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AUSTRALIAN ENERGY MARKET OPERATOR

AEMO Cost Data Forecast For the NEM

Review of Cost and Efficiency Curves

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AEMO COST DATA FORECAST FOR THE NEM
REVIEW OF COST AND EFFICIENCY CURVES

SYNOPSIS

This report outlines the results of a review of the capital cost and efficiency curves provided by AEMO used for modelling new entrants in the NEM.

This report aims to compare thirty nine cases that comprise a number of fossil fuel and renewable technologies.

Disclaimer

PROJECT 101010-00596 - AEMO COST DATA FORECAST FOR THE NEM

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0	Issued	Nello Nigro	J. Meister	N/A	17-Dec-10	N/A	
A	Revised & Issued	Nello Nigro	J Meister	N/A	14-Jan-11		N/A
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APPENDIX 3 BATTERY LIMITS

1 INTRODUCTION

Following an enquiry from The Australian Energy Market Operator (AEMO) dated 18 October 2010 and subsequent discussions, a proposal was submitted by WorleyParsons to review cost and efficiency curves.

The agreed commencement date for this review was 22nd November and all work is to be completed by 14th January 2011. A draft report was issued to AEMO on the 17th December 2010.

It was understood that AEMO was seeking an update of data provided for NTNDP Modelling (for the parameters and 39 agreed technologies described in Section 2 entitled 'Work Scope'. It was agreed that WorleyParsons provide the following deliverables:

- Cost curves relating 2009 industry figures to latest industry cost forecasts, plant efficiency updates and O&M cost updates (in lieu of a full update); and
- Identify instances where there is a significant variance between the industry database currently available to WorleyParsons and that available to AEMO through the 2009 update process.

Variances on a case by case basis have been identified and outlined in this report. Further analysis of these variances has been agreed to be the subject of an extended work scope.

For each agreed technology the cost curves were reviewed and updated according to five Scenarios as outlined below:

- Scenario 1 – Fast Rate of Change
- Scenario 2 – An Uncertain World
- Scenario 3 – Modest Rate of Change
- Scenario 4 – Independent Climate Action
- Scenario 5 – Slow Rate of Change

It is understood that the previous modelling outcomes (NTNDP Modelling Assumptions: Supply Input Spreadsheets for all five scenarios) are available on the AEMO webpage http://www.aemo.com.au/planning/ntndp2010.html and that further details would be made available if required.

2 WORK SCOPE

The agreed work scope was to review the 2009 AEMO data in particular the relevant cost and efficiency curves for the following generating technologies:

1. IGCC – Brown Coal
2. IGCC – Brown Coal with CCS
3. IGCC – Black Coal
4. IGCC – Black Coal with CCS
5. Supercritical Pulverised Coal – Brown Coal
6. Supercritical Pulverised Coal – Brown Coal with CCS
7. Supercritical Pulverised Coal – Black Coal
8. Supercritical Pulverised Coal – Black Coal with CCS
9. Supercritical Pulverised Coal – Black Coal Oxy Combustion CCS
10. CCGT – Without CCS
11. CCGT – With CCS
12. OCGT – Without CCS
13. Solar Thermal – Parabolic Trough with 6 hrs Storage
14. Solar Thermal – Parabolic Trough without Storage
15. Solar Thermal – Central Receiver with 6 hrs Storage
16. Solar Thermal – Central Receiver without Storage
17. Photovoltaic – PV Fixed Flat Plate
18. Photovoltaic – PV Single Axis Tracking
19. Photovoltaic – PV Two Axis Tracking
20. Wind – Small Scale (50MW)
21. Wind – Medium Scale (200MW)
22. Wind – Large Scale (500MW)
23. Geothermal – Enhanced Geothermal System (EGS)
24. Geothermal – Hot Sedimentary Aquifers (HSA)

25. Biomass – Bagasse
26. Biomass – LFG
27. Biomass – Small Waste to Energy
28. Geothermal – Enhanced Geothermal System (EGS) - Other
29. Geothermal – Hot Sedimentary Aquifers (HSA) - Other
30. Small IGCC – Black Coal
31. Small IGCC – Black Coal with CCS
32. Small Supercritical Pulverised Coal – Black Coal
33. Small Supercritical Pulverised Coal – Black Coal with CCS
34. Small Supercritical Pulverised Coal – Black Coal Oxy Combustion CCS
35. 300MW CCGT – Without CCS
36. 300MW CCGT – With CCS
37. 100MW CCGT – Without CCS
38. 100MW CCGT – With CCS
39. Wave Power

For each of the above mentioned technologies, the cost curves are required to be established according to the following five scenarios:

Scenario 1 – Fast Rate of Change

Scenario 2 – An Uncertain World

Scenario 3 – Modest Rate of Change

Scenario 4 – Independent Climate Action

Scenario 5 – Slow Rate of Change

Our methodology and assumptions are outlined in Section 3.

It was agreed that we would identify any significant variations between our industry knowledge and the 2009 NTNDP modelling assumptions.

3 OUR METHODOLOGY AND ASSUMPTIONS

3.1 Overview

The cost estimating methodology used to assess current costs for the respective generating technologies included benchmarking against recent project costs known to WorleyParsons and comparison with forward estimates from various industry sources.

For thermal technologies such as IGCC, Supercritical Pulverised Coal, CCGT/OCGT and Biomass, the respective cost estimates were based on relevant databases contained in standard software such as Thermoflow's GTPro, GTMaster, SteamPro and Peace. This software models plant performance and provides EPC and total project cost data. All cost estimates derived using such software was based on current Australian conditions such as exchange rate and materials & labour cost.

In general, data for future trends was based on OEM information, industry body & industry analysis papers and WorleyParsons's (internal) knowledge bank.

For renewable technologies such as solar, geothermal, wind and wave, our cost estimate databases are based on our direct experience in projects, surveys of vendors' products, access to industry association papers and public domain material.

The five scenarios may broadly be described as follows:

- Scenario 1 (Fast rate of change): successful deployment of both centralised and decentralised supply-side technologies, combined with high demand side participation, facilitates a rapid transformation of the sector to meet strong emission targets. Australia remains competitive on the global stage and reaps the benefit of strong international growth.
- Scenario 2 (An uncertain world): carbon policy uncertainty creates barriers for emerging demand and supply-side technologies. Strong international demand for Australia's resources drives high domestic economic and population growth, resulting in high energy demand.
- Scenario 3 (Modest rate of change) International agreement on carbon reduction targets and the impact of climate change has been reached. The carbon price paths are universally adopted but are only moderate. All sectors of the Australian economy are doing reasonably well, with economic growth at intermediate levels. Moderate carbon price targets push development of new technologies along at a reasonable pace and globally some of the new low emissions technologies are maturing.
- Scenario 4 (Independent Climate Action) International agreement on climate change objectives is not reached and there is no development of and international carbon trading scheme. Climate change is impacting on agriculture and tourism and Australia chooses to move to a low carbon economy faster than its trading partners by imposing a carbon tax on its industry. Population growth and emigration is at the low end of the range and reduces economic growth in Australia.

- Scenario 5 (Slow rate of change): low domestic economic growth and population growth, driven by difficulties accessing capital, slows the rate of transformation of the stationary energy sector. Australia moves further towards a service economy, with some manufacturing and energy-intensive industry moving off-shore.

3.2 Cost Estimate Components

3.2.1 Direct & Indirect Costs

The total cost estimate figures (in A$/kW) for each technology assume direct and indirect cost components. WorleyParsons cost curves are expressed as A$/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 for 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.
- Interest during construction and financing costs.

The estimates carry an accuracy of +/-40%, with the exception of solar thermal, Photovoltaic, Geothermal, and wave power technologies since the level of maturity for these technologies is at an earlier stage that fossil fuel technologies such as IGCC, Supercritical Pulverised Coal, and CCGT/OCGT.

Contracting Strategy

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

Estimate Scope

The estimates represent a complete power plant facility on a generic site. Site-specific considerations such as soil conditions, seismic zone requirements, or unique local conditions such as accessibility, local regulatory requirements, etc. are not considered in the estimates.

The battery limits for each technology are discussed in greater detail in the discussion outlined under in Appendix 3 for fossil fuelled technologies.

Labour costs are based on 2010 Australian rates and productivities, in a competitive bidding environment.

Direct Cost Estimate

Direct cost estimate for each technology assumes costs associated for all major plant, materials, minor equipment and labour to develop the respective power plant to the stage of commercial operation.

Owners Cost Estimate

Provision has been made for development costs necessary to cover expenses prior to start of construction and all non EPC hard costs during construction. Specific development cost items that are assumed are listed below:

- Studies & Project Development
- Site Acquisition
- Legal Fees
- Project Support Team
- Development Approvals
- Duties & Taxes
- Operator Training
- Commissioning Fuel
- Commissioning & Testing

Contingency

Allowance is made for a contingency to cover plant, materials and labour that is not fully defined and that would be expected to be spent during the construction stage (this allowance is intended to cover any cost overruns and change orders not covered under the EPC contract). The contingency varies according to the level of cost estimate accuracy and cost data source.

3.2.2 O&M Costs

O&M costs would be reviewed and updated using current WorleyParsons data bank for O&M data. This data has been compiled as a result of recent studies and project work where O&M costing was necessary.

3.3 Forward Curve Assumptions

Our methodology used to produce forward cost curves assumes that the 2010 capital estimate is broken down into three cost components namely; commodity, equipment and labour cost components.

There are two levels of factors that were applied to estimate the forward cost curve. The first level assumes the impact for:

- Exchange rate variations over the period 2010 to 2030 for each of the five scenarios;
- Productivity variations for each of the scenarios over the applicable timeframe; and,
- Commodity index/variation over the applicable timeframe for each scenario

The second level assumes the technological improvement factor that is applied on a year by year basis over the period 2010 to 2030.

3.3.1 Exchange Rate Variation

Our assumptions for the starting point for exchange rate was based on the current average rate of A$1.00=US$1.00. Therefore the starting point for all capital costs is based on the current exchange rate. Based on the description of the five scenarios we assumed that the average exchange rate variation for the five scenarios would be as follows:

Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
High	High	Medium	Medium	Low
US$0.85=A$1.00	US$0.85=A$1.00	US$0.75=A$1.00	US$0.75=A$1.00	US$0.60=A$1.00

3.3.2 Productivity Rate Variation

Based on the description of the five scenarios we assumed that the productivity rate variation for the five scenarios are as follows:

Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
High	High-medium	Medium	Medium-low	Low
1.75%	1.45%	1.30%	1.0%	0.80%

3.3.3 Commodity Variation

Based on the description of the five scenarios we assumed that the commodity variation for the five scenarios are as follows:

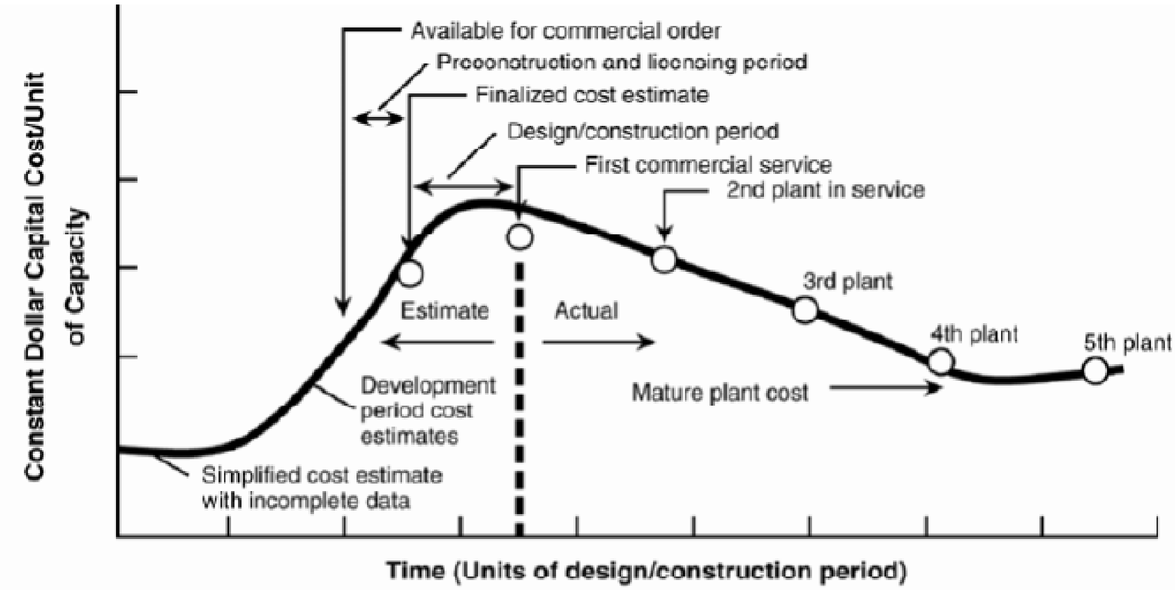
Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
High	High	Medium	Medium	Low
3.3%	2.9%	2.5%	2.1%	1.7%

Similarly as for the exchange rate, Scenario 1 was assumed to have the highest commodity variation with reducing values to the lowest value for Scenario 5. The value and profile for commodity variation was linked to the average GDP/GSP profile for Australia over the period 2010 to 2030. According to the report by KPMG entitled “Economic Scenarios and Forecasts for AEMO – 2009 Update” the average GDP growth rate over the forecast horizon from 2010 to 2030 is 3.3% for the high Scenario assumed Scenario 1 (fast rate of change), 1.7% for the low Scenario, assumed Scenario 5 (slow rate of change) and 2.5% for the medium Scenario.

3.3.4 Technological Improvement

The impact for technological improvement has probably the most influence over pricing trends for the different generating technologies during the period 2010 to 2030.

In general we assumed the trend expected for each technology according to the level of maturity for that technology and in accordance with typical grubb curves[1] such as the generic curve shown below:



For fossil fuel technologies with CCS technology significant improvement in process and efficiency gains would be realised throughout the assessment timeframe as new CCS processes are proven and commercialised. Our estimates for current starting cost for fossil fuel technologies with CCS are based on recent OEM estimates for their CCS technology. Therefore we assumed that for all cases involving CCS (IGCC & Supercritical plants), the technology is commercially available from 2010 (and at the start of the downward trend of the grub curve) but not necessarily guaranteed by OEMs due to the fact that large scale CCS plant required for utility size power plants have not yet been built. Therefore we show the cost curves for the CCS cases starting at 2010 and varying according to technological improvements. Variation between scenarios assumed varying rates for

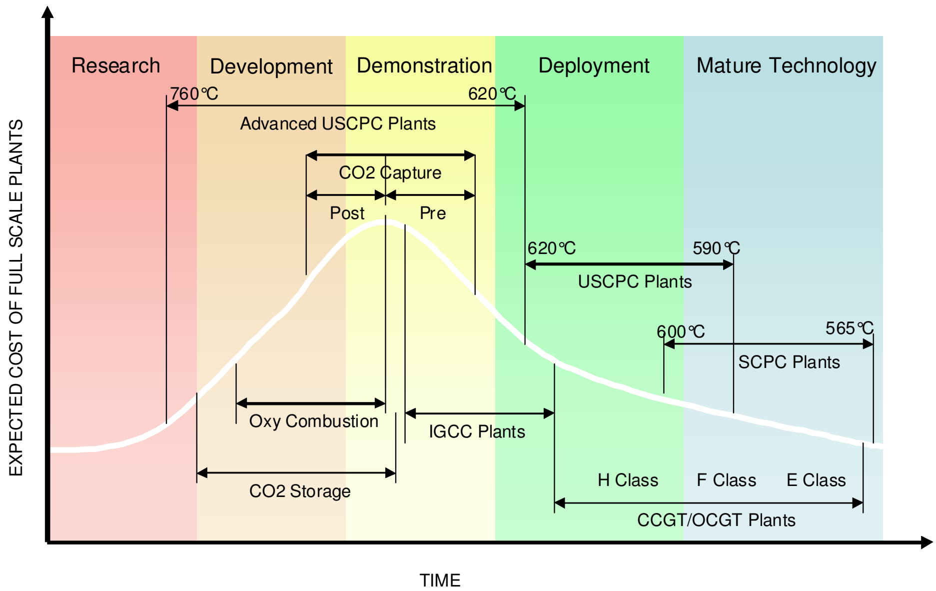
[1] Australian Electricity Generation Technology Costs – Reference Case 2010, February 2010, EPRI

commercialisation for improved technology (such as improved MEA process, KS solvent, Chilled Ammonia, Aqueous Ammonia, etc) to reflect early commercialisation for a fast rate of change (scenario 1) to a delayed commercialisation for a slow rate of change (scenario 5). Improvements in CCS technologies were generally assumed to be step changes occurring as new technology is assumed to be introduced (from 2018 – 2021).

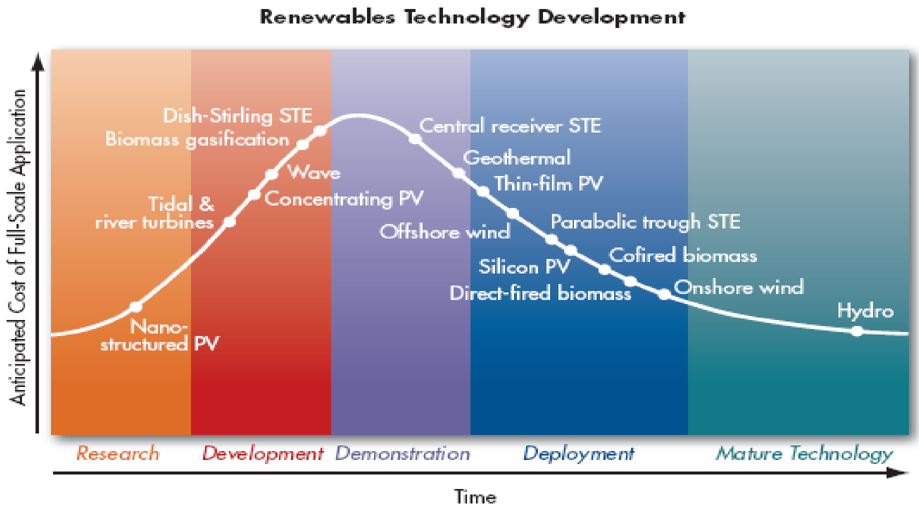
The cost estimate for Oxy fuel technology is based on current estimates provided by OEMs for recent studies. Similar to CCS technology, Oxy fuel technology has not yet been built in utility size power plants. We have assumed that the technology for utility size plants is commercially available but will not necessarily be guaranteed by OEMs. Our cost curves for scenario 1 & 2 show cost remaining relatively flat for the first few years then decreasing in cost as the technology obtains experience through actual operation of a utility size plant. Our cost curves for scenario 3, 4 and 5 show a continuous upward trend in cost reflecting a slower rate of technology improvement under these scenarios.

For CCGT and Supercritical Pulverised Coal technologies there are still gains to be made as new materials are implemented and improvements to overall performance are implemented. In cases where small changes occurred often, a linear rate of improvement was assumed over the assessment period. Likewise IGCC technology is expected to improve in output and performance at a faster rate over the next decade and slowing down as the technology matures and gains become smaller.

The Grubb curve assumed for fossil fuel technologies is shown below.



Renewable technologies have varying levels of development maturity as seen by the following grubb curve[2]. While wind and Solar are approaching maturity, technologies such as biomass and wave energy are still in the development phase.



[2] Dynamic Characteristics of Wave and Tidal Energy Converters, OES-IA Document No. T0321

4 DISCUSSION & RESULTS

4.1 Cost Curves

Cost curves were plotted for each of the 39 technologies and the tabulated values for these curves are provided in Appendix 1. The WorleyParsons cost curves were plotted on the same axis as the 2009 ACIL Tasman cost curves that were obtained from the NTNDP modeling assumptions spreadsheet for each scenario.

It was noted that the ACIL Tasman cost curves had different starting points for each scenario and that scenario 2, 3 and 4 in most cases were the identical. The WorleyParsons cost curves took the approach that all costs for each scenario started at the same level in year 2010 and then, based on the scenario and the assumptions for that scenario, followed a certain trend to the year 2030.

A brief description of the curves and how they compare with the 2009 data can be found in the following sub-sections.

4.1.1 IGCC Technology

4.1.1.1 Brown Coal IGCC without Carbon Capture and Storage

Technology description

Integrated brown coal gasification and combined cycle (IGCC) power generation technology is moderately developed with a limited number of gasifier and gas turbine manufacturers currently offering commercial plants. Australian experience of the technology is limited to a 10MW pilot plant which has been built and operated by HRL using an air blown gasifier. Similar technology has been proposed for a full scale 400MW air blown IGCC plant to be built by HRL.

Performance

The unit as modelled was for a 504MW, two unit plant, with GE Frame 9E gas turbines, operating in a combined cycle configuration, fed by syngas produced in two oxygen-blown Shell gasifiers, using brown coal of a mid-range moisture content of 37%. A cost adder of 4% was included to allow for additional coal drying equipment in case of typical Victorian brown coal resources, which have typical moisture contents in the 50-70% range.

The plant efficiency on a higher heating value basis for the SA coal was 38.44%. In case of Victorian brown coal use, the efficiency could fall from 2 to 6% less than this, depending on the coal drying process used upstream of the coal gasification process.

Capital Cost Split and Equipment cost trends

Bottom-up cost modelling of the Brown coal IGCC plant (using Victorian brown coal fuel) indicated a basis cost of $5990/kW on a fully installed cost basis, and a split of capital cost of 7% commodities, 55% equipment and 38% labour. The high portion of capital cost apportioned to equipment cost leads to a large currency exchange rate exposure of future plant capital costs, as well as to non-exchange rate trends such as downward cost movement of technologies along a learning (or "Grubb") curve. Thus, if the Australian dollar remains strong such as would be characteristic for scenario 1, the downward cost trends of technology improvements would dominate, while if the Australian dollar weakens from its current position, as typical for the weak growth, scenario 5 case, overall capital costs for IGCC brown coal are expected to increase.

