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LOAD AND AMBIENT TEMPERATURE EFFECTS ON ELECTRIC POWER SYSTEMS

TECHNICAL NOTE 33

Companion to CCSD Technology Assessment Report 63

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EXECUTIVE SUMMARY

In CCSD Technology Assessment Report 63, Ikeda et al. (2007a), Ikeda et al. (2007b), results were reported for simulations using GateCycle[®] Software from GE Enter for a range of power generation systems, both with and without carbon dioxide capture. The simulations were carried out on the basis of technologies available now or expected in the near future to be available for installation in Australia. Reference conditions relevant to Australia were applied and data obtained on key performance indicators such as sent-out thermal efficiency, carbon dioxide emission and cooling water consumption. The simulations were validated where possible by comparisons against design data from recent commercial plant, published flow sheets or vendor information as available.

The present work concludes this study with consideration of a number of factors that may affect the generality of the results presented in Technology Assessment Report 63. These include effects of power plant duty cycles, the range and impacts of ambient conditions existing within Australia and of the likely uncertainty in the determination of efficiency for the technologies. A comparison of results obtained here with those obtained by others is also presented.

It is seen that the Pulverised Coal (PC) supercritical steam technology suffers only minor degradation in performance as load reduces. However, performance of technologies that include for carbon capture does deteriorate substantially as load reduces. The deterioration appears to be larger for post combustion capture using amine based scrubbing than for oxy-fuel technology. The overall impact of the deterioration is small when high capacity factors are assumed but would be important at light duty cycles.

Ambient temperature conditions at five representative sites within eastern Australia were reviewed in detail. It was found that mean dry bulb temperatures at four of the sites, including three inland sites covering the main inland coal producing regions in eastern Australia, were within the range of 17.7 to 19.3 °C. Mean wet bulb temperatures were within the range 13.5 to 15.1 °C.

Differences in performance between these site conditions and that assumed during this work (dry bulb of 25 °C and 60 % relative humidity) are found to be small. However, detailed analysis of cycle performance as a function of ambient conditions highlighted the importance of correctly specifying cycle parameters such as condenser backpressure and steam turbine exhaust flow area. While condenser back-pressure is routinely defined for these types of analyses, turbine internal design features such as exhaust flow area are often implicit in the analysis. Proper optimisation of these factors can substantially increase predicted performance.

Performance predicted here for various technologies appears to be generally similar to that obtained by others using overseas conditions and coals. Where differences occur they can be traced to assumptions in regard to condenser backpressure, pollution control equipment such as flue gas desulphurisation, coal analyses and plant flowsheets. The spread in efficiencies that could be produced by selection of different coal from within the suite of

Australian coals is of the same order as the difference between efficiency under Australian conditions and efficiency under ambient conditions occurring in northern Europe.

Technology assessments reported in the literature rarely present discussion of the uncertainty of the results. An approach based on international plant testing standards is proposed here to estimate uncertainty in the calculated result. Application of the method to an ultra-supercritical steam cycle technology suggests a standard uncertainty (defined as \pm one standard deviation) of the efficiency estimate at ± 0.24 %. This means that, when for example firing the high ash CRC296 in this technology, a true sent-out efficiency within the range 40.88 % to 41.84 % is predicted to 95 % confidence levels.

This estimate assumes that the steam cycle parameters are well defined and accurately determined. It therefore does not, for example, allow for uncertainty in measurement of steam temperature or pressure. In practice this would imply a zero deviation between true steam conditions and the set point values. The estimate also implicitly assumes that the details of the steam cycle are fully specified. This is often not the case as numerous factors such as steam pipe pressure drops, control valve settings, operating strategies or steam turbine design details are not detailed in study reports and different assumptions with regard to these variables will substantially change results.

This project has focussed on standard air-fired PC power plants with a less detailed analysis of oxy-fuel and IGCC technologies. More detailed work on the latter technologies was constrained by the relative immaturity of the technologies which leads to numerous alternative technology flow sheet possibilities and uncertainty about the performance that can actually be achieved with certain key components such as heavy duty gas turbines when fired by hydrogen in IGCC with carbon capture. Further work with these technologies should be pursued as the technologies mature.

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1 INTRODUCTION

Combustion of black coal in power stations presently produces the majority of the electricity generated in Australia. It is also responsible for around 20 % of Australia's total greenhouse gas emissions, AGO (2005). Improvements in black coal power generation technologies are therefore of importance in both maintaining Australia's present competitive advantage in low cost energy and in meeting increasingly stringent greenhouse gas and other environmental emission targets.

Numerous improvements to coal fired power generation technologies are being pursued around the world and results of these developments are widely published. However, the performance of these technologies is usually defined for coals and under conditions that are not appropriate to Australia. As a result of this detailed studies of the sent out efficiency of generation, the emission of selected pollutants including CO₂ and of the consumption of certain resources in alternative coal fired power generation technologies have been carried under Project 3.3 out specifically for Australian coals and conditions, Ikeda et al. (2007a), Ikeda et al. (2007b).

These works reported performance across the full range of Australian thermal power coals and for a range of current and near term technologies. Technologies considered included supercritical, ultra-supercritical and ultra-supercritical double reheat PC steam cycle technologies with conventional air firing and ultra-supercritical PC steam cycle technology with oxygen firing (oxy-fuel). All these technologies were assessed with both wet and dry cooling. One IGCC technology was also included for comparison. The PC and the IGCC technologies were modelled with and without CO₂ capture and compression while the oxy-fuel technology was considered only with CO₂ capture and compression. Moreover, the evaluation was applied to a broad range of overseas coals.

The present report concludes this work by considering the reliability of the results obtained from the modelling. Effects addressed include expected deterioration of performance under duty cycles that will include part load operation, the range of ambient conditions appropriate to Australia's geography and their impact on performance estimates and optimised plant design for each site. An assessment is made of the uncertainty of the estimates obtained and results obtained here are compared with those reported elsewhere.

The work covered in this report has focussed on standard air-fired PC power plant, which is the dominant power generation presently deployed in Australia. More detailed evaluation of evolving technologies, particularly IGCC, was constrained by the difficulties in properly defining plant flow sheets for Australian conditions. Effects that are relevant to the latter issue include designing for minimum water consumption, lower levels of sulphur in coal and selecting the most appropriate class of gas turbine technology for Australia, particularly with hydrogen firing. A more detailed investigation of these issues is recommended for further work.

This present work is the final report in the study, previously documented in Ikeda et al. (2007a), Ikeda et al. (2007b) and Ikeda et al. (2004).

2 PART LOAD OPERATION

It is common for technologies to be compared at full load only e.g. DOE/NETL (2007), EPRI (2002). However, power plants are required to operate over a wide load range to match the grid demand and this is particularly the case for the relatively small capacity, geographically dispersed Australian grid.

For example while the NEMMCO NSW region experienced a peak demand of over 13,500 MW during 2007, the demand was also below 6,500 MW for about 10 % of the time. This demand profile is in part tracked by intermediate and peak loading plants. However, the relatively small number of generators on the system requires that many base load units be part loaded during low load periods to maintain adequate levels of spinning reserve and system security.

For Australian conditions it is appropriate to consider performance across a range of loads. One approach to this is to determine performance at a number of load points and to then determine an average, weighted according to the energy generated at each load condition over a typical year.

Large coal fired plant in Australia currently achieve annual availabilities of up to 95 % and capacity factors of the order of 80 %. A unit with the loading pattern illustrated in Table 1 would have an availability of 95 % and a capacity factor of 88 % as may be expected for a new entrant unit.

Load	Percent of Year
100 %	70 %
80 %	20 %
60 %	5 %

Table 1: Assumed loading pattern

GateCycle may be operated in either “design” or “off-design” modes. In the design mode component sizing is determined by the software using internal algorithms that apply standard factors for heat and mass transfer, machine efficiencies, etc. However, in the “off-design” mode performance is based on a predetermined set of component designs that are held constant during the run, irrespective of operating parameters such as fuel input or ambient temperature. The part load performance estimate is therefore determined by the GateCycle algorithms for each plant component under the off design condition.

