year (*Clean Energy Council, 2010*).

Given that many solid biomass fuelled power plants are associated with process plants, with elements of the plant specific to the individual site, it is not possible to specify a typical solid biomass waste fuel fired power plant. However, based on data from overseas (Claverton Group, 2012), the indicative capital cost of wood waste fired power plant employing boiler and steam turbine generator technology are outlined in Table 3.8.2.

Table 3.8.2: Indicative capital cost of wood waste fired power plant employing boiler and steam turbine generator technology

Power Output	2 MW	20 MW	80 MW
Capital Cost $M/MW	6.0	5.0	4.5

For the purposes of comparison, a 'reference' plant is nominated against which performance data and costs are provided. The reference unit is a stand-alone power plant, generating 20 MW firing wood waste, operating year round. It employs a medium pressure boiler and condensing steam turbine generator. No steam is extracted from the turbine for process use.

Performance parameters and cost estimates

The key performance parameters and associated cost estimates for each biomass technology are contained in Table 3.8.3.

Table 3.8.3: Key performance parameters and associated cost estimates for each biomass technology

Technology Description	Landfill Gas	Sugar Cane Waste	Other Biomass Waste
Capital Costs A$/kW net	3,000	4,000	5,000
Local Equipment/Construction Costs (includes commodities)	22%	55%	55%
International Equipment Costs	70%	27%	27%
Labour Costs	8%	18%	18%
Engineering Procurement Contractors (EPC) costs	95%	93%	94%
Owners Costs	5%	7%	6%
Construction profile % of capital Cost	Year 1 = 100%	Year 1 = 20% Year 2 = 80%	Year 1 = 20% Year 2 = 80%
First year available for Construction	2012	2012	2012
Typical new entrant size MW gross/net	1 MW	36 MW gross	20 MW
Economic Life (years)	30	30	30
Lead time for development (years)	1	2	2
Average capacity factors	70%	75%	80%
Thermal Efficiency (sent out – HHV)	33%	22%	27%
Thermal Efficiency (sent-out HHV) learning rate (% improvement per annum	No change	No change	No change
Auxiliary Load (%)	5%	11%	12%
FOM ($/MW/year) for 2012	150,000	125,000	125,000
VOM ($/MWh sent out) 2012	10	8	8
Percentage of emissions captured (%)	0%	n/a	n/a
Emissions rate per $kgCO_2e$/MWh (or $kgCO_2e$/GJ fuel)	Nil (based on the assumption that LFG is classified as renewable)	Nil (based on the assumption that sugar cane waste is totally renewable)	Nil (based on the assumption that wood waste is totally renewable)

While technology is not the primary driver in relation to future developments in power generation from sugar cane and other biomass waste in Australia, there are some technology developments which could take place in the longer term.

One technology development that has been trialled is drying or pelletising of bagasse. The advantage of this is that the fuel is much easier to transport and, because of its reduced water content, can be fired more efficiently in a boiler. However, the economics of bagasse drying or pelletising have not proved to be attractive where this technology has been tested, and there are currently no plans for its commercial adoption in Australia.

Another opportunity for a significant increase in power generation from solid biomass fuel is by co-firing in an existing power plant. Only minor alterations need to be made to some existing coal-fired power plants to enable wood use for co-firing. A number of coal-fired plants in Australia have already operated in co-firing mode, but, a range of technical difficulties have been encountered and this has largely been discontinued.

Another potential technical development is integrated gasification combined cycle (IGCC), provided this can be developed to a practical and economic level with biomass fuel. The potential conversion efficiency from biomass to electricity using this type of technology has been estimated by industry researchers at approximately 55 per cent, or approximately double the export potential of currently available co-generation plants. No significant progress has been made on full scale development of such plants and none is anticipated in Australia in the foreseeable future.

3.9 Geothermal technology options

Unlike countries such as Italy, the United States of America (USA) and New Zealand, Australia does not have access to high temperature conventional (i.e. hydro-thermal) geothermal resources. There are two types of geothermal resource available in Australia: Hot Sedimentary Aquifer (HSA), and Engineered Geothermal System (EGS).

A Hot Sedimentary Aquifer (HSA) system is characterised by hydrothermal groundwater resources in a sedimentary basin. This setting is typical of some of the low temperature resources in the USA, particularly Nevada, which were developed in the 1980s.

There are two characteristics required for successful HSA production wells. The aquifer must have sufficient temperature to be economically viable and sufficient permeability to provide an economic flow rate. Data available from shallower oil wells has been used to predict temperatures with reasonable accuracy, but no established methods exist for accurate prediction of permeability. This means that it is necessary to drill expensive exploration wells to determine if there is sufficient permeability for a viable project.

The current understanding of EGS dates back to the first efforts to extract the earth's heat from rocks with no pre-existing high permeability at the Fenton Hill hot dry rock experiments in the US in the early 1970s. Building on the experience from the Fenton Hill project, other international projects (at Rosemanowes, Hijiori, Ogachi, and Soultz) attempted to further develop the concept of creating a reservoir in crystalline rock in other geological settings.

The recent development of EGS has been most successful in Europe. The 3 MW plant at Landau is the first commercially funded EGS project and others are planned in Switzerland, Spain, UK and several other European countries.

Development of a geothermal project requires the consideration and evaluation of a number of factors, such as site (geography), geology, reservoir characteristics, geothermal temperature, plant size and type. While the majority of the overall cost of a geothermal scheme is typically associated with power plant construction in hydro-thermal schemes, well drilling comprises the major component of schemes based on HSA and, particularly, EGS technology.

There are two main factors affecting the total cost of wells in a geothermal scheme:

- The cost of drilling each well, and
- The average productivity of the wells.

It is difficult to predict the well completion cost as there is significant variance between wells. In addition to this uncertainty, the production rate of the wells is not well defined. For HSA in Australia, there is only a limited database to draw upon with only two known wells having been drilled to target depth.

Table 3.9.1: Key performance parameters and associated cost estimates for HSA and EGS geothermal technology options

Technology Description	Geothermal HSA	Geothermal EGS
Capital Costs A$/kW net	7,000	10,600
• Drilling (all wells)	• 53%	• 75%
• Power Plant	• 36%	• 19%
• Brine Reticulation	• 6%	• 3%
• Geoscience & Permitting	• 6%	• 3%
Local Equipment/Construction Costs (includes commodities)	43%	46%
International Equipment	23%	17%
Labour Costs	34%	37%
Engineering Procurement Contractors (EPC) costs	90%	90%
Owners Costs	10%	10%
Construction profile % of capital Cost	Year 1 = 40% Year 2 = 40% Year 3 = 20%	Year 1 = 40% Year 2 = 45% Year 3 = 15%
First year available for Construction	2020	2025
Typical new entrant size	10–20MW	5–10MW
Economic Life (years)	25–50	25–50
Thermal Efficiency (sent out – HHV)	Resource dependent	Resource dependent
Thermal Efficiency (sent-out HHV) learning rate (% improvement per annum	Resource dependent	Resource dependent
Auxiliary Load (%)	7–13% depending on reservoir	6–12% depending on reservoir
Capacity Factor	83%	83%
FOM ($/MW/year) for 2012	200,000	170,000
VOM ($/MWh sent out) 2012	0	0
Percentage of emissions captured (%)	Not applicable	Not applicable
Emissions rate per kgCO_2e/MWh	0	0

Recent and future advances in fracturing technology offer the potential for step change reductions in per-well and therefore – due to the major capital cost of wells – electricity generation costs. Fracturing technologies stand to benefit from the major R&D expenditures in development of vast US and Canadian (and other worldwide) shale gas resources. Improvements in resource exploration and assessment methods will also reduce costs.

The key to HSA development is to find shallow systems that reduce development costs and allow the use of proven hydrothermal systems and supporting technology. Secondary reservoir stimulation techniques, known as Secondary Enhancement of Sedimentary Aquifer Play (SESAP) is also being researched as a way to increase permeability and production rates of HSA.

3.10 Nuclear technology options

Nuclear power technology currently being sold into the international marketplace is predominantly comprised of large scale plants (1000–1600 MW) using the Generation III technology such as the AP1000 (Westinghouse) and EPR1600 (AREVA). Generation III technology utilises advanced light water reactors (LWR) which are generally variants on the earlier Generation II technology, but with major advances in safety and constructability. Generation III LWR reactors operate at saturated conditions with boiler steam outlet temperatures of about 300 C. Under these conditions thermal efficiencies of around 33 per cent are achievable.

Due to the large scale of Gen III technology, it is only suitable as an alternative to coal-based power plant technology. Small Modular Reactors (SMR) are an emerging nuclear technology which is comparable in scale to gas turbine technology with a generator capacity ranging from 25 MW to 1200 MW. SMR technology could potentially be commercially available in the next 5–10 years. Cost estimates for SMR technology are based on projections in the absence of commercial operating experience.

Data available for nuclear power reveals that, due to the high capital costs and lengthy plant construction times, projects are more sensitive to finance conditions. Furthermore, delays in construction cause a higher impact on generation costs than for other electricity generation technologies.

As SMR technology is modular, capital can be phased in over a period of time with revenue generated after the first module is installed. SMRs also have shorter projected lead time to generate electricity compared to giga watt (GW) scale (Gen III) designs. Current projections are that the lead time for SMR will be 2–3 years compared to 4–5 years for Gen III. SMRs are intended to be prefabricated in a factory environment and shipped to site for installation.

WorleyParsons estimate that the average overnight capital cost for four first-of-a-kind (FOAK) nuclear power plants in the US based on AP1000 Gen III technology is $4210/kWe. With standardisation of design, it is projected that Nth-of-a-Kind (NOAK) versions of this power plant technology will cost $3470/kWe in the US. The overnight cost for new nuclear projects in Asia is significantly less. The AP1000 in China costs of the order of $2300/KWe, and the APR1400 in Korea costs $1556/KWe.

It should be noted that the LCOE analysis for nuclear technologies does *not* include disposal/storage of spent fuel or provision for decommissioning of plant. A report in the Journal of Economic Perspectives (Davis, 2012) puts the contribution of spent fuel storage in the order of US$1/MWh.

As noted in Section 2, decommissioning costs have not been included for any of the technologies in the calculation of LCOE. While there is an expectation that decommissioning for nuclear plants will be higher per MW installed capacity than many other technologies, there is very little current experience of actual plant decommissioning. In addition, given the operating timeframes of new build plants, the decommissioning cost will be incurred well outside the modelled period.

Table 3.10.1: Key performance parameters and associated cost estimates for nuclear technology options

Technology Description	LWR – GW Scale	LWR – SMR
FOAK Capital Costs A$/kW net	4,210	7,908
NOAK Capital Costs A$/kW net	3,470	4,778
Local Equipment/Construction Costs (includes commodities)	28%	25%
International Equipment Costs	51%	57%
Labour Costs	21%	18%
Engineering Procurement Contractors (EPC) costs	87%	92%
Owners Costs	13%	8%
Construction profile % of capital Cost	Linear over six years	Linear over 3 years
First year available for Construction	2012	2020
Typical new entrant size MW gross/net	1,250MW	500MW
Economic Life (years)	60	60
Average capacity factors	83%	83%
Thermal Efficiency (sent out – HHV)	10,400 Btu/kWh	10,400 Btu/kWh
Thermal Efficiency (sent-out HHV) learning rate (% improvement per annum	None	None
Auxiliary Load (%)	35MW	15MW
FOM ($/MW/year) for 2012	34400	42200
VOM ($/MWh sent out) 2012	14.74	14
Percentage of emissions captured (%)	n/a	n/a
Emissions rate per kgCO_2e/MWh	0	0

It is expected that further technological advances will be made in relation to three areas of nuclear technology over the next 40 years: high temperature gas and metal reactors, fuel neutron reactors, and nuclear fusion (World Nuclear Association, 2011).

High Temperature Gas and Liquid Metal reactors offer the potential of improved safety and relatively high reactor outlet temperatures (~600 C) with associated improved thermal efficiencies. Current designs are at the proof of concept stage and the more advanced designs are undergoing licensing assessment by the Nuclear Regulatory Commission in the US.

Fast Neutron Reactors are able to consume or convert uranium isotope, U-238, to fissile plutonium, which greatly improves uranium fuel utilisation compared to LWRs. Some more advanced fast reactor designs are intended to utilise the spent fuel from LWR (Generation III/III+) technology in a manner which would consume long lived actinides. This technology exists today and has been deployed in research reactors for over 40 years. However, further work is underway to commercially deploy the technology. It is possible that commercial fast reactor technology will be available for commercial operation by 2030. France has declared an intention to commission a commercial fast reactor for domestic use by 2022.

While fusion conditions can currently be created for research purposes, the ability to economically do so with a net positive energy has so far eluded researchers. It is possible that commercial fusion technology could become a reality by 2050. The nuclear fusion reaction accessible with current technology requires atoms of two heavy hydrogen isotopes – deuterium and tritium – to fuse. It is envisaged that tritium will be bred within the reactor from a lithium blanket and so it is not required to be transported to or from the reactor site.

4. LCOE Results

Key points

- Estimated costs of several fossil fuel-based electricity technologies differ from previous studies, primarily as a result of a carbon price and higher projected market fuel prices.
- Estimated costs of solar photovoltaic technologies have declined dramatically in the past two to three years as a result of a rapid increase in global production of photovoltaic modules.
- Differences in the cost of generating electricity, especially between fossil fuel based and renewable electricity generation technologies, are expected to decline in the future.
- Biomass electricity generation technologies in 2012 are some of the most cost competitive forms of electricity generation and are projected to remain so out to 2050.
- By 2050 some renewable technologies, such as solar photovoltaic and wind on-shore, are expected to have the lowest LCOE of all the evaluated technologies.
- Among the non-renewable technologies, nuclear and combined cycle gas (and in later years combined with carbon capture and storage) offer the lowest LCOE over most of the projection period and remain cost competitive with renewable technologies out to 2050.

4.1 Individual technologies

For each of the 40 technologies analysed, tables and charts are provided to summarise LCOE out to 2050. The AETA model 2012 (free to download from www.bree.gov.au) provides component and LCOE costs for each Australian region. The charts provided in this section for each technology are for the state of New South Wales (NSW), or for Victoria or the South West Interconnect System region in Western Australia, where the technology is not deployable in NSW.

The carbon price for a project built in a year is calculated annually from the price of carbon in the operating year, for each year of operation for 30 years, and is included in the LCOE formula defined in Section 2.

For many of the technology options, the LCOE is projected to increase over time. Some of the reasons for the increase in LCOE are common to all technologies. One reason arises from a projected weakening in the Australian dollar exchange rate from its current historic highs, resulting in upward pressure on the cost of imported power plant components in Australian dollar terms. Another contributing factor arises from the cost of labour, which is projected to increase above CPI levels.

Some of the cost increases over time are unique to a particular group of technologies. For example, technologies which have CO_2 emissions will experience LCOE increases from a gradual increase in the carbon price. Increases in the real cost of fuel used by some technologies also contribute to a rising LCOE.

Table 4.1: IGCC plant based on brown coal, LCOE, Victoria

LCOE ($/MWh)	Year					
Region – Victoria	2012	2020	2025	2030	2040	2050
With a Carbon Price	n/a	195	215	235	272	288
Without a Carbon Price	n/a	132	133	135	139	143

Figure 4.1: IGCC plant based on brown coal, LCOE, Victoria

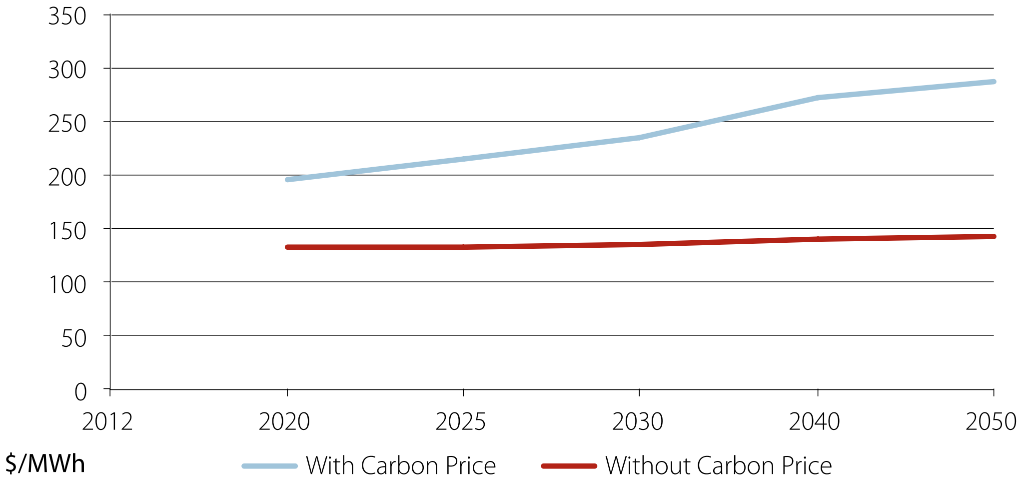


Table 4.2: IGCC plant based on brown coal with CCS, LCOE Victoria

LCOE ($/MWh)	Year					
Region – Victoria	2012	2020	2025	2030	2040	2050
With a Carbon Price	n/a	n/a	211	214	222	228
Without a Carbon Price	n/a	n/a	199	199	202	206

Figure 4.2: IGCC plant based on brown coal with CCS, LCOE Victoria

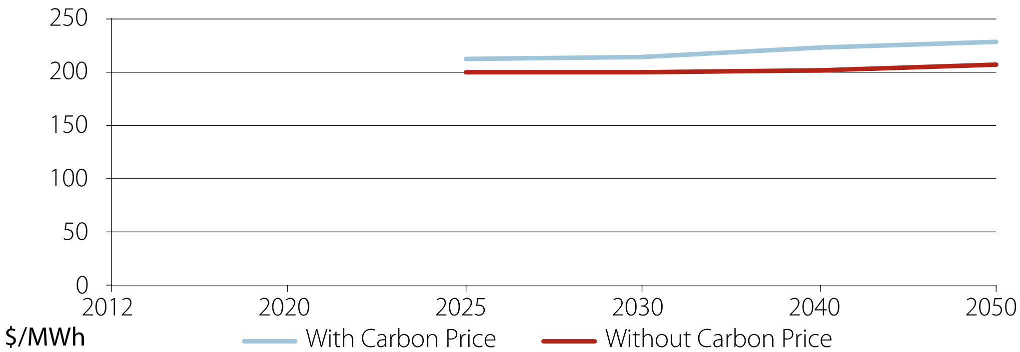


Table 4.3: IGCC plant based on bituminous coal, LCOE, NSW

LCOE ($/MWh)	Year					
Region – NSW (including ACT)	2012	2020	2025	2030	2040	2050
With a Carbon Price	n/a	178	194	211	241	250
Without a Carbon Price	n/a	125	126	127	130	129