Expected Technological Improvement

Five curves for the rate of technological cost improvement were constructed, corresponding to each of the five scenarios. Scenario 5, corresponding to low growth, assumed a net real technology $/kW improvement of equipment costs of 5% by 2030, or 0.25% per year. By contrast, the same measure for scenario 1 assumed a steady cost improvement of 1% per year, with additional 1-2% improvements between 2014 and 2018, leading to a net equipment cost improvement in real terms of 25% by 2030. The additional cost improvements from 2014 to 2018 were included to take into account expected transition of more specialised equipment supply to low cost countries, and as a secondary influence, possible unit capacity cost improvements due to gas turbine and gasifier technology developments. Such improvements could include widespread introduction of steam cooling technology to gas turbine hot gas path components.

Technology cost improvement curves for Scenarios 2 to 4 were blended between these two extremes.

Projections for exchange rate variation, labour productivity variation and commodity index variation were kept common to those selected for the other technology cost curves.

4.1.1.2 Black Coal IGCC without Carbon Capture and Storage

Technology description

IGCC for black coal was modelled using a similar model to that which was used for the Brown coal IGCC cost estimate, using a typical Hunter valley thermal coal as the input fuel instead of brown coal, and an appropriately adjusted plant thermodynamic model.

Performance

A net plant output of 509MW and a HHV basis efficiency of 41.1% was calculated for the plant as modelled, using Shell gasifier technology, GE Frame 9E gas turbines, and acid gas syngas cleanup without carbon dioxide capture from the syngas stream.

Capital Cost Split and Equipment cost trends

The bottom-up cost model for Black coal IGCC indicated a split of capital cost very close to that for Brown coal IGCC, with 7% Commodity, 56% specialized and non-specialized equipment, and 37% labour, leading to the same dominance of exchange rate and technological improvement as the main factors expected to influence real capital costs for black coal IGCC. A baseline figure of A$4802/kW fully installed was calculated using the Thermoflow GTPro/PEACE plant performance and cost modelling software.

Expected Technological Improvement

While there are more reference plants for gasification and IGCC technology using black coal, the number of such full scale plants is still limited, and the same expected technology cost improvement curves were assumed to apply as for brown coal IGCC technology.

4.1.1.3 Brown Coal IGCC with Carbon Capture and Storage

Technology description

Brown Coal fuelled IGCC with carbon capture was modelled around two oxygen-blown, dry-feed, Shell gasifiers with convective cooling of the raw syngas, fuelling GE 9FA gas turbines. Capture and compression of CO_2 from the syngas stream was modelled in the process as an amine absorbent process, after the acid gas cleanup and water-gas shift stages of syngas processing. Other alternative carbon capture processes could include integrated acid gas and carbon dioxide removal (such as Selexol process) which may vary the plant efficiency and output slightly.

The GE9FA was selected due to its higher thermal efficiency, since if carbon capture and storage is to be carried out, a higher efficiency gas turbine will require less fuel use for a given power output, which may provide savings in the carbon capture, transmission and storage portions of the capital and operating costs.

Performance

The results of the plant performance and cost modelling for this baseline configuration were a net plant output of 764MW, a net efficiency of 33.62% (Victorian brown coal HHV basis), and capital cost of A$7792/kW. The net efficiency is significantly lower than that for a non-carbon capture IGCC plant using the same fuel. The unit capital cost appears high but may be subject to greater uncertainty than other, proven technologies. No full scale IGCC plants with full CO_2 capture such as this exist to date, and thus accurate cost benchmark data is not available.

Capital Cost Split and Equipment cost trends

The capital cost split for Brown Coal IGCC with CCS was again very similar to that for other IGCC based technologies, with 7% commodity, 55% equipment and 38% labour. Similar comments with respect to the sensitivity of these capital portions to the external parameters of exchange rate, productivity and commodity indexes apply.

Expected Technological Improvement

With respect to the curves developing technological improvement over time, a similar technology improvement was assumed as for the other IGCC cases, with an additional, sharp decline in capital cost of 12-17% over the otherwise steady cost improvement was applied. Generally the decline in capital costs are based on the predictions described by the EPRI roadmap where for IGCC there is expected to be improvements in the following:

- Improved reliability & flexibility of gasifier
- O2 separation
- H2 turbines and fuel cells
- Carbon capture
- Successful demonstration of similar technologies

Therefore the sharp decline accounts for a major improvement in the costs of carbon capture equipment and O2 separation due for commercial deployment of the technology following successful large scale demonstrations, which is forecast to commence from around 2017/18 for the high growth scenario 1, or later, around 2020/21, for the low growth scenario 5. Intermediate scenarios were set with a similar change to commence in the years between these two cases.

4.1.1.4 Black Coal IGCC with Carbon Capture and Storage

Technology description

Black Coal fuelled IGCC with carbon capture was modelled as for Brown coal ICGG-CCS, with two oxygen-blown, dry-feed, Shell gasifiers, convective cooling of the raw syngas, fuelling two GE 9FA gas turbines. Capture and compression of CO_2 from the syngas stream was modelled as an amine absorbent process taking place after the acid gas cleanup and water-gas shift stages of the syngas cleanup process. As for Brown coal IGCC, optimisation of the process my indicate variations such as Selexol process acid gas removal or other gasifier technology as having superior overall long run power generation costs.

As for the Brown coal IGCC case, the GE9FA gas turbine was selected due to its higher thermal efficiency, since if carbon capture and storage is to be carried out, a higher efficiency gas turbine will require less fuel use for a given power output, which may provide savings in the carbon capture, transmission and storage portions of the capital and operating costs. Future gas turbine technology such as steam-cooled "G" technology or "H" technology gas turbines may improve output, cost and efficiency parameters, however given the lack of any reference plants using IGCC with carbon capture even for current commercially available gas turbines, this was not modelled.

Performance

The results of the plant performance and cost modelling for the baseline black coal IGCC-CCS configuration were a net plant output of 750MW, a net efficiency of 36.81% (HHV basis), and capital cost of A$6288/kW. As for Brown coal IGCC-CCS, this unit capital cost is comparative to other technologies high but may be subject to greater variation than proven technologies. No full scale IGCC plants with full CO_2 capture such as this exist to date, and thus accurate cost benchmark data is not available.

Capital Cost Split and Equipment cost trends

The capital cost split for black coal IGCC with CCS was again very similar to that for other IGCC based technologies, with 7% commodity, 55% equipment and 38% labour. Similar comments with respect to the sensitivity of these capital portions to the external parameters of exchange rate, productivity and commodity indexes apply.

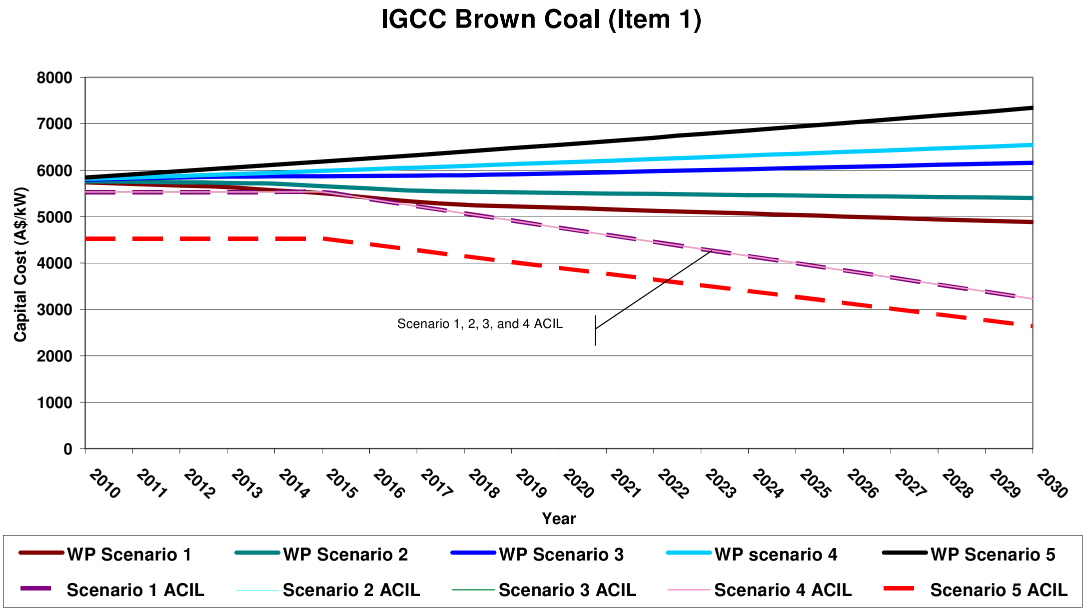
Expected Technological Improvement

With respect to the curves developing technological improvement over time, a similar technology improvement was assumed as for the Brown Coal IGCC-CCS cases, with the additional decline in capital cost of 12-17% over the otherwise steady cost improvement applied to account for a major improvement in the costs of carbon capture equipment. As for the Brown Coal IGCC-CCS, this improvement is expected in line with commercial deployment of such equipment following successful large scale demonstrations, which is forecast to commence at the earliest from around 2017 for the high growth scenario 1, or later, around 2020, for the low growth scenario 5. Intermediate scenarios were set with a similar change to commence in the years between these two cases. As for the Brown Coal IGCC-CCS cases, the lack of reference plants results in a high degree of uncertainty about the deployed costs and timelines for this technology.

4.1.1.5 Cost Curves

Item 1 IGCC Brown Coal

A starting cost estimate of A$5772/kW was estimated for a plant size of 252MW for this technology. As shown by the following graph, the starting cost is slightly above that of scenario 1 (ACIL Tasman) but within 10% of the present cost band.

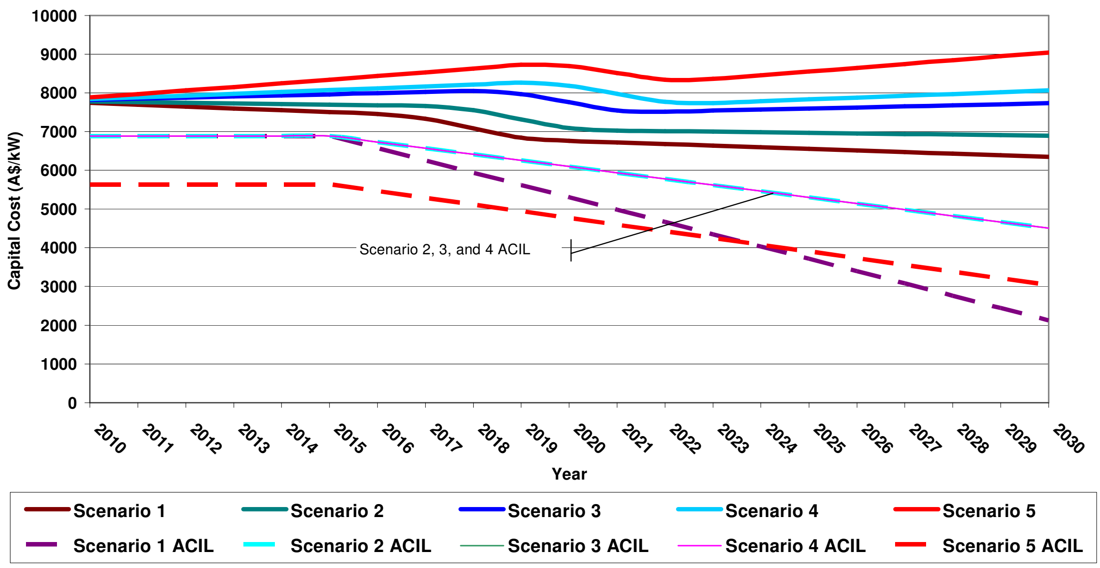


As shown by the above figure, there is a common point for the stating point for all scenarios in 2010. For scenarios 3, 4 and 5, there is an upward trend in cost due mainly to the variation in exchange rate. For scenarios 1 & 2, exchange rate has a lesser effect however, the technological improvements and productivity improvements have an overall effect of reducing costs for those scenarios over the 20 year period.

Item 2 IGCC Brown Coal with CCS

A starting cost estimate of A$7792/kW was estimated for a plant size of 764MW for this technology. As shown by the following graph, the starting cost is significantly higher than that of scenario 1 (ACIL Tasman).

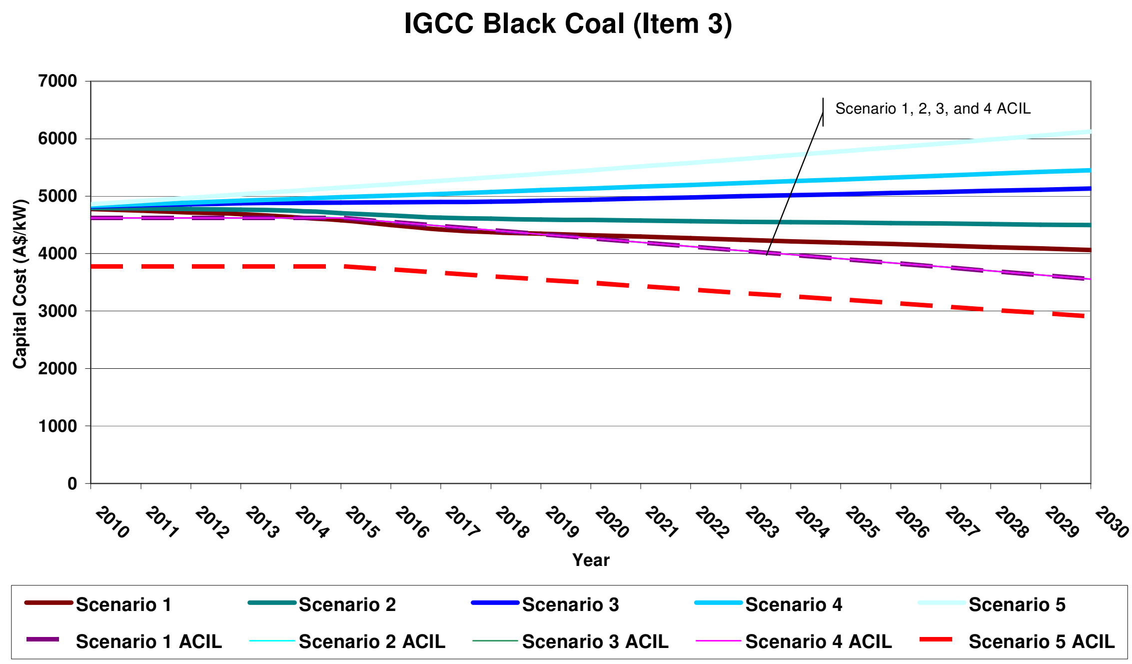
IGCC Brown Coal With CCS (Item 2)



Similarly to item 1, there is a common point for the stating point for all scenarios at 2010. For scenarios 4 and 5, there is an upward trend in cost due mainly to the variation in exchange rate. The drop in cost during the 2018-2021 period is due to the expected cost reduction as new improved technology is introduced for CCS. Despite the upward trend that exchange rate has on each scenario, scenarios 1, 2 & 3 show a downward trend due mainly to the technological improvements expected for both IGCC and CCS technologies over the 20 year period.

Item 3 IGCC Black Coal

A starting cost estimate of A$4802/kW was estimated for a plant size of 509MW for this technology. As shown by the following graph, the starting cost is almost identical to that of scenario 1 (ACIL Tasman).

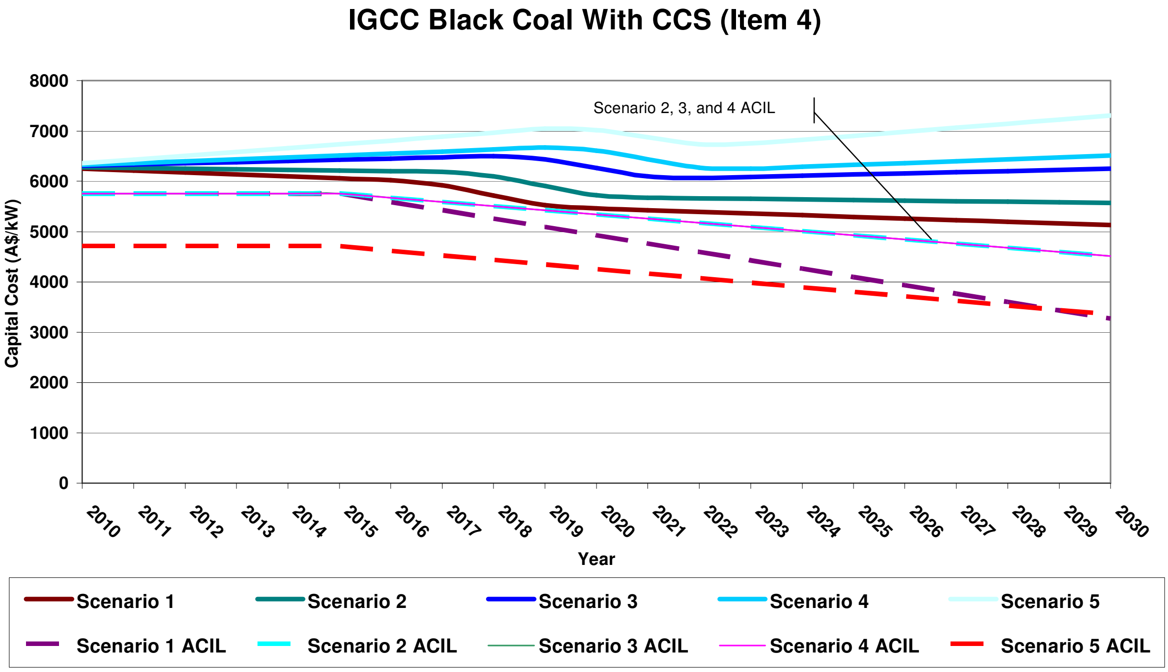


Similarly as for item 1 above, there is a common stating point for all scenarios in 2010. For scenarios 3, 4 and 5, there is an upward trend in cost due mainly to the variation in exchange rate.

For scenarios 1 & 2, exchange rate has a lesser effect however the technological improvements and productivity improvements have an overall effect of reducing costs for those scenarios over the 20 year period and therefore the curves for these scenarios have a downward trend.

Item 4 IGCC Black Coal with CCS

A starting cost estimate of A$6288/kW was estimated for a plant size of 751MW for this technology. As shown by the following graph, the starting cost is slightly higher than that of scenario 1 (ACIL Tasman) but within 10% of the current cost band.



Similarly as for item 2, there is a common stating point for all scenarios at 2010. For scenarios 4 and 5, there is an upward trend in cost again due mainly to the variation in exchange rate. The drop in cost during the 2018-2021 period is due to the expected cost reduction as new improved technology is introduced for CCS. Again despite the upward trend that exchange rate has on each scenario, scenarios 1, 2 & 3 show a downward trend due mainly to the technological improvements expected for both IGCC and CCS technologies over the 20 year period.

4.1.2 Supercritical Pulverised Coal Technology

Technology Description

Unlike subcritical units that produce steam at temperatures around 538℃ and pressures around 16.5 MPa, Supercritical pressure units generate steam at pressures of at least 24.8 MPa with steam temperatures of 565-593℃. Supercritical units operate at about two percentage points higher efficiency than subcritical units (i.e., increasing from 36.5 to 38.5% efficiency on a higher heating value basis for plants with wet cooling towers).

For the Pulverised Coal cases evaluated in this report, there are two types of coal examined namely; Hunter Valley Black Coal and Latrobe Valley Brown Coal. Brown Coal has very high moisture content and requires drying before it can be used. Owing to the high amount of water to be removed, the drying process requires a lot of energy and, therefore, energy efficiency in this process is very important. Black Coal does not require drying.

For Supercritical plants the major components included in the cost for a pulverised Brown/Black coal-fired plant include coal-handling equipment, steam generator island, turbine generator island including all balance of plant (BOP) equipment, bottom and fly ash handling systems as well as emission control equipment. Particulate emissions are typically controlled using electrostatic precipitator or fabric filter systems.

Supercritical Pulverised Coal plant configurations with CCS will 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%. 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 was assumed to be of the order of 150 Bar.

An alternative Pulverised Coal technology considered in this report is the oxy-combustion system for CO_2 capture. In this technology the fuel is combusted in a blend of oxygen and recycled flue gas which is 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 flue gas recycle loop may include dewatering and de-sulphurisation processes. As a result, the flue gas downstream of the recycle slipstream take-off consists primarily of CO_2 and water vapour (with small amounts of nitrogen, oxygen, and criteria pollutants). After the water is condensed, the CO_2 rich gas is compressed and purified to remove contaminants and prepare the CO_2 for transportation and storage.

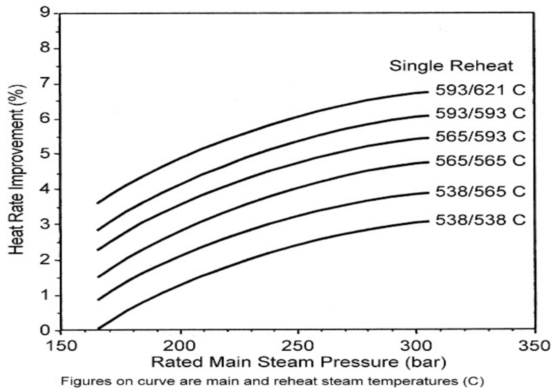
The oxygen stream is produced in an air separation unit (ASU). This is a large system that consumes a considerable amount of electricity. In an effort to reduce its load and penalty on power output, new, more energy-efficient oxygen separation technologies are in development. In addition, the oxy-combustion plant will have additional flue gas treatment modules, several heat exchangers to extract

low grade heat, and fans and ducts for flue gas recirculation (FGR). Space must be provided for these, in addition to the CO_2 capture hardware.
The battery limits for this technology and other fossil fuel technologies are shown in Appendix 3.

Expected Technological Improvement

The major technical issues with advancing Pulverised Coal technology are mostly associated with new 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 operate at temperatures in excess of 700ºC. The following Figure illustrates the effect of increasing the steam conditions on improved overall plant efficiency.

Figure 4.1.2 Improvement in Heat Rate with Increasing Steam Conditions[3]



There are already plans to build a commercial-scale Supercritical Pulverised Coal facility with main steam temperature of 700ºC by 2016. There are current activities 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 today's technology.

While an increase in thermal efficiency does not directly impact post-combustion capture processes, it does however mean that a more efficient power plant produce less CO_2 per MWh. Likewise a facility fitted with post combustion CO_2 capture plants 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 decreases the auxiliary power load of the capture system.