Modelling of selected PC technologies was carried out at loads of 60, 80 and 100 % of full load. It was assumed that the boiler remained at full boiler pressure over the load range while the turbine throttle valve is closed in to reduce steam flow through the turbine. Coal flow is reduced in proportion to the steam flow. The turbine was assumed to incorporate full arc steam admission with a double row governing stage. Steam turbine efficiency and

other pressures and flows through the system are determined by GateCycle on the basis of internal algorithms.

Modelling of systems such as the oxygen plant (oxy-fuel combustion), post combustion capture process and CO₂ compression was carried out assuming that key process parameters such as air compressor outlet pressure for the oxygen plant, product pressure for the CO₂ compression plant, percentage capture of CO₂ and amine concentrations for the post combustion capture plants were maintained constant across the load range. Stream flows generally reduce in proportion to the load reduction while compressor, pump and fan efficiencies are scaled according to the GateCycle internal algorithms.

Runs were carried out for all coals at outputs of 60 %, 80 % and 100 % of full load for both wet and dry cooled ultra supercritical technology USC1¹. A more limited coal set was then used for USC1 technology with post combustion capture (100 % and 80 % load only) and for oxy-fuel, also with carbon capture and compression.

Figure 1 shows the net efficiency as load changes of the USC1 technology for the full set of CRC coals and for both wet and dry cooled cases. The relative change in efficiency with load is seen effectively to be independent of coal selection.

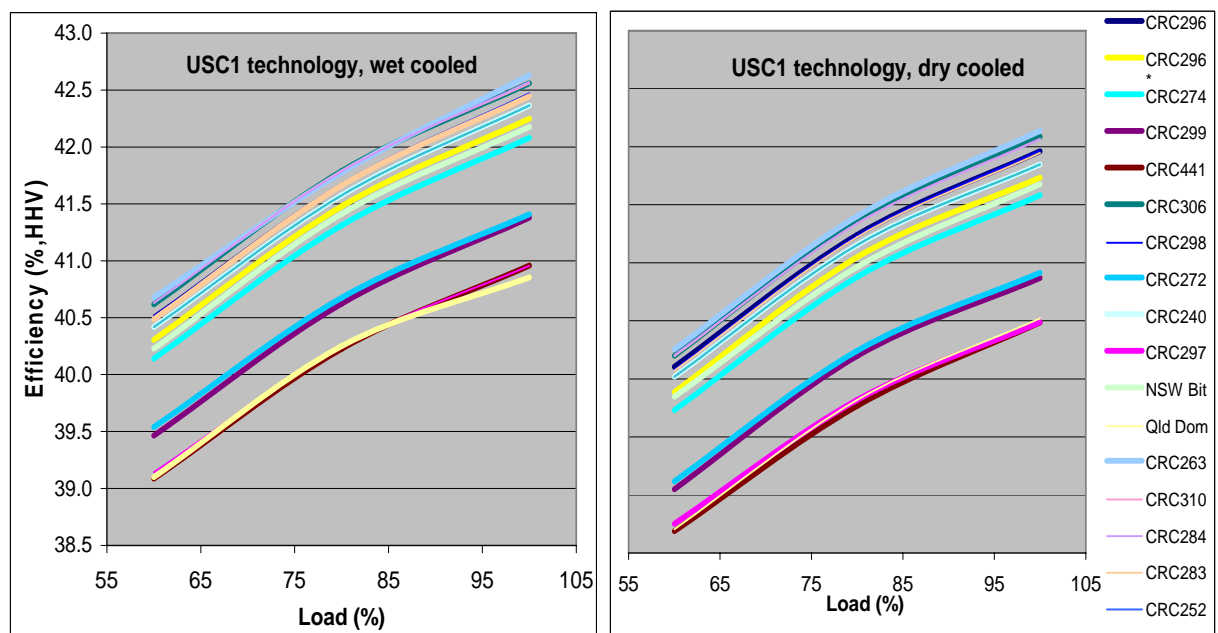


Figure 1: Effect of reduced load on efficiency for different coals, USC1 technology, wet and dry cooled. Refer Ikeda et al (2007a) for analyses of the CRC coals.

¹ SC technology denotes supercritical PC technology with main steam pressure and temperature of 25.0 MPa & 566 °C respectively with reheat to 565 °C, USC1 technology denotes ultra-supercritical PC technology with main steam pressure and temperature of 27.5 MPa & 605 °C respectively with reheat to 613 °C, USC2 denotes ultra-supercritical PC technology with 30.0 MPa/630 °C main steam conditions and reheat to 630 °C, refer Ikeda et al. (2007a).

Figure 2 illustrates the effect of load change on efficiency as a function of technology. Part load efficiency is expressed as a fraction of the full load efficiency to make the figure independent of technology and coal selection. Results are averaged across all coals.

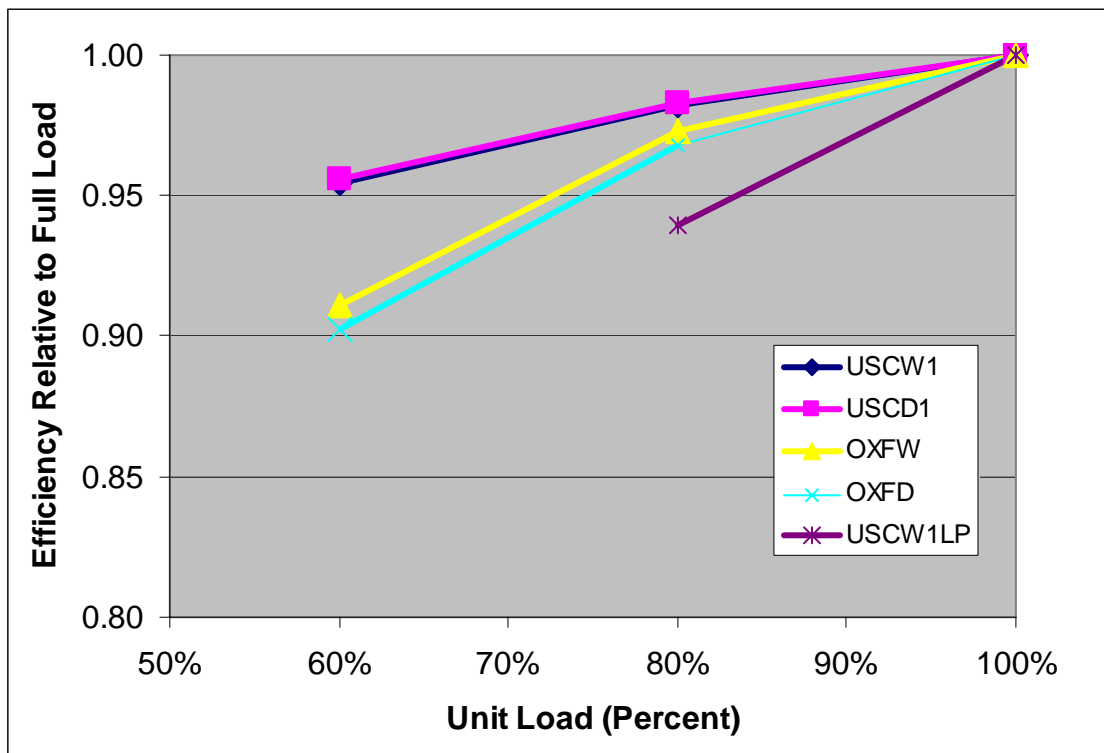


Figure 2: Net efficiency as a function of load, efficiency expressed relative to full load efficiency for each technology. USCW1 and USCD1 denote ultra supercritical level 1 with wet and dry cooling respectively, OXFW and OXFD denote oxy-fuel with USC1 technology respectively, USCW1LP denotes ultra supercritical level 1 technology, wet cooled and post combustion capture using bled steam extracted from the low pressure turbine.