Figure 4.3: IGCC plant based on bituminous coal, LCOE, NSW

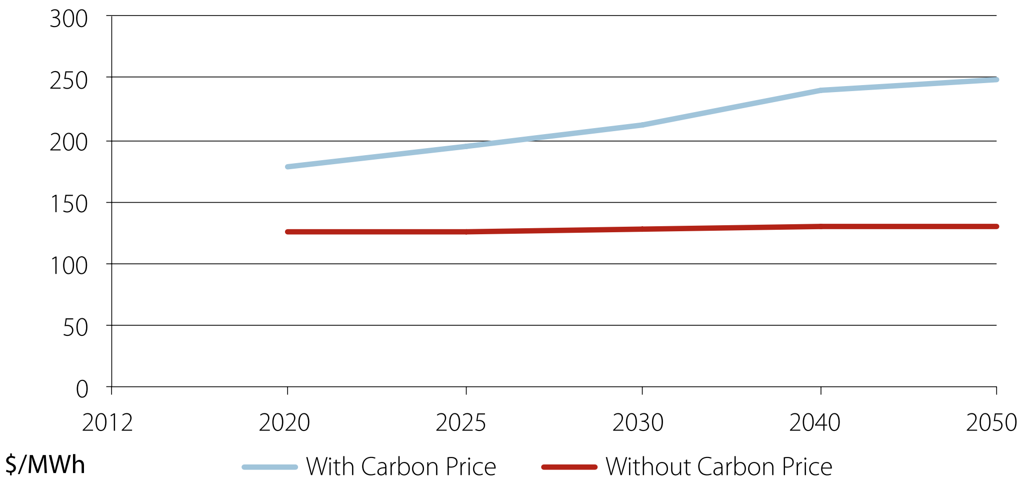


Table 4.4: IGCC plant based on bituminous coal with CCS, LCOE, NSW

LCOE ($/MWh)	Year					
Region - NSW (including ACT)	2012	2020	2025	2030	2040	2050
With a Carbon Price	n/a	n/a	253	253	259	263
Without a Carbon Price	n/a	n/a	242	241	242	245

Figure 4.4: IGCC plant based on bituminous coal with CCS, LCOE, NSW

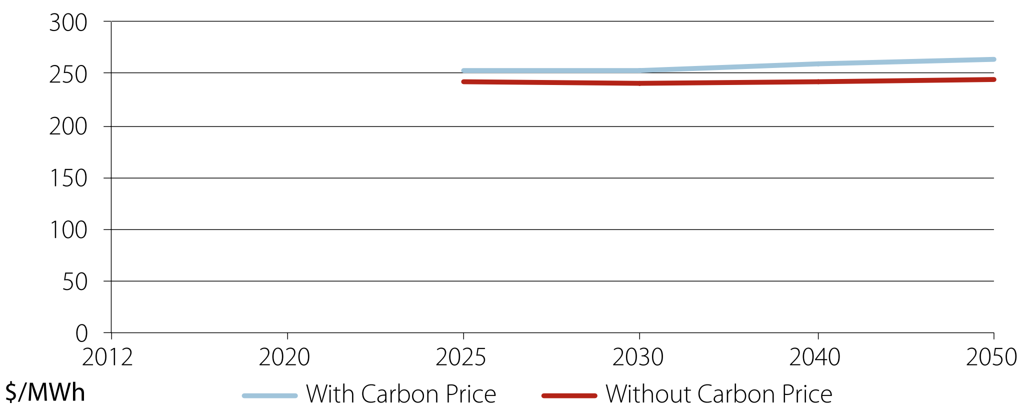


Table 4.5: Direct injection coal engine based on brown coal, LCOE, Victoria

LCOE ($/MWh)	Year					
Region – Victoria	2012	2020	2025	2030	2040	2050
With a Carbon Price	n/a	129	143	157	184	200
Without a Carbon Price	n/a	89	90	92	96	99

Figure 4.5: Direct injection coal engine based on brown coal, LCOE, Victoria

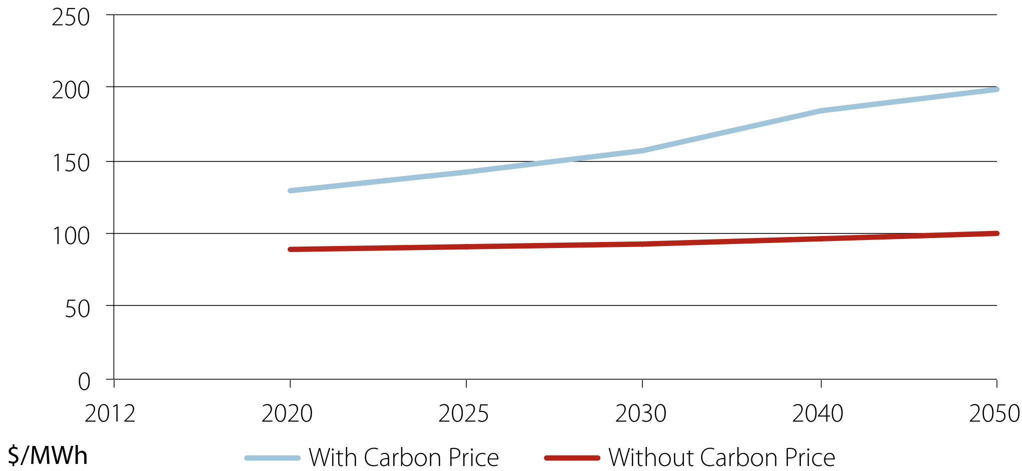


Table 4.6: Pulverised coal supercritical plant based on brown coal, LCOE, Victoria

LCOE ($/MWh)	Year					
Region – Victoria	2012	2020	2025	2030	2040	2050
With a Carbon Price	n/a	162	180	200	233	244
Without a Carbon Price	n/a	95	95	95	96	97

Figure 4.6: Pulverised coal supercritical plant based on brown coal, LCOE, Victoria

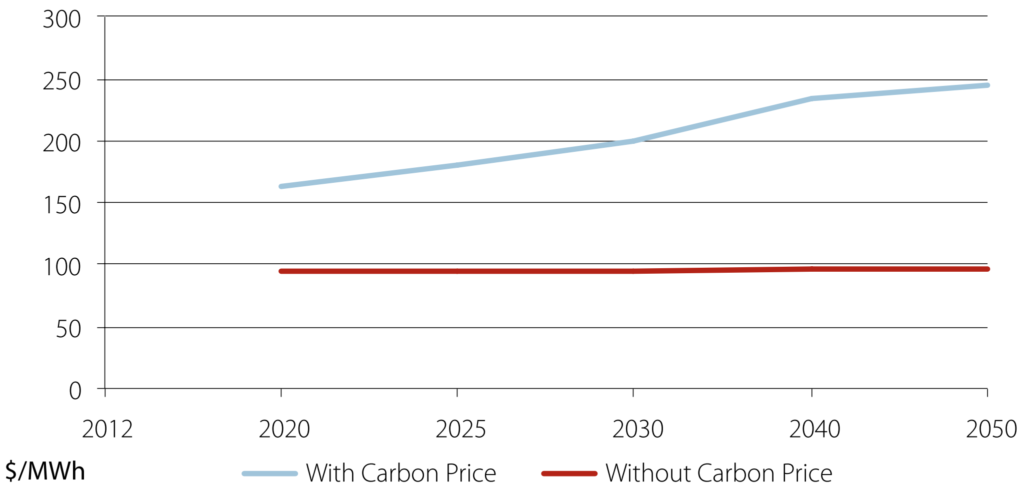


Table 4.7: Pulverised coal supercritical plant based on brown coal with post-combustion CCS, LCOE, Victoria

LCOE ($/MWh)	Year					
Region – Victoria	2012	2020	2025	2030	2040	2050
With a Carbon Price	n/a	n/a	205	202	207	209
Without a Carbon Price	n/a	n/a	192	186	186	187

Figure 4.7: Pulverised coal supercritical plant based on brown coal with post-combustion CCS, LCOE, Victoria

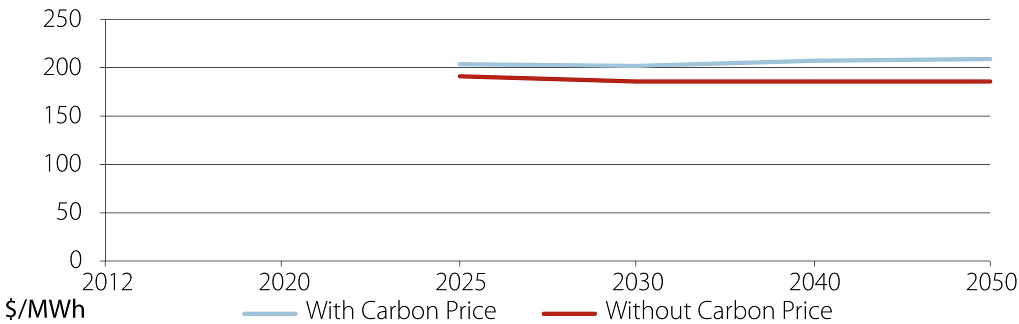


Table 4.8: Pulverised coal subcritical plant based on brown coal with retrofit post-combustion CCS, LCOE, Victoria

LCOE ($/MWh)	Year					
Region – Victoria	2012	2020	2025	2030	2040	2050
With a Carbon Price	n/a	n/a	153	152	158	160
Without a Carbon Price	n/a	n/a	140	136	136	137

Figure 4.8: Pulverised coal subcritical plant based on brown coal with retrofit post-combustion CCS, LCOE, Victoria

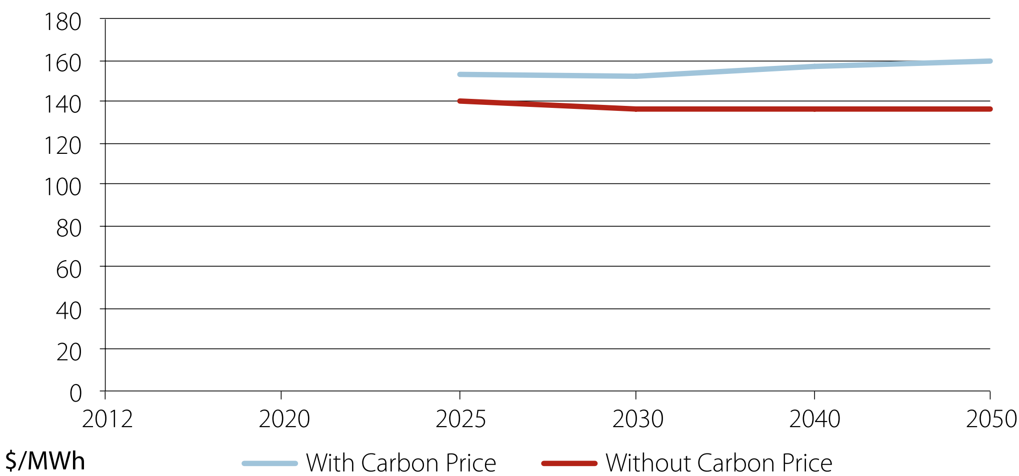


Table 4.9: Pulverised coal supercritical plant based on bituminous coal, LCOE, NSW

LCOE ($/MWh)	Year					
Region – NSW (including ACT)	2012	2020	2025	2030	2040	2050
With a Carbon Price	n/a	135	149	164	188	196
Without a Carbon Price	n/a	84	84	84	85	85

Figure 4.9: Pulverised coal supercritical plant based on bituminous coal, LCOE, NSW

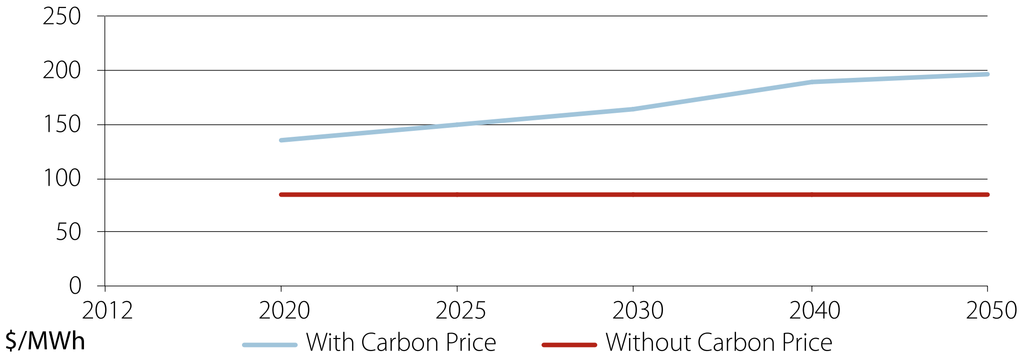


Table 4.10: Pulverised coal supercritical plant based on bituminous coal, LCOE, SWIS

LCOE ($/MWh)	Year					
Region - SWIS (WA)	2012	2020	2025	2030	2040	2050
With a Carbon Price	n/a	152	166	181	205	213
Without a Carbon Price	n/a	100	100	100	100	100

Figure 4.10: Pulverised coal supercritical plant based on bituminous coal, LCOE, SWIS

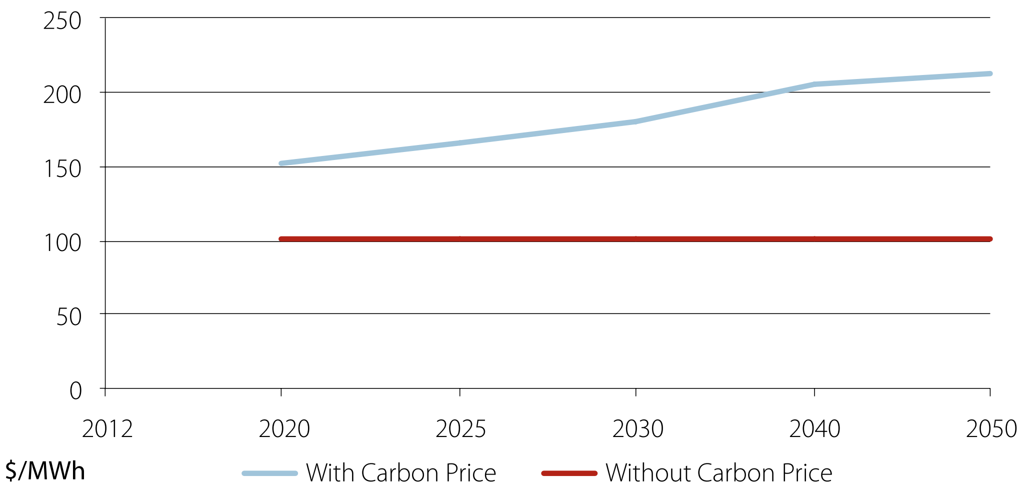


Table 4.11: Pulverised coal supercritical plant based on bituminous coal with CCS, LCOE, NSW

LCOE ($/MWh)	Year					
Region - NSW (including ACT)	2012	2020	2025	2030	2040	2050
With a Carbon Price	n/a	n/a	205	203	206	207
Without a Carbon Price	n/a	n/a	196	192	192	192

Figure 4.11: Pulverised coal supercritical plant based on bituminous coal with CCS, LCOE, NSW

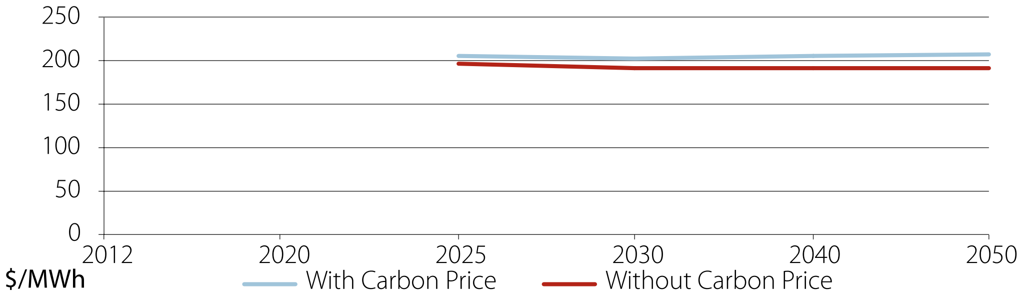


Table 4.12: Pulverised coal subcritical plant based on bituminous coal with retrofit post-combustion CCS, LCOE, NSW

LCOE ($/MWh)	Year					
Region - NSW (including ACT)	2012	2020	2025	2030	2040	2050
With a Carbon Price	n/a	n/a	162	162	165	167
Without a Carbon Price	n/a	n/a	153	151	151	152

Figure 4.12: Pulverised coal subcritical plant based on bituminous coal with retrofit post-combustion CCS, LCOE, NSW

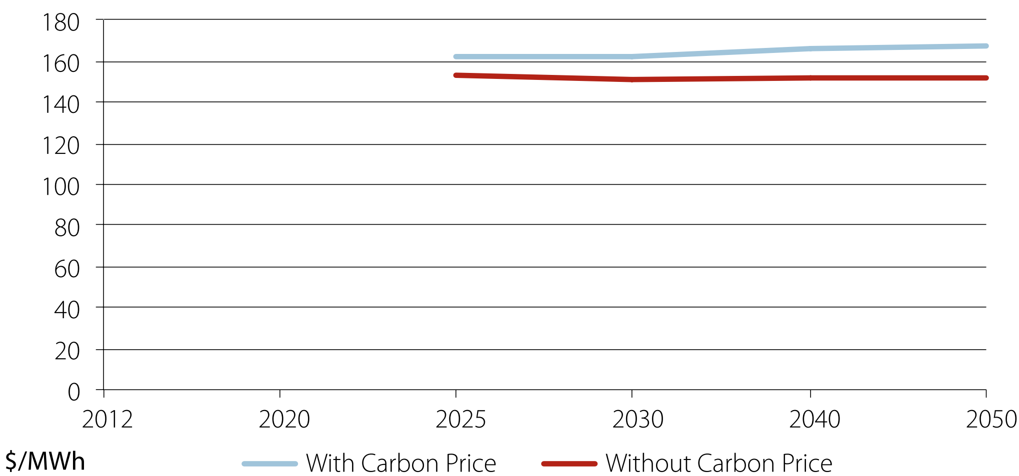


Table 4.13: CCGT power plant with retrofit CCS, LCOE, NSW

LCOE ($/MWh)	Year					
Region - NSW (including ACT)	2012	2020	2025	2030	2040	2050
With a Carbon Price	n/a	n/a	132	132	135	136
Without a Carbon Price	n/a	n/a	127	126	127	128