In addition to improved Rankine cycle efficiency by increasing steam temperature and pressure, it is also assumed that post-combustion CO_2 capture technology will improve significantly by 2030. The current MEA based amine system is expected to improve significantly over the next several years and there is likely to be a few step changes in lower cost and higher efficiency processes such as Chilled

[3] Source "Australian Electricity Generation Technology Costs – Reference Case 2010" Prepared by EPRI, February 2010.

Ammonia CCS system. Advancement in CO_2 compressor technology, with inter-cooling systems, will also work towards reducing the overall $/kW cost and reduce the auxiliary loads need to run the CCS plant.

For the cases involving Brown Coal, it is expected that new coal drying technologies, using low grade heat, will be used to dry the coal more efficiently and to a lower moisture content that has ever been done in the past.

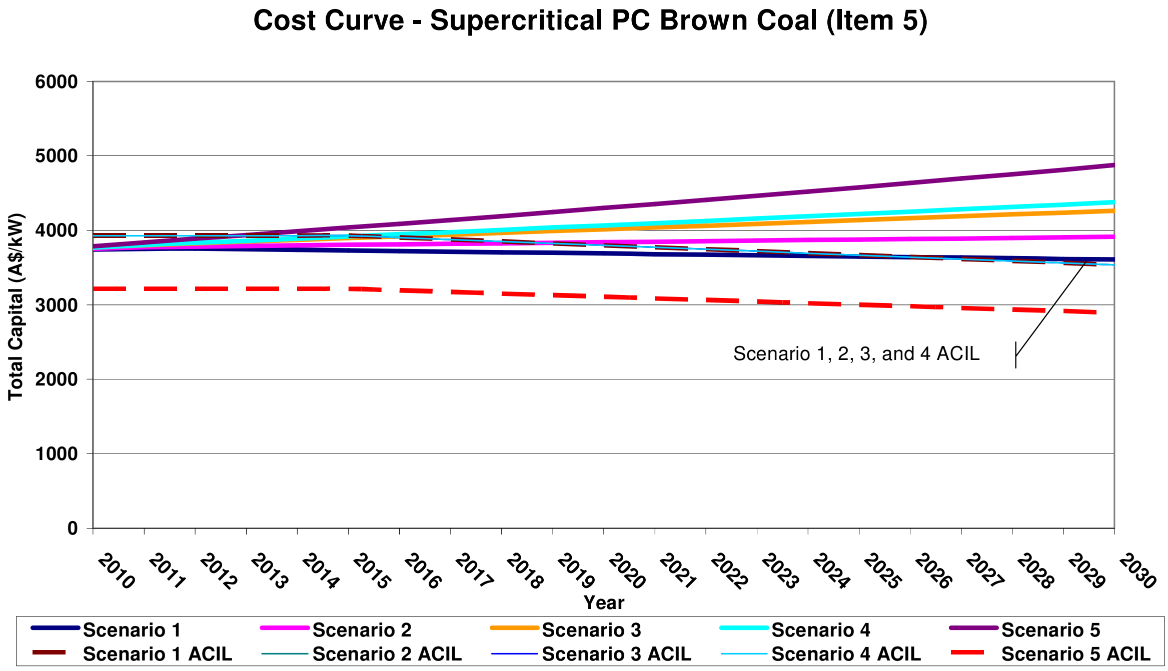
The anticipated Pulverised Coal, Post Combustion Capture and Oxy Combustion performance and cost improvements by 2030 as recently published in the report entitled "Australian Electricity Generation Technology Costs – Reference Case 2010" prepared by EPRI are:

		Black Coal CCS	Brown Coal CCS	Black Coal Oxy
	Current Technology	2030 Technology	2030 Technology	2030 Technology
Capex (Relative to current technology)	1.00	0.81	0.83	0.80
Thermal Efficiency (change)	Base	10.1%	12.5%	8.0%

4.1.2.1 Supercritical Pulverised Coal (Large Plant) Cost Curves

Item 5 Supercritical Pulverised Coal - Brown Coal

A starting cost estimate of A$3732/kW was estimated for a plant size of 750MW for this technology. As shown by the following graph, the starting cost is slightly below scenario 1 (ACIL Tasman) and is probably due to firming of the exchange rate over the past year.

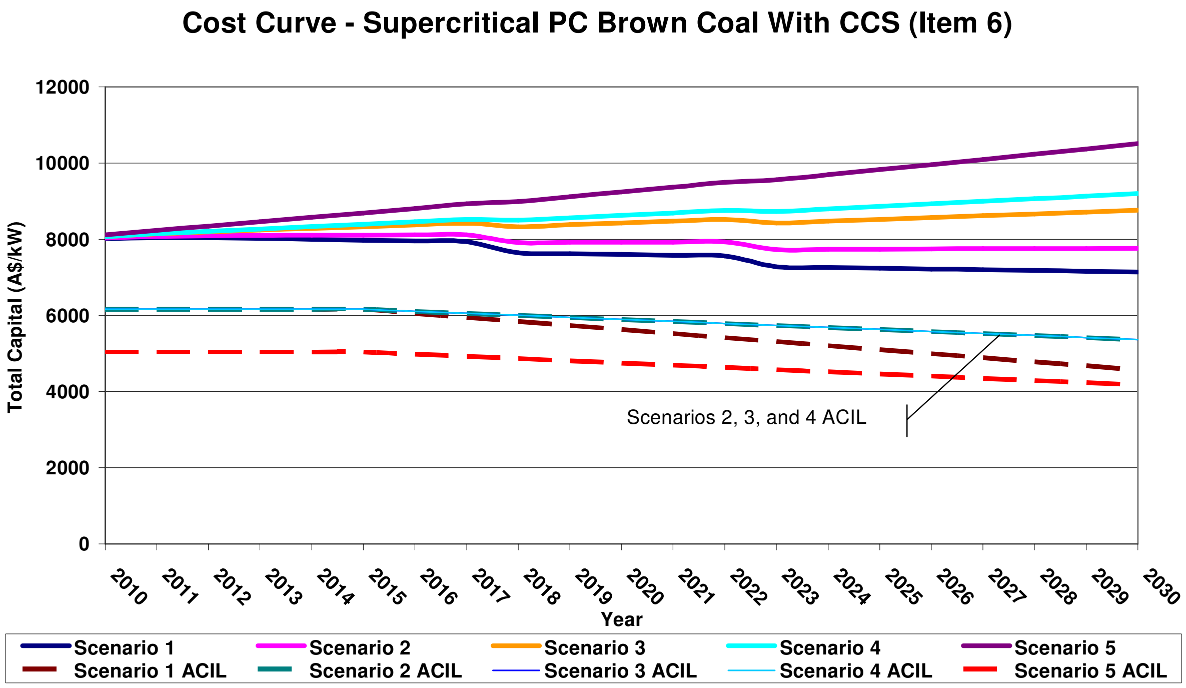


As shown by the above figure, scenarios 2, 3, 4 and 5, there is an upward trend in cost due mainly to the variation in exchange rate. Essentially any technological improvement is overshadowed by lower exchange rates for these scenarios.

For scenarios 1, exchange rate has a lesser effect. The technological improvements and productivity improvements have an overall effect of reducing costs for this scenario over the 20 year period and therefore this curve has a downward trend.

Item 6 Supercritical Pulverised Coal - Brown Coal with CCS

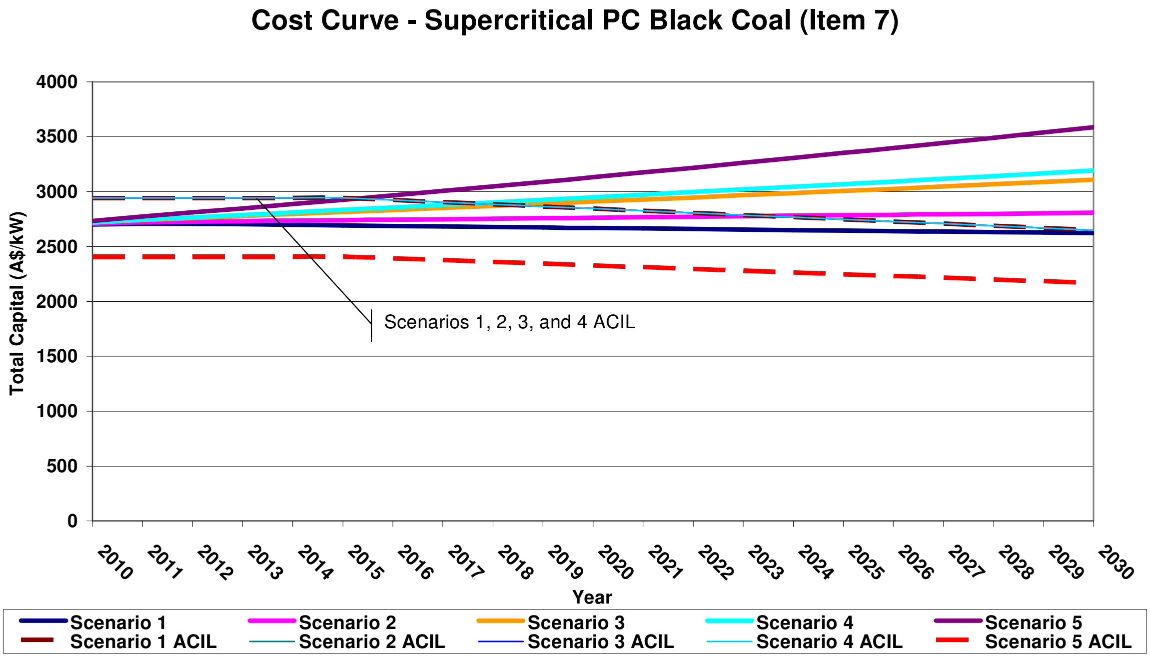
A starting cost estimate of A$7996/kW was estimated for a plant size of 750MW (Vic brown coal fired) for this technology plant with CCS. Step changes in capital costs are shown in future years to show the likely impact for improved CCS processes. The starting cost is significantly above the cost of scenario 1 (ACIL Tasman).



Again there is a common stating point for all scenarios at 2010. For scenarios 3, 4 and 5, there is an upward trend in cost due mainly to the variation in exchange rate. The drop in cost for all scenarios during the 2018-2021 period is due to the expected cost reduction as new improved technology is introduced for CCS. Despite the upward trend that exchange rate has on each scenario, scenarios 1 & 2 show a downward trend due mainly to the technological improvements expected for both supercritical thermal and CCS technologies over the 20 year period.

Item 7 Supercritical Pulverised Coal Black Coal

A starting cost estimate of A$2695/kW was estimated for a plant size of 750MW this technology and fuel. As shown by the following graph, the starting cost is slightly below scenario 1 (ACIL Tasman) which again is probably due to firming of the exchange rate over the past year.

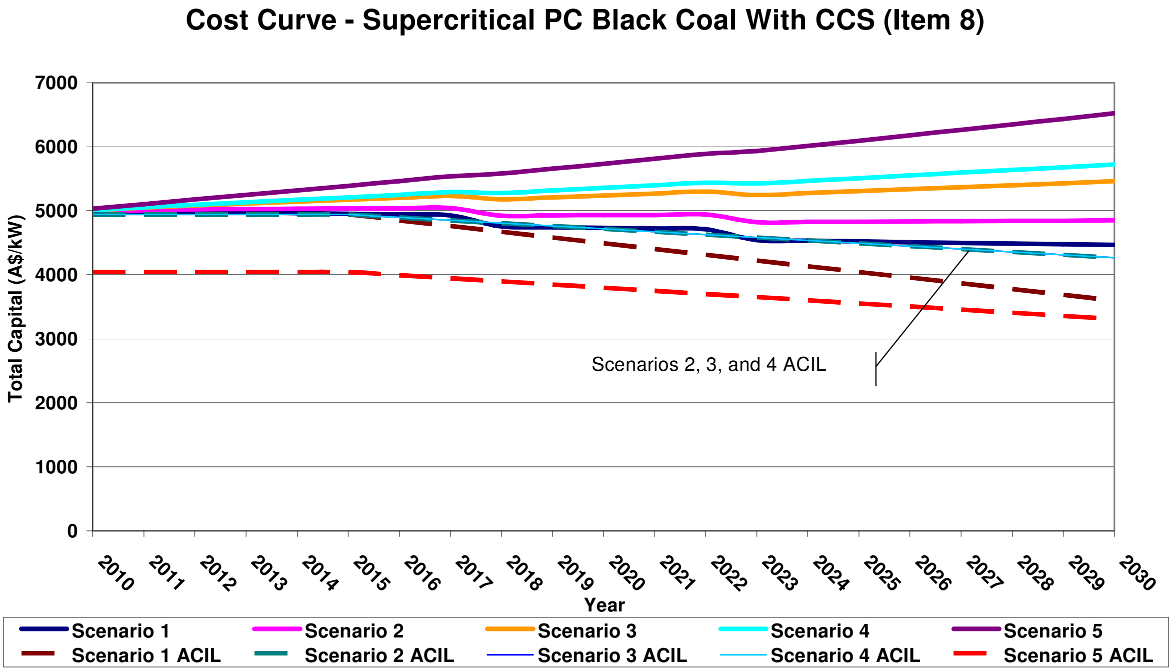


As shown by the above figure, scenarios 2, 3, 4 and 5, there is an upward trend in cost due mainly to the variation in exchange rate. Essentially any technological improvement is overshadowed by lower exchange rates for these scenarios.

For scenarios 1, exchange rate has a lesser effect. Technological improvements and productivity improvements have an overall effect of reducing costs for this scenario over the 20 year period and therefore this curve has a downward trend.

Item 8 Supercritical Pulverised Coal Black Coal with CCS

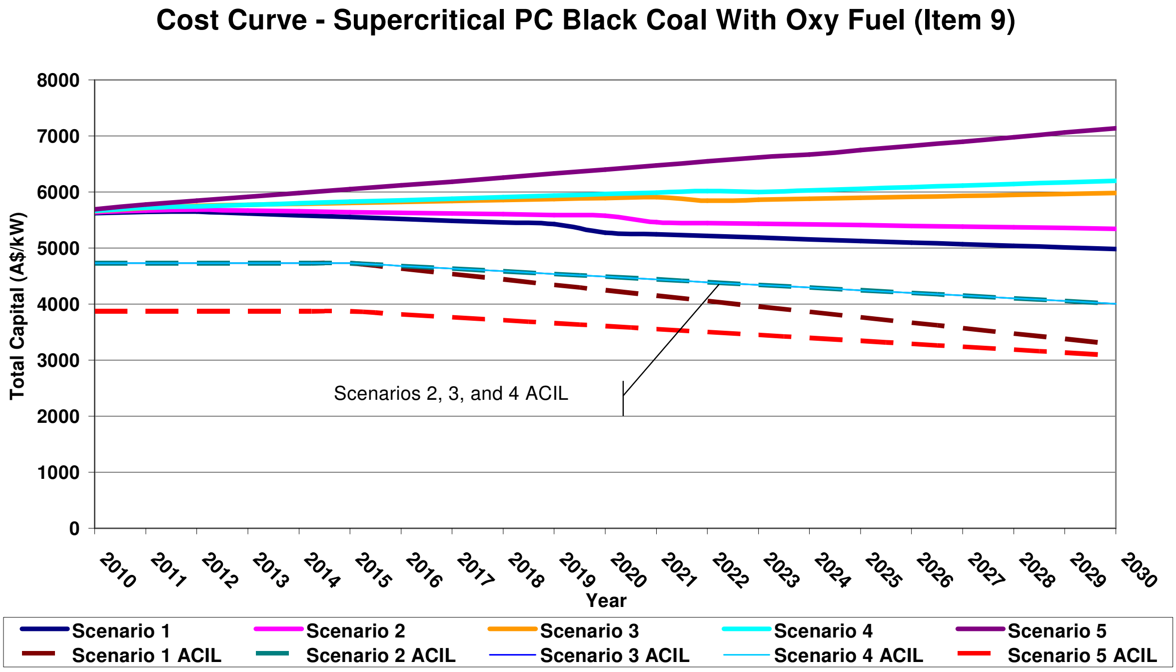
A starting cost estimate of A$4959/kW was estimated for a plant size of 750MW for this technology plant with a CCS facility. Again Step changes in capital costs are shown in future years to show the likely impact for improved CCS processes. The starting cost is almost identical to the cost for scenario 1 (ACIL Tasman).



Again there is a common stating point for all scenarios at 2010. For scenarios 3, 4 and 5, there is an upward trend in cost due mainly to the variation in exchange rate. The drop in cost for all scenarios during the 2018-2022 period is due to the expected cost reduction as new improved technology is introduced for CCS. Despite the upward trend that exchange rate has on each scenario, scenarios 1 & 2 shows a downward trend due mainly to the technological improvements expected for both supercritical thermal and CCS technologies over the 20 year period.

Item 9 Supercritical Pulverised Coal - Black Coal Oxy Combustion

A starting cost estimate of A$5606/kW was estimated for a plant size of 750MW for this Oxy fired technology plant. The starting cost is significantly higher than the cost for scenario 1 (ACIL Tasman).



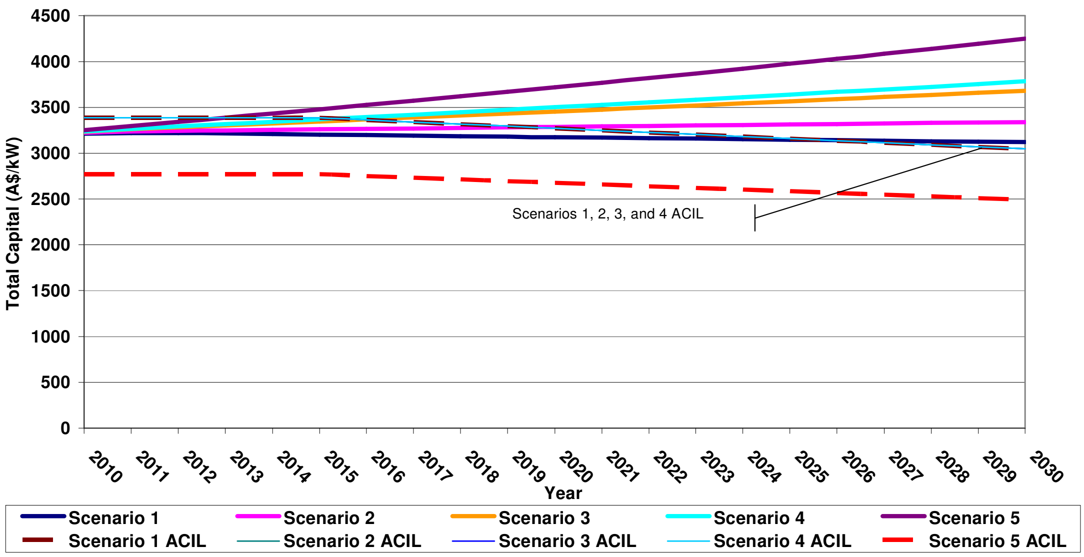
We have assumed that Oxy fuel technology is commercially available (but not necessarily guaranteed by the OEMs) from 2010 and therefore shown the cost curves starting at 2010. As shown by the above figure, scenarios 3, 4 and 5, show an upward trend in cost due mainly to the variation in exchange rate. The drop in cost for all scenarios during the 2018-2022 period is due to the expected cost reduction as new efficient technology is introduced for CCS. Again despite the upward trend that exchange rate has on each scenario, scenarios 1 & 2 shows a downward trend due mainly to the technological improvements expected for both supercritical thermal and CCS technologies over the 20 year period.

4.1.2.2 Supercritical Pulverised Coal (Small Plant) Cost Curves

Item 32 Supercritical Pulverised Coal - Black Coal

A starting cost estimate of A$3207/kW was estimated for a plant size of 450MW of this technology and fuel. As shown by the following graph, the starting cost is slightly below scenario 1 (ACIL Tasman) which again is probably due to firming of the exchange rate over the past year.

Cost Curve - Supercritical PC Black Coal - Small (Item 32)

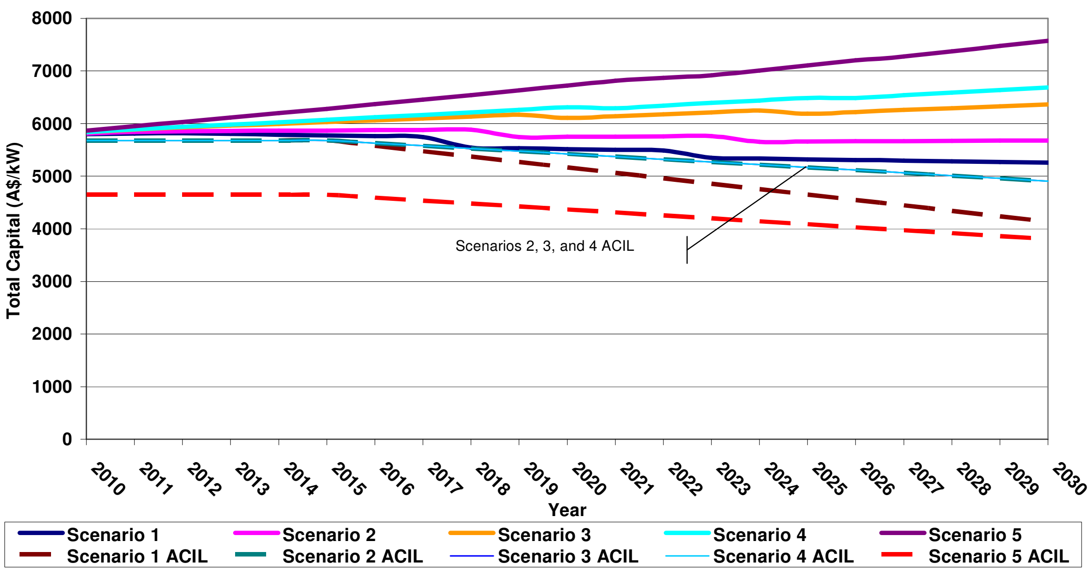


The trend for the above case closely follows the trends shown by item 7.

Item 33 Supercritical Pulverised Coal - Black Coal With CCS

A starting cost estimate of A$5781/kW was estimated for a plant size of 450MW of this technology with a CCS facility. As shown by the following graph, the starting cost is almost identical to scenario 1 (ACIL Tasman).