It is clear that the different technologies respond differently to load reductions. It is also seen that technology assessment on the basis of full load only will overestimate the likely performance of all technologies. Based on the loading pattern set out in Table 1 the weighted average efficiency of the USC1 and oxy-fuel technologies would be approximately 0.5 % and 1.2 % lower than the full load efficiencies respectively.

Simulations of the post combustion capture presented computational difficulties at part load as the temperature and pressure of the extracted steam falls with load while the quality of steam demanded by the amine regeneration plant remains constant. Runs were completed at 80 % load and it is clear that overall cycle efficiency falls sharply with load. However converged solutions were not obtained for loads of 60 % with the flow sheet assumed and further investigation of strategies for part load operation of post combustion capture plant is warranted.

Little information appears to have been published on part load operation of IGCC technology and it is expected that operational strategies will depend on factors such as level of integration and gas turbine technology. Part load simulations for IGCC technology were not carried out here. However, cycle efficiency of conventional gas

turbine plant will reduce more rapidly than that for PC plant as load reduces, suggesting that IGCC plant will do likewise. Further investigation is warranted.

3 AMBIENT CONDITIONS AT AUSTRALIAN SITES

The ambient conditions to which the plants are exposed differ between Australian power plants and their overseas counterparts: they will also differ between sites within Australia. A review of ambient temperature data for selected Australian sites was carried out to assess the significance of the differences on the results obtained here.

Table 2 compares ambient conditions used in the present study with that assumed by others. Both wet and dry bulb temperatures are higher in the present study than those used in overseas studies. It is noted that in these studies plant design is based on mean ambient conditions for the purpose of performance assessment: in practice equipment is normally designed on the basis of worst-case condition.

	Current Study	IEAGHG (2003)	EPRI(2002)
Dry bulb temperature	25 °C	9 °C	17.2 °C
Wet bulb temperature ^a	19.5 °C	5.6 °C	12.7 °C
Relative humidity	60 %	60 %	55%
Elevation	111 m	Sea level	152.4 m
Cooling water temperature ^b	-	12 °C	-
Condenser back pressure ^b (wet cooled)	6.0 kPa	-	6.78 kPa
Condenser back pressure ^b (dry cooled)	12.0 kPa	dry cooling not considered	dry cooling not considered
Ambient pressure	1.00 bar	1.013 bar	0.99 bar

Table 2: Ambient conditions assumed in different technology studies

a): Wet bulb temperature calculated from dry bulb temperature and relative humidity

b): Condenser performance specification according to cooling water temperature for IEA(2003) and to turbine back pressure for Current Study and EPRI(2002)

Wet and dry bulb temperature data was obtained from the Australian Bureau of Meteorology for 5 sites in NSW and Queensland as set out in Table 3. These sites were selected to broadly represent the range of sites with good access to coal in NSW and Queensland, within the constraints of publically available site weather data (wet bulb temperature not available for Inglewood Forest).

These data show generally similar mean dry bulb temperatures for all sites except for Gladstone airport, which is approximately 4° C higher. The inland sites show lower mean wet bulb temperatures than do the coastal sites, including the most southerly site at Norah Head on the NSW coast near Newcastle. The inland sites also showed much greater dispersion of the data with higher maximums and lower minimums than at coastal sites. The high dry bulb temperatures particularly will influence the performance of gas turbine based plant such as IGCC at the inland sites.

Site	Norah Head	Gladstone Airport	Gunnedah Airport	Kingaroy Airport	Inglewood Forest
Site Type	Coastal	Coastal	Inland	Inland	Inland
Location	NSW Central Coast	Qld Central Coast	NSW Namoi Valley	Qld South Burnett Region	Qld Darling Downs
Data Period	11 yrs	12 yrs	5½ yrs	6 yrs	6½ yrs
Data Frequency	½ hourly	½ hourly	hourly	hourly	hourly
Mean Dry Bulb Temp	18.0 °C	22.4 °C	18.6 °C	17.7 °C	19.3 °C
Mean Wet Bulb Temp	15.1 °C	18.6 °C	13.5 °C	13.6 °C	n/a
Dry Bulb Standard Deviation	4.3 °C	4.8 °C	8.6 °C	7.3 °C	7.2 °C
Wet Bulb Standard Deviation	4.1 °C	4.2 °C	5.6 °C	5.6 °C	n/a

Table 3: Ambient temperature averages for five Australian sites.

Technology assessment studies usually consider performance under only a single ambient condition. However the plant will be required to operate over the full year and in some cases it is necessary to consider the effect of annual and diurnal temperature variation. Figures 3 and 4 show temperature duration curves for each of the sites.