Figure 4.13: CCGT power plant with retrofit CCS, LCOE, NSW

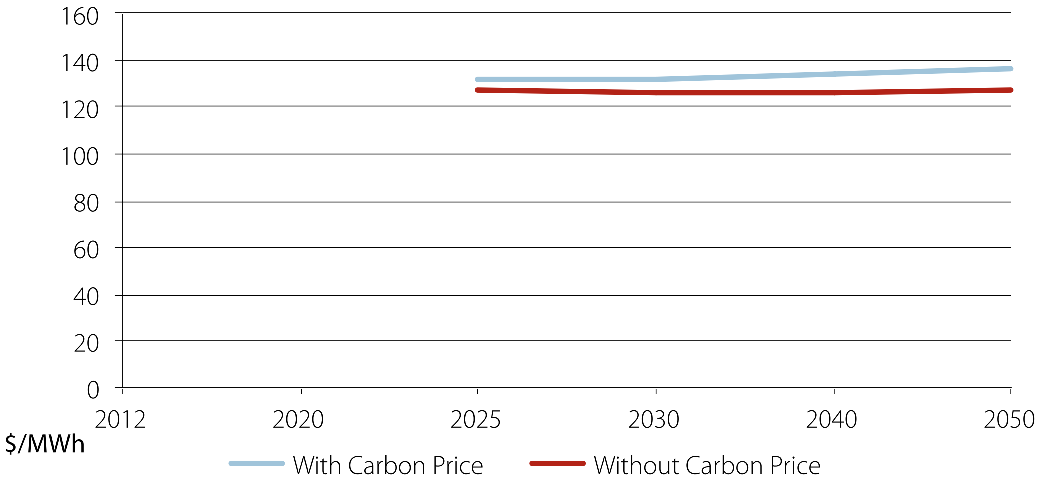


Table 4.14: Oxy combustion pulverised coal supercritical plant based on bituminous coal, LCOE, NSW

LCOE ($/MWh)	Year					
Region - NSW (including ACT)	2012	2020	2025	2030	2040	2050
With a Carbon Price	n/a	n/a	209	228	258	267
Without a Carbon Price	n/a	n/a	127	128	127	127

Figure 4.14: Oxy combustion pulverised coal supercritical plant based on bituminous coal, LCOE, NSW

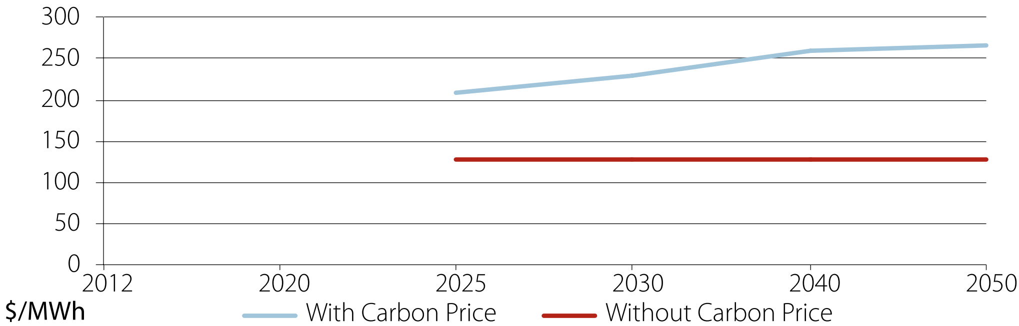


Table 4.15: Oxy combustion pulverised coal supercritical plant based on bituminous coal with CCS, LCOE, NSW

LCOE ($/MWh)	Year					
Region - NSW (including ACT)	2012	2020	2025	2030	2040	2050
With a Carbon Price	n/a	n/a	215	215	214	213
Without a Carbon Price	n/a	n/a	215	215	214	213

Figure 4.15: Oxy combustion pulverised coal supercritical plant based on bituminous coal with CCS, LCOE, NSW

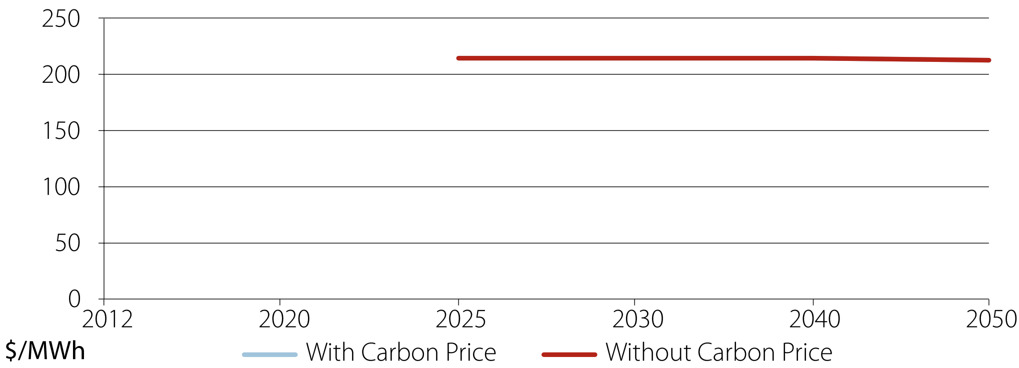


Table 4.16: Combined cycle plant burning natural gas, LCOE, NSW

LCOE ($/MWh)	Year					
Region – NSW (including ACT)	2012	2020	2025	2030	2040	2050
With a Carbon Price	103	120	129	135	144	146
Without a Carbon Price	89	98	101	100	96	93

Figure 4.16: Combined cycle plant burning natural gas, LCOE, NSW

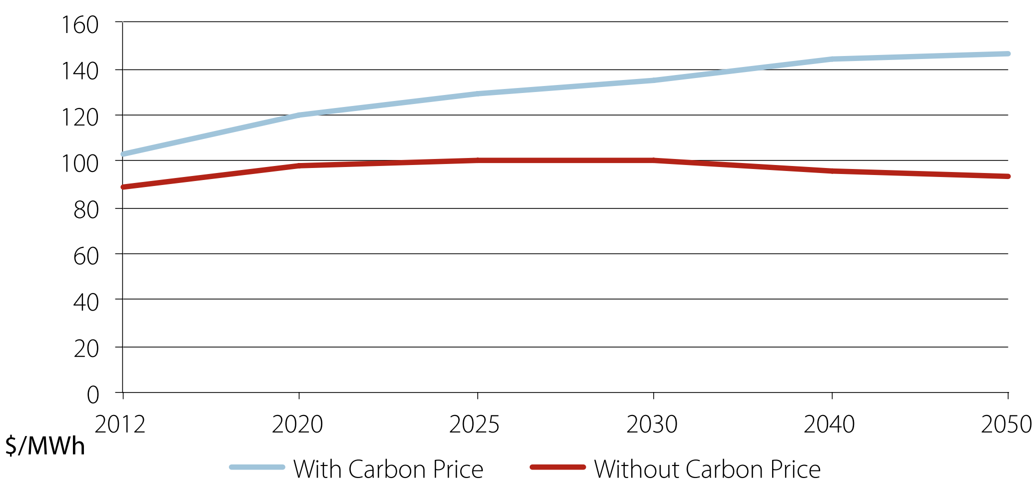


Table 4.17: Combined cycle plant burning natural gas, LCOE, SWIS

LCOE ($/MWh)	Year					
Region - SWIS (WA)	2012	2020	2025	2030	2040	2050
With a Carbon Price	133	135	137	140	149	151
Without a Carbon Price	118	113	108	105	101	98

Figure 4.17: Combined cycle plant burning natural gas, LCOE, SWIS

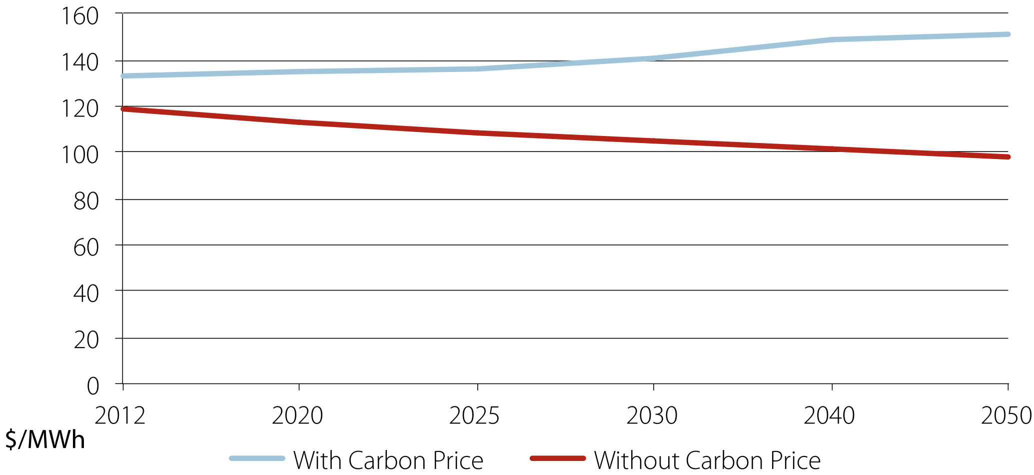


Table 4.18: Combined cycle plant with post combustion CCS, LCOE, NSW

LCOE ($/MWh)	Year					
Region - NSW (including ACT)	2012	2020	2025	2030	2040	2050
With a Carbon Price	n/a	n/a	166	163	160	157
Without a Carbon Price	n/a	n/a	162	158	152	148

Figure 4.18: Combined cycle plant with post combustion CCS, LCOE, NSW

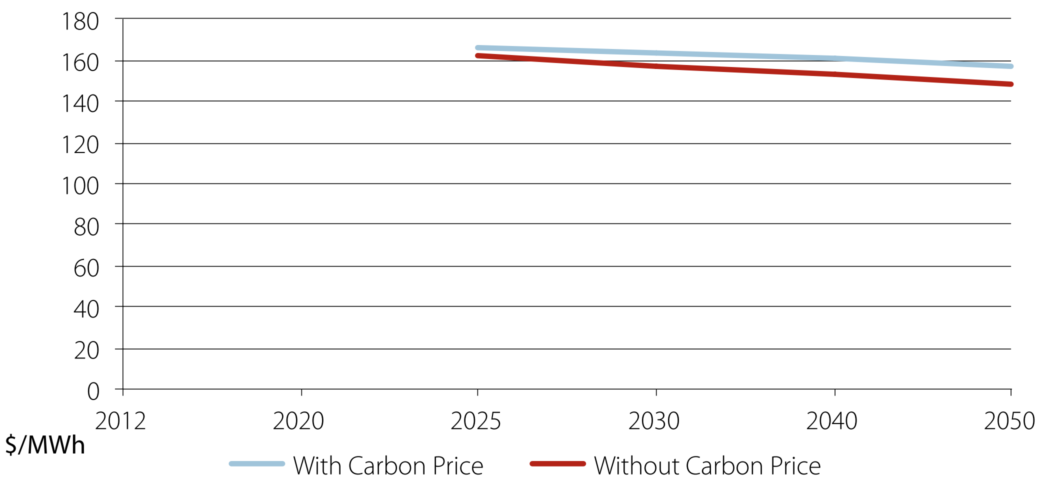


Table 4.19: Open cycle plant burning natural gas, LCOE, NSW

LCOE ($/MWh)	Year					
Region - NSW (including ACT)	2012	2020	2025	2030	2040	2050
With a Carbon Price	215	239	253	262	275	281
Without a Carbon Price	196	210	215	214	210	207

Figure 4.19: Open cycle plant burning natural gas, LCOE, NSW

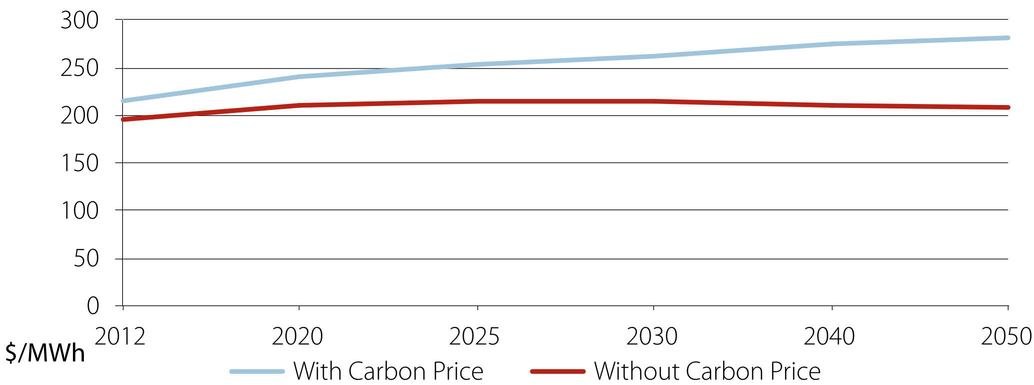


Table 4.20: Solar thermal plant using linear fresnel reflector technology w/o storage, LCOE, NSW

LCOE ($/MWh)	Year					
Region - NSW (including ACT)	2012	2020	2025	2030	2040	2050
With a Carbon Price	366	247	223	226	229	235
Without a Carbon Price	366	247	223	226	229	235

Figure 4.20: Solar thermal plant using linear fresnel reflector technology w/o storage, LCOE, NSW

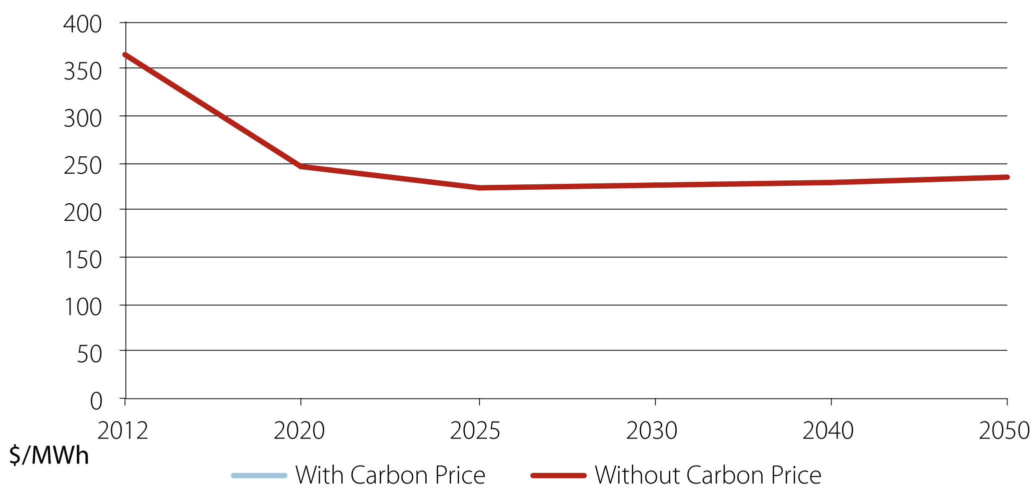


Table 4.21: Solar thermal plant using parabolic trough technology w/o storage, LCOE, NSW

LCOE ($/MWh)	Year					
Region - NSW (including ACT)	2012	2020	2025	2030	2040	2050
With a Carbon Price	347	236	213	216	219	226
Without a Carbon Price	347	236	213	216	219	226

Figure 4.21: Solar thermal plant using parabolic trough technology w/o storage, LCOE, NSW

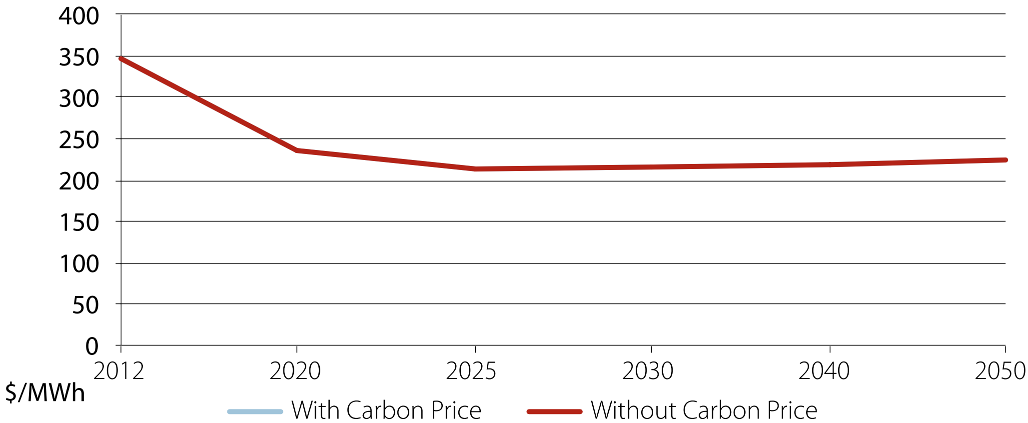


Table 4 22: Solar thermal plant using parabolic trough technology with storage, LCOE, NSW

LCOE ($/MWh)	Year					
Region – NSW (including ACT)	2012	2020	2025	2030	2040	2050
With a Carbon Price	339	228	207	208	209	213
Without a Carbon Price	339	228	207	208	209	213

Figure 4.22: Solar thermal plant using parabolic trough technology with storage, LCOE, NSW

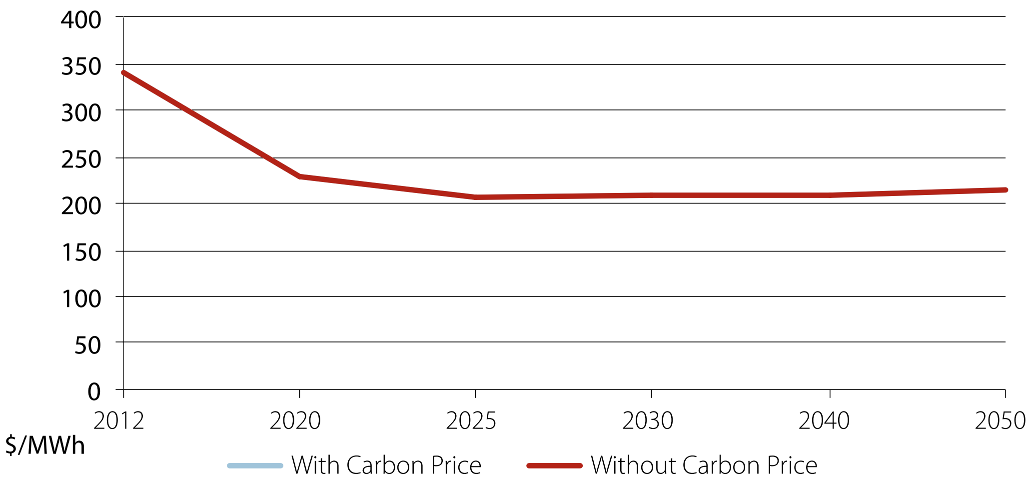


Table 4.23: Solar thermal plant using compact linear fresnel reflector technology with storage, LCOE, NSW

LCOE ($/MWh)	Year					
Region - NSW (including ACT)	2012	2020	2025	2030	2040	2050
With a Carbon Price	358	240	217	218	219	223
Without a Carbon Price	358	240	217	218	219	223

Figure 4.23: Solar thermal plant using compact linear fresnel reflector technology with storage, LCOE, NSW