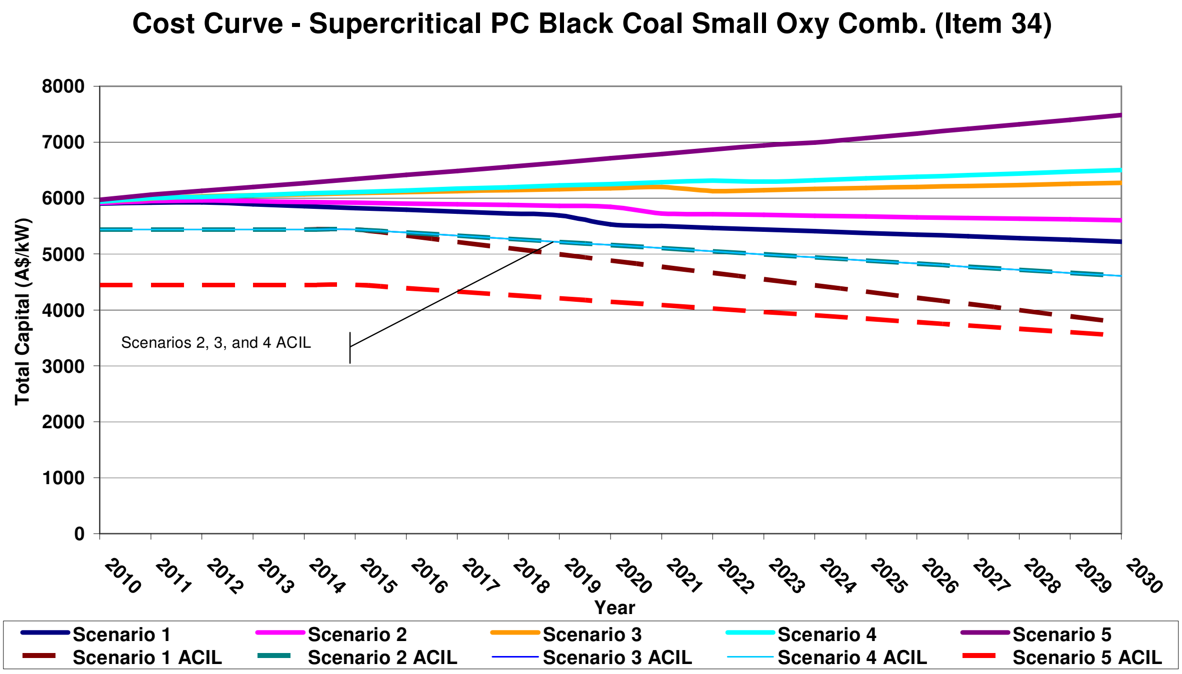
Cost Curve - Supercritical PC Black Coal - Small With CCS (Item 33)



The trend for the above case closely follows the trends shown by item 8.

Item 34 Supercritical Pulverised Coal - Black Coal Oxy Combustion

A starting cost estimate of A$5878/kW was estimated for a plant size of 450MW for this Oxy fired technology plant. The starting cost is higher than the cost for scenario 1 (ACIL Tasman) but less than 10% variation of the current cost band.



The trend for the above case closely follows the trends shown by item 9.

4.1.3 CCGT/OCGT Technology

Technology Description

There are various types and categories of gas turbines available in the market today. These include the earlier designed E class, the state-of-the-art heavy-duty F, G and H class turbine models, and the aeroderivative gas turbines that are generally used in power, cogeneration, and industrial applications. These gas turbines are available in certain given ratings. Their efficiencies depend on several factors such as inlet mass flow, compression ratio and expansion turbine inlet temperature. The earlier design of heavy duty gas turbines had maximum turbine inlet temperatures ranging anywhere between 815-1093°C. More recent state-of-the-art heavy-duty gas turbine designs have turbine inlet temperatures that reach over 1315-1371°C. These turbines are designed with state of the art hot gas path materials and coatings, advanced secondary air cooling systems, and enhanced sealing techniques that enable higher compression ratios and turbine inlet temperatures.

Combined cycle plants can operate with both the lower class of gas turbines and the advanced class of gas turbines. The combined cycle gas turbine can be built up from the discrete size gas turbine. The HRSG and steam turbine are sized to the exhaust energy available from the gas turbine. There are various configurations of combined cycles with various numbers of HRSG pressure levels. The best heat rates are obtained in combined cycles in which the steam cycle requirements are matched by maximising the recoverable energy from the gas turbine exhaust.

The addition of a CCS facility for a CCGT plant is not common because the CO_2 content in the flue gas is less than for coal fired plants (CO_2 concentration in a combined cycle plant's flue gas is only four percent compared to 12 to 15 percent for coal) and therefore the CCS plant will need to be designed accordingly. The flue gas flow in a natural gas-fired plant is about 50 percent greater than in a coal fired power plant per megawatt of capacity because ambient air is used as the compressible medium by the gas turbine. Thus, the lower CO_2 concentration in exhaust gas combined with the higher flue gas flow rate could potentially double the cost per ton of capturing carbon.

Expected Technological Improvement

Combined cycle technology is a mature generating technology. Combined cycles in the future will be based on advanced heavy-duty gas turbines which will operate at even higher firing temperatures and high pressure ratios, and will include more aero-dynamic features. Recently announced machines incorporate advanced air cooling and steam cooling technologies to allow turbine inlet temperatures well above 1426°C. A new J technology by MHI claims to operate at over 1649°C turbine inlet temperature which further increases efficiency. With these advanced gas turbines a more efficient reheat steam turbine cycle can also be selected for higher efficiency for the bottoming cycle. With these newer machines and upgraded materials (new alloys for pressure parts in HRSGs), combined cycle efficiencies can approach about 60% (HHV basis).

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

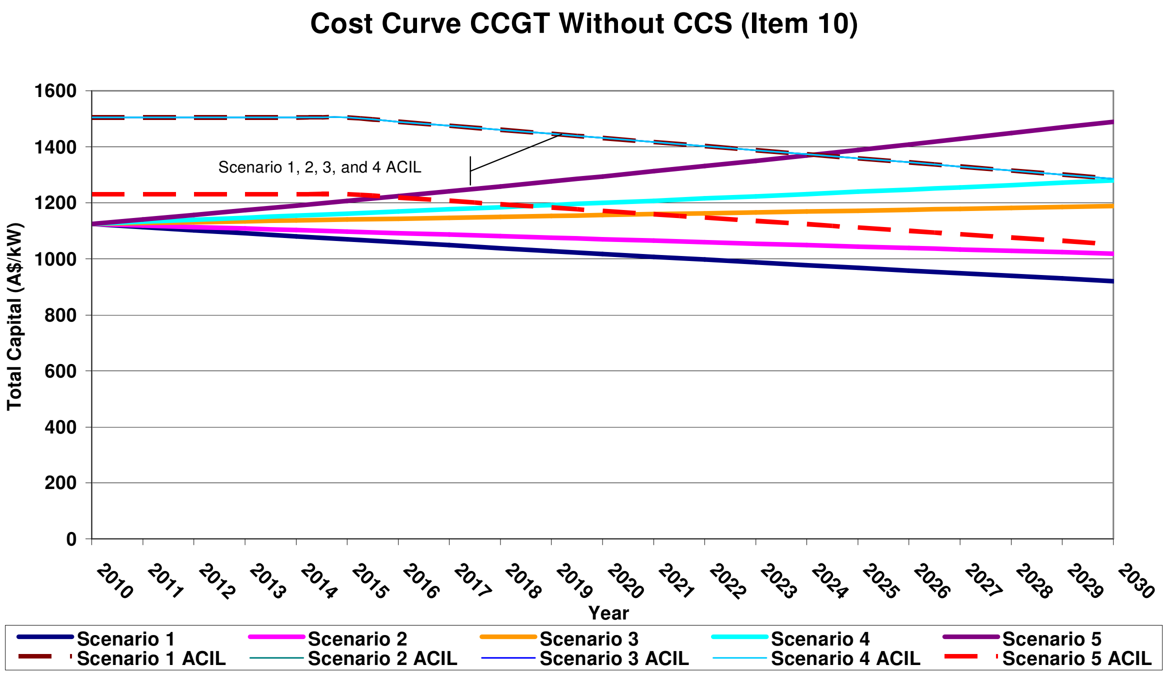
In comparison with today's technology, the thermal efficiency of a CCGT with post-combustion capture of CO_2 is expected to increase by at least eight percentage points by 2030, and the capital cost could decrease by up to 18%. The estimated performance and cost improvements are summarised in the table below.

	Current Technology	**2030 Technology**
Capex (Relative to current technology)	1.00	0.82
Thermal Efficiency (% Change)	Base	8.0%

4.1.3.1 CCGT (Large Plant) Cost Curves

Item 10 CCGT without CCS

A starting cost estimate of A$1125/kW was estimated for a plant size of 700MW of this technology without a CCS facility. As shown by the following graph, the starting cost is significantly lower than scenario 1 (ACIL Tasman).

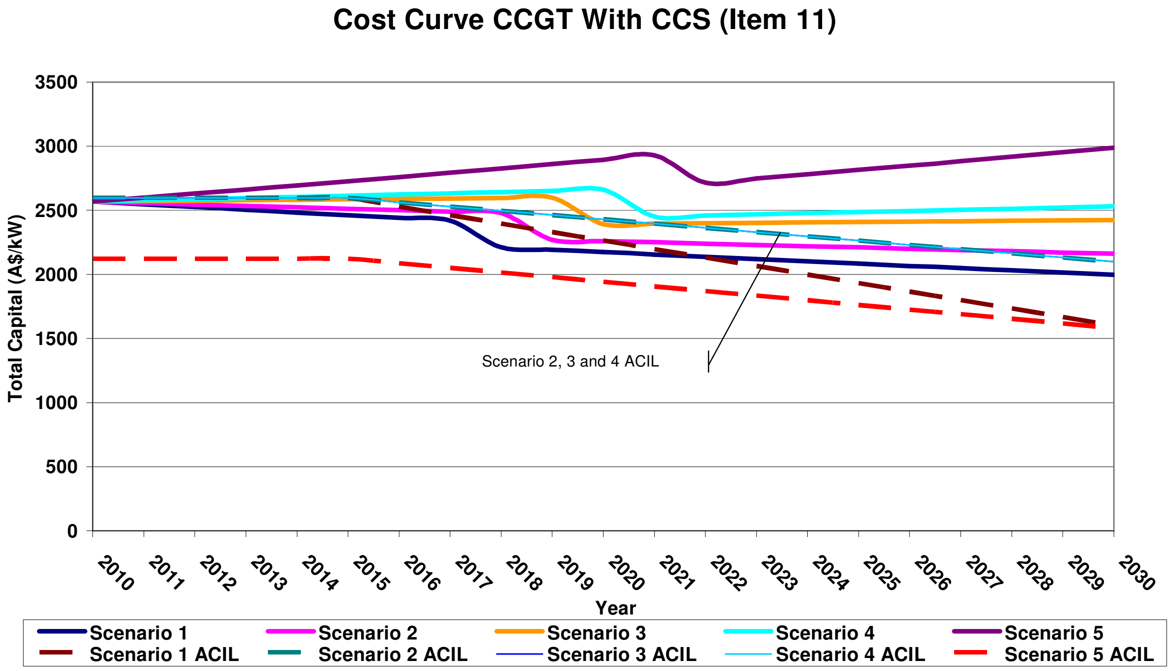


As shown by the above figure, scenarios 3, 4 and 5, there is an upward trend in cost again due mainly to the variation in exchange rate. Since the technology is mature, the improvement over this period is not expected to be as significant as other less mature technologies. Essentially any technological improvement is overshadowed by lower exchange rates for these scenarios.

For scenarios 1 & 2, exchange rate has a lesser effect. The technological improvements and productivity improvements have an overall effect of reducing costs for these scenarios over the 20 year period and therefore these curves have a downward trend.

Item 11 CCGT with CCS

A starting cost estimate of A$2568/kW was estimated for a plant size of 700MW of this technology with a CCS facility. As shown by the following graph, the starting cost is almost identical to scenario 1 (ACIL Tasman). The sharp, staggered cost reduction represent improvements to the CCS plant from the Amine to Chilled Ammonia process.



As shown by the above figure, scenario 5 has an upward trend in cost again due mainly to the variation in exchange rate. Essentially any technological improvement is overshadowed by lower exchange rates for this scenario.

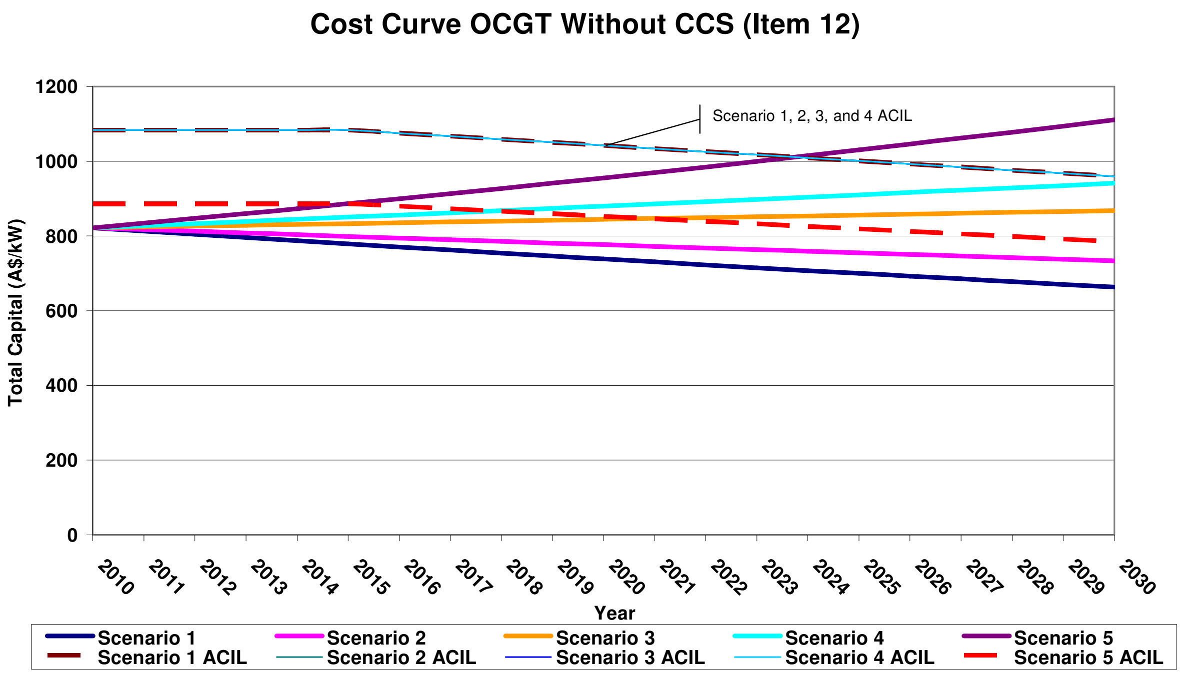
The drop in cost during the 2018-2021 period is due to the expected cost reduction as new improved technology is introduced for CCS.

For scenarios 1, 2, 3 & 4, exchange rate will have a lesser effect than technology improvement for CCS. The technological improvements and productivity improvements have an overall effect of reducing costs for these scenarios over the 20 year period and therefore these curves have a downward trend.

4.1.3.2 OCGT Cost Curve

Item 12 OCGT without CCS

A starting cost estimate of A$822/kW was estimated for a plant size of 160MW for this technology without a CCS facility. As shown by the following graph, the starting cost is significantly lower than scenario 1 (ACIL Tasman).



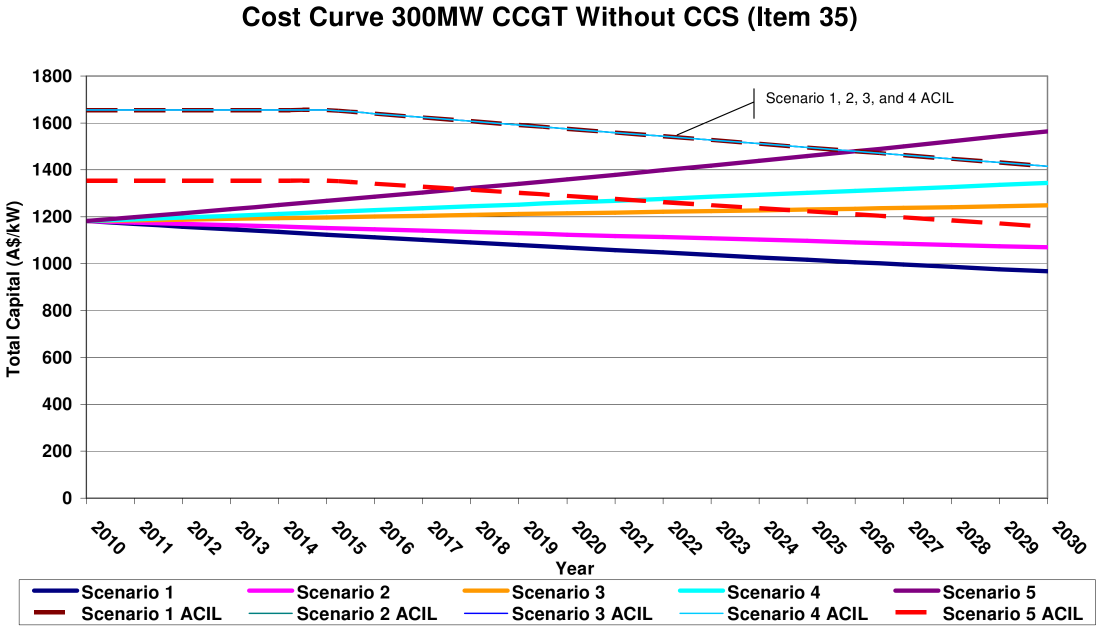
As shown by the above figure, scenarios 3, 4 and 5, has an upward trend in cost again due mainly to the variation in exchange rate. Since the technology for OCGT is mature, the improvement over this period is not expected to be as significant as other less mature technologies. Essentially any technological improvement is overshadowed by lower exchange rates for these scenarios.

For scenarios 1 & 2, exchange rate will have a lesser effect. The technological improvements and productivity improvements have an overall effect of reducing costs for these scenarios over the 20 year period and therefore these curves have a downward trend.

4.1.3.3 CCGT (Small Plant) Cost Curves

Item 35 300MW CCGT without CCS

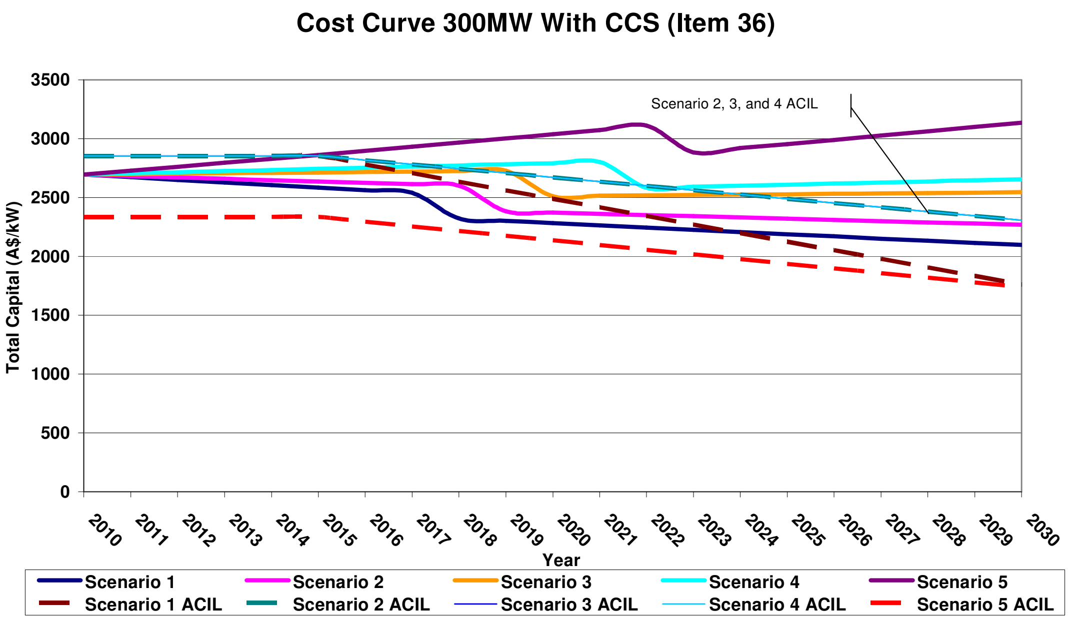
A starting cost estimate of A$1181/kW was estimated for a plant size of 300MW for this technology without a CCS facility. As shown by the following graph, the starting cost is significantly lower than scenario 1 (ACIL Tasman).



The trend for the above case closely follows the trends shown by item 10.

Item 36 300MW CCGT with CCS

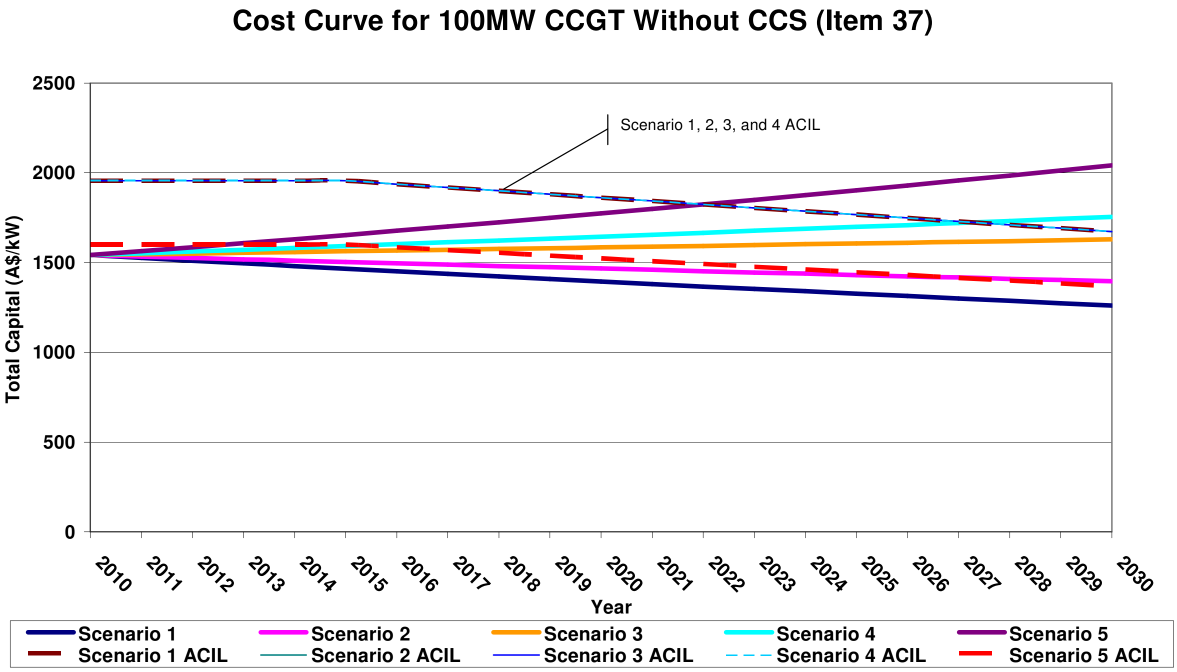
A starting cost estimate of A$2696/kW was estimated for a plant size of 300MW of this technology with a CCS facility. As shown by the following graph, the starting cost is close to that of scenario 1 (ACIL Tasman).