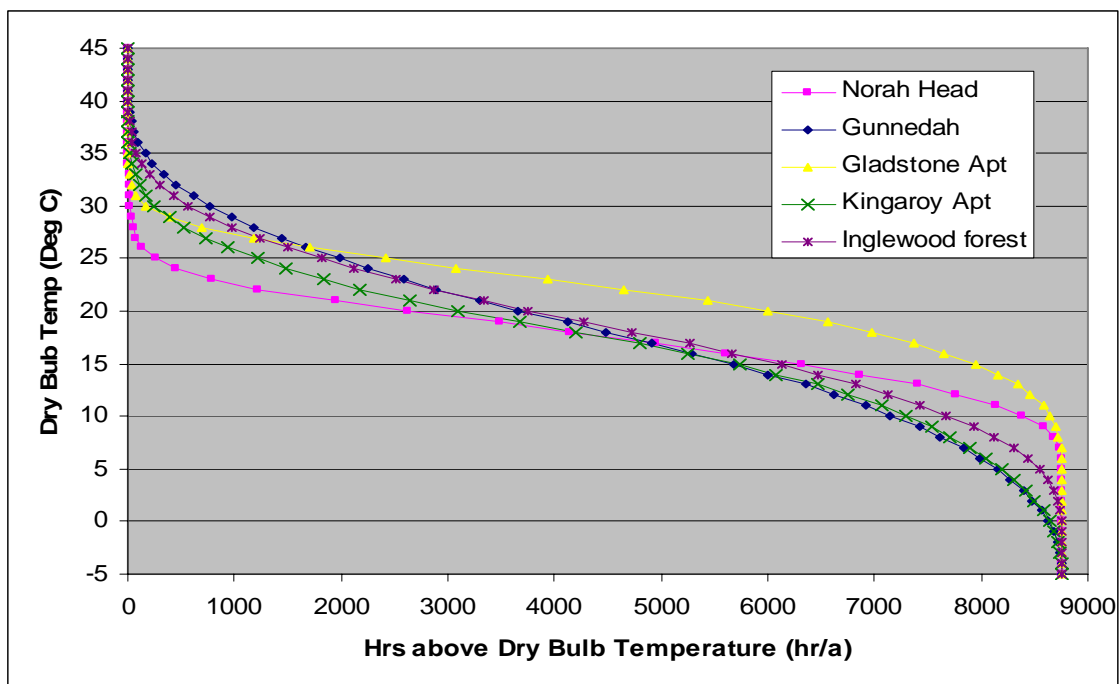


Figure 3: Dry bulb temperature duration curves for five Australian sites

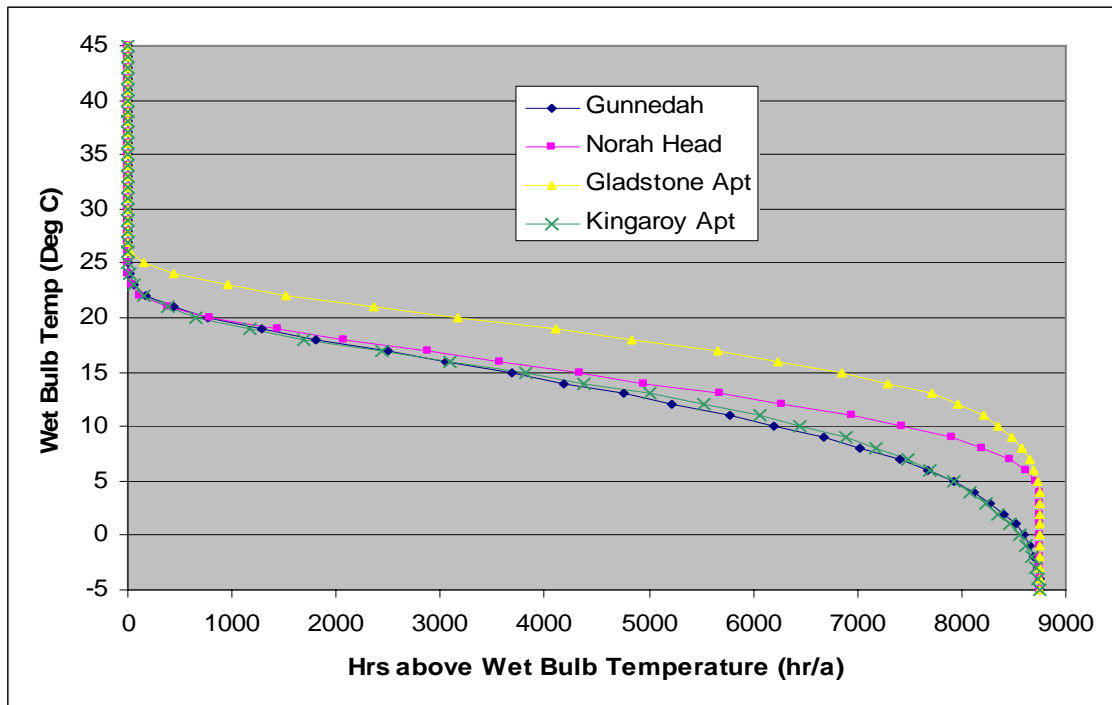


Figure 4: Wet bulb temperature duration curves for four Australian sites

For the inland sites the wet bulb temperature will fall between 3 and 21 °C for 90 % of the time while the dry bulb temperatures will fall between about 5 and 30 °C for 90 % of the time. The coastal sites generally show less spread in the data with higher minimum wet and dry bulb temperatures than the inland sites.

Ambient temperatures affect the different technologies in different ways. For plant based on the Rankine steam cycle (PC and oxy-fuel) the primary impact is to change the minimum temperature in the steam cycle, lower ambient temperature allowing lower condenser pressure and higher cycle efficiency.

A further distinction may be made between wet and dry cooled systems. With wet cooled systems the steam leaving the low pressure turbine is condensed against circulating cooling water. The cooling water is in turn cooled by exposure to ambient air in cooling towers where evaporation of part of the circulating cooling water carries the heat into the atmosphere. With a dry cooled system the steam leaving the low pressure turbine is passed through a heat exchanger where the heat is dissipated directly to the atmosphere by radiation and convection. The key design variable for wet cooled systems is the ambient wet bulb temperature while for dry cooled systems it is the ambient dry bulb temperature.

For gas turbine based combined cycle technologies (IGCC and gas turbine combined cycle) both dry bulb and wet bulb temperatures are important. A change in dry bulb temperature will impact both output, via change to mass flow through the gas turbine compressor, and efficiency through compression work required. In addition to this the wet bulb temperature will affect the cooling system performance (assuming wet cooled systems) and the thermodynamic properties of the gas being handled by the gas turbine.

GateCycle was used to assess the impact of different ambient conditions on wet and dry cooled Rankine cycle plant with USC1 steam conditions (27.5 MPa/600 °C/613° C) and a

mid rank coal (CRC272²). Plant was assumed designed on the basis of 25 °C dry bulb and 60 % relative humidity.

Net efficiency, expressed as a fraction of efficiency at design temperature is plotted in Figure 5 for dry bulb temperatures between 10 °C and 40 °C. For these runs relative humidity and all plant design settings were held constant (GateCycle off design mode).

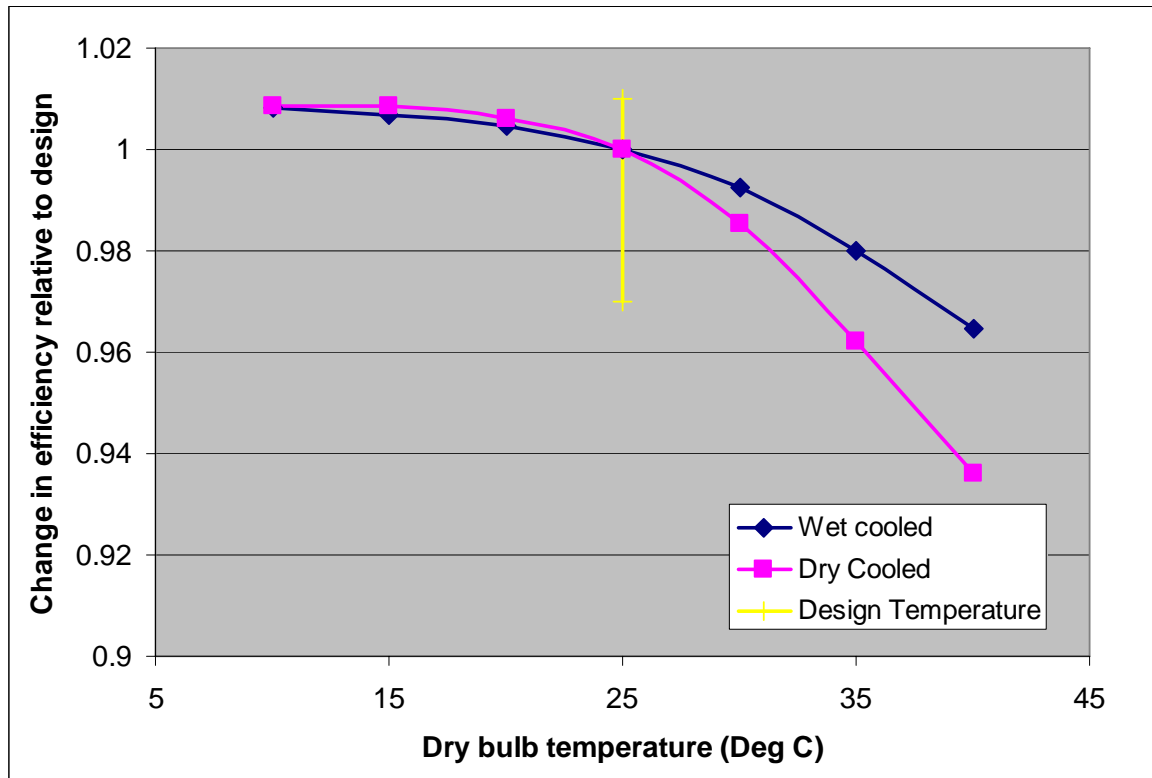


Figure 5: Effect of ambient temperature change on sent out efficiency of PC plant, USC1 technology level, Coal CRC272, plant design basis 25° C dry bulb, 60 % relative humidity.

It is seen that the efficiency increases as temperature decreases to about the design temperature and then plateaus. This effect is due to a number of effects including increasing kinetic energy losses in the exhaust steam as steam specific volume increases and to reducing turbine efficiency as a result of increasing amount of condensed water in the steam, both occurring as back pressure is reduced.

From Figure 3 it is seen that the dry bulb temperature at each of the sites considered remains below 25 °C for about 80 % of the time. As efficiency is relatively stable for temperatures below 25 °C the minor differences between sites will not significantly affect results shown here.

All model results presented previously in this project, Ikeda et. al. (2007a), Ikeda et. al. (2007b) assume a double ended low pressure steam turbine with 760 mm long last row blades as would be commonly used for units of this capacity, Boss M. (2002). With the

² Coal analysis available in Ikeda et al. (2007a)

unit gross output of the order of 450 MW this results in a relatively low cost turbine but also in high exhaust steam velocity and therefore high turbine exhaust losses. A turbine of this design is likely to be selected where coal costs are low. However, if maximum efficiency is sought then a turbine with greater exhaust flow area may be used to reduce exhaust losses, Reinker J.K. & Mason P. Further, low ambient temperatures can allow the economic production of low back-pressure in the condenser. Low back-pressures further increase the specific volume of the exhaust steam and point to a greater increase in optimum exhaust flow area.