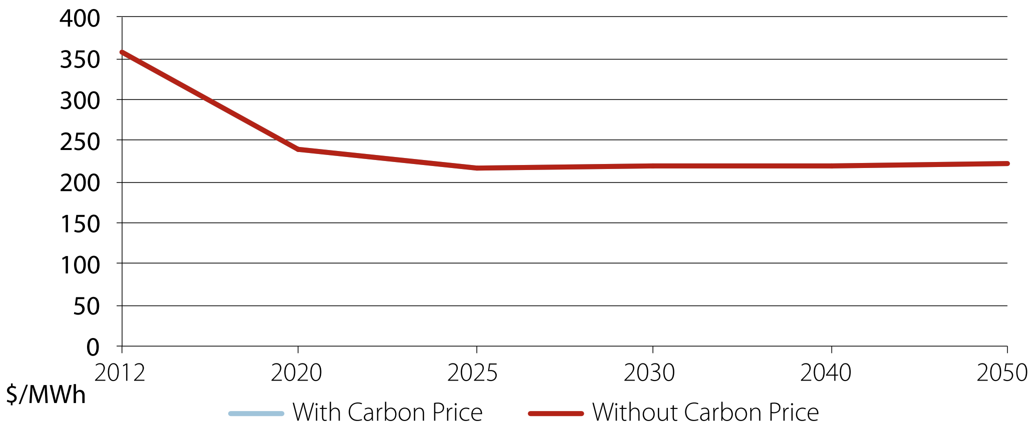


Table 4.24: Solar thermal plant using central receiver technology w/o storage, LCOE, NSW

LCOE ($/MWh)	Year					
Region - NSW (including ACT)	2012	2020	2025	2030	2040	2050
With a Carbon Price	304	217	200	201	202	205
Without a Carbon Price	304	217	200	201	202	205

Figure 4.24: Solar thermal plant using central receiver technology w/o storage, LCOE, NSW

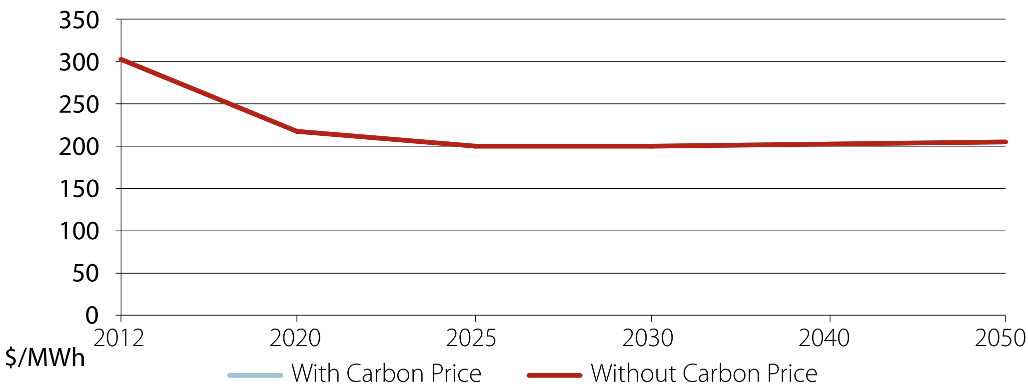


Table 4.25: Solar thermal plant using central receiver technology with storage, LCOE, NSW

LCOE ($/MWh)	Year					
Region - NSW (including ACT)	2012	2020	2025	2030	2040	2050
With a Carbon Price	311	208	187	189	189	193
Without a Carbon Price	311	208	187	189	189	193

Figure 4.25: Solar thermal plant using central receiver technology with storage, LCOE, NSW

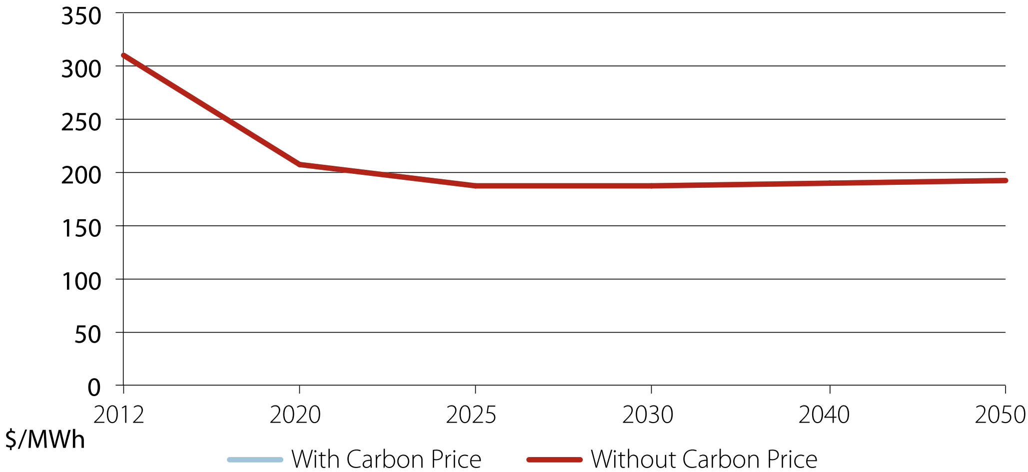


Table 4.26: Solar photovoltaic - non-tracking, LCOE, NSW

LCOE ($/MWh)	Year					
Region - NSW (including ACT)	2012	2020	2025	2030	2040	2050
With a Carbon Price	224	133	122	116	90	86
Without a Carbon Price	224	133	122	116	90	86

Figure 4.26: Solar photovoltaic - non-tracking, LCOE, NSW

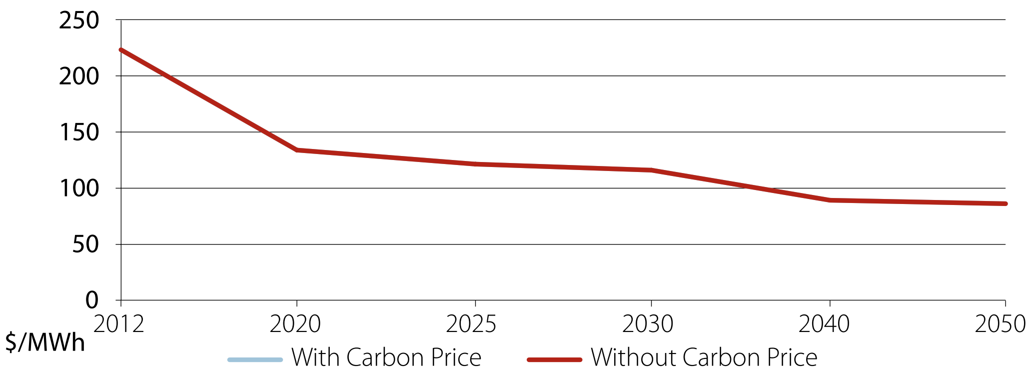


Table 4.27: Solar photovoltaic - single axis tracking, LCOE, NSW

LCOE ($/MWh)	Year					
Region - NSW (including ACT)	2012	2020	2025	2030	2040	2050
With a Carbon Price	229	154	147	140	111	110
Without a Carbon Price	229	154	147	140	111	110

Figure 4.27: Solar photovoltaic - single axis tracking, LCOE, NSW

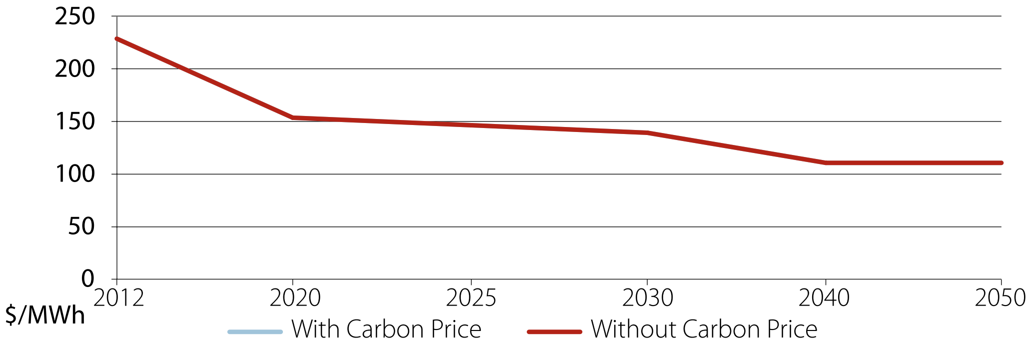


Table 4.28: Solar photovoltaic - dual axis tracking, LCOE, NSW

LCOE ($/MWh)	Year					
Region - NSW (including ACT)	2012	2020	2025	2030	2040	2050
With a Carbon Price	293	206	197	190	153	152
Without a Carbon Price	293	206	197	190	153	152

Figure 4.28: Solar photovoltaic - dual axis tracking, LCOE, NSW

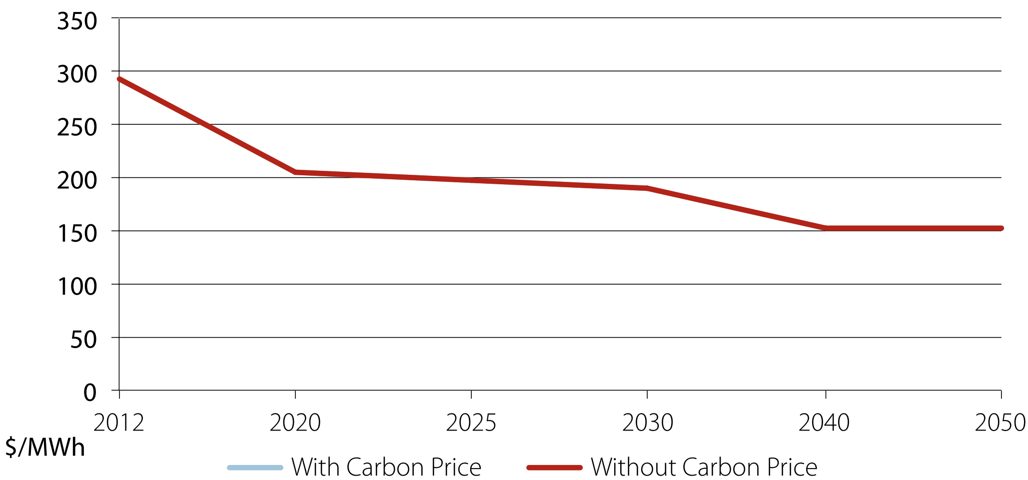


Table 4.29: On-shore Wind; 100 MW, LCOE, NSW

LCOE ($/MWh)	Year					
Region - NSW (including ACT)	**2012**	**2020**	**2025**	**2030**	**2040**	**2050**
With a Carbon Price	116	90	91	93	96	99
Without a Carbon Price	116	90	91	93	96	99

Figure 4.29: On-shore Wind; 100 MW, LCOE, NSW

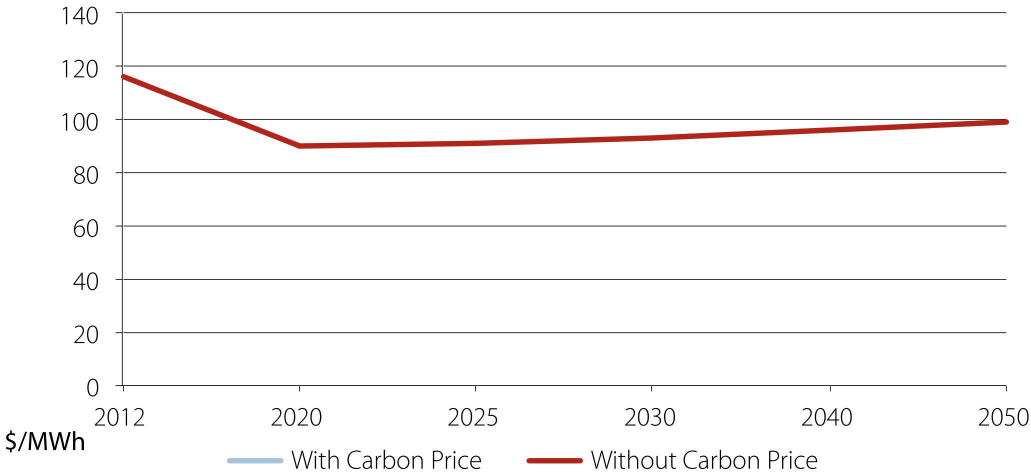


Table 4.30: Off-shore Wind; 100MW, LCOE, NSW

LCOE ($/MWh)	Year					
Region - NSW (including ACT)	**2012**	**2020**	**2025**	**2030**	**2040**	**2050**
With a Carbon Price	194	178	182	180	186	193
Without a Carbon Price	194	178	182	180	186	193

Figure 4.30: Off-shore Wind; 100MW, LCOE, NSW

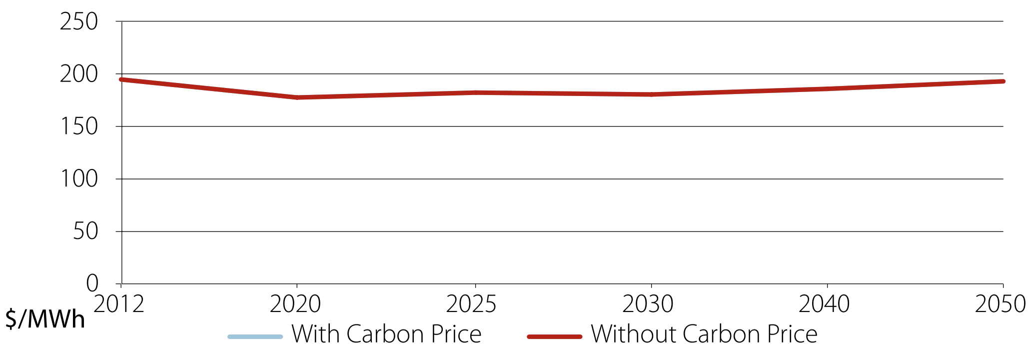


Table 4.31: Wave/ocean, LCOE, NSW

LCOE ($/MWh)	Year					
Region - NSW (including ACT)	**2012**	**2020**	**2025**	**2030**	**2040**	**2050**
With a Carbon Price	n/a	303	222	220	225	226
Without a Carbon Price	n/a	303	222	220	225	226

Figure 4.31: Wave/ocean, LCOE, NSW

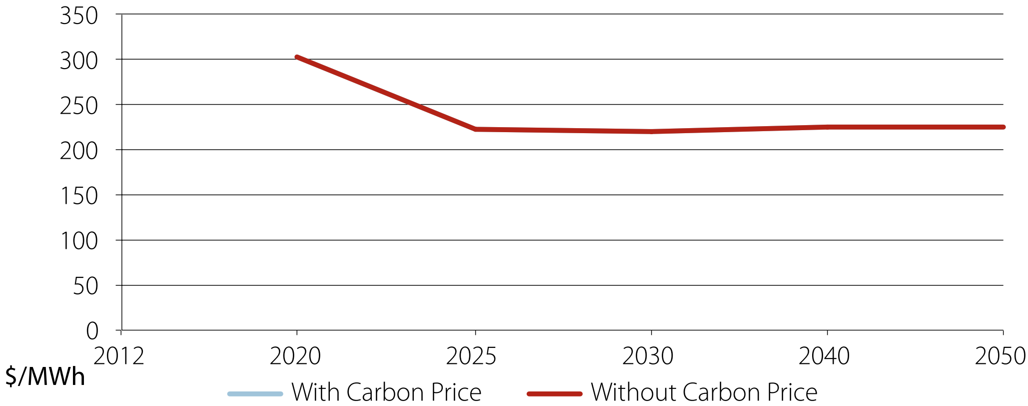


Table 4.32: Geothermal - hot sedimentary aquifer, LCOE, NSW

LCOE ($/MWh)	Year					
Region - NSW (including ACT)	**2012**	**2020**	**2025**	**2030**	**2040**	**2050**
With a Carbon Price	n/a	154	156	157	160	165
Without a Carbon Price	n/a	154	156	157	160	165

Figure 4.32: Geothermal - hot sedimentary aquifer, LCOE, NSW

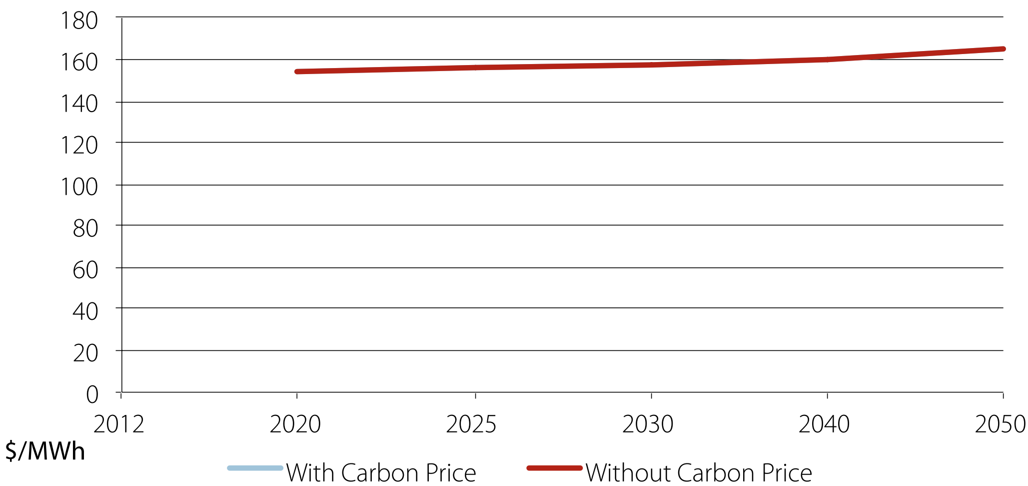


Table 4.33: Geothermal - hot rock, LCOE, NSW

LCOE ($/MWh)	Year					
Region - NSW (including ACT)	2012	2020	2025	2030	2040	2050
With a Carbon Price	n/a	n/a	215	214	217	222
Without a Carbon Price	n/a	n/a	215	214	217	222

Figure 4.33: Geothermal - hot rock, LCOE, NSW

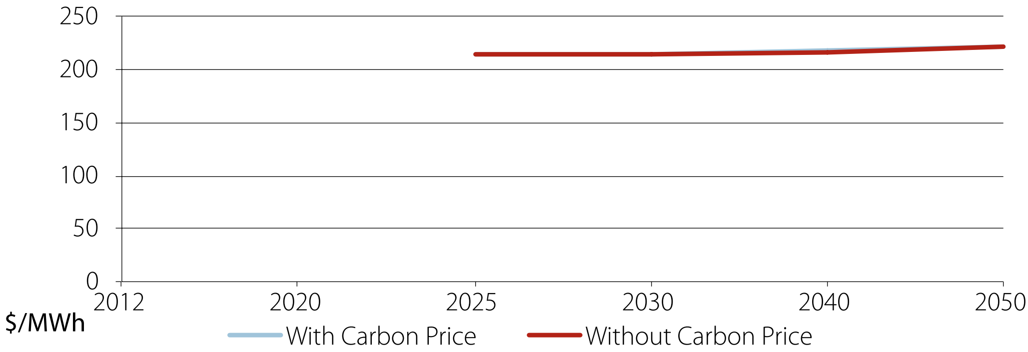


Table 4.34: Landfill gas power plant, LCOE, NSW

LCOE ($/MWh)	Year					
Region - NSW (including ACT)	2012	2020	2025	2030	2040	2050
With a Carbon Price	91	94	96	99	103	107
Without a Carbon Price	91	94	96	99	103	107