The trend for the above case closely follows the trends shown by item 11.

Item 37 100MW CCGT without CCS

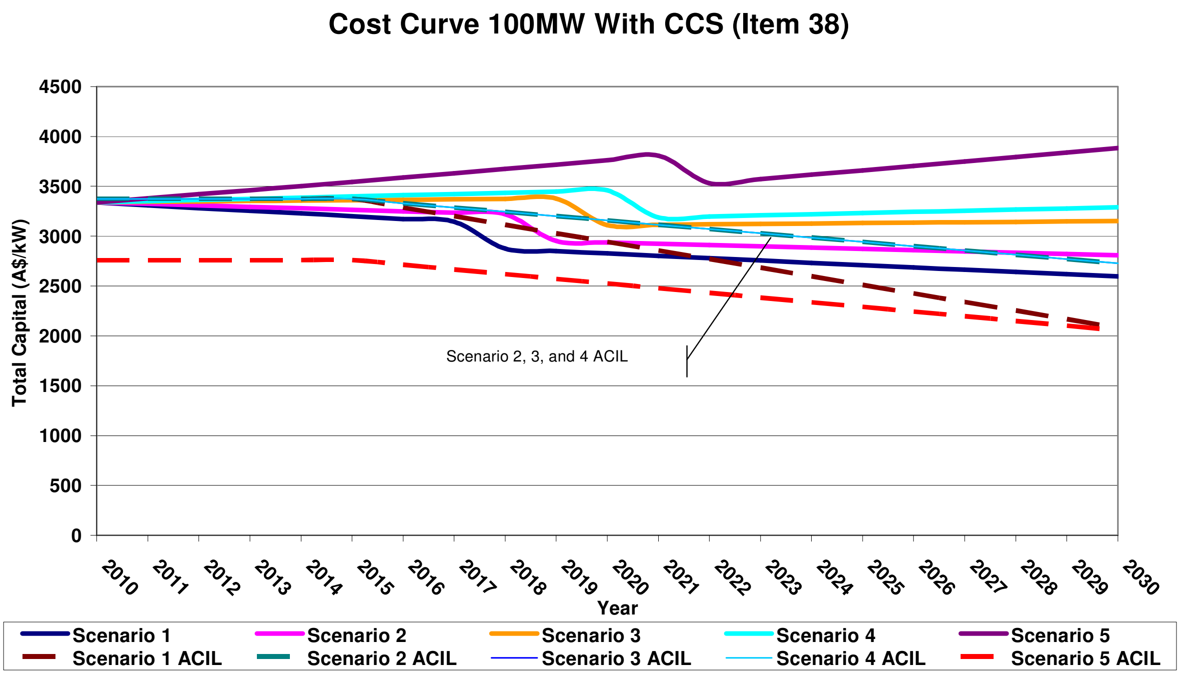
A starting cost estimate of A$1541/kW was estimated for a plant size of 100MW for this technology without a CCS facility. As shown by the following graph, the starting cost is significantly lower than scenario 1 (ACIL Tasman).



The trend for the above case closely follows the trends shown by item 10.

Item 38 100MW CCGT with CCS

A starting cost estimate of A$3338/kW was estimated for a plant size of 100MW of this technology with a CCS facility. As shown by the following graph, the starting cost is almost identical to scenario 1 (ACIL Tasman).



The trend for the above case closely follows the trends shown by item 11.

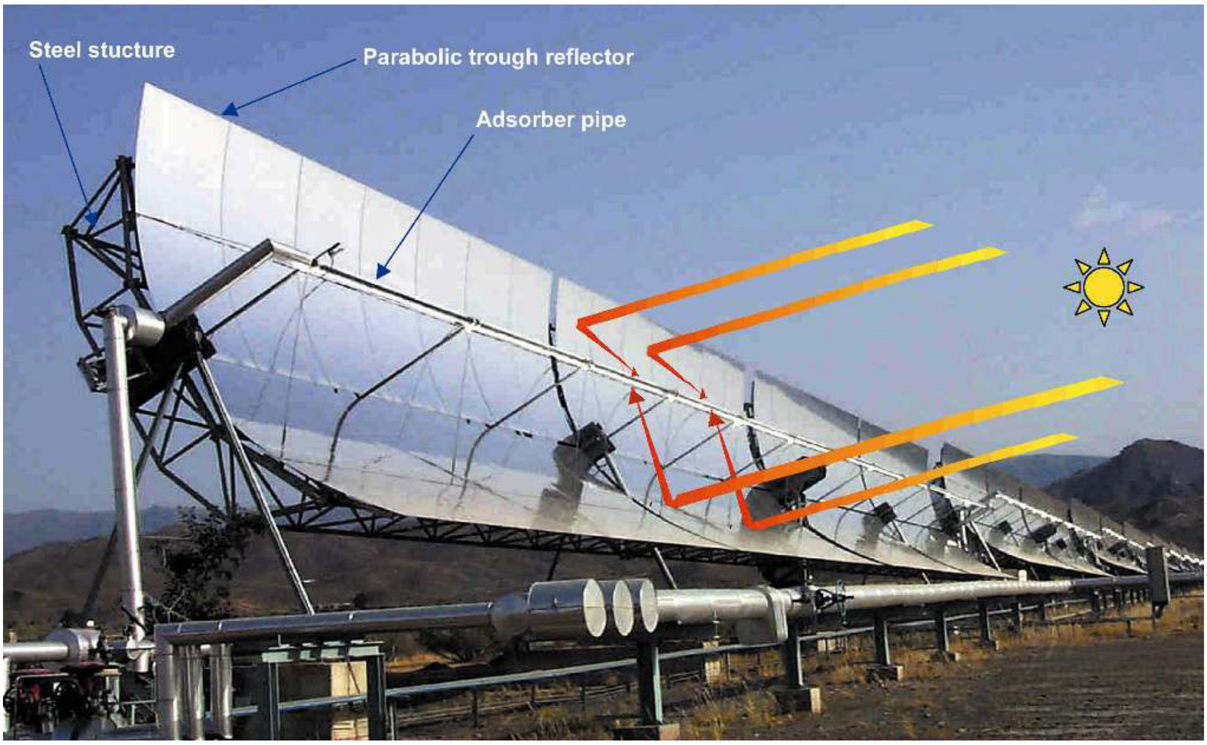
4.1.4 Solar Thermal/Photovoltaic Technologies

4.1.4.1 Description of Technology - Solar Thermal

Solar thermal technologies use sunlight to heat a medium and then use that medium to drive a power generation system. By using mirrors, the sun's energy can be concentrated up to approximately 1,000 times. The concentrated sunlight is then focused onto a receiver containing a gas or liquid that is heated to high temperatures and used to generate steam that is delivered to a steam turbine that generates power.

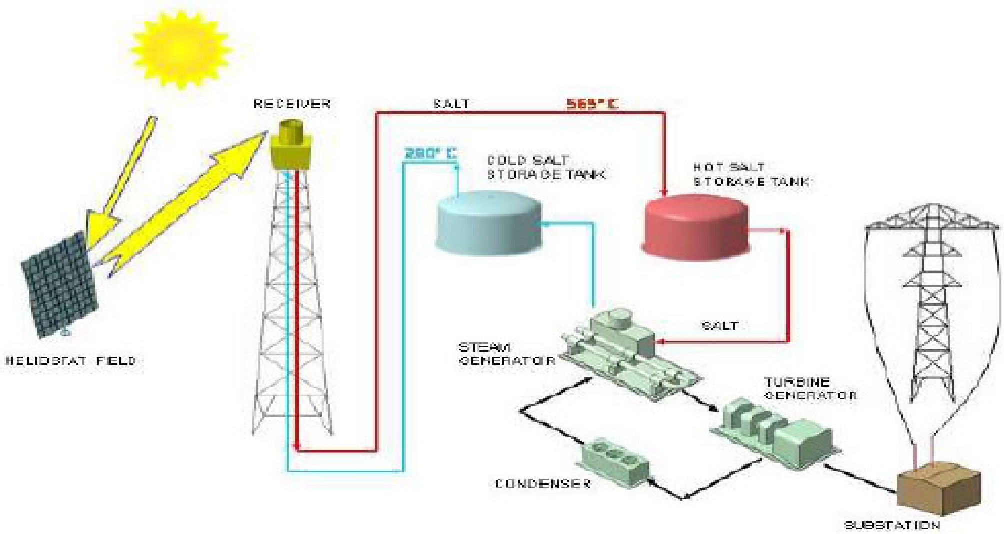
Two solar thermal technologies that will be investigated in this report are parabolic trough and a central receiver tower. Both of these systems are based on the concept of concentrating direct normal irradiation to produce steam used in electricity generating steam turbine cycles. In these technologies the solar power generating systems use glass mirrors that continuously track the position of the sun while absorbing its 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, thus directly producing 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.

The parabolic trough system is shown in the figure below.



The central receiver system is shown in the figure below.

A thermal energy storage system may be added to these systems such as the system shown below for a central receiver system.



Solar Thermal Future Improvements

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

Anticipated Improvements in Solar Thermal Capital Costs by 2030

	Parabolic Trough		**Central Receiver**	
	With 6hs Storage	Without Storage	With 6hs Storage	Without Storage
Capex (Relative to 2015 technology)	0.70	0.65	0.65	0.60

Each of the solar thermal technologies is at a different stage of development. Currently, the most mature technology is the parabolic trough, which is at the commercial phase. Central receiving towers have been demonstrated and are ready for scale up and commercialisation.

Utilising molten salt (as heat transfer fluid), as opposed to synthetic oil, has the potential of obtaining 565℃+ steam, without the cost/performance issues associated with using water as the heat transfer fluid. However, significant engineering and O&M issues arise due to the high freezing temperature of molten salts. R&D using molten salts in parabolic trough systems is ongoing.

It is expected that development and/or further refining of these systems for power generation will continue well into the 2025-2030 timeline.

4.1.4.2 Input for Cost Curves

Description of Technology - Solar photovoltaic

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

PV technology can be installed as fixed flat plates on roofs or a large field and can be mounted on tracking devices that have single axis and two axis tracking.

Technology Development

PV technology is still evolving and has not yet reached mature commercial status. Without subsidies, it is currently best suited economically to small installations (several watts to a few kilowatts) in special applications, including electrical switching and lighting at remote locations, billboard lighting and emergency telephones along freeways. Other important present markets for PV, driven by significant subsidies, include those derived from growing public interest in “green power,” such as residential and commercial rooftop retrofit installations of 1 to 500 kW each.

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

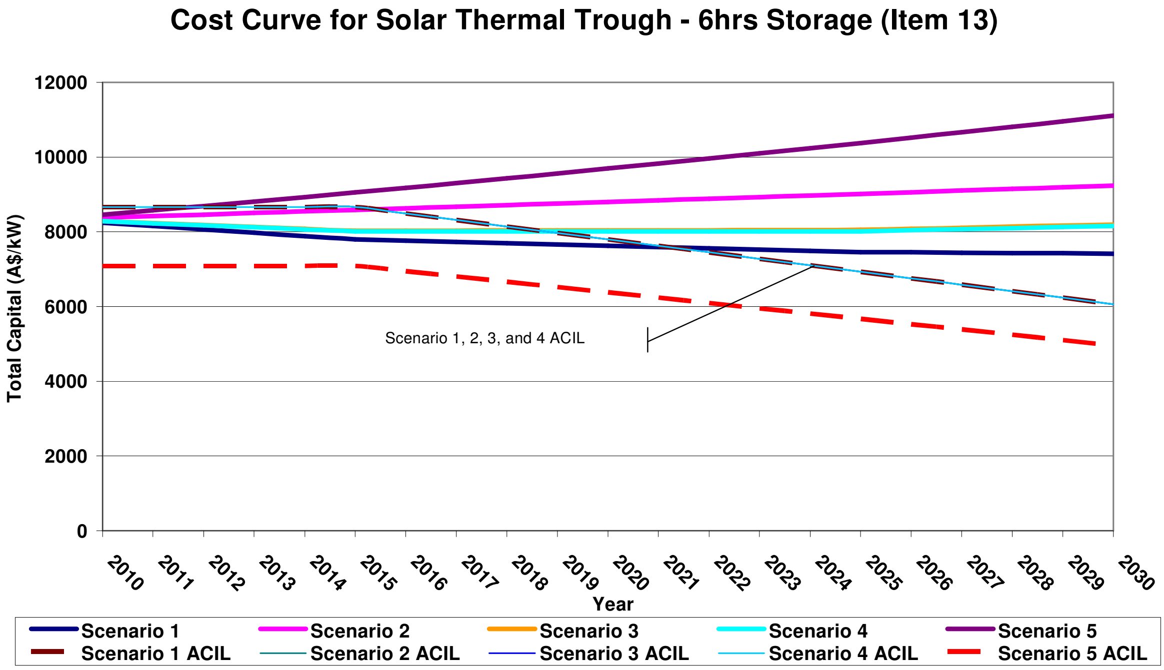
The following table summarises the impact of the anticipated improvements on photovoltaic capital costs and collection efficiency. It can be seen that the biggest improvements in collection efficiency are expected from the multi-junction cells that are currently receiving a significant R&D focus.

	Fixed Flat Plate	Single Axis Tracking	Two Axis Tracking
Capex (Relative to 2015 technology)	0.65	0.65	0.65
Collection Efficiency (relative to 2015) (% Change)	+2.9%	+2.9%	+10%

4.1.4.3 Solar Thermal Cost Curves

Item 13 Solar Thermal Parabolic Trough With 6hrs Storage

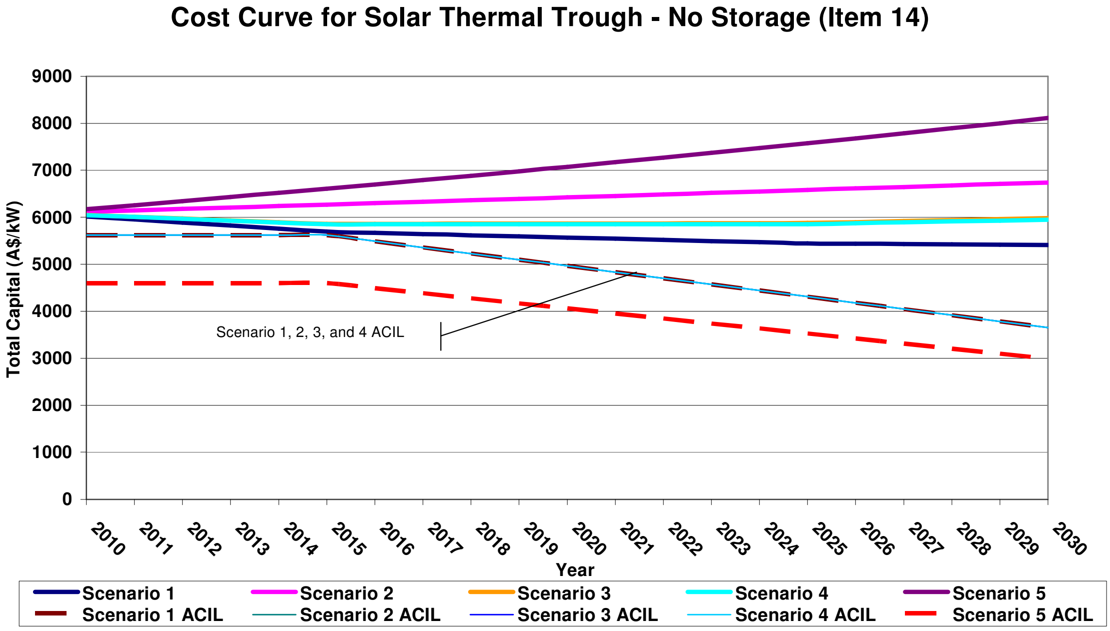
A starting cost estimate of A$8339/kW was estimated for a plant size of 150MW for this technology with 6hrs storage capacity. As shown by the following graph, the starting cost is almost identical to scenario 1 (ACIL Tasman).



As shown by the above figure the curve for scenario 3 & 4 remains relatively flat over the 20 year period as there is a greater reliance on renewable for these scenarios. The curve for scenarios 2 & 5 show an upward trend; driven mainly by less reliance for renewables (scenario 2) and a lower exchange rate (scenario 5). The curve for scenario 1 shows a downward trend influenced mainly by a strong exchange rate strong growth and a fast rate of change.

Item 14 Solar Thermal Parabolic Trough Without Storage

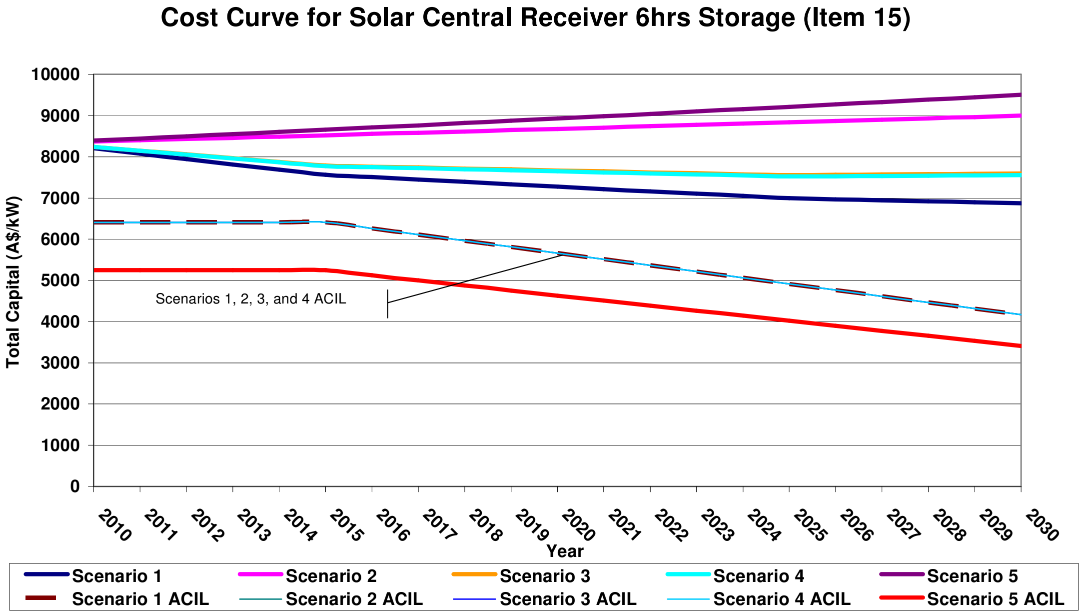
A starting cost estimate of A$6087/kW was estimated for a plant size of 150MW for this technology without storage capacity. As shown by the following graph, the starting cost is slightly higher than that of scenario 1 (ACIL Tasman) but is within 10% of the current cost band.



The trend for the above case follows that of item 13.

Item 15 Solar Thermal Central Receiver With 6hrs Storage

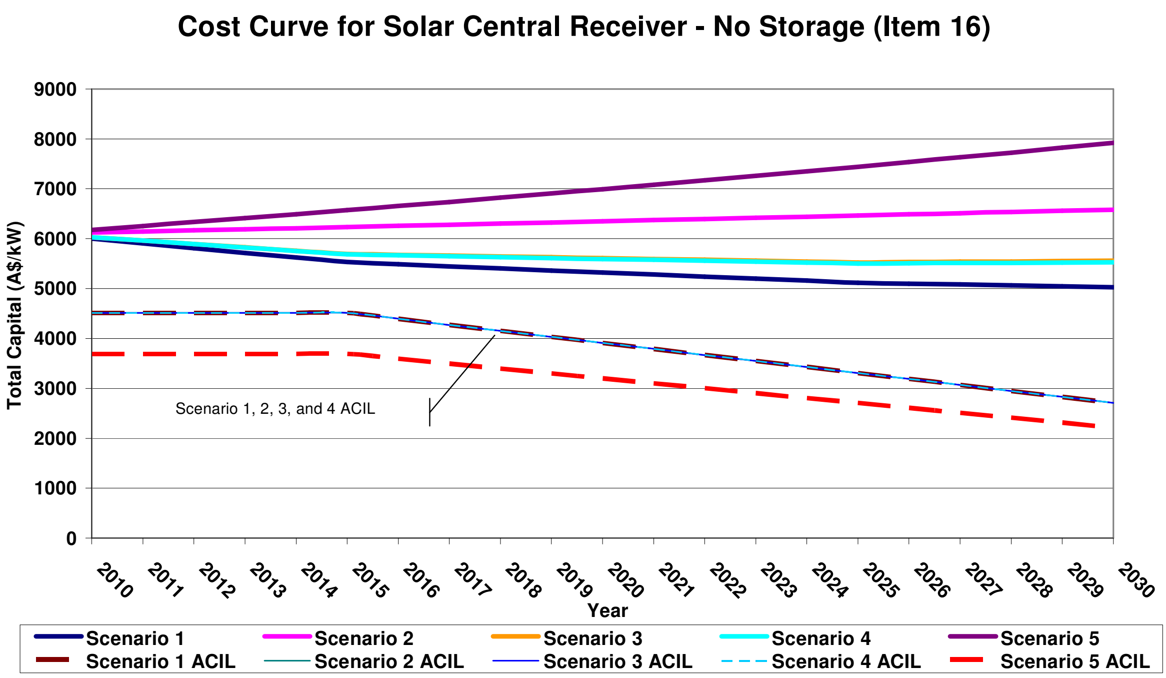
A starting cost estimate of A$8339/kW was estimated for a plant size of 30MW for this technology with 6hrs storage capacity. As shown by the following graph, the starting cost is significantly higher than that of scenario 1 (ACIL Tasman).