Figure 6 indicates net efficiency as a function of low pressure turbine exhaust area at three different back pressure levels for a USC1 steam cycle. The sensitivity to exhaust flow area, as well as the substantial improvement in efficiency as turbine exhaust area increases, is clear.

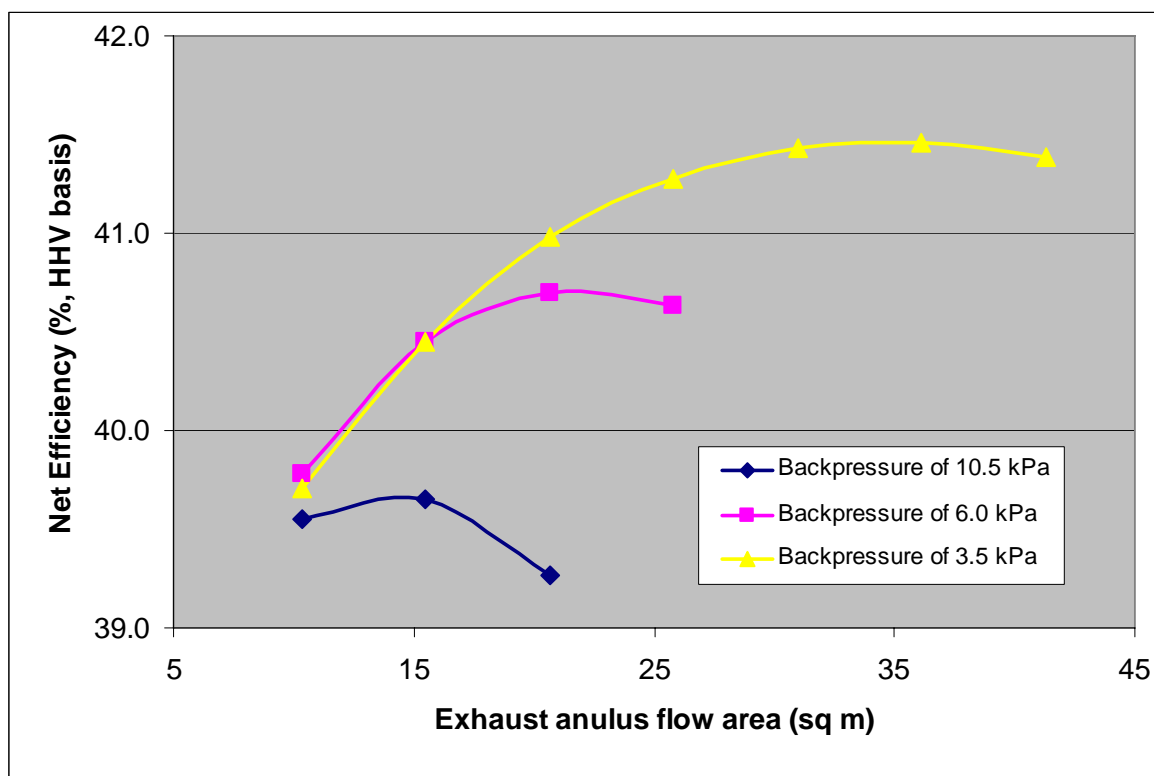


Figure 6: Effect of LP turbine exhaust area on net cycle efficiency at three backpressure levels, USC1 technology, wet cooled, Coal CRC272.

The turbine arrangement assumed by Ikeda et al. (2007a, 2007b) provides a total exhaust flow area of 10.3 m² and a backpressure of 6.0 kPa. Increasing the last row blade length to 914 mm is well within material limits for 50 Hz turbines, Reinker & Mason, would provide a flow area of approximately 15 m² and would result in an increase in efficiency of approximately 0.7 % absolute for the same backpressure. Alternatively providing two double flow low pressure turbines would allow a flow area of 20.6 m² and result in an improvement in almost 1 % absolute over that determined for the base design.

Saturation temperature of steam in the condenser, and thereby turbine backpressure, may be determined from ambient temperature by allowing for the cooling tower approach temperature and for the condenser saturation approach temperature³.

Data has been published for the backpressure that would typically be used in power plants for a range of cooling water temperatures, Avallone & Baumeister (1996). This data suggests a typical condenser approach temperature of the order of 12 to 14 °C. Similarly wet cooling towers typically are designed for an approach temperature of the order of 5 to 7 °C, US EPA. On this basis a condenser saturation temperature some 17 to 21 °C above the ambient wet bulb temperature would be expected. The lower value would imply the greater capital and operating costs and would be used where higher fuel costs exist while the higher approach values may be used where lower fuel costs occur.

Table 4 shows design backpressures obtained for four dry bulb temperatures using two design cases. In the low approach temperature case a temperature difference of 17 °C is taken while the high approach temperature case uses a difference of 21 °C. The design back pressure of 6.0 kPa used in the present project is close to that obtained assuming a low approach temperature.

Dry bulb temp	Design Backpressure	
	Low approach temperature	High approach temperature
30 °C	7.7 kPa	9.5 kPa
25 °C	6.1 kPa	7.6 kPa
20 °C	4.8 kPa	6.0 kPa
10 °C	2.9 kPa	3.7 kPa

Table 4: Expected design backpressure range for three ambient temperatures, 60 % relative humidity assumed.

Backpressures below that indicated by the low approach temperature case may be achieved by additional capital expenditure on plant. For example a cooling tower approach temperature of 3 °C would require a cooling tower approximately 60 % larger than that for an approach temperature of 6 °C, Elliott et al. (1998) and would result in a reduction in back pressure at design conditions of approximately 1 kPa, all else remaining equal. If, in addition, the condenser surface area is increased by 50 %, a reduction in backpressure by a further 1 kPa is indicated by correlations given by Avallone and Baumeister (1996). In other words a backpressure of 4.0 k Pa is achievable under ambient conditions of 25 °C and 60 % RH with condensers and cooling towers some 50 % to 60 % greater than that required for a backpressure of 6.0 kPa.

A 1 % absolute increase in efficiency will reduce gas flows by about the same proportion. Size and cost of plant such as CO₂ scrubbing plant is approximately proportional to gas flow and will therefore also decrease by about 1 % absolute for a 1 % increase in

³ Cooling tower approach temperature is defined as ambient wet bulb temperature less the temperature of the cooled water leaving the tower. Condenser saturation approach temperature is here defined as steam saturation temperature less the temperature of cooling water entering the condenser.

efficiency. The cost of CO₂ scrubbing plant is currently expected to be of the order of 60 % of the cost of a pulverised coal fired plant without CO₂ capture, IPCC (2005). Careful optimisation of LP steam turbines and cooling systems for capture ready plants are then expected to lead to worthwhile economies due to the concurrent effects of increasing efficiency and reduced capital cost and energy penalty of CO₂ scrubbing. These optimised designs may well differ substantially from that currently deployed within Australia and from those pertinent to overseas coals and site conditions.

Data provided above also allows the effect of the different ambient conditions set out in Table 2 to be estimated. Interpolating between the maximum efficiency values for each backpressure from Figure 6 on the basis of backpressure calculated from the given ambient conditions assuming a low approach temperature difference, shows an increase from Project 3.3 efficiency values to efficiency under the EPRI condition of 0.55 % absolute and an increase to the IEA conditions of 1.05 % points absolute.

This brief review of factors involved in back pressure optimisation has focussed on conventional wet cooled systems with forced draft cooling towers. It is recommended that further investigation of dry cooled and of alternate cooling systems such as hybrid (mixed wet/dry systems) and of systems such as the Heller indirect cooled system be performed.

4 COMPARISON WITH PUBLISHED RESULTS

A number of technology comparisons have been reported using coal selections and ambient condition assumptions different to that taken here. Results from selected studies are compared below with that obtained during the present work.