Figure 4.34: Landfill gas power plant, LCOE, NSW

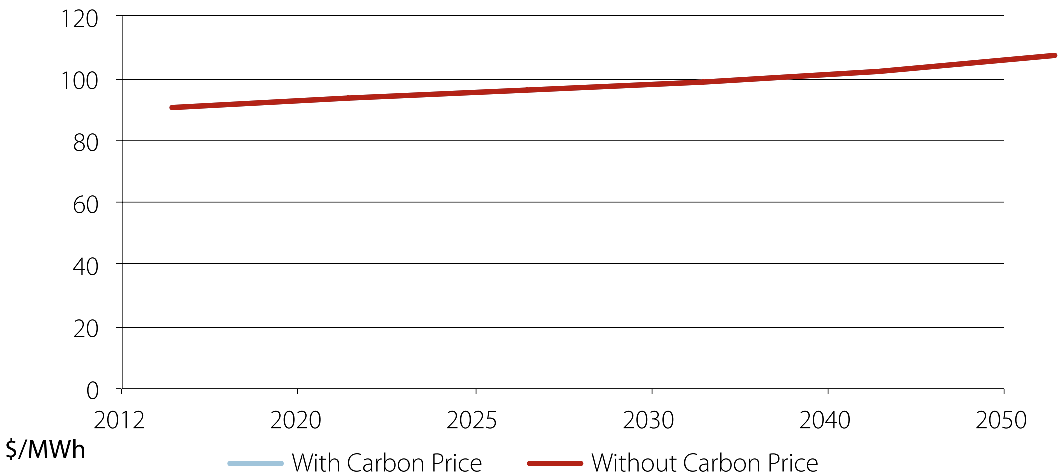


Table 4.35: Sugar cane waste power plant, LCOE, NSW

LCOE ($/MWh)	Year					
Region - NSW (including ACT)	2012	2020	2025	2030	2040	2050
With a Carbon Price	112	115	118	119	121	126
Without a Carbon Price	112	115	118	119	121	126

Figure 4.35: Sugar cane waste power plant, LCOE, NSW

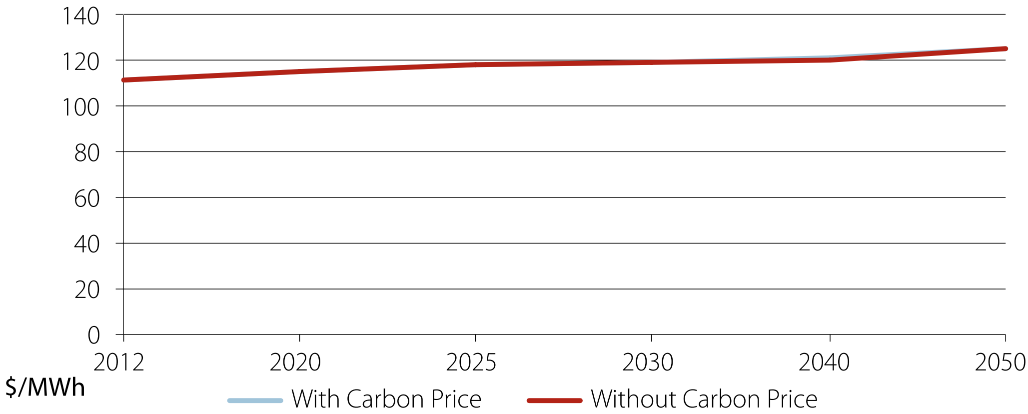


Table 4.36: Other biomass waste power plant, LCOE, NSW

LCOE ($/MWh)	Year					
Region - NSW (including ACT)	2012	2020	2025	2030	2040	2050
With a Carbon Price	128	132	135	136	138	143
Without a Carbon Price	128	132	135	136	138	143

Figure 4.36: Other biomass waste power plant, LCOE, NSW

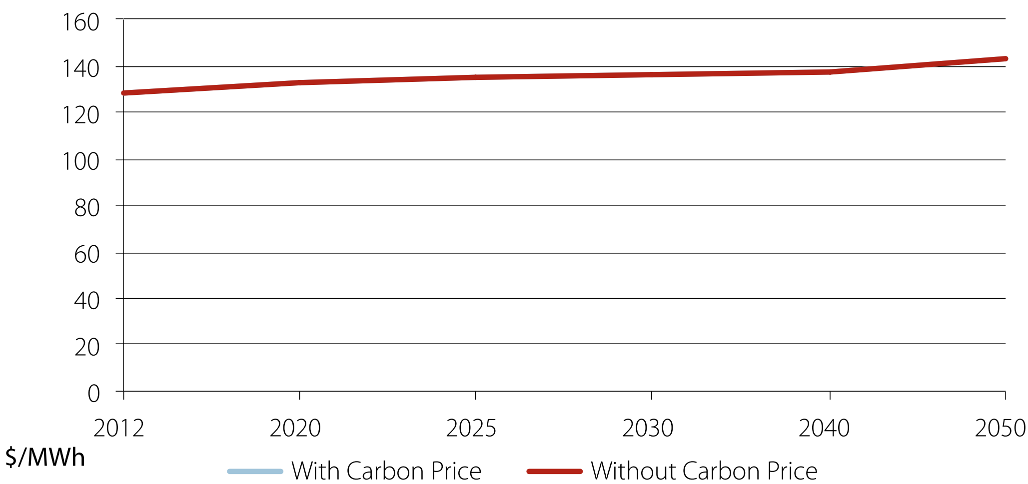


Table 4.37: Nuclear (GW scale LWR), LCOE, NSW

LCOE ($/MWh)	Year					
Region - NSW (including ACT)	2012	2020	2025	2030	2040	2050
With a Carbon Price	96	99	100	102	105	108
Without a Carbon Price	96	99	100	102	105	108

Figure 4.37: Nuclear (GW scale LWR), LCOE, NSW

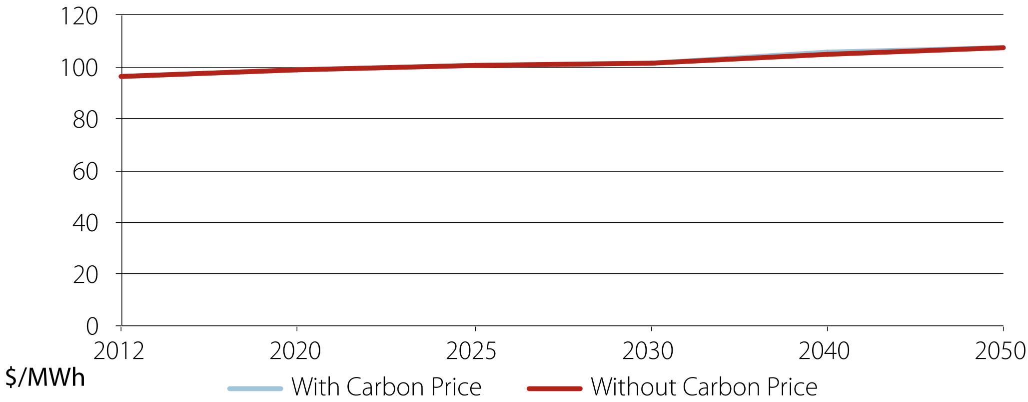


Table 4.38: Nuclear (SMR), LCOE, NSW

LCOE ($/MWh)	Year					
Region - NSW (including ACT)	2012	2020	2025	2030	2040	2050
With a Carbon Price	n/a	113	115	116	121	123
Without a Carbon Price	n/a	113	115	116	121	123

Figure 4.38: Nuclear (SMR), LCOE, NSW

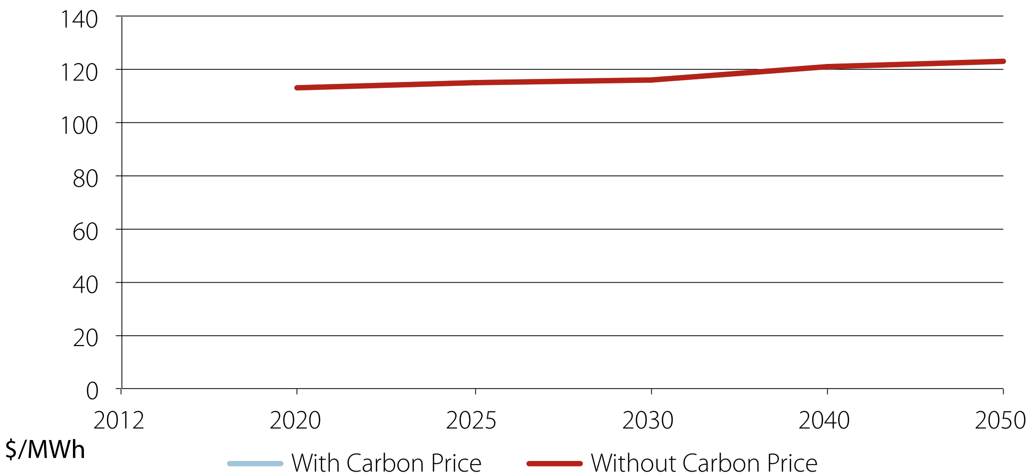


Table 4.39: Solar/coal hybrid, LCOE, NSW

LCOE ($/MWh)	Year					
Region - NSW (including ACT)	2012	2020	2025	2030	2040	2050
With a Carbon Price	124	130	142	157	183	193
Without a Carbon Price	93	82	81	82	82	83

Figure 4.39: Solar/coal hybrid, LCOE, NSW

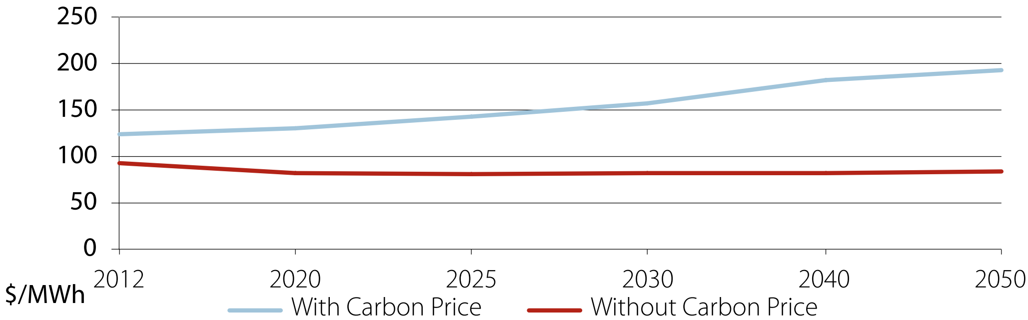
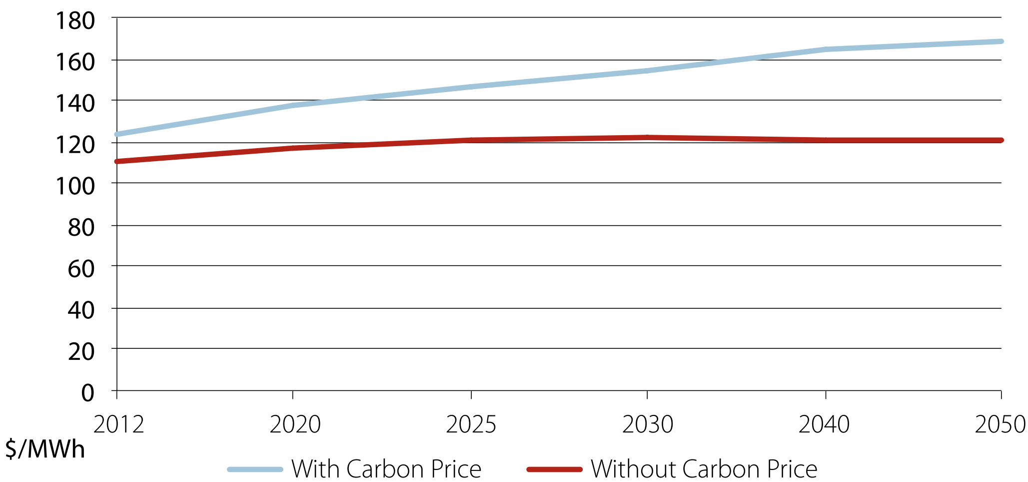


Table 4.40: ISCC; parabolic trough with combined cycle gas, LCOE, NSW

LCOE ($/MWh)	Year					
Region - NSW (including ACT)	2012	2020	2025	2030	2040	2050
With a Carbon Price	124	138	148	154	165	169
Without a Carbon Price	111	118	121	122	121	121

Figure 4.40: ISCC; parabolic trough with combined cycle gas, LCOE, NSW



5. Technology Cost comparisons

This section provides a relative ranking of the AETA technologies, and makes comparisons of the capital costs and LCOE estimates to previous Australian and international studies.

5.1 Technology Comparisons of LCOE

Key points

- LCOE costs are provided for the years 2012, 2020, 2025, 2030, 2040, and 2050.
- Cost ranges are provided for each technology that accounts for differences in fuel prices, and state-based variations.
- LCOE costs vary substantially across the technologies from \$91/MWh to \$366/MWh in 2012 and \$86/MWh to \$288/MWh in 2050.

Figure 5.1 to 5.5 provide a relative ranking of technology LCOEs by 2012, 2020, 2030, 2040 and 2050 for NSW. The figures illustrate how the LCOE of various technologies change over time. Differences are explained by a multiplicity of factors including the technical developments, learning rates or cost reductions, carbon prices, exchange rate effects, and fuel prices.