As shown by the above figure the curve for scenario 3 & 4 have a slight downward trend over the 20 year period since there is a greater reliance on renewable for these scenarios. The curve for scenarios 2 & 5 show an upward trend; driven mainly by less reliance for renewables (scenario 2) and a lower exchange rate (scenario 5). The curve for scenario 1 shows a stronger downward trend influenced mainly by a strong exchange rate, strong growth and a fast rate of change.

Item 16 Solar Thermal Central Receiver Without Storage

A starting cost estimate of A$6100/kW was estimated for a plant size of 150MW for this technology without storage capacity. As shown by the following graph, the starting cost is significantly higher than that of scenario 1 (ACIL Tasman).



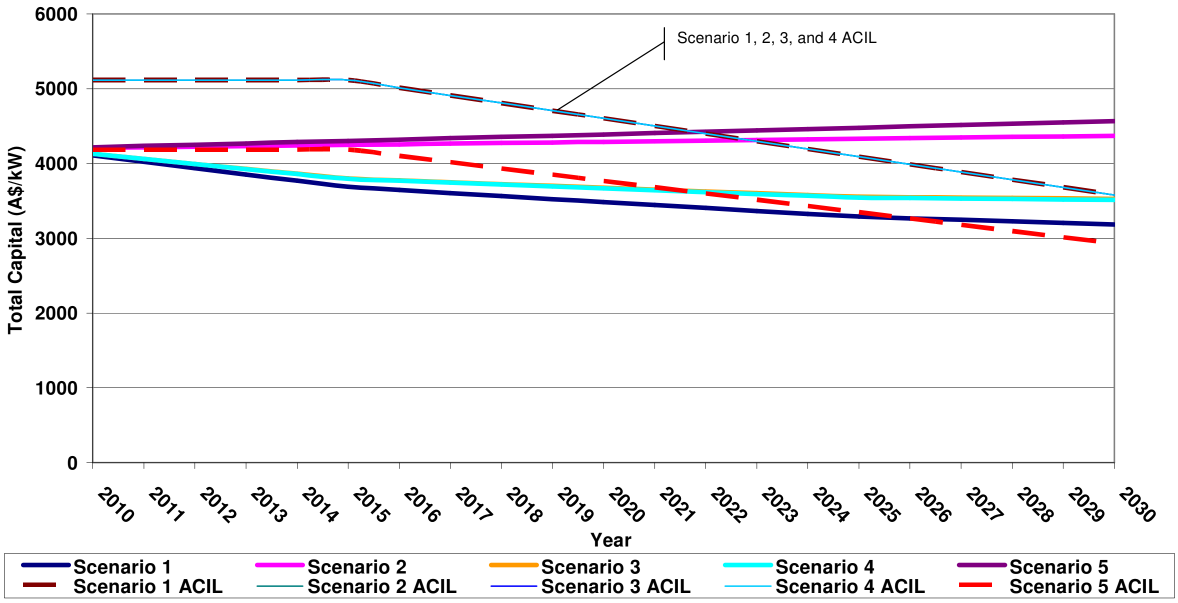
The trend for the above case follows that of item 15.

4.1.4.4 Photovoltaic Cost Curves

Item 17 Photovoltaic PV Fixed Flat Plate

A starting cost estimate of A$4200/kW was estimated for a plant size of 30MW for this technology. As shown by the following graph, the starting cost is significantly lower than that of scenario 1 (ACIL Tasman) and is likely to be attributed to the significant reduction in PV process in 2010.

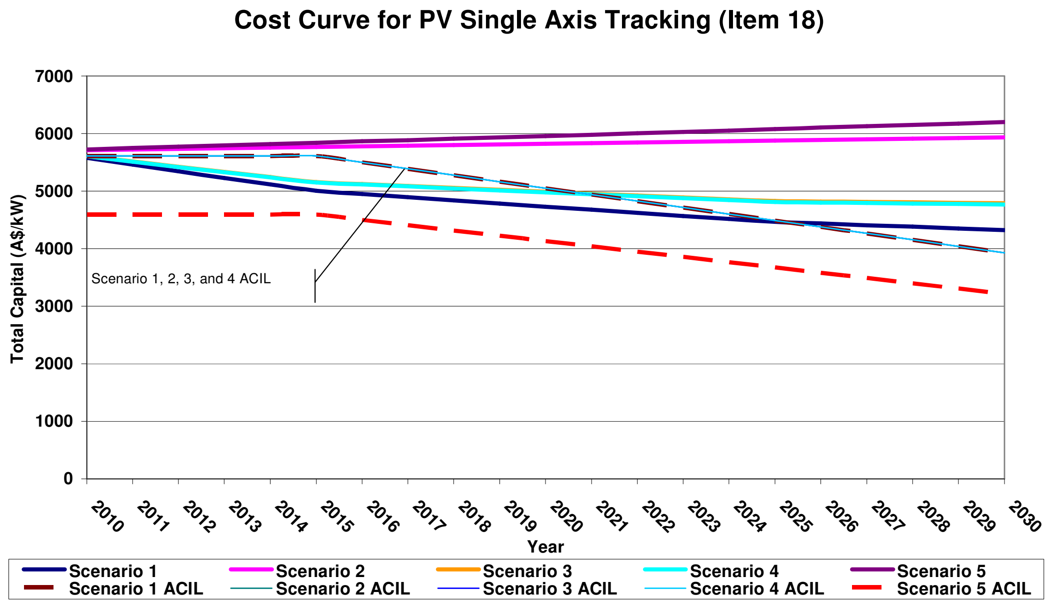
Cost Curve for PV Flat Plate (Item 17)



As shown by the above figure the curve for scenario 1, 3 & 4 have a downward trend over the 20 year period since there is a greater reliance on renewable for these scenarios and in the case of scenario 1 there is strong exchange rate, strong growth and a fast rate of change. The period 2011 to 2015 the cost for this technology is expected to improve as more and more PV installations are built therefore the gradient for the curves for scenario 1, 3 & 4 is steeper during the 2011-2015 period than the gradient post 2015. The curve for scenarios 2 & 5 show a slight upward trend; driven mainly by less reliance for renewables (scenario 2) and a lower exchange rate (scenario 5).

Item 18 Photovoltaic PV Single Axis Tracking

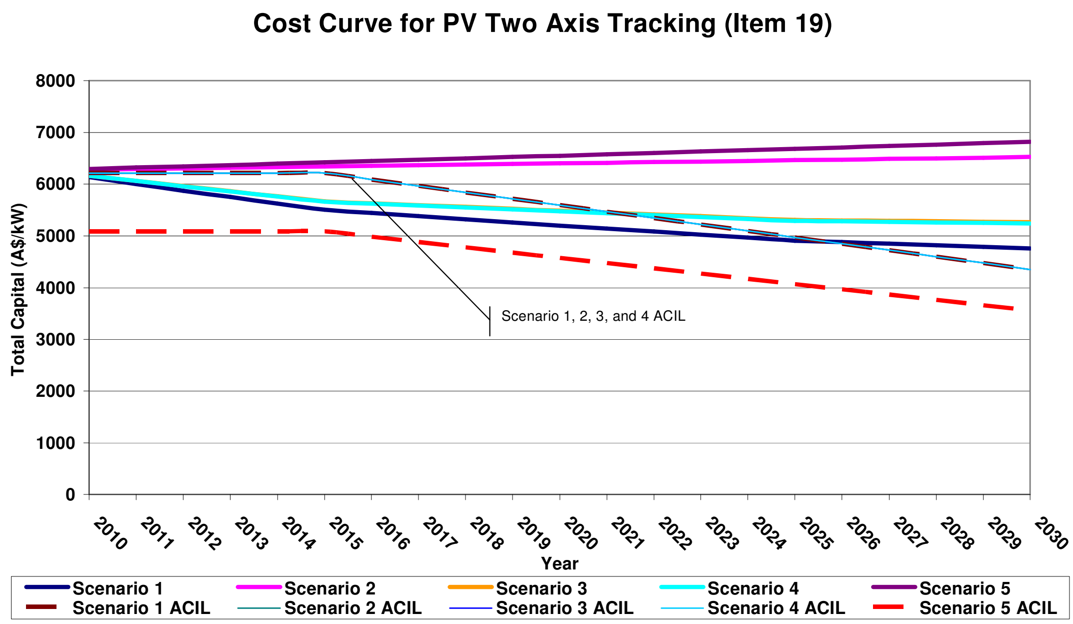
A starting cost estimate of A$5700/kW was estimated for a plant size of 30MW for this technology. As shown by the following graph, the starting cost is almost identical to that of scenario 1 (ACIL Tasman).



The trend for this case follows that of item 17.

Item 19 Photovoltaic PV Two Axis Tracking

A starting cost estimate of A$6270/kW was estimated for a plant size of 30MW for this technology. As shown by the following graph, the starting cost is significantly higher than that of scenario 1 (ACIL Tasman) and is almost identical to that of scenario 1 (ACIL Tasman).



The trend for this case follows that of item 18.

4.1.5 Wave Technologies

4.1.5.1 Description of Technology

Review of public domain information was undertaken to ascertain the status of wave technologies. With reference to a Waveplam presentation in February 2009[4], the following conclusion was drawn regarding wave power development:

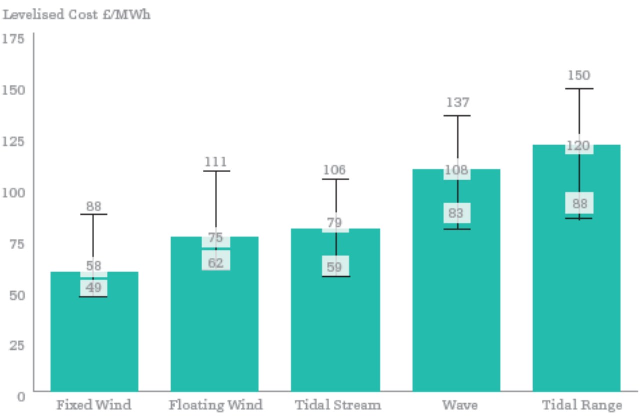
- Many devices are under various stages of development
- No floating device has demonstrated long term reliable operation
- Cost of devices is difficult to obtain
- Cost of electricity is difficult to obtain due to limited cost information and operational experience

Most of the leading technologies are pre prototype technologies undergoing process model testing

Public Domain Reference Information

The following extracts of documents provide background information as to the state of development for wave technologies.

Summary of 2050 cost estimates for marine technologies



The chart above shows 2050 costs for each technology in the central scenario, along with the likely cost range given the economics of different site types and the uncertainty inherent in such long term forecasting.[5]

[4] WP2 Task 2.1 State of the Art Analysis Waveplam Dr Tony Lewis Presentation to EU Sustainable Energy week – Brussels – 11 February 2009
[5] The Offshore Valuation – A valuation of the UK's offshore renewable energy resource – The Offshore Evaluation Group

Wave & Tidal Site segmentation

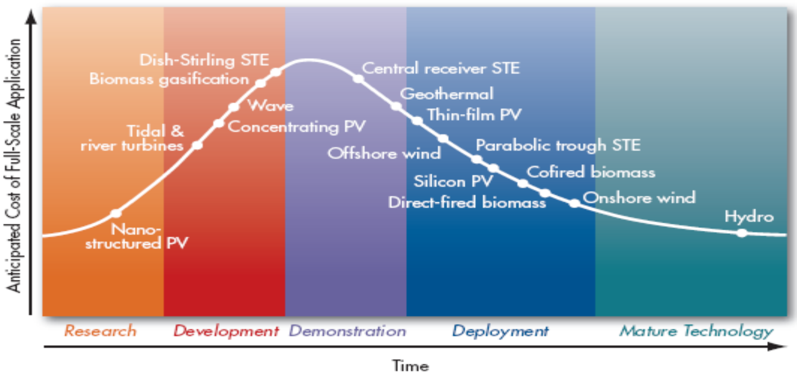
Site	Technology	Description	Available MW	Levelised Cost (£/MWh) 2020	Levelised Cost (£/MWh) 2025	Levelised Cost (£/MWh) 2035	Levelised Cost (£/MWh) 2045
1	Wave	Single site	4,566	195	161	132	119
1	Tidal Stream	High attractive	9,418	135	106	79	64
3	Tidal Stream	Medium Attractive	23,687	179	140	104	85
4	Tidal Stream	Least Attractive	23,687	241	188	141	114
1	Tidal Range	Site type 1	1,027		146	138	112
2	Tidal Range	Site type 2	609		204	192	156
3	Tidal Range	Site type 3	875		242	228	185
4	Tidal Range	Site type 4	989		254	240	194
5	Tidal Range	Site type 5	6,393		172	162	132
6	Tidal Range	Site type 6	3,805		254	240	194

[6]

Technology Description

The technology for wave and tidal current energy conversion is still in its relative infancy. The installed capacity of ocean energy devices supplying to national grids worldwide is less than 10 MW as of 2010[1]. There are many challenges which must be overcome for wave and tidal energy to be both feasible and economical enough to compete with or complement more mature renewable sources such as wind energy[2, 3]. There are a multitude of designs for wave energy devices, at various stages of development, employing many means of energy conversion. Each device has its own particular advantages and disadvantages, but there is as of yet no clear indication which technology type or group of technologies will emerge as viable from an engineering and economic point of view.[7]

Renewables Technology Development



While the actual numbers vary, the cost of bringing new power options to the marketplace follows a similar trajectory for most technologies—increasing during research and development and falling off substantially after successful full-scale demonstration and as a large number of units are deployed. Investment values on the curve are positioned relative to each technology's anticipated final RD&D cost and should not be used to compare investments among different technologies. [8]

[6] The Offshore Valuation – A valuation of the UK's offshore renewable energy resource – The Offshore Evaluation Group
[7] Dynamic Characteristics of Wave and Tidal Energy Converters, OES-IA Document No. T0321
[8] NREL Report on Ocean Technologies July 2009, DOE/GO-102009-2823

The limited experience of marine energy technologies generating electricity into the grid makes it particularly difficult to assess the economic feasibility of different device options for large-scale deployment.

Some previous studies have tried to estimate the cost of electricity by assuming relatively small deployments and partially neglecting implications of manufacturing, installation and operation. Other more advanced works have concentrated also on the development of different scenarios and application of learning curves to define a range of variability of the cost estimates.

Many cost models have been based on the Net Present Value approach but quite a lot of uncertainty can be found on how to take into account risk factors within the definition of proper discount rates. Other elements often neglected or poorly considered in the existing methodologies are the scalability of the costs with the deployment size and the device-specificity of some factors.

Determination of operational and maintenance costs is quite complicated because of the absence of reliable data on failures from real sea experience. Parametric models have been developed for this purpose but they do not seem to consider the problem of finding adequate site-access time windows because of environmental conditions.[9]

Comparison with the wind industry

The historical accumulative installed capacity of wind energy is shown below[10].

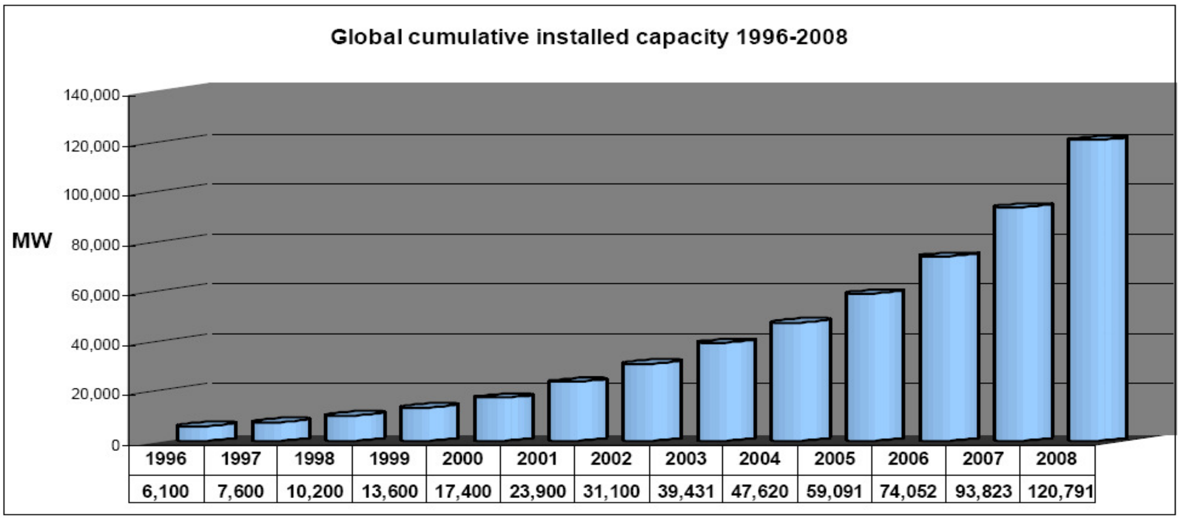


Table 1: Accumulative historical installed capacity of wind

The possible exponential growth of a technically and commercially viable renewable energy technology has been demonstrated by wind energy, which in 2008 installed 27GW of wind turbines.

[9] Global analysis of pre-normative research activities for marine energy, Equimar Deliverable D1.1
[10] : Global Wind Energy Council (GWEC) : Global Installed Wind Power Capacity – Press Release

Wave energy devices are not as technically advanced or proven as wind turbines were in 1996, as wind technology had by then converged on three bladed, upwind, horizontal axis wind turbines with composite blades. No such technological convergence is yet evident in the ocean energy industry.

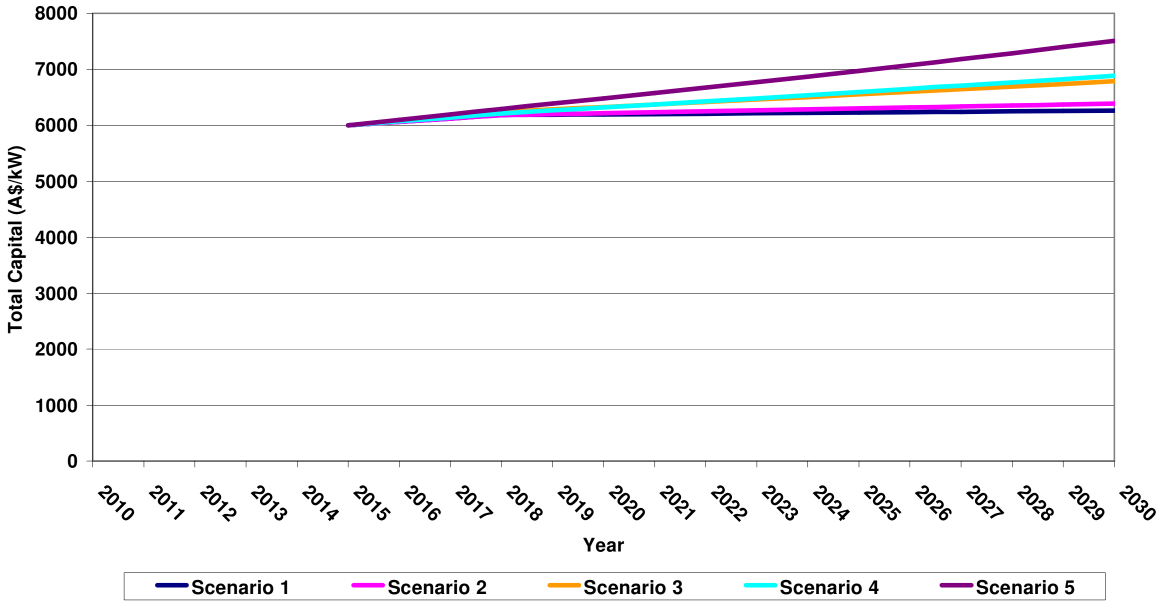
Cost Curve Considerations

Very few documents reviewed provided an indication of installed capital cost. Values of $6/W[11] in Australia and $3.5/W in the US[12] were cited but without justification. Deployment is expected to ramp up form 2012 although it suspected that this is unlikely given the current state of development.

For the purpose of this report we have predicted the following trends:

- Commercial development of wave power devices will not commence until 2015
- Rate of development will be slow as the projected Levelised Cost is high compared with other technologies
- Commercial demonstration will take up to 10 years prior to larger scale deployment.

Cost Curve for Wave Power (Item 39)



The cost curves for each scenario start from 2015/2016 period. This is due mainly to reflect that wave energy is still in the development phase and that approximately 5 years will elapse before it is likely that demonstration projects are developed. The case assumes a small scale wave power generator of 0.5MW to 2MW capacity. The curves for wave power all show an upward trend throughout the 20

[11] Australian Sustainable Energy – by the numbers, Peter Seligman, Melbourne Energy Institute, University of Melbourne, July 2010
[12] The Ocean – The next frontier in Renewable Energy, Enterprise Florida and GTM research.

year period. The gradients for scenarios 3, 4 and 5 are steeper than the gradients for scenario 1 & 2. The gradient for 1 & 2 shows a flattening effect during the latter part of the 20 year period due mainly to the better exchange rate for these scenarios and technological improvements that are expected as more and more wave energy installations are implemented. Scenario 5 shows a significantly stronger gradient than the rest of the scenarios due mainly to the slower rate of change and significantly less technological improvements over the 20 year period.

4.1.6 Wind Technology

WorleyParsons has examined the capital costs associated with wind energy projects in respect of five different future stationary energy sector scenarios, defined by MMA report.

The examination considered wind energy projects defined in project scale terms as;

Small scale (50MW)

Medium scale (200MW)

Large Scale (500MW)

This examination used a range of techniques to arrive at forward price curves for each project scale and sector scenario (15 options in total) through to 2030. Comparison was then made with AEMOs own figures across the same scale and scenario which had been provided to WorleyParsons.

The techniques used included benchmarking against recent project costs known to WorleyParsons and comparison with forward estimates from various industry sources, including the International Energy Agency and wind energy industry bodies such as the Global Wind Energy Council.