Figure 7 compares net sent out efficiency as determined in this project with results by others across a range of pulverised coal fired plant steam conditions. Results are arranged in order of increasing main steam pressure. Data from the current project are indicated by the green bars, with the range due to the compositions of the different Australian coals assessed indicated by the hatched area.

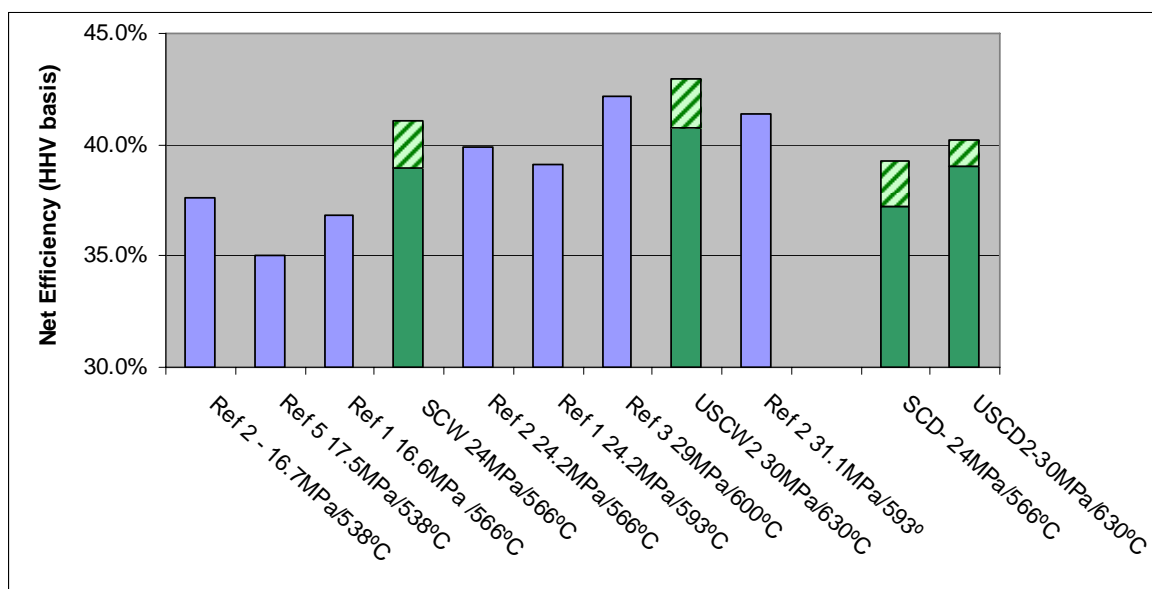


Figure 7: Net sent out efficiency (% HHV basis) reported for alternative technologies. Blue bars represent results by others, green bars show represent results obtained during the present project, hatched section for SCW, SCD, USCW2 and USCD2 indicate range of efficiencies produced by the 18 Australian coals considered here. Ref 1 denotes DOE/NETL (2007), Ref 2 denotes DOE/FE (1999), Ref 3 denotes IEAGHG (2003), Ref 4 denotes DOE/NETL (2002), Ref 5 denotes EPRI (2002). SCW denotes supercritical wet cooled, SCD denotes supercritical dry cooled, USCW2 denotes ultra supercritical level 2 wet cooled, USCD2 denotes ultra supercritical level 2 dry cooled, refer footnote 1 on page 3 for steam conditions.

Overall the estimates of efficiency obtained here for wet cooled plant are similar to that obtained by others although some Australian coals do result in marginally higher efficiency. No comparable data for dry cooled power plants was identified.

Figure 8 compares the impact of amine based post combustion capture on net sent out efficiency as determined by the present work and as compared with that determined by others.

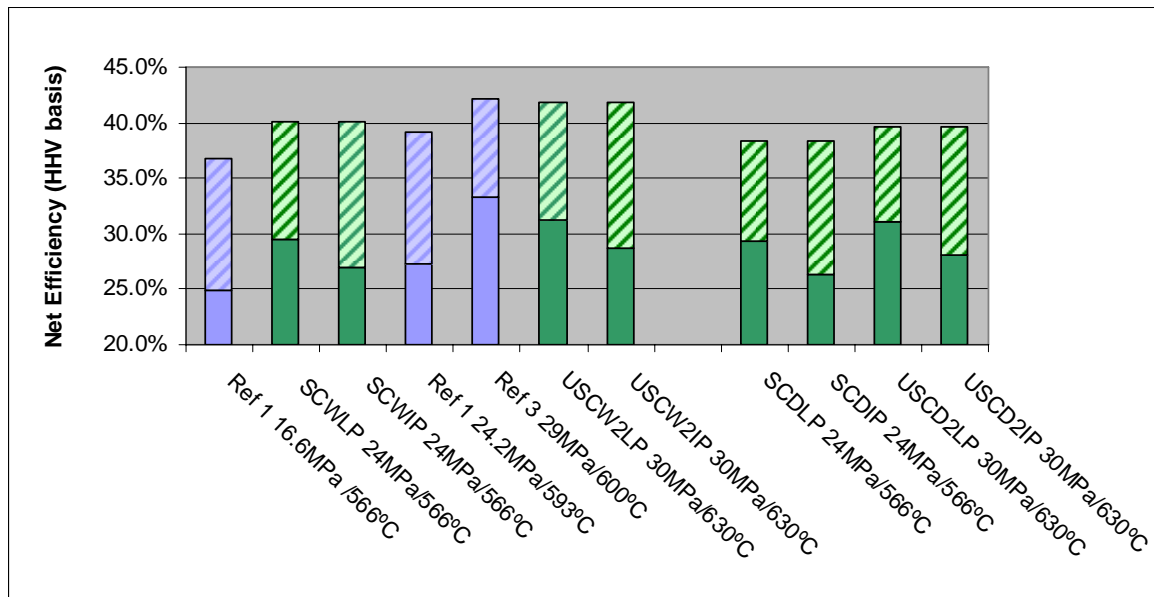


Figure 8: Net sent out efficiency (% HHV Basis) for pulverised coal technology before and after implementation of MEA based CO₂ scrubbing. Blue bars represent results by others, green bars show represent results obtained through the present work, total height of bars indicates efficiency without CO₂ capture, hatched area indicates loss due to scrubbing. SCWLP denotes supercritical wet cooled technology with the steam for amine regeneration being taken from an LP turbine bled steam extraction point, SCWIP denotes supercritical wet cooled technology with the steam for amine regeneration being taken from the IP/LP turbine steam crossover duct. Refer caption on Figure 7 for key to references.

As before results obtained here are generally similar to that obtained elsewhere although with some differences between studies in regard to the loss due to scrubbing (denoted by the hatched sections in the figure). Detail review of the models indicates that this is largely due to different assumptions in regard to integration of the amine regeneration system into the steam cycle and to a lesser extent by details of the amine plant flow sheet. The impact of alternative steam integration strategies is highlighted by cases SCWLP and SCWIP. In case SCWLP the amine regeneration steam is bled from an intermediate point in the LP turbine while in SCWIP it is taken from the IP/LP crossover steam duct. Extraction of steam from the LP turbine results in substantially less impact on efficiency from CO₂ capture than does extraction of steam from the IP/LP crossover duct.

Figure 9 shows auxiliary energy consumption as a percentage of gross generator output for various levels of steam cycle technology from various sources while Figure 10 shows auxiliary energy when CO₂ scrubbing is implemented.

Auxiliary energy consumption figures determined here for conventional steam plant are similar to but slightly lower than those obtained by others. The slightly lower values obtained here are due to the non inclusion of FGD for local conditions. Ref 3 indicates a high auxiliary energy consumption value, this is due to the assumption of electric drive for the main boiler feed pump in this case as compared to steam turbine driven feed pumps assumed elsewhere. Auxiliary energy determined with CO₂ scrubbing is generally similar in all cases.