Figure 5.1: LCOE for Technologies (NSW), 2012

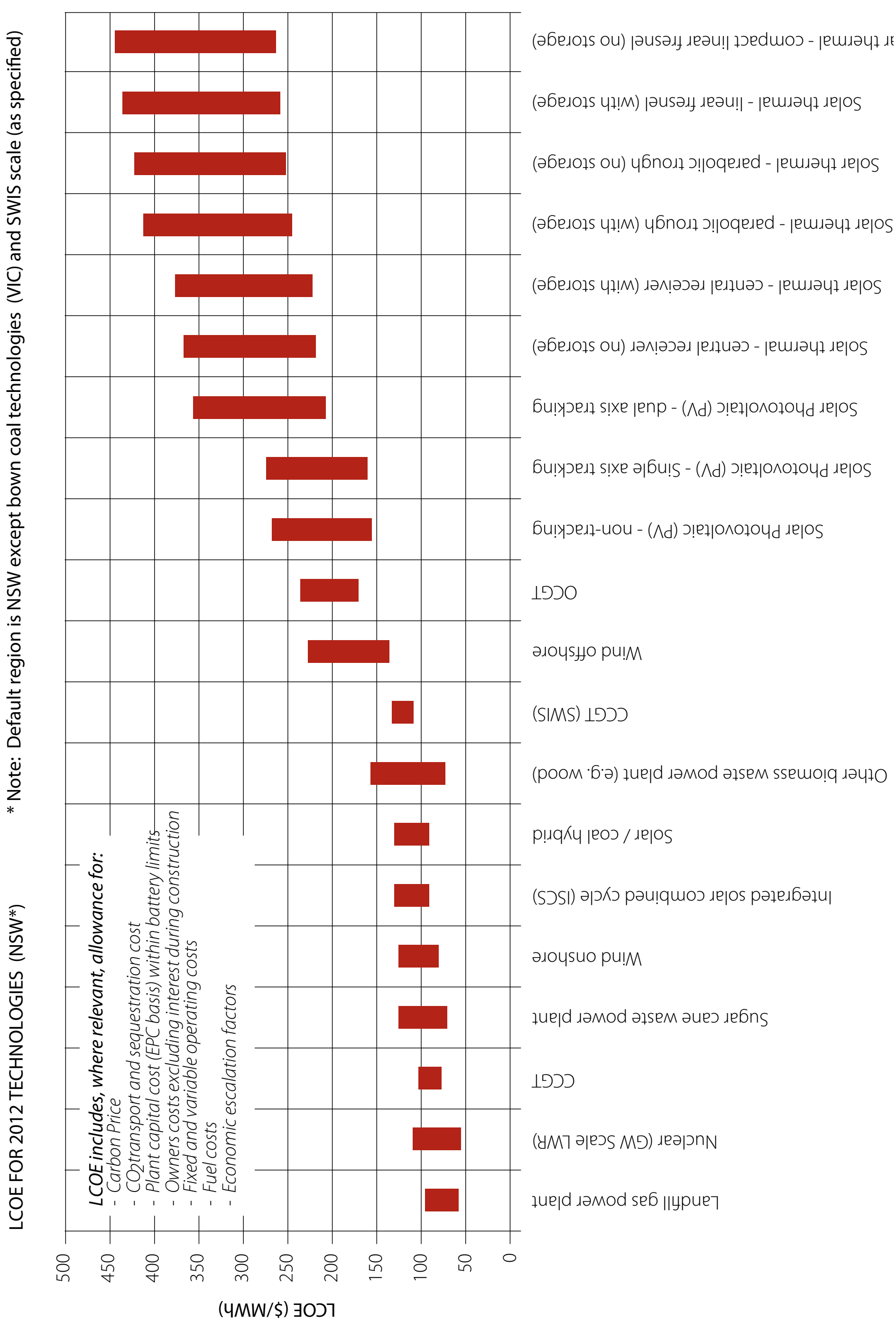


Figure 5.2: LCOE for Technologies (NSW), 2020

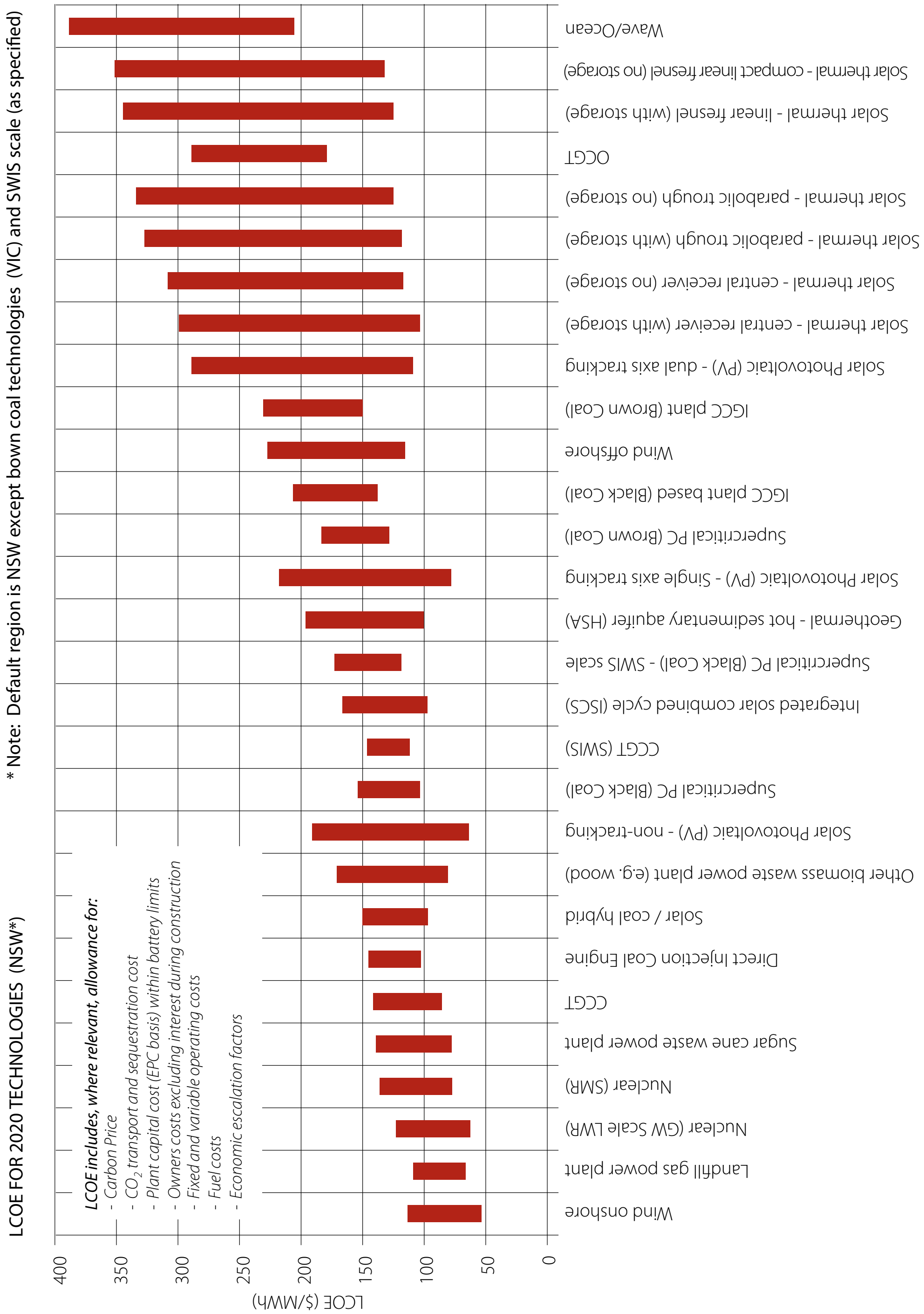


Figure 5.3: LCOE for Technologies (NSW), 2030

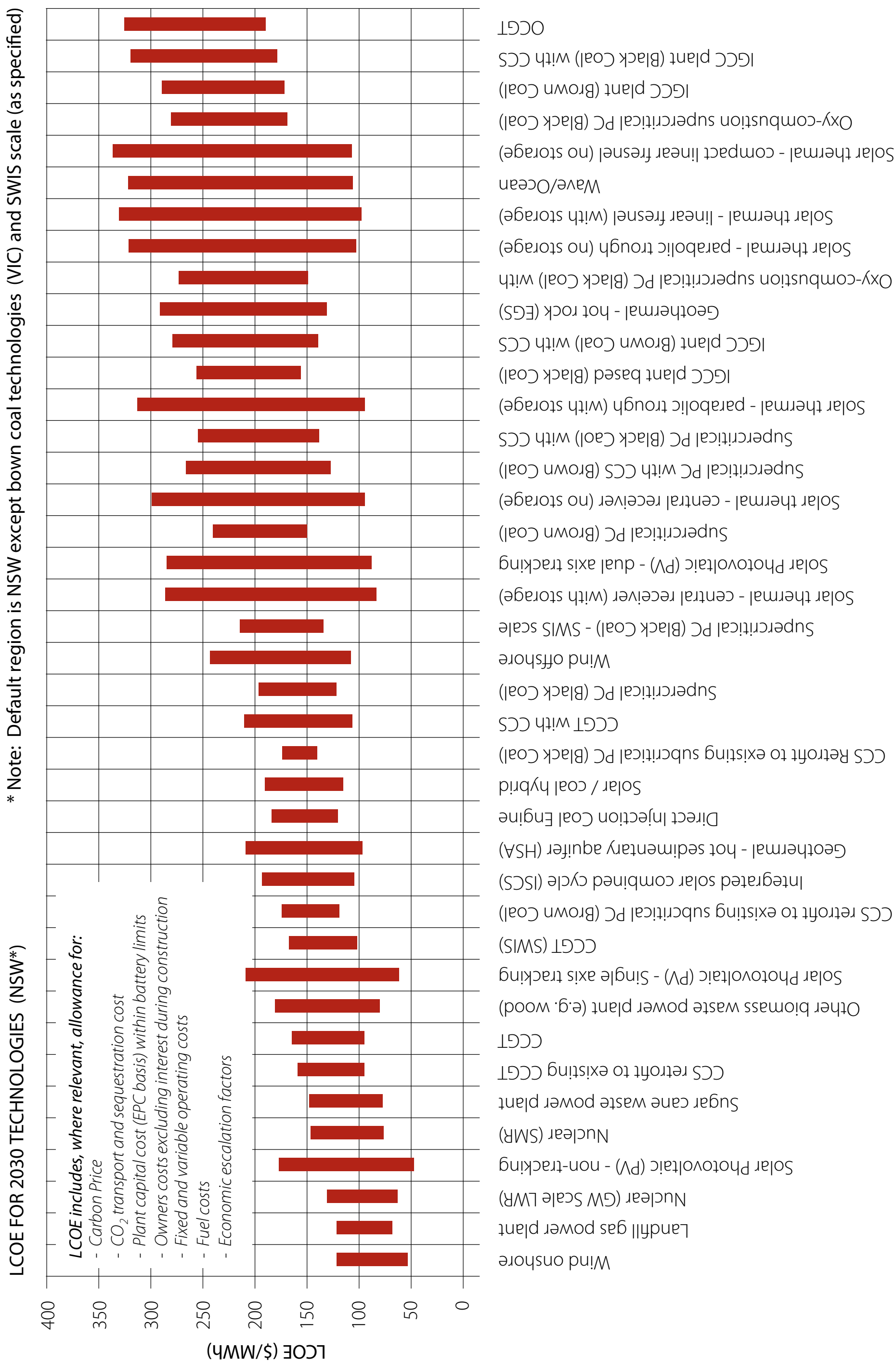


Figure 5.4: LCOE for Technologies (NSW), 2040

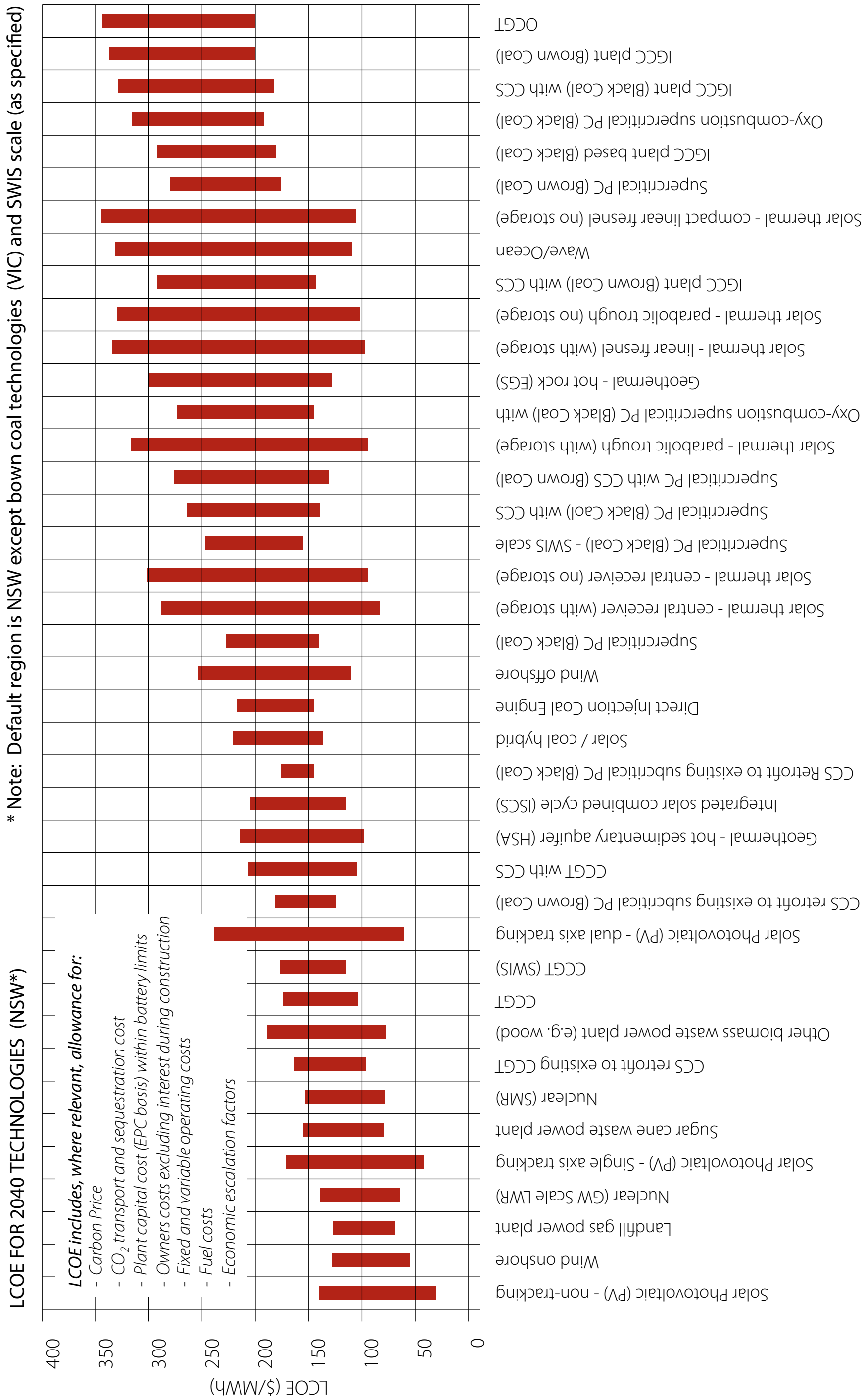
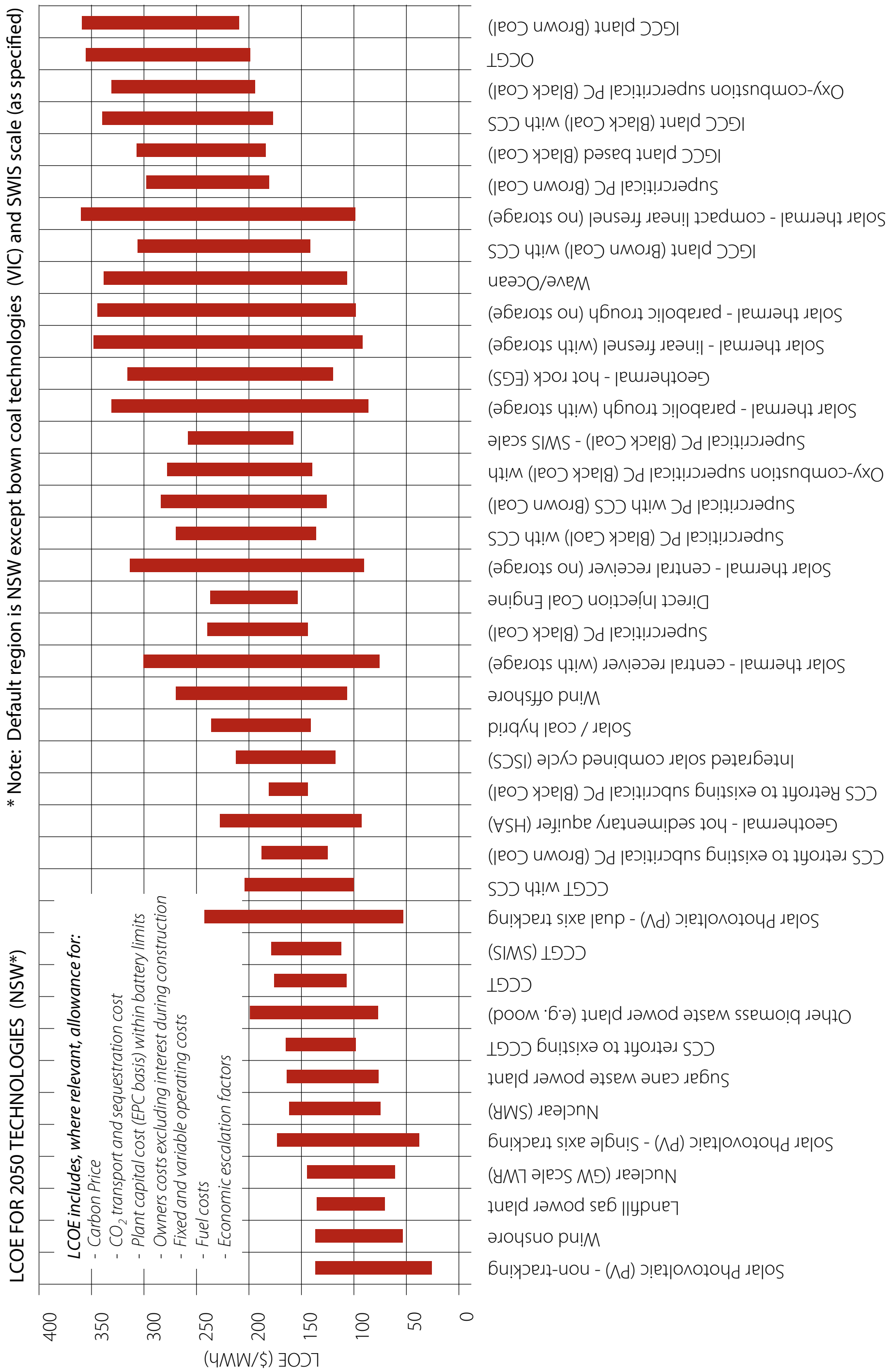


Figure 5.5: LCOE for Technologies (NSW), 2050



The inter-technology LCOE comparisons figures (see Figures 5.1 to 5.5) reveal changes in relative costs of technologies over time. Key results highlight that changes from 2012 to 2020 and after include:

- Carbon capture and storage technologies become commercially available from 2030;
- Between 2012 and 2020, except for biogas (land fill) and on-shore wind technologies, renewable technologies have higher LCOEs than the lowest cost non-renewable technologies;
- The relative LCOE rankings significantly change post 2030. LCOEs of several renewable technologies become lower than the non-renewables, including CCS technologies, from 2030 onwards;
- After 2040, several renewable and CCS-technologies such as solar PV, on-shore wind, bioenergy, and CCS retrofit technologies become lower cost than non-renewable fossil fuel technologies without CCS (Figure 5.5).

5.2 Comparisons with Other Studies

Key points

- A number of studies into electricity generation costs have been conducted over the past few years in Australia and overseas. While there is general consistency between values, there are notable differences. Differences in costs arise primarily from macroeconomic factors and technical assumptions. While the macroeconomic assumptions (e.g. amortisation period, discount rate) are unique to each study, the technical assumptions can also differ between studies as a consequence of recent technological developments.
- Estimated costs of several fossil fuel-based electricity technologies may differ from previous studies, primarily as a result of a carbon price, higher projected market fuel prices and differences in the assumed discount rate and projected exchange rate.
- Most domestic and overseas studies have not included carbon prices in their assessment.

Current cost estimates

Table 5.2.1 compares AETA LCOE estimates with those derived from ACIL Tasman and EPRI studies. The most significant difference between the macroeconomic assumptions used in the AETA and the ACIL Tasman and EPRI studies is that the AETA incorporates a CO_2 price. In the absence of a CO_2 price, the AETA estimates show closer alignment with the LCOE estimates from other Australian studies for technologies with significant CO_2 emission levels.

Table 5.2.1: LCOE Comparison (A$/MWh) with other Australian studies, current estimates[1]

TECHNOLOGY	AETA 2012	AETA (excl. CO2 price)	ACIL Tasman 2011	EPRI 2010
IGCC black coal	(176–189)	(125–136)	107 (96–118)	130
IGCC black coal with CCS	(193–253)	(183–243)	196.5 (151–242)	213
Supercritical pulverised brown coal	162	95	71.5 (66–77)	91
Supercritical pulverised brown coal with CCS	205	192	144 (134–154)	191
Supercritical pulverised black coal	(135–145)	(84–94)	64 (56–72)	78
Supercritical pulverised black coal with CCS	(162–205)	(153–196)	176 (130–222)	167
Oxy combustion pulverised black coal with CCS	(168–215)	(168–215)	171 (127–215)	166
CCGT	(96–108)	81–93	62 (59–65)	97
CCGT – SWIS scale	133	118	79 (71–87)	
CCGT with CCS	(142–166)	(137–161)	103 (91–115)	153
OCGT	(203–259)	(183–239)	188.5 (175–202)	227
Solar thermal – parabolic trough	(330–402)	(330–402)	365 (245–485)	479 (400–558)
Solar thermal – parabolic trough with storage	(322–393)	(322–393)	346.5 (227–466)	451.5 (376–527)
Solar thermal – central receiver	(290–349)	(290–349)	308 (194–422)	390.5 (325–456)
Solar thermal – central receiver with storage	(295–361)	(295–361)	261 (169–353)	339 (283–395)
PV – non-tracking	(212–264)	(212–264)	383 (252–514)	452 (431–473)
PV – single axis tracking	(217–268)	(217–268)	327 (219–435)	414 (392–436)
PV – dual axis tracking	(277–344)	(277–344)	300 (197–403)	363.5 (327–400)
Wind – on-shore	(111–122)	(111–122)	126.5 (83–170)	164.5 (137–192)
Geothermal – hot sedimentary aquifer	(150–163)	(150–163)	135.5 (116–155)	116.5 (85–148)
Geothermal – hot rock	(208–229)	(208–229)	146 (127–165)	167 (116–218)
Nuclear (Gen 3+)	(94–99)	(94–99)	115 (107–123)	173

1: WorleyParsons' estimates are based on costs in first year that technology is commercially deployed

The capital cost of a technology typically represents a major component of the overall cost of electricity generation. Table 5.2.2 provides a comparison between the capital cost estimates in the AETA, EPRI and ACIL Tasman studies, as well as studies by ROAM and SKM-MMA for Treasury, and by the International Energy Agency (IEA), based on US costs.