In addition to the wind energy specific factors considered, the new entrant costs were escalated according to the estimated category cost split and scenario-specific parameters of exchange rate trend, productivity trend and commodity price trend, as per all other power generation technology curves generated by WorleyParsons under this study.

General Comparison

Results are shown for each project scale in Figures 1-3 for Small, Medium and Large scale respectively. Here, WorleyParsons curves for each of the five scenarios are compared to that produced by ACIL Tasman.

Although the portion of the cost curves attributed to technology cost improvement (which impacts the equipment portion of capital costs) showed a similar trend to the ACIL Tasman curves, with costs declining slightly, this effect was swamped by effects of exchange rate, commodity price and productivity trends, to produce overall trends of increasing real costs which the curves show.

Capital Costs - WorleyParsons believes that the ACIL Tasman capital costs are generally high. Here WorleyParsons has estimated costs based on all project components through to the HV connection point, including all turbine and balance of plant, project management, insurances, land costs, approval costs, EPC premium and development costs based on the current exchange rate. It assumes an approximately 20km connection asset but does not include any deep network augmentation that might be required for network access.

Curve Shapes – The curve shapes for technology improvement factor alone compare favourably, showing a lowering of capital cost per kW with time, which reflects the general expectation of both the industry and industry observers – notably, the WorleyParsons 2030 estimates fall within those of ACIL Tasman. However, WorleyParsons believes an increase in costs is generally likely in Australia in the immediate future due to a higher delivery load and lack of resources to meet the Enhanced Renewable Energy Target, with this situation peaking around 2015. This cost increase is irrespective of Scenario, as all include ERET and generally wind energy is expected to provide a higher percentage of RECs than other technologies.

Scenario Spread – The spread of scenarios was generally greater than the ACIL Tasman figures, with more resolution evident between each. In particular, while the ACIL Tasman figures indicated convergence of real capital costs for wind power over the time period, WorleyParsons estimates indicates divergence of real costs, due to the cumulative divergence of assumed trends for exchange rate, commodity price and labour productivity.

WorleyParsons estimated that Scenario 1 would provide the lowest overall installed cost which was not in agreement with the ACIL Tasman data. The main factor driving this was the fact that scenarios 2 to 5 assumed decline in exchange rate value of the Australian dollar from the current high values. In the worst case, scenario 5, this fall was assumed to be of the order of 30% worsening, which impacts adversely on equipment costs due to the fact that the great majority of equipment used in wind power generation is sourced offshore.

Scenario Comparison

Each scenario was compared in respect of high level capital cost influencers, assumed to be;

Capital – the ability to obtain funds and the cost of those

Commodities – the influence of commodity prices on fabricated items

Social – the general acceptance of wind and affects of such on projects

Remoteness – additional costs required if projects were more remote

Opportunity – the premium that could be extracted for wind energy

Carbon price – the affect that a carbon price would have on wind projects

Grid – extra costs associated with grid constraints & penetration

These issues could not be examined in great detail by WorleyParsons given the time available for the work nor do they cover all the issues which affect capital cost. However, they are believed representative of the major issues and were used by associating each with either a positive or negative influence on capital through an “influence factor”.

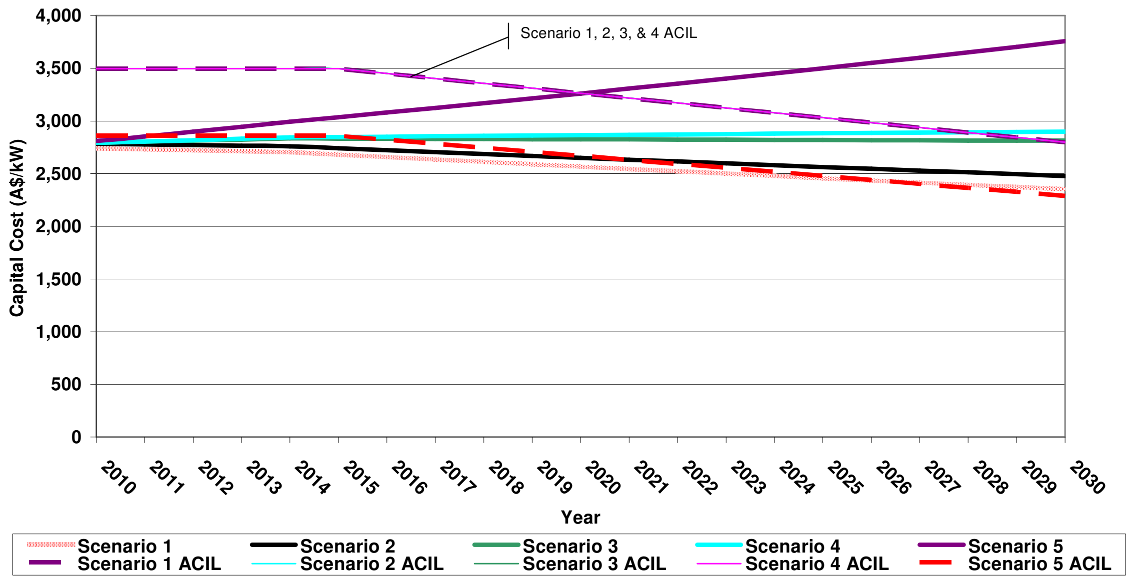
This influence factor was simply a percentage capital increase/decrease associated with each, which varied depending on the scenario. Factors changed considerably between scenarios and in many cases a rise in one was offset by a fall in another – for example scenarios with good renewable prospects but poorer economies saw increased opportunity influencers but decreased commodity prices, and vice versa.

4.1.6.1 Wind Cost Curves

Item 20 Small Scale Wind (50MW)

A starting cost estimate of A$2750/kW was estimated for a plant size of 50MW for this technology. As shown by the following graph, the starting cost is almost identical to scenario 5(ACIL Tasman) and is significantly lower than scenario 1.

Cost Curve for Wind Small Scale 50MW (Item 20)

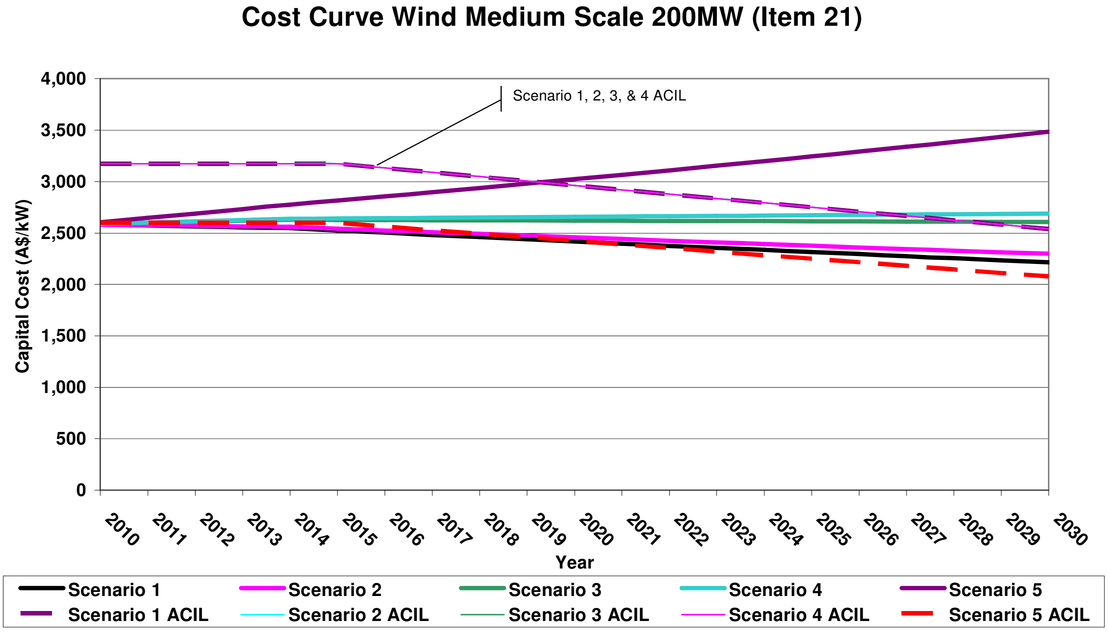


Cost curves for scenarios 1 & 2 have a downward trend predominantly due to a favorable exchange rate and further technological improvements as the technology matures. Curves for scenario 3 and 4 show a slight upward trend for costs due mainly to a less favorable exchange rate. Essentially any technological improvement is overshadowed by lower exchange rates for these two scenarios.

The cost curve for scenario 5 shows an upward trend due mainly to the slow rate of change and a lower exchange rate (A$1.00=US$0.60).

Item 21 Medium Scale Wind (200MW)

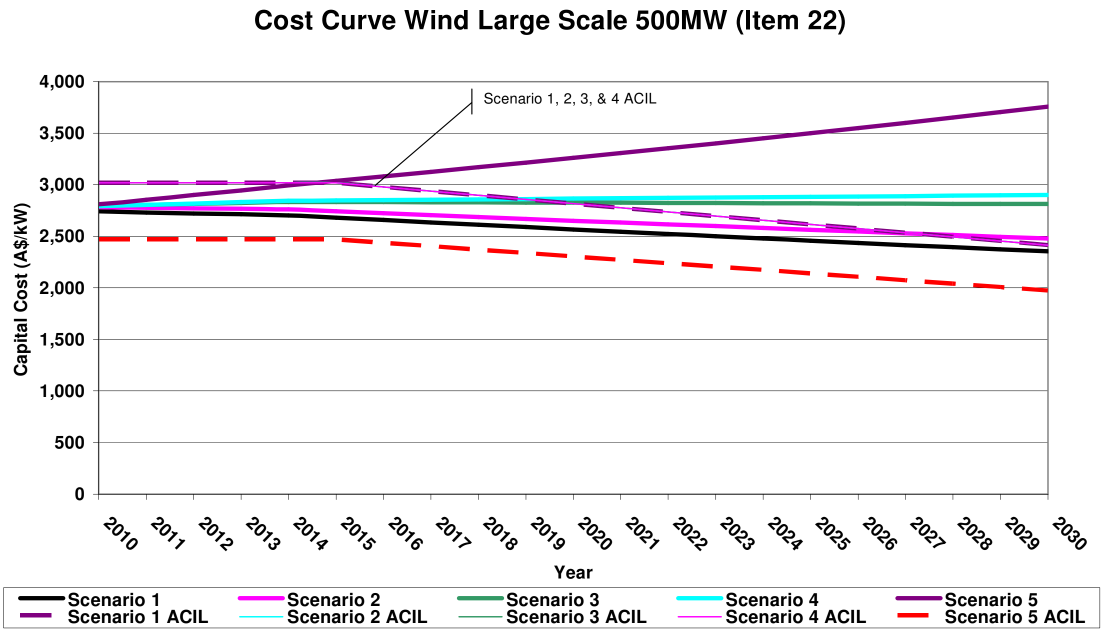
A starting cost estimate of A$2550/kW was estimated for a plant size of 200MW for this technology. As shown by the following graph, the starting cost is almost identical to scenario 5 (ACIL Tasman) and is significantly lower than scenario 1.



The trend for this case follows that of item 20.

Item 22 Large Scale Wind (500MW)

A starting cost estimate of A$2450/kW was estimated for a plant size of 500MW for this technology. Our starting cost sit between ACIL Tasman's scenario 1 & scenario 5.

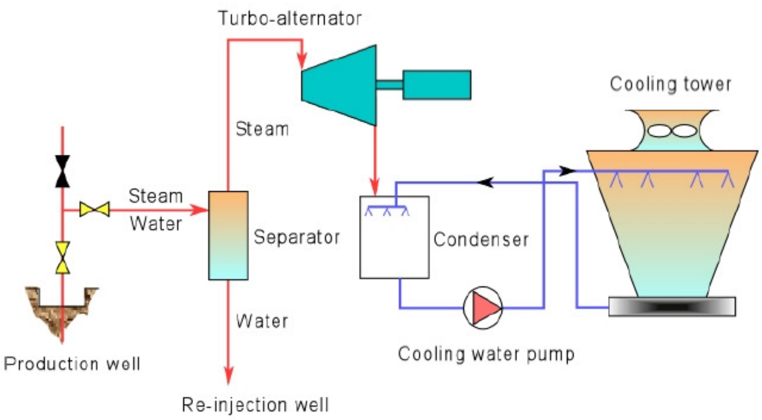


The trend for this case also follows the trend for item 20.

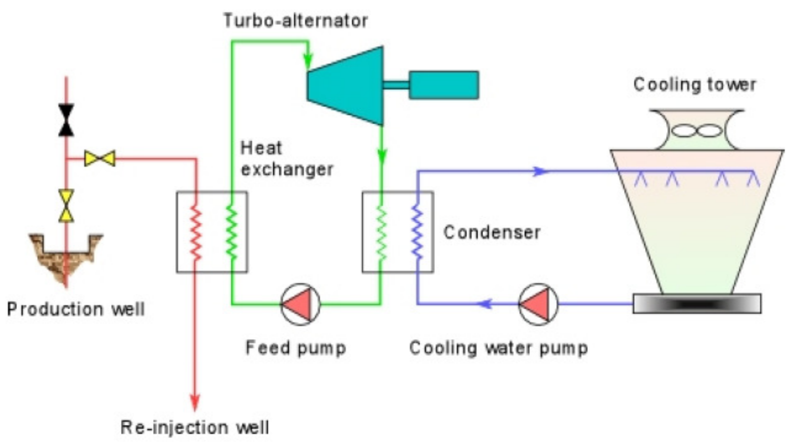
4.1.7 Geothermal

Technology Description

For the more common type of geothermal plant involves flash steam and hot water (hydrothermal technology). Hot water is removed from the production well and flashed in a separator, where the drop in pressure causes part of the water to flash to steam. The steam is then delivered to a condensing steam turbine generator while the separated water is re-injected into the hydrothermal reservoir. Once the steam passes through the steam turbine, it is condensed and returned to the reservoir to be reheated. A schematic of the process is shown by the following figure.



A system which is best suited for Australia is based on a binary configuration. This system involves geothermal water being removed from the production well and passed through a heat exchanger, where it transfers heat to a secondary liquid (the working fluid). The working fluid then boils to vapour and expands through a turbine generating power. The working fluid is then condensed to a liquid and begins the cycle again. The geothermal water is returned to the reservoir and re-injected into a return well where it is reheated. A simple diagram of the system is shown below.



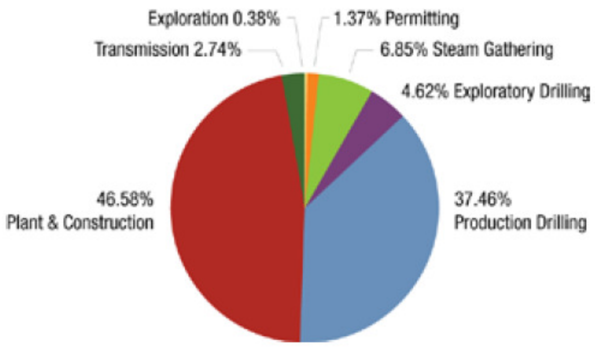
A type of enhanced geothermal system known as Hot rock (HR) systems are systems that utilise geothermal resources by creating reservoirs by fracturing geothermally-heated hot rock formations at depths of 2,000 to 10,000 meters to extract geothermal heat. Surface water is pumped into the hot fractures and most of that water is recovered through production wells, as in a natural geothermal system. The superheated water transfers its heat to a secondary fluid or working fluid and is then recirculated and pumped back down the injection well.

Hot sedimentary aquifers (HSA) are reservoirs in which rain water that has been absorbed into the ground is heated at temperatures that increase with depth or by contact with hot rocks. The water collects in porous rocks between two impermeable sedimentary layers, creating an aquifer from which hot fluid can be extracted by a drilling process. HSA typically requires a dual fluid cycle for power generation due to the temperature of the fluid. The key to HSA research and development is to find shallow systems that reduce the 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.

The development of geothermal energy requires the consideration and evaluation of a number of factors, such as site (geography), geology, reservoir size, geothermal temperature, and plant type. In 2009, New Energy Finance published a breakdown of estimated costs for each developmental stage as shown by Figure 4.1.6 below. The majority of the overall cost is typically attributed to construction of the power plant, due to the high cost of raw materials including steel. The second highest cost intensive processes are the exploratory and production drilling stages, which together comprise 42.1% of the total cost.

Figure 4.1.6 Estimated Developmental Costs for a typical 50MW Geothermal Power Plant

Developmental Stage	Cost ($ per kW installed)
Exploration	14
Permitting	50
Steam Gathering	250
Exploratory Drilling	169
Production Drilling	1,367
Plant & Construction	1,700
Transmission	100
Total	3,650



Source: Taylor, M. New Energy Finance, 2009

Geothermal power systems combine fuel supply and power conversion systems into one system. The geothermal fluid serves as the equivalent of fuel. Unlike fuel-fired power systems, in a geothermal plant, the fuel supply (the geothermal resource) and electricity generation (the power plant) are integrated and physically connected. As a result, the power plant cost is even more site-specific than for other power generation technologies. The cost is affected not only by the size and design of the power plant, but also the geothermal resource temperature and pressure, steam, impurity and salt content, and well depth. The table below shows cost estimate range based on the best and worst conditions.

	EGS (HR*)	EGS Other (HR*)	HSA	HSA Other
Total Plant Cost	5,480-10,750 (mid point $8,115)		5,100-8,300 (mid point $6,700)	

Expected Technological Improvement

Hydrothermal technologies are generally considered proven and commercial technologies. Power generation equipment is readily available for hydrothermal plants in various capacities and the drilling technology required for tapping the resource is now well established with lower risk than in the past.

However, risks do still exist with hydrothermal power plants and exploration and drilling costs can be expensive in some circumstances. Occasionally drilling results in dry holes and there is also risk associated with reservoir cooling. In the past two decades, no real improvements have been made in the exploration process[13]. Risk also lies in reservoir management to maintain the reservoir output. Reservoir life depends on the success of re-injection into the geothermal reservoir, and supplemental injection may be needed to extend the reservoir life.

Hot Rock (HR) is not yet a commercial technology, though it is believed to be proven as technically feasible, with technology readiness projected for 2015. Like hydrothermal plants, HR is a base load renewable technology that is low cost to operate and has low cost volatility due to a lack of fuel costs. The same plant and drilling technologies can be used as hydrothermal plants, but with a less site-specific restriction on plant location compared to a hydrothermal resource. The resource risk is also lower than that for a hydrothermal plant.

HR has a high up front cost, up to 70-80% of total costs, in developing the well field. Resource exploration and assessment methods need to be improved to reduce costs and stimulation technologies for generating the cracks within the rock also need improved development.

HSA is also not yet commercially proven. However, it is often considered the easier to develop of the near term geothermal projects. HSA uses a conventional dual fluid cycle, involves shallower drilling, and does not require resource stimulation, and therefore it is considered less risky than HR. Several potential sedimentary basins have been identified in Australia, which may further reduce exploration, drilling, and reservoir risks.

Australia does not have the wet, high-temperature geothermal environments found in volcanically active countries such as in New Zealand. Consequently, Australia's hydrothermal systems are neither hot enough nor under enough pressure to produce large amounts of steam. Therefore most

[13] Australian Electricity Generation Technology Costs – Reference Case 2010, February 2010, Prepared by EPRI/WorleyParsons

Australian geothermal resources will be exploited using dual fluid cycle power generation systems and HR resources as outlined in previous text.

Hot rock is still largely experimental as it has yet to be developed commercially. Well costs increase exponentially with depth and because HR resources are much deeper than hydrothermal resources, they are much more expensive to develop. Regardless of the fact that the technical feasibility of creating HR reservoirs has been demonstrated at experimental sites in other parts of the World operational uncertainties regarding the resistance of the reservoir to flow, thermal drawdown over time, and water loss have so far made commercial development very risky. Lower-cost resource assessment and lower cost drilling technologies are required to take HR systems to the level of commercial use.

It is understood that characterising the commercial potential of identified geothermal reservoirs very early in the project phase is a high priority. Techniques such as fracture mapping, more accurate thermal-gradient wells, and other, untested methods should be evaluated and refined, if appropriate. The main objective will be to measure the temperature, fluid characteristics, and permeability of the resource prior to committing to expensive production wells and generation equipment.

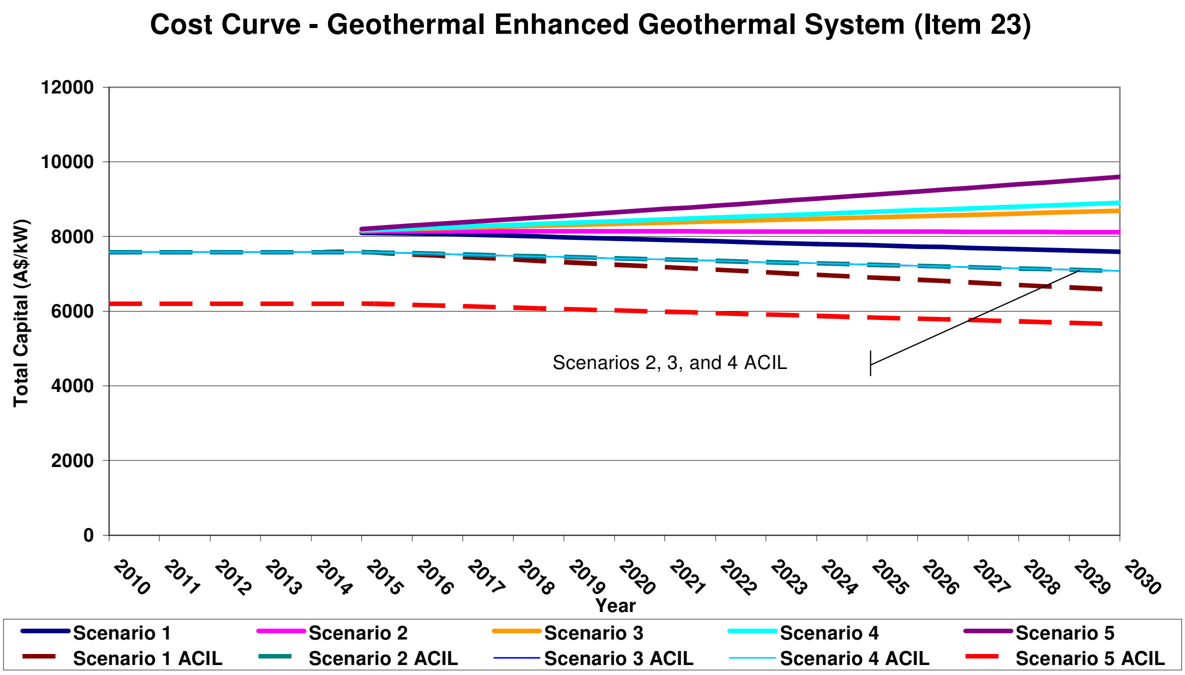
Since HR systems are still widely experimental, evaluation and testing must be conducted to confirm the economic viability of these systems. We therefore assumed that commercially available plants will be available by approximately 2015 and the start of our cost curves reflects this assumption.