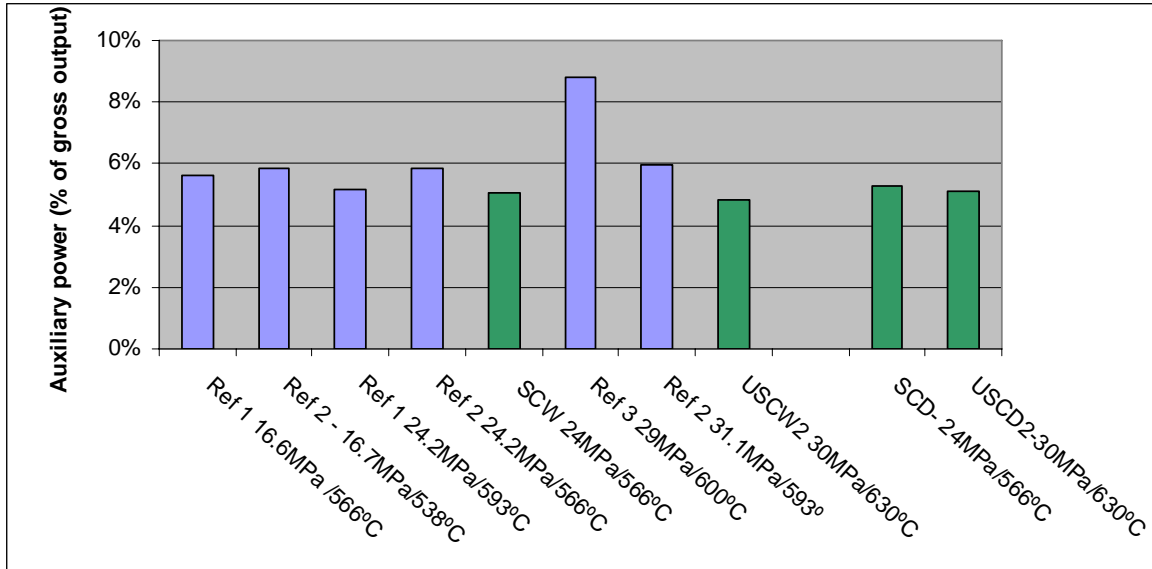


Figure 9: Auxiliary Energy as percentage of gross generator output, blue bars represent results by others, green bars represent results obtained through the present work. SCW denotes supercritical wet cooled, SCD denotes supercritical dry cooled, USCW2 denotes ultra supercritical level 2 wet cooled, USC2D2 denotes ultra supercritical level 2 dry cooled, refer footnote 1 page 3 for details of steam conditions. Auxiliary power consumption figures relate to PC technologies employing steam driven boiler feed pumps except Ref 3 which includes for electric feed pumps. Refer caption on Figure 7 for key to references.

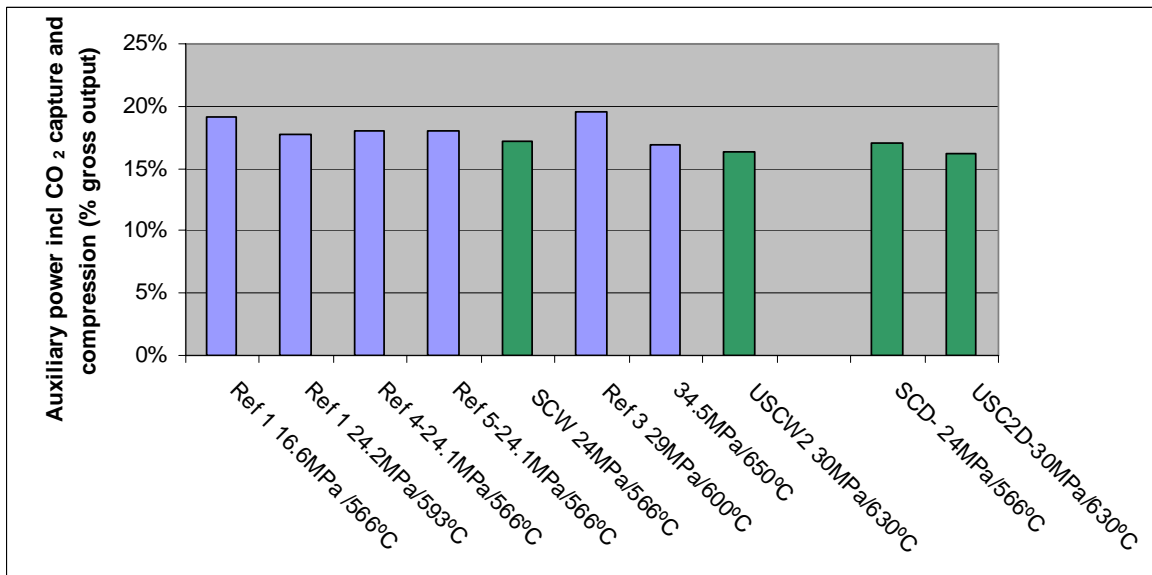


Figure 10: Auxiliary energy as percent of gross generator output with MEA based post combustion capture of CO₂, blue bars represent results by others, green bars represent results obtained through the present work. SCW denotes supercritical wet cooled, SCD denotes supercritical dry cooled, USCW2 denotes ultra-supercritical level 2 wet cooled, USC2D2 denotes ultra-supercritical level 2 dry cooled. Refer footnote 1 page 3 for details of steam conditions, refer caption on Figure 7 for key to references.

Figure 11 compares cooling water makeup requirements determined here with results reported by NETL/DOE (2007). The NETL/DOE data provides results for subcritical and supercritical technologies. The results presented from the present work are all for ultra supercritical level 1 technology (steam conditions 27.5 MPa/605 °C/613 °C) and illustrates results of two coals and for two levels of integration of the amine plant with the power plant.

Water consumption determined in the present study for PC plant without carbon capture, denoted by the solid fill green bars, is low compared to the NETL/DOE results as neither FGD nor auxiliary plant cooling load (cooling load due to oil and hydrogen coolers, air conditioner coolers, etc) was allowed for in the present work. While process water consumption in the FGD plant is relatively minor there is a significant cooling duty requirement to reduce the flue gas temperature from the air heater outlet temperature to the FGD outlet temperature.

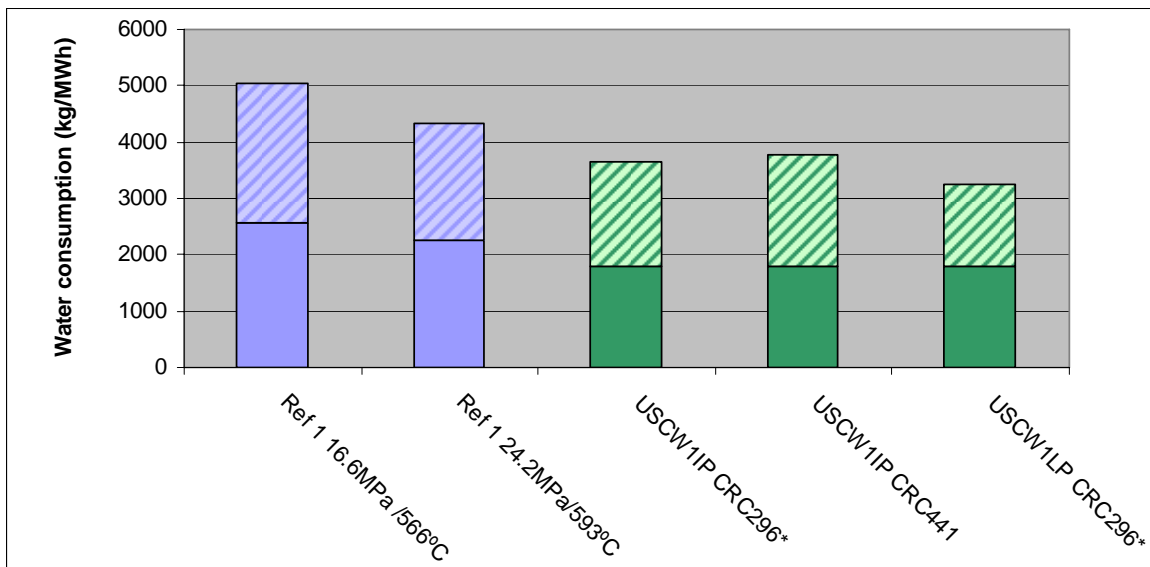


Figure 11: Cooling water consumption for post combustion capture, blue bars represent results by others, green bars represent results obtained through the present work, solid bars give main power plant consumption without CO₂ capture, hatched bars indicate consumption after CO₂ capture and compression plant is fitted. Ref 1 denotes DOE/NETL (2007), USCW1IP denotes ultra-supercritical level 1 wet cooled with amine regeneration steam taken from the IP/LP crossover duct, USCW1LP denotes ultra-supercritical level 1 wet cooled technology with amine regeneration steam bled from the LP turbine. Chemical analysis for coals CRC296* and CRC411 and flow sheets for different regeneration steam sources schemes as defined in Ikeda et al (2007a), refer footnote 1 page 3 for details of steam conditions for different technologies.