Table 5.2.2: Capital cost comparison, $/kW sent out - Current

TECHNOLOGY	AETA[3] 2012	ACIL Tasman 2011	EPRI 2010	SKM-MMA for Treasury 2011	ROAM for Treasury 2011	IEA 2012
IGCC brown coal	6306			6601	6191	
IGCC brown coal with CCS				9816	8365	
IGCC black coal	5346	5099	5099	3643	4768	
IGCC black coal with CCS		6841	7715	5418	6396	
Supercritical pulverised brown coal	3788	3979	3979	2900	3722	
Supercritical pulverised brown coal with CCS		7363	7363		6880	
Supercritical pulverised black coal	3124	2967	2967	2235	2774	2300
Supercritical pulverised black coal with CCS		5855	5855	3828	5476	
Oxy combustion pulverised black coal with CCS		6286	6286	5676	5877	
CCGT	1062	1409	1173	1300	1317	1000
CCGT with CCS		2788	2518	2755	2607	
OCGT	723	995	801		931	500
Solar thermal – parabolic trough	4920	5677	5677	6500	5308	65002
Solar thermal – parabolic trough with storage	8950	8751	8751	9500	8182	
Solar thermal – central receiver	5900	4559	4559		4262	
Solar thermal – central receiver with storage	8308	6475	6475		6054	
PV – non-tracking	3380	4650	6265–6755		4348	4000
PV – single axis tracking	3860	5100	6991–7633		4769	
PV – dual axis tracking	5410	5650	6908–8373	6175	5283	
Wind – on-shore	2530	2744	3224	2400	2699	1800
Geothermal – hot sedimentary aquifer		7765	4112–7310	6500	7260	
Geothermal – hot rock		8116	5483–10750	7000	7586	
Biomass – other (e.g. wood)	5000			6382	4675	
Nuclear (Gen 3+)	3470	5742	5742			4600

1 Capital costs converted from $/kW installed to $/kW sent out. 2 Concentrated solar power (CSP) technology is not specified

In general, a comparison of capital costs does not reveal substantial differences between technologies. However, a noticable difference between the AETA and other studies is the estimated cost of photovoltaic systems at the time the studies were undertaken. This result arises because the cost of photovoltaic modules has fallen by approximately 50 per cent over the past 2–3 years. At present, modules comprise of approximately one-half of the capital cost of photovoltaic systems.

Capital cost comparison need to be treated with caution. This is because methodological differences mean it is impossible to determine whether the same capital cost components are consistently covered. For example, it is unclear whether all these studies include owner's costs. Further, because the studies have been conducted in different years, there are likely to be macroeconomic differences arising from inflationary effects and movements in the Australian dollar exchange rate. Differences in cost estimates are also to be expected when comparing Australian and overseas studies as a result of country-specific factors, such as labour costs.

Tables 5.2.3 and 5.2.4 compare the AETA estimates for fixed and variable operating and maintenance (O&M) costs in 2012 with the estimates contained in other recent Australian studies.

Table 5.2.3: Fixed cooperating and maintenance cost comparison, $/kW-yr

TECHNOLOGY	AETA 2012	EPRI 2010/ACIL Tasman 2011
IGCC black coal	79.6	72.7
IGCC black coal with CCS	98.7	103.7
Supercritical pulverised brown coal	60.5	41.4
Supercritical pulverised brown coal with CCS	91.5	67.4
Supercritical pulverised black coal	50.5	33.1
Supercritical pulverised black coal with CCS	73.2	55.3
Oxy combustion pulverised black coal with CCS	62	60.1
CCGT	10	13.6
CCGT with CCS	17	24.8
OCGT	4	9.3
Solar thermal – parabolic trough	60	55
Solar thermal – parabolic trough with storage	65	73
Solar thermal – central receiver	70	55
Solar thermal – central receiver with storage	60	73
PV – non-tracking	25	38–63
PV – single axis tracking	38	47–80
PV – dual axis tracking	47	62–86
Wind – on-shore	40	37–42
Geothermal – hot sedimentary aquifer	200	100–150
Geothermal – hot rock	170	150–225
Nuclear (Gen 3+)	34.4	125–147

Table 5.2.4: Variable operation and maintenance cost comparison, $/MWh

TECHNOLOGY	AETA 2012	EPRI 2010/ACIL Tasman 2011
IGCC black coal	7	12.8
IGCC black coal with CCS	8	20
Supercritical pulverised brown coal	8	5.1
Supercritical pulverised brown coal with CCS	15	16.4
Supercritical pulverised black coal	7	4.6
Supercritical pulverised black coal with CCS	15	15.7
Oxy combustion pulverised black coal with CCS	14	9.1
CCGT	4	2
CCGT with CCS	9	4.2
OCGT	10	2.5
Solar thermal – parabolic trough	15	0
Solar thermal – parabolic trough with storage	20	0
Solar thermal – central receiver	15	0
Solar thermal – central receiver with storage	15	0
PV – non-tracking	0	0
PV – single axis tracking	0	0

TECHNOLOGY	AETA 2012	EPRI 2010/ACIL Tasman 2011
PV – dual axis tracking	0	0
Wind – on-shore	12	0
Geothermal – hot sedimentary aquifer	0	0
Geothermal – hot rock	0	0
Nuclear (Gen 3+)	14.7	6.1

Many of the cost improvements are similar in the two studies.

Future cost estimates

It is common for LCOE studies to include projected LCOE and capital costs several decades into the future. The projected capital costs in 2030 are given in Table 5.2.5 and provide a ready comparison across studies.

Unlike other Australian studies, the AETA assumes a significant weakening (ca. 20 per cent) in the AUS to US dollar exchange rate over the next 20 years. This assumption increases future capital costs as much of the capital cost of electricity generation technologies are assumed to be closely associated with imported equipment.

Table 5.2.5: Capital cost comparison - $/kW sent out, 2030 estimates

TECHNOLOGY	AETA 2012	ACIL Tasman 20111	EPRI 2010	SKM-MMA for Treasury 2011	ROAM for Treasury 2011	IEA 2012
IGCC brown coal with CCS	7758			8029	5637	
IGCC black coal	5123–5860	3922		2980	3707	
IGCC black coal with CCS	6536–7323	4871	4721	4432	5024	
Supercritical pulverised brown coal	3768	3583		2624	3365	
Supercritical pulverised brown coal with CCS	6130	6097	6097		6034	
Supercritical pulverised black coal	2947–3128	2670		2022	2508	2300
Supercritical pulverised black coal with CCS	4453–4727	4792	4792	3131	4709	
Oxy combustion pulverised black coal with CCS	5363–5697	5003	5003	4642	5004	
CCGT	1015–1221	1205	1173	1177	1132	1000
CCGT with CCS	2095–2405	2077	2077	2371	2133	1600
OCGT	694–809	881	881		826	500
Solar thermal – parabolic trough	2475–3090	3690	3690	4336	3577	30002
Solar thermal – parabolic trough with storage	4563–5659	6125	6125	6337	5861	
Solar thermal – central receiver	3203–3984	2735	2735		2700	
Solar thermal – central receiver with storage	4203–5253	4209	4209		4074	
PV – non-tracking	1482–1871	3255	4072–4391		3115	1440
PV – single axis tracking	2013–2542	3570	4544–4961		3415	
PV – dual axis tracking	3056–3860	3955	4490–5443	4123	3783	
Wind – on-shore	1701–1917	2195	2902	2066	2185	1550

TECHNOLOGY	AETA 2012	ACIL Tasman 2011[1]	EPRI 2010	SKM-MMA for Treasury 2011	ROAM for Treasury 2011	IEA 2012
Geothermal – hot sedimentary aquifer	6645–7822	6724	3834–6817	5317	7260	
Geothermal – hot rock	10331–11811	7655	5171–10140	5726	6565	
Biomass – other (e.g. wood)	5097–5522			4171	4675	
Nuclear (Gen 3+)	3589–3867	4876	4876			4250

1 Capital costs converted from $/kW installed to $/kW sent out. 2 Concentrated solar power (CSP) technology is not specified.

In terms of projected capital costs out to 2030, AETA LCOEs are similar to other studies for most technologies. A notable difference between the AETA estimates and the earlier studies is the estimated capital cost of photovoltaic systems. It is now expected that the substantial cost reduction trend experienced in recent years will continue to occur into the future.

Another noticeable difference relates to the capital cost of hot rock (i.e. enhanced) geothermal systems. The AETA LCOE for this technology are substantially higher than the estimates made by ACIL Tasman, SKM-MMA and ROAM, and are at the high end of the cost range estimated by EPRI. The major reason for the cost difference arises from a more recent and better informed appraisal of drilling costs that comprise a major component of the capital cost of hot rock geothermal systems.

Summaries of recent international studies

A number of other countries and organisations have conducted their own assessments of electricity generation costs. These costs have been developed for the United Kingdom, Spain, the United States, and for multiple countries and regions by the International Energy Agency and International Renewable Energy Agency. Many of these studies employ a similar levelised cost of electricity methodology. Nevertheless, it is difficult to compare costs across these studies because the technical and economic assumptions can vary substantially and are not always transparent or fully documented.

Table 5.2.6 summarises selected LCOE from some of the recent international studies on electricity generation costs. Further details on cost break downs, and assumptions, are provided in the studies themselves.

Table 5.2.6: International comparison of current levelised costs of electricity generation (A$/MWh)

TECHNOLOGY	AETA 2012 *	AETA (excl. CO2 price)	IRENA 2012	UKDECC 2011 *	IIASA 2012 a	IEA 2012 b	IEA 2010 c *	IDAE 2011
IGCC black coal	(176–189)	125		195			109	
IGCC black coal with CCS	(193–253)	183–243		208			110	
Supercritical pulverised brown coal	162	95						
Supercritical pulverised brown coal with CCS	205	192						
Supercritical pulverised black coal	(135–145)	(84–94)				68	103	
Supercritical pulverised black coal with CCS	(162–205)	(153–196)		167				
Oxy combustion pulverised black coal with CCS	(168–215)	168–215						
CCGT	(96–108)	81–93		118		49	97	
CCGT – SWIS scale	133	118						
CCGT with CCS	(142–166)	137–161		162			122	
OCGT	(203–259)	183–239				102		
Solar thermal – parabolic trough	(330–402)	330–402	136–349			175	380	359–411
Solar thermal – parabolic trough with storage	(322–393)	322–393	136–349					
Solar thermal – central receiver	(290–349)	290–349						
Solar thermal – central receiver with storage	(295–361)	295–361	165–281					
PV – non-tracking	(212–264)	212–264	243–631	485	146–679	243	391	298–349
PV – single axis tracking	(217–268)	217–268						
PV – dual axis tracking	(277–344)	277–344						
Wind – on-shore	(111–122)	111–122	68–136	139	39–146	87	83	104–129
Geothermal – hot sedimentary aquifer	(150–163)	150–163		145	29–87		55	123–136
Geothermal – hot rock	(208–229)	208–229						
Nuclear (Gen 3+)	(94–99)	94–99				83	91	

Sources: IRENA 2012; UKDECC 2011 (includes Parsons Brinckerhoff and Arup reports for UKDECC); IIASA 2012; IEA 2012; IEA 2010; IDEA 2011.

Notes: All international studies have been converted to 2011 A$ based on 2011 average exchange rates, except IEA 2010 where 2008 exchange rates are used. a Not explicitly specified as levelised costs. b estimated from graph for United States. c based on United States estimates. * Includes explicit carbon price, also the LCOE intervals represent state estimates.

IRENA (International Renewable Energy Agency), Renewable Energy Technologies: Cost Analysis Series, 2012

In June 2012, the International Renewable Energy Agency (IRENA) released a set of five reports on wind, biomass, hydropower, concentrating solar power and solar photovoltaics, designed to improve the information available on the current state of deployment, types of technologies available and their costs and performance.

The three cost indicators used in the study were: equipment cost (factory gate FOB and delivered at site CIF); total installed project cost, including fixed financing costs; and the levelised cost of electricity (LCOE). The analysis excludes the impact of government incentives or subsidies, taxation, system balancing costs associated with variable renewables, CO_2 pricing, or the benefits of renewables in reducing other externalities.

Solar Photovoltaics

The total installed cost of PV systems can vary widely within individual countries and between countries and regions. Despite the recent declines in PV system costs, the LCOE of PV remains relatively high in the study. The LCOE of residential systems without storage assume a 10 per cent cost of capital and is in the range US$250–650/MWh in 2011. When electricity storage is added, the cost range increases to US$360–710/MWh. The LCOE of current utility-scale thin film PV systems is estimated to be between US$260–590/MWh in 2011.

According to this study, the prospects for continued cost reductions are very good. PV module costs have a learning rate of 22 per cent, implying that costs will decline by just over a fifth with every doubling of capacity.

Wind power

Installed costs in 2010 for on-shore wind farms typically range between US$1800–2200/kW in most major markets, although are substantially lower in China and Denmark. Wind turbines account for 64–84 per cent of total installed costs on-shore. Off-shore wind farms are more expensive and cost US$4000–4500/kW, with the wind turbines accounting for 44–50 per cent of the total cost.

The LCOE of typical new on-shore wind farms in 2010, assuming a cost of capital of 10 per cent, is between US$60–140/kWh. The higher capital costs of off-shore are somewhat offset by the higher capacity factors achieved. As a result, the LCOE of an off-shore wind farm is between US$130–190/kWh. Cost reduction opportunities towards best practice levels exist for on-shore wind farms, while experience off-shore should help to reduce costs over time. Assuming that capital costs on-shore decline by 7–10 per cent by 2015, and O&M costs trend towards best practice, the LCOE of on-shore wind could decline by 6–9 per cent. The LCOE of off-shore wind could decline between 8–10 per cent by 2015, but are projected to always be higher than on-shore.

Concentrating solar power

The study notes that concentrating solar power (CSP) plants are capital intensive. Operations and maintenance (O&M) costs are relatively high for CSP plants. However, cost reduction opportunities are substantial.

Assuming the cost of capital is 10 per cent, the LCOE of parabolic trough plants today is in the range US$200–360/MWh and that of solar towers between US$170–290/MWh. Nevertheless, in areas with excellent solar resources it could be as low as US$140–180/MWh. The LCOE depends primarily on capital costs and the local solar resource.

Given that there is only limited installed CSP capacity, and according to this study, there is not enough data exists to identify a robust learning curve. However, the opportunities for cost reductions for CSP plant are considered advantageous given that the commercial deployment of CSP is in its infancy. The study projects that capital cost reductions of 10–15 per cent and modest reductions in O&M costs by 2015 could see the LCOE of parabolic trough plants decline to between US$180–320/MWh by 2015 and that of solar tower plants to between US$150–240/MWh.

Biomass

The total installed costs of biomass power generation technologies vary substantially by technology and country. The LCOE of biomass-fired power plants ranges from US$60–290/MWh, depending on capital costs and feedstock costs. For landfill gas, for example, LCOE is US$90–120/MWh. Where low-cost feedstocks are available and capital costs are modest, biomass can be a very competitive power generation option. Where low-cost agricultural or forestry residues and wastes are available, biomass can often compete with conventional power sources.

Only marginal cost reductions are anticipated in the short-term, but the long-term potential for cost reductions from the technologies that are not yet widely deployed is promising.

UK Department of Energy and Climate Change (DECC), *Electricity Generation Cost Model 2011 Update,* 2011

The UK DECC recently commissioned updates of cost assumptions and technical inputs for its Levelised Electricity Cost Model. This includes key timings such as construction and operation period, technical data such as efficiency and power output, capital costs, and operation and maintenance costs. DECC used this data to calculate levelised costs for each technology.

The Parsons Brinckerhoff (PB) 2011 report covers non-renewable technologies, while the Arup 2011 report focuses on renewable technologies. The method to calculate levelised costs is consistent across both studies. The levelised costs are based on a 10 per cent discount rate, DECC's projected fuel prices, and Carbon Price Support. It includes two cases – projects starting in 2011 and projects starting in 2017. It separates the projects into FOAK (first of a kind) and NOAK (N^{th} of a kind).

The PB report finds that, in general, electricity generation from different gas turbine technologies is well established and, therefore, require less capital investment. The most substantial proportion of the levelised costs for these technologies is due to the carbon and fuel costs. The capital costs for IGCC are higher than for conventional coal fired technologies. The CCS technology options are much more expensive than the primary technology options, but it is expected there will be significant learning associated with CCS which will reduce costs.

The Arup report has two parts. Part A considers the maximum feasible resource potential of renewable electricity technologies, constraints to expansion and potential annual build rate scenarios to 2030. Part B provides generation costs of renewable electricity technologies.

Solar PV systems have relatively higher levelised costs in the report primarily due to their high capital costs. Technologies with the lowest levelised costs include energy from waste, geothermal, and advanced conversion technologies.

International Institute for Applied Systems Analysis (IIASA), *Global Energy Assessment (GEA)*, 2012

The GEA provides an integrated energy assessment to analyse energy challenges, opportunities and strategies, for developing, industrialised and emerging economies. It explores 60 alternative energy transformation pathways and finds that 41 of these pathways simultaneously satisfy the following goals:

- universal access to affordable modern energy carriers and end-use conversion (especially electricity and clean cooking) by 2030;
- enhanced energy security at regional and national levels; and
- climate change mitigation (contain global mean temperature increase to less than 2°C above pre-industrial levels, with a probability of at least 50 per cent).

A broad portfolio of supply side options, focusing on low carbon energy from renewables, bioenergy, nuclear power and CCS was explored in the study. The GEA analysis indicates that a rapid transformation to clean energy technologies would require an increase in annual investments from present levels of approximately $US1.3 trillion to $US1.7 trillion, about 2 per cent of current world gross domestic product. The difference corresponds roughly to the current level of energy subsidies.

The report argues for the creation of market conditions, via government interventions, that invite and stimulate investments in energy options and that provide incentives for rapid investments in energy end use and supply technologies and systems.

IEA/NEA, *Projected Costs of Generating Electricity, 2010 edition*

The joint IEA/NEA publication is a regular exercise published about every five years. It aims to be a complete study on the levelised cost of electricity. The study focuses on the expected plant level costs of baseload electricity generation by power plants that could be commissioned by 2015. It also includes the generation costs of a wide range of renewable energy sources. In addition, it covers projected costs related to advanced power plants with carbon capture and storage, which might reach the level of commercial availability and be commissioned by 2020. The report uses a discount rate of 5 and 10 per cent for each technology. It includes a carbon price of US$30 per tonne of CO_2. It also includes an extensive sensitivity analysis of the impact of variations in key parameters such as discount rates, fuel prices and carbon costs on LCOE.

A key finding of this study is that there is no technology that has a clear overall advantage globally or even regionally. That is to say, there is no single electricity generating technology that can be expected to be the cheapest in all situations. Country specific circumstances determine the LCOE, and it is impossible to make any generalisation on costs above the regional level or even within regions.

For comparative purposes and based on 10 per cent discount rate and for the US, LCOE for geothermal are around 2008 A$55/MWh and on-shore wind are approximately in 2008 A$83/MWh while solar thermal much higher at about A$380/MWh and solar PV at around A$391/MWh.

IDEA (Institute for Energy Diversification and Saving), *Evolución tecnológica y prospectiva de costes de las energías renovables (Technological evolution and future of renewable energy costs),* 2011 – in Spanish only

In 2010, the IDEA (Institute for Energy Diversification and Saving in Spain), in collaboration with Boston Consulting Group, undertook a detailed study on the technological developments and costs for renewable energy technologies, both current and over the period 2020–2030. The study included technologies for electricity and heat generation, and transport.