Because Australia's geothermal resources do not appear to support the more commercial hydrothermal technologies, advancement of geothermal power outside of HSA in Australia will depend upon the development of rock fracturing technologies to allow for high production rates from the abundant HR resource.

Most of the necessary drilling and well testing equipment is adapted from the oil and gas industry which presents a major issue for geothermal projects competing with the higher rewarding oil & gas projects. Another major issue for geothermal projects in Australia is that the most active areas for geothermal opportunities are in very remote locations away from the main load centres. This implies that geothermal projects will most likely be developed for local power supply since long distance HV transmission lines would probably be prohibitive.

Item 23 Geothermal Enhanced Geothermal System (EGS)

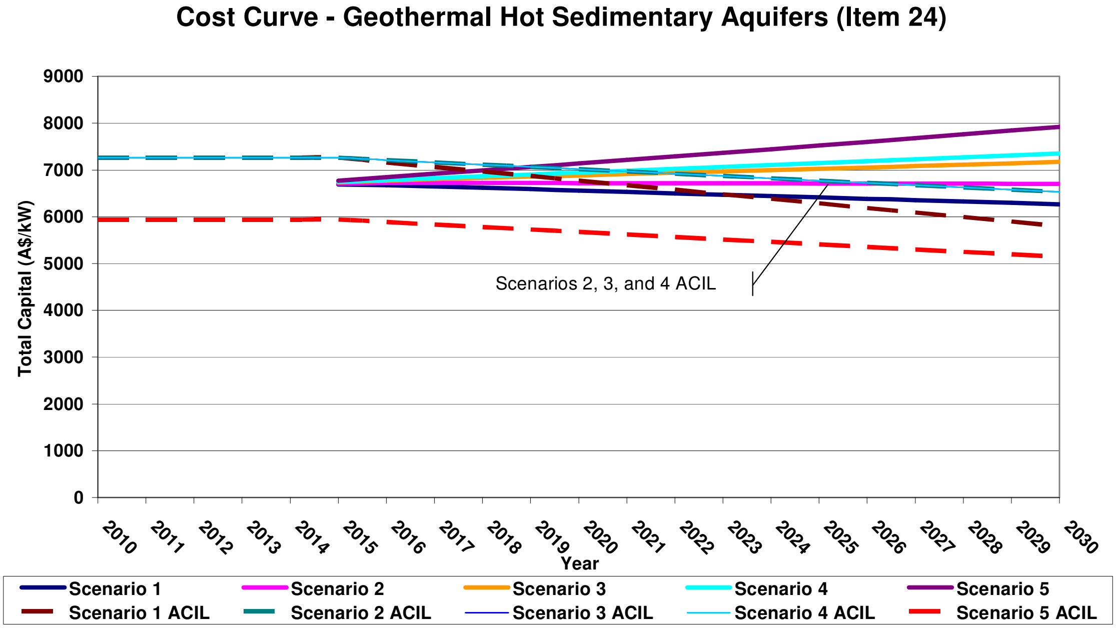
A starting cost estimate of A$8115/kW was estimated for a plant size of 50MW for this technology. As shown by the following graph, the starting cost is slightly above the cost for scenario 1(ACIL Tasman) but within 10% of the current cost band.



Most Geothermal technologies are considered to still be in the demonstration phase. Therefore we have assumed that commercially available/proven plants in Australia will not be available until about 2015. The range for the cost curves is expected to be large depending on a number of key factors such as exchange rate, technological improvements, site suitability, productivity, etc. As shown by the above curves, scenario 1 and 2 have a slight downward trend which is due mainly to a favourable exchange rate and strong technological improvements. Scenarios 3, 4 and 5 show an upward trend due to a less favourable exchange rate. Site related costs such as depth of well etc have not been considered by the cost curve since drilling costs are very site specific and could add a significant cost to the project.

Item 24 Hot Sedimentary Aquifers (HSA)

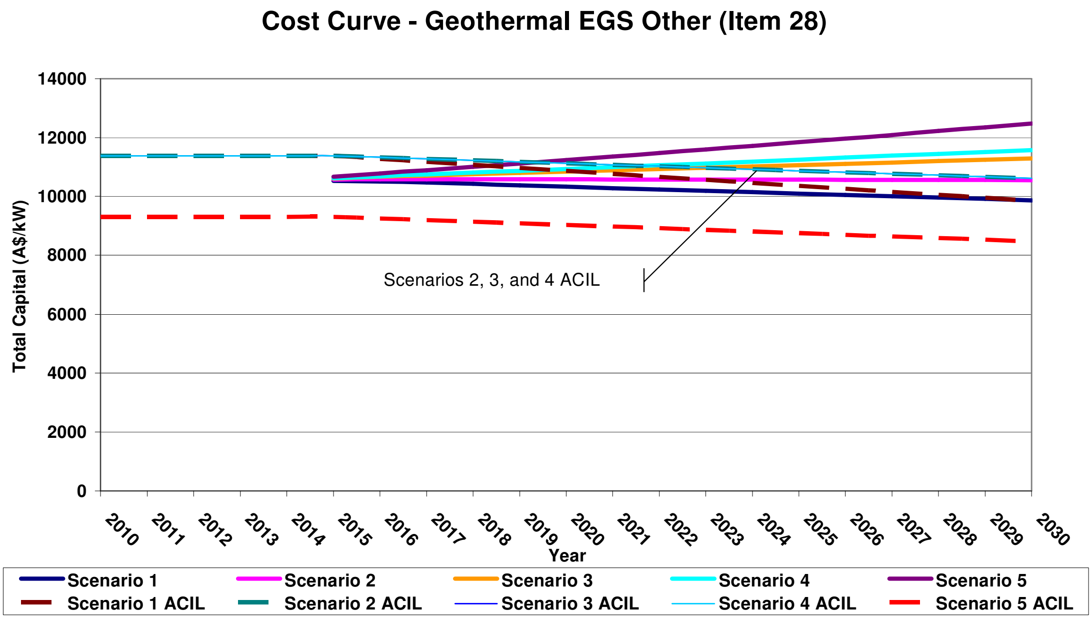
A starting cost estimate of A$6700/kW was estimated for a plant size of 50MW for this technology. As shown by the following graph, the starting cost is slightly below the cost for scenario 1(ACIL Tasman) but within 10% of the current cost band.



The trend for this case also follows the trend for item 23.

Item 28 Geothermal Enhanced Geothermal System (EGS) - Other

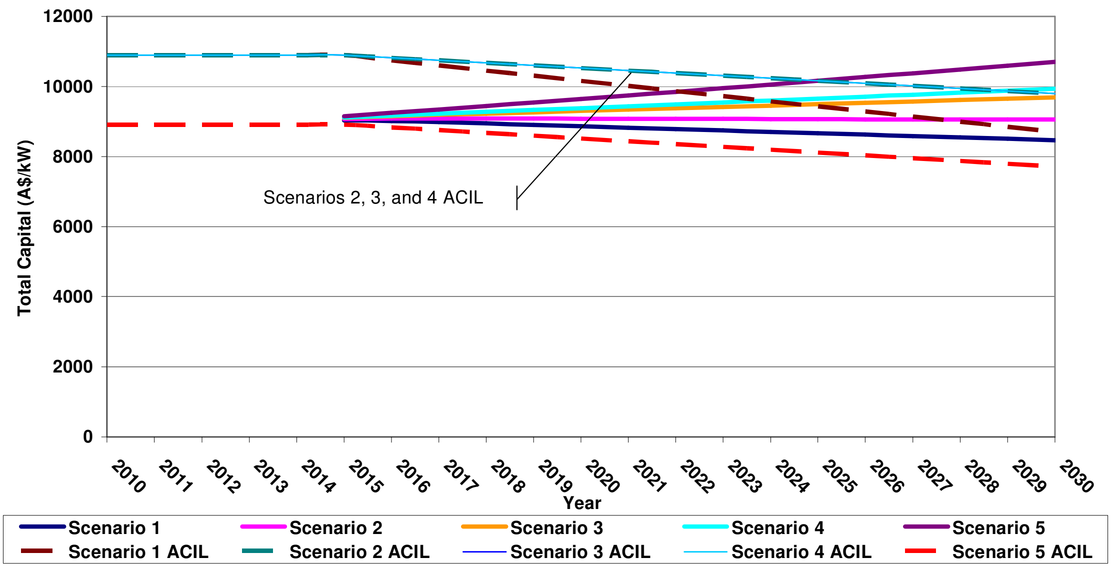
A starting cost estimate of A$10550/kW was estimated for a plant size of 50MW for this technology. As shown by the following graph, the starting cost is slightly below the cost for scenario 1(ACIL Tasman) but within 10% of the current cost band.



The trend for this case also follows the trend for item 23.

Item 29 Hot Sedimentary Aquifers (HSA) - Other

A starting cost estimate of A$9050/kW was estimated for a plant size of 50MW for this technology. As shown by the following graph, the starting cost is significantly below the cost for scenario 1(ACIL Tasman).



The trend for this case also follows the trend for item 23.

4.1.8 Biomass

Technology Description

Biomass generating technology uses fuels that are produced by living plant and animal matter. The use of these renewable fuels enable generators to produce power on a continuous basis since the fuels are produced and stored for consumption when needed.

Fuels that are currently used as biomass fuels are, bagasse/agribusiness residues, landfill gas (LFG), and various waste product that can be processed and fired in either a standard boiler or a circulating fluidised bed boiler (CFB). Generally fuel pricing for biomass fuels is highly sensitive to locale and the competitive pressures of local and regional economies.

Currently the technologies that are commercially available, or commercially offered, include various forms of co-firing along with stand-alone (100% biomass-fired) Rankine cycle generating systems using modified boiler plant or modified CFB plant. This report assumes that the stand-alone biomass plants supply superheated steam to condensing turbines where power is generated.

For the case of bagasse fuel, a 50MW facility is assumed to fire 100% bagasse which produces high pressure steam for a steam turbine/generator.

For the case of LFG, engines are usually used for smaller facilities but in the case considered a 50MW facility is assumed to fire 100% LFG in a gas fired boiler which produces high pressure steam for a steam turbine/generator.

For the case of waste to energy, again a 50MW facility is assumed to fire 100% wood waste which produces high pressure steam for a steam turbine/generator.

Expected Technological Improvement

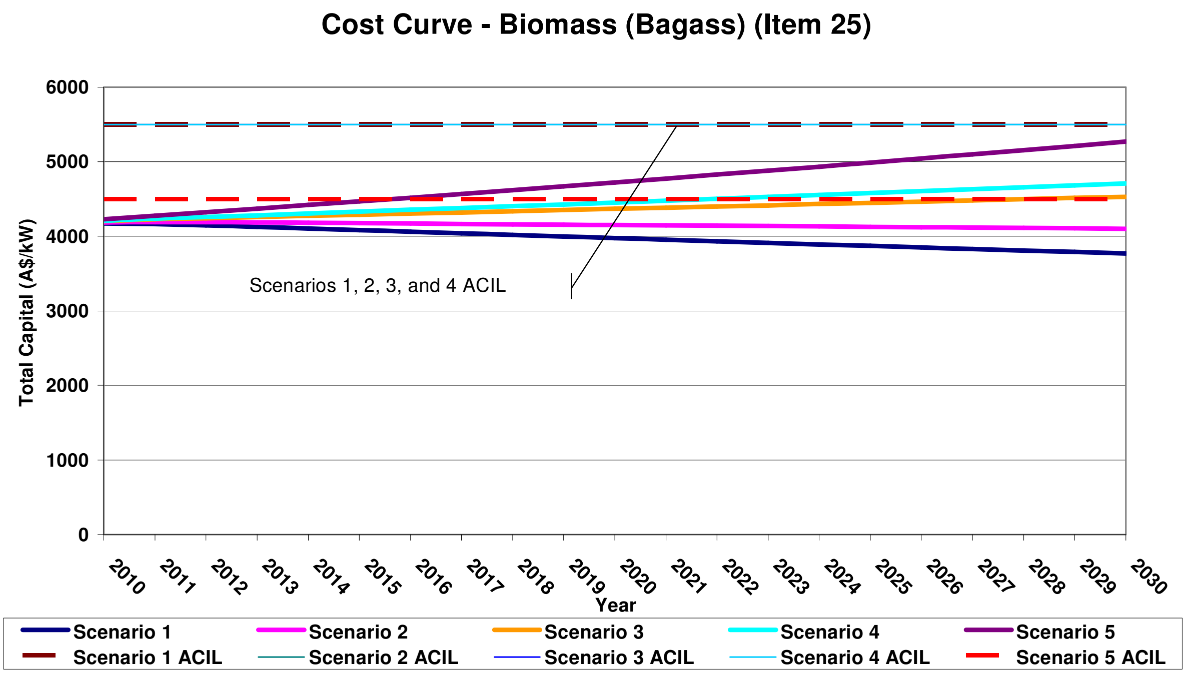
Biomass is not a new form of power generation and has been commercially available for many decades. The focus now is on the carbon neutral fuel source for most biomass applications.

Generally improvements in Biomass technology will come from improvements made to the Rankine cycle steam parameters for plant in the small capacity category that is likely to be used to fire biomass fuels.

4.1.8.1 Biomass Technologies

Item 25 Biomass Bagasse

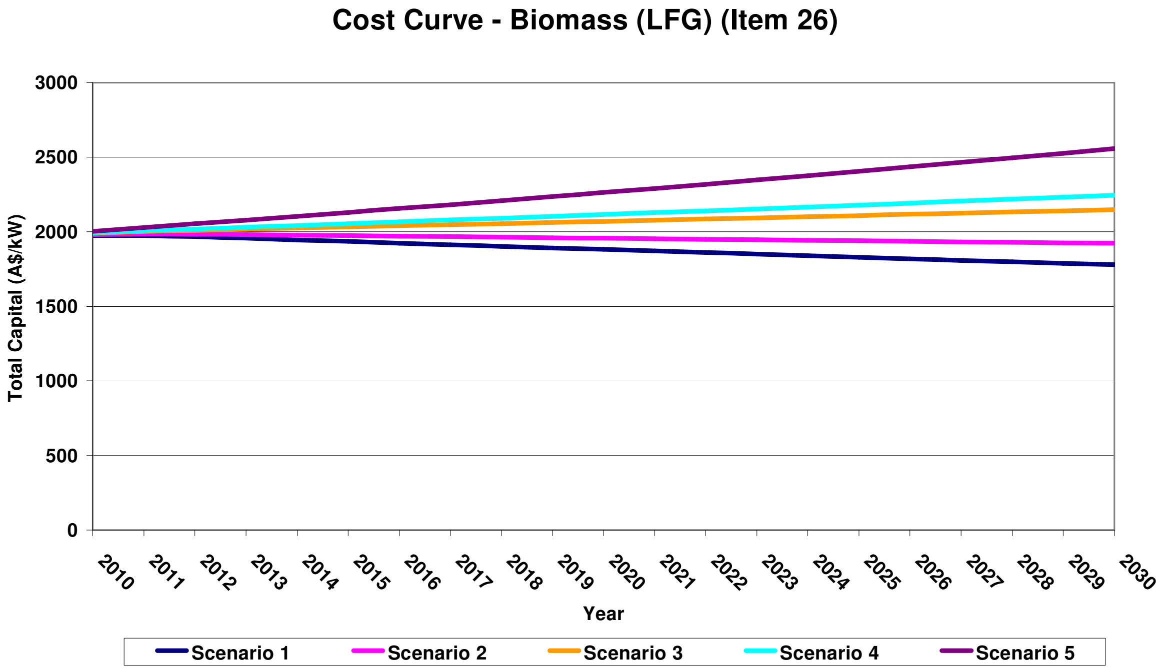
A starting cost estimate of A$4179/kW was estimated for a plant size of 50MW for this technology. As shown by the following graph, the starting cost is significantly lower than that of scenario 1 (ACIL Tasman).



Biomass firing on bagass has been demonstrated in northern Queensland and many other parts of the World. Therefore the cost curves for scenarios 1 & 2 shows a downward trend as more plants are built; the trend being driven by technological improvements. However scenario 3, 4 and 5 shows an upward trend due mainly to the lower exchange rate and lower productivity figures.

Item 26 Biomass LFG

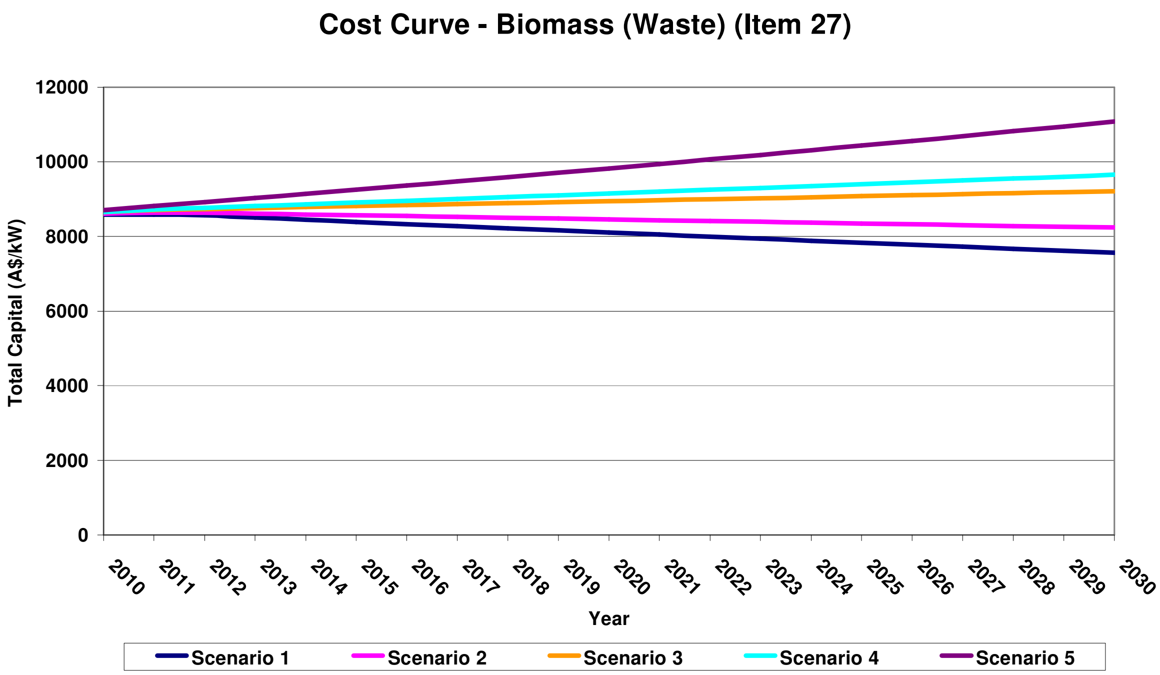
A starting cost estimate of A$1977/kW was estimated for a plant size of 50MW for this technology. There were no curves provided by ACIL Tasman and therefore we cannot comment any further.



LFG fired power generation is also a demonstrated technology but is highly dependant on site conditions. The capital cost for this case is based on a prepared site for ease of recovery of land fill gas. Curves for scenarios 1 & 2 shows a downward trend due mainly to the favourable exchange rate and technological improvements. Curves for scenario 3, 4, and 5 show an upward trend due to slower rate for technological improvements and a less favourable exchange rate.

Item 27 Biomass Small Waste to Energy

A starting cost estimate of A$8588/kW was estimated for a plant size of 50MW for this technology. There were no curves provided by ACIL Tasman and therefore we cannot comment any further.



Waste to energy power generation can be considered in the last stages of the demonstration phase with many small plants being build for demonstration purposes in Europe and Japan. This technology is highly dependant on the composition of the waste used as fuel. Curves for scenarios 1 & 2 shows a downward trend due mainly to the favourable exchange rate and technological improvements. Curves for scenario 3, 4, and 5 shows an upward trend due to slower rate for technological improvements and a less favourable exchange rate.

4.2 Efficiency Curves

Efficiency curves for each technology case were reviewed and amended where necessary. The revised efficiency curves are shown on the revised NTNDP Modelling Assumptions Input Spreadsheets contained in Appendix 2. The WP efficiencies are based on net sent out power.

4.3 O&M Costs

O&M costs for each technology were reviewed and amended where necessary. The revised O&M costs are shown on the revised NTNDP Modelling Assumptions Input Spreadsheets.

Appendix 1 Cost Curves (Tables of Values)

The cost curve table of values for each of the five scenarios are contained in the amended spreadsheets attached to this report.

Appendix 2 Efficiency Curves (Table of Values)

The efficiency curve table of values for each of the five scenarios are contained in the amended spreadsheets attached to this report.

Appendix 3 Battery Limits

Item	IGCC	Supercritical Pulverised Coal	Oxy combustion	IGCC & SC with CCS
Fuel	Inlet end of the coal stockpile and reclaim system at the coal yard	Inlet end of the coal stockpile and reclaim system at the coal yard	Inlet end of the coal stockpile and reclaim system at the coal yard	
Cooling Water	Power plant boundary.	Power plant boundary.	Power plant boundary.	Power plant boundary.
Site Drains	Power plant boundary	Power plant boundary.	Power plant boundary.	Power plant boundary.
Outgoing Power	Switch-yard outgoing dead-end tower	Switch-yard outgoing dead-end tower	Switch-yard outgoing dead-end tower	
Roads	Plant service roads should terminate at the site access gate.	Plant service roads should terminate at the site access gate.	Plant service roads should terminate at the site access gate.	
CO_2			Outlet flange of the compressor plant	Outlet flange of the compressor plant