Water consumption rates obtained in the present work for plants fitted with CO₂ capture are somewhat below that determined by DOE/NETL (2007). While details of the breakup of water usage within the plant is not provided by DOE/NETL it appears that factors contributing to this difference include more advanced steam conditions being taken here as compared to DOE/NETL. This results in a higher net efficiency for the base plant and therefore less CO₂ to capture per MWh generated. This benefit is magnified as the efficiency penalty for capture reduces in proportion to the amount of CO₂ to be captured

and the amine plant cooling water demand also reduces as the CO₂ captured reduces. Further, the steam conditions in the IP/LP crossover duct specified in the present study are closer to that required by the amine regeneration plant than was assumed by DOE/NETL. This results in the more effective use of low grade heat. DOE/NETL also have different terminal conditions for the compressed CO₂ and assume somewhat different amine regeneration pressures than used in the present study. The impact of these differences highlights a need for further optimisation studies in regard to matching amine post combustion capture with power plant.

A breakdown of the cooling duty determined in the present study for USCW1 technology, CRC296* coal and with amine regeneration steam bled from the low pressure turbine is show in Figure 12.

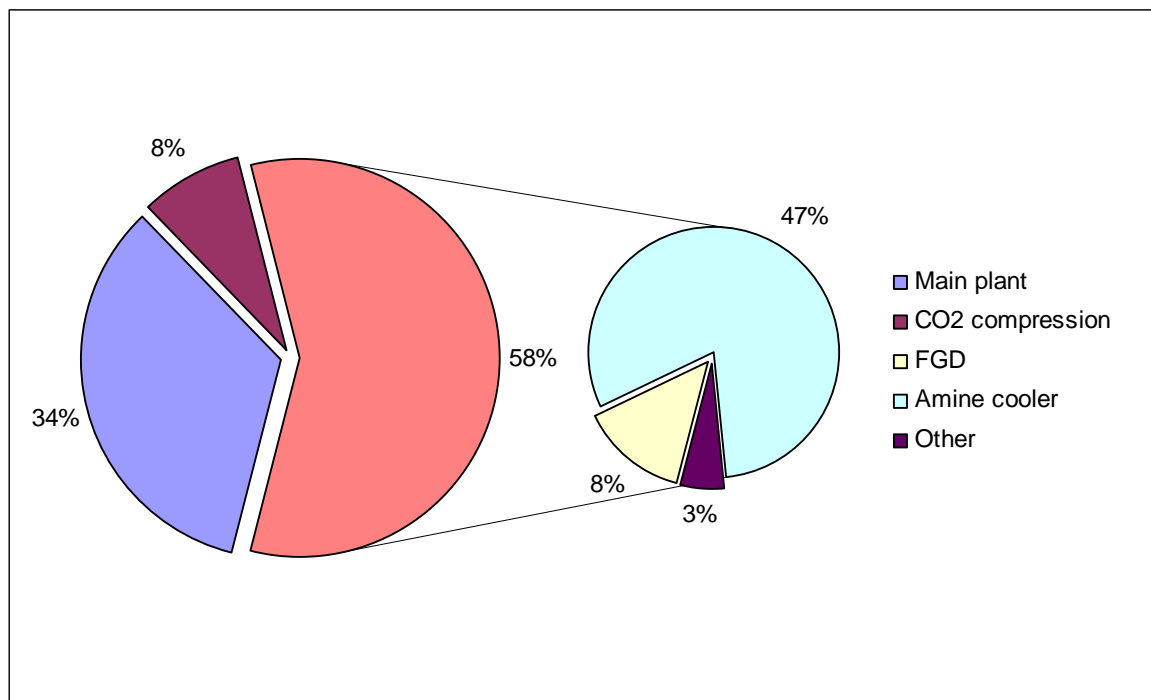


Figure 12. Breakdown of cooling demand for ultra supercritical plant USCW1 with post combustion carbon capture, coal CRC296*, amine regeneration steam from LP turbine. Total cooling demand from the amine capture plant is broken out.

From the figure the amine plant cooling demand exceeds that of the main power plant. It should be noted that with post combustion capture the main plant cooling load is reduced somewhat from that seen without post combustion capture as some of the steam that would have otherwise flowed to the main plant condenser is routed to the amine plant, thereby reducing condenser duty.

The scale of the heat rejected from both amine and CO₂ compression plant suggests substantial opportunity for benefit from integration of these plants with the main steam cycle. More detailed investigation of amine capture plant integration with dry cooled plant is also required to clarify interactions between air cooling and both amine plant and CO₂ liquefaction processes.

5 UNCERTAINTY IN EFFICIENCY DETERMINATION

The calculation of power plant efficiency requires that numerous assumptions be made. Each of these assumptions will contain a level of uncertainty as to the true value of the variable concerned and will therefore contribute a level of uncertainty to the final value of efficiency determined. In considering the conclusions of this and the previous reports, or to compare results of this work with others, it is necessary to understand the uncertainty in the results.

This section discusses the level of uncertainty in the calculation of sent out efficiency for pulverised coal technologies with specific reference to the case USC1. The approach taken generally follows that set out in ASME PTC19.1-2005 where random uncertainty is taken to be zero as discussed below.

Here we calculate efficiency as a function of certain input variables that are specified or assumed. This may be written as:

$$y = F\{x_1, x_2, x_3, \dots, x_N\} \quad \text{Eqn 1}$$

where

y	:	the result of calculation (efficiency)
$x_{1 \dots N}$:	N variables used in the calculation of y
$F\{\dots\}$:	the function relating y to $x_1 \dots x_N$

The uncertainty of the result of the calculation can be obtained from the variances and covariances of the input variables. In the absence of any covariance between x_i and x_j then this uncertainty may be approximated by a first order Taylor series expansion of the function $F\{\dots\}$ at the point of interest, ASME PTC19.1-2005, Kessel W. (1998), Taylor B and Kuyatt C.(1994). Uncertainty of the result can then be written as:

$$u_c^2(y) = \sum_{i=1}^N \left(\frac{\partial F}{\partial x_i} \right)^2 u^2(x_i) \quad \text{Eqn 2}$$

where

y	:	the calculated result (efficiency)
$u_c(y)$:	the combined standard uncertainty of the calculated result
$\partial F / \partial x_i$:	the partial derivative of $F\{\dots\}$ with respect to x_i
$u^2(x_i)$:	the standard uncertainty associated with the input estimate x_i
N	:	the number of input variables

The expanded uncertainty of the result can now be written in terms of the standard uncertainty as:

$$U_{R,95} = 2.0u_c(y) \quad \text{Eqn 3}$$

Where the true value of the calculated result is expected to lie within the band $y \pm U_{R,95}$ to about a 95 % confidence level and the factor 2.0 represents the Student's t value for 95 % confidence levels and a high degree of freedom.

Variables used in the calculation of efficiency may be divided into those which are specified as boundary