The study presents levelised costs of electricity generation, and a detailed breakdown of the determinants of costs, including investment, operating and fuel costs, efficiency, and hours of operation, among other factors. It also takes into account technological advances and learning effects, as well as the effect of economies of scale. The levelised costs use a common discount rate of 7.8 per cent, except for biomass and biogas which is discounted at 9.4 per cent. Results are provided in 2010 Euro cents per kWh for 2010 and 2020.

Currently, the technologies with the lowest levelised costs of generation include hydropower and on-shore wind, with solar photovoltaic among the highest cost technologies. The study finds that there is significant potential for cost reduction in several renewable technologies.

EERE (US Office of Energy Efficiency and Renewable Energy) 2012, Transparent Cost Database

As part of the US Energy Department's Open Energy Information platform (Open EI), the study has been launched as a new public database featuring cost and performance estimates for electricity generation, advanced vehicle, and renewable fuel technologies. The Transparent Cost Database collects program cost and performance estimates for technologies in a public forum where they can be viewed and compared to other published estimates. The data gathered are for informational purposes only, and inclusion of a report in the database does not represent approval of the estimates by the Department of Energy.

The database includes literature on technology cost and performance estimates (both current and future projections) for vehicles, biofuels, and electricity generation. It includes data on overnight capital costs, fixed and variable operating costs, and levelised costs. LCOE are calculated using a single discount rate of 7 per cent in order to compare technology costs and are provided for all technologies in US$/kWh.

The database shows for the perod 2008–2012 that the lower cost technologies include pulverised coal, hydropower, nuclear, natural gas combined cycle, and on-shore wind. The higher cost technologies include solar photovoltaic, concentrating solar power and ocean energy.

6. Conclusions

The Australian Energy Technology Assessment (AETA) provides the best available and most up-to-date cost estimates for 40 electricity generation technologies under Australian conditions. To ensure that the cost estimates for the various technologies are consistent, all common input costs (e.g. labour, materials, components, carbon price) are itemised.

AETA has been developed in close consultation with a stakeholder reference group drawn from industry and research/academic organisations with interests and expertise in a diverse range of electricity generation technologies. For most technologies its results compare favourably to previous studies undertaken in Australia and internationally.

A key finding of the study is that the costs of solar photovoltaic technologies have dropped dramatically in the past two to three years as a result of a rapid increase in global production of photovoltaic modules. As a result of on-going cost reductions, differences in the cost of generating electricity, especially between fossil fuel based and renewable electricity generation technologies, will diminish. Nevertheless, LCOE costs do vary substantially across the technologies and range from the lowest cost of $91/MWh (landfill gas power plant) to the highest cost of $366/MWh (solar thermal c.l.f.) in 2012 and from $86/MWh (solar PV non-tracking) to $288/MWh (IGCC brown coal plant) in 2050.

By 2030 some renewable technologies, such as solar photovoltaic and wind on-shore, are expected to have the lowest LCOE of all of the evaluated technologies. Among the non-renewable technologies, combined cycle gas (and in later years combined with carbon capture and storage) and nuclear offer the lowest LCOE over most of the projection period and remain cost competitive with the lower cost renewable technologies out to 2050. The AETA cost estimates suggest that Australia's electricity generation mix out to 2050 is likely to be very different to the current technology mix.

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Annex A

Consultations with Stakeholders

This study has been undertaken in close consultation with a Stakeholder Reference Group drawn from Australian industry and domestic as well as overseas research/academic organisations with interests and expertise in a diverse range of electricity generation technologies. These stakeholders were invited to provide evidence of the latest estimates for the costs and performance of various technologies.

In addition, the AETA project also had a Project Steering Committee comprising staff from BREE, DRET, AEMO, CSIRO and other independent experts to provide technical advice and support. The following agencies participated in the stakeholder reference group meetings or were forwarded the documents presented at the meetings.

AETA Stakeholder Reference Group

ACRE, Resources, Energy & Tourism

AGL, Australia

Australian Energy Market Commission

Australian Energy Market Operator

Australian Geothermal Energy Association

Australian National Low Emissions Coal R&D

Australian National University

Australian Pipeline Industry Association

Australian PV Association

Australian Solar Institute

Australian Solar Thermal Energy Association

Australian Sugar Milling Council

Australian Treasury

Bright Source Energy

Bureau of Resourses and Energy Economics

Clean Energy Council

CSIRO

Department of Climate Change and Energy Efficiency

Department of Resources, Energy and Tourism

Economic Research Institute for ASEAN and East Asia

Energy Networks Association

Energy Retailers Association of Australia

Energy Supply Association of Australia

Energy Users Association of Australia

ExxonMobil

GE Australia

Global CCS Institute

Granite Power

Grid Australia

Industrial Machinery Department

International Energy Agency, France

International Power Suez

IRENA Innovation and Technology Centre

National Generators Forum

Oceanlinx Limited

Origin Energy

Private Generators Group

Rio Tinto

Santos

The Institute of Energy Economics, Japan

The Energy Research Institute, New Delhi

TruEnergy

University of Melbourne Energy Institute

University of New South Wales

University of Queensland

UQ Energy Economics & Management Group

Two AETA Stakeholders Reference Group meetings took place on 10 February 2012 and 13 June 2012. In addition, the AETA Project Steering Committee met on several occasions.

Stakeholders views were conveyed to BREE and WorleyParsons through written submissions, as well as telephone communication.

Annex B

Fuel costs

This annex is primarily drawn from the ACIL Tasman report provided to WorleyParsons. ACIL Tasman was engaged by WorleyParsons as a sub-contractor for the provision of fuel cost projections for BREE.

ACIL Tasman's scope of work includes providing fuel cost projections to support Levelised Cost of Electricity (LCOE) estimates to be undertaken by WorleyParsons across the forty generating technologies. Fuel cost projections are, therefore, required for black and brown coal, natural gas, bagasse, biomass (other) and nuclear sources. Solar, wind, wave and geothermal technologies are assumed to have zero fuel costs. Fuel costs for landfill gas are associated with the plant development (development and connection of wells) and hence are assumed to be capitalised.

The study provided fuel costs estimates for each Australian State and Territory (ACT may be combined with NSW) where the State/Territory is homogenous in this regard, and for two sub-regions within a large state such as WA (South WA and North WA) and QLD (North Queensland, and South Queensland). Cost estimates were provided for years 2012, 2020, 2025, 2030, 2040 and 2050.

The fuel cost estimates treat a given region as homogenous, however, it should be noted that significant differentials can occur within regions. For example, locations that are mine-mouth coal or on existing gas pipeline networks may have substantially lower cost than remote locations where additional transport of fuel is required.

Based on the fuels and regions to be examined, ACIL Tasman assessed the availability of fuel within each region before projecting its prices.

Natural gas

For natural gas within NEM regions, ACIL Tasman has drawn upon the analysis undertaken for AEMO as part of its National Transmission Network Development Plan. Natural gas costs were projected under a range of scenarios which extended out to 2032. ACIL Tasman, therefore, has used the 2012, 2020 and 2030 cost estimates for this work.[11] For each State/Territory ACIL Tasman has used the average prices from the AEMO zones contained within to represent the price for the jurisdiction.

For the mid-case values ACIL Tasman have adopted the levelised results from the AEMO Planning scenario using demand sensitivity 4 (the mid case). For the low and high cases, ACIL Tasman have adopted the most extreme outcomes from the AEMO modelling. In the low

11 Note: the 2012–13 value has been used for 2012; whereas values for 2020 and 2030 are taken as the average of 2019–20, 2020–21 and 2029–30, 2030–31 respectively.

case ACIL Tasman has used Scenario 1 demand sensitivity 1 (lowest priced scenario with the lowest demand settings); and in the high case Scenario 2 demand sensitivity 7 (highest priced scenario with the highest demand settings). This sets the range for upper and lower bound range for projected prices to 2030.

The timeframes of 2040 and 2050 extend beyond ACIL Tasman's typical modelling horizon and are subject to significant uncertainty. Price outcomes will depend critically upon on a number of factors such as:

- Technology and production cost improvements for natural gas;
- Available resource base which is revealed through these technology improvements both domestically and internationally;
- Domestic demand for natural gas in the context of competing fuels and generating technologies, greenhouse gas policy and renewable technology cost reductions; and
- International demand for LNG and the extent to which domestic prices reflect international gas pricing.

Scenarios can easily be developed in which natural gas continues to play an important role in the Australian and international energy mix out to 2050. Similarly, equally plausible scenarios could also be developed in which natural gas becomes more of a niche energy source and other alternatives such as renewables, nuclear, coal-based CCS or other as yet undeveloped technologies emerge as the dominant primary energy source.

Given this uncertainty, ACIL Tasman has held the 2030 gas cost estimate flat in real terms for 2040 and 2050.

For Western Australia (SWIS and NWIS) prices have been taken from projections undertaken in the context of other recent projects. Upper and lower bound estimates have been constructed to ensure the potential range of possible price outcomes is contained within.

Black coal

As with natural gas, the black coal price projections, ACIL Tasmanhave drawn upon the analysis undertaken for AEMO as part of stage 1 of this project. ACIL Tasman therefore have used the 2012, 2020 and 2030 cost estimates for this work. Unlike the natural gas price projections however, no demand sensitivities were undertaken and only a single price path was developed per scenario. Prices for the high, medium and low estimates were taken from Scenario 2, 3 and 5 respectively. For each State/Territory ACIL Tasmanhave used the average prices from the AEMO zones contained within to represent the price for the jurisdiction.

ACIL Tasman has held the 2030 cost estimate flat in real terms for 2040 and 2050. This is justified due to uncertainty about the global demand for thermal coal in this period. Historically, increasing costs of extracting coal from more marginal deposits are generally offset by mining efficiency improvements.

For Western Australia (SWIS) prices have been taken from projections undertaken in the context of other recent projects. Upper and lower bound estimates have been constructed to ensure the potential range of possible price outcomes.

Brown coal

Brown coal has the lowest energy costs in the NEM. The average mining cost in the Latrobe Valley is understood to be \$5.00 to \$6.00/tonne, which translates to around \$0.50 to \$0.70/GJ. This is an all up cost, including capital associated with the mine development. On a marginal cost basis (i.e. excluding capital cost components), costs are as low as \$0.10/GJ.

ACIL Tasman has assumed brown coal costs for new entrants of \$8.00, \$6.00 and \$4.50/tonne under the high, medium and low scenarios. An assumed average energy content of 9 GJ/tonne, gives fuel costs of \$0.89, \$0.67 and \$0.50/GJ respectively. These costs are de-escalated at 0.25 per cent per annum to represent assumed improved mining efficiencies over time

Brown coal is only available in Victoria. Coal currently used in South Australia (which can be classified as black or brown coal) at Leigh Creek has limited reserves and is assessed as not being sufficient in size to underpin new entry.

Bagasse

Bagasse is the fibrous residue of the cane stalk left after crushing and extraction of the juice. It consists of fibres, water and relatively small quantities of soluble solids – mostly sugar.

Cane is collected and transported to the mill for crushing which is, typically, also the location of the generation facility. However the majority of the bagasse is not combusted immediately, but stored for later use.

Fuel costs for bagasse relate to the variable costs associated with material handling. Bagasse is typically stored under cover away from the mill during crushing season for later generation. It has a relatively low energy content, ranging from 8 GJ/tonne to 17 GJ/tonne – depending upon moisture content and other factors – and is therefore a bulky feedstock.

ACIL Tasman estimates handling costs of around \$10/tonne, however, this may vary considerably from site-to-site. Based on energy contents of 8, 12 and 17 GJ/tonne gives fuel costs of \$1.25/GJ, \$0.83/GJ and \$0.59/GJ. These values have been used to provide the estimated fuel cost range for bagasse for both QLD and NSW regions. As these costs are comprised primarily of diesel and labour costs, these have been held constant in real terms throughout. There is no differentiation in costs between regions.

Biomass (other)

Biomass can consist of a range of fuel types from sewage gas, wood and wood wastes through to biomass-based components of municipal solid waste. Variable fuel costs for these sources can vary greatly with sewage gas being the lowest at effectively zero, with all costs forming part of the capital costs of the plant.

Plants utilising wood and wood waste products (such as black liquor or wood chip) can also vary greatly depending on whether the product is a process by-product (as is the case with black liquor at paper plants, or wood chips at a logging mill), or whether they are harvested specifically for generation purposes. In the case of the former, variable fuel costs represent material handling costs only, while in the latter, fuel costs can include planting, harvesting, collection, transport and storage components. Costs can range from as little as \$0.40/GJ to as much as \$3.00/GJ.

Biomass-based components of municipal solid waste represent the most expensive input, with significant costs associated with the collection of material from refuse sites and storage.

It is difficult to provide a single fuel cost which covers the entire spectrum of possible biomass fuels. ACIL Tasman has therefore, provided a range of costs for the low, medium and high cases which span the potential range of variable fuel costs associated with biomass plants. The values selected are \$0.40/GJ, \$1.50/GJ and \$3.00/GJ for the low, medium and high cases respectively. These costs have been held constant in real terms to 2050 and are uniform across all regions.

Nuclear

In 2006 the Prime Ministerial Uranium Mining, Processing and Nuclear Energy Review Task Force engaged the Electric Power Research Institute (EPRI) to conduct an independent review and analysis of nuclear energy in the Australian context. As reported by the EPRI, estimates of nuclear fuel costs vary across a number of previous studies. Values range from A\$4.49/MWh to A\$9.56/MWh, with an average of A\$6.32/MWh. Escalating this average cost estimate at an assumed rate of 3 per cent per annum yields around A\$7.50/MWh in 2012 dollars.

More recent data from the World Nuclear Association[12], suggests approximate US dollar cost to obtain 1 kg of uranium as UO_2 reactor fuel (at current spot uranium price as at March 2011) is around \$2,770/kg.

Based on 45,000 MWd/tonne burn-up, this gives 360,000 kWh electrical per kg (using an assumed thermal efficiency of around 34 per cent). This equates to a fuel cost of 0.77 c/kWh (US\$7.70/MWh). This is similar to the average from the EPRI literature review.

If Australia were to develop nuclear plants, it would likely have to become part of an international enrichment cycle. Thus, additional transportation costs would be incurred on enriched and spent fuel rods. However, these costs are likely to be small in the context of overall uranium enrichment and fabrication process.

12 See http://world-nuclear.org/info/inf02.html (accessed 12th February 2012)

Table B1: Estimated nuclear fuel costs

Scenario	2012	2020	2030	2040	2050
High	1.00	0.98	0.96	0.95	0.93
Medium	0.75	0.74	0.72	0.71	0.70
Low	0.50	0.49	0.48	0.47	0.46

Note: Real 2012–13 $/GJ

Data source: ACIL Tasman

Fuel cost projections

The fuel projection estimates made by ACIL Tasman are provided in Table 2.3.1 of the AETA report.

Annex C

CSIRO Learning rates projections

An important component of the projected LCOE is the future capital cost of each technology. CSIRO assisted WorleyParsons to develop these cost projections. The initial technology capital costs, prepared by WorleyParsons were incorporated into CSIRO's capital cost projection methodology. CSIRO's methodology provides projections of the rate of change in technology costs over time based on a global and local technology learning and adoption model.

Different approaches can be used for projecting electricity generation technology capital costs and each has its own advantages and disadvantages. The approaches include bottom-up engineering and materials cost analysis, economic modelling with learning curves, recent quotes and price estimates, Delphi/subject matter groups and surveys or a combination of any of these. In this exercise, CSIRO combined bottom-up engineering, economic modelling with learning curves and review by a stakeholder group.

The bottom-up engineering cost estimates are, typically, a good indicator of current costs of a technology and can be used to identify potential cost reductions in terms of materials or the technology itself. CSIRO used learning curves within the framework of an economic model to project the future costs. Learning curves, when used in an economic model that projects uptake of technologies, are a useful indicator of future costs.

The economic model developed and used by CSIRO is the Global and Local Learning Model (GALLM). It features endogenous technology learning, nine regions, and twenty different electricity generation technologies. Projections are made out to the year 2050, both of uptake and capital cost, per technology. It includes a method for projecting cost increases due to market forces and global and local learning curves for technologies where data is available.

Projected technology availability dates and initial capital costs were used as starting points for the model. The model was then run and the changes in capital costs projected.

The resultant cost projections show decreases in costs up to the year 2050 for all technologies that have some uptake in the model. Technological change occurs more rapidly in the next two decades and slows toward the end of the projection period. Larger cost decreases occurred for emerging technologies such as wave, solar and carbon capture and storage (CCS) technologies. The hot fractured rocks technology, while emerging, has reduced potential for cost reduction due to limited global economically-recoverable resources. Consequently, most learning must be driven locally whereas other technologies can free ride on cost savings driven by deployment globally. Drilling is also a high percentage of total capital costs.

Comparing capital costs projected by this study in the year 2030 and those from previous studies (from 2009–2011), reveals that the projected AETA costs of the majority of the coal-based technologies, biomass and hot fractured rocks are higher than in previous studies. Solar technologies, and, in particular large scale photovoltaics (PV), are projected to be lower in cost than in previous studies. This is due to the higher than expected global uptake of rooftop PV that reduces the costs of the PV modules.

The CSIRO GALLM model

GALLM is a mixed integer linear program of the world electricity sector where the objective function is the sum of all discounted costs in the projection period. The basic constraints of GALLM were adapted from the ERIS model which was published by (Kypreos et al., 2000). The approach outlined in the ERIS model was to construct learning curves that are seprated into 11 segments of various lengths forming a mixed-integer linear representation of the notionally non-linear learning curve. This approach largely avoids the problems of high computational resources and path dependency that are a challenge in a non-linear framework, the possible exception of a Monte Carlo approach).

Key features

1. GALLM features endogenous technology learning, using the learning curves for world regions with high electricity demand (including up to the following: USA, Western Europe, Eastern Europe, China, India, Russia, Australia, rest of developed world and rest of less-developed world) with local learning curves for some technologies, where data is available.
2. GALLM is solved as a mixed integer linear program where costs are minimised to reach a given level of electricity demand. Projected global and regional electricity demand has been sourced from the International Energy Agency (2011).
3. Carbon prices have been included in the GALLM model, but only for those countries yet to announce a carbon price scheme. The less-developed world commences its exposure to a carbon price occurs later in the projection period.
4. GALLM includes a penalty constraint to account for the possibility that market forces may sometimes add a premium to the cost of technologies when demand for their deployment is high. GALLM includes a constraint on the deployment of intermittent technologies. Lower cost bounds have been included for all relatively immature technologies. These lower bounds are set to low levels to avoid any particular technology reaching this limit. The cost bounds are based on projected costs of these technologies by the International Energy Agency (2008).
5. The main outputs of GALLM are projections of the electricity generation technology mix, regionally and globally, out to the year 2050 and the capital costs of the technologies modelled, also out to 2050.

Australian Energy Technology Assessment 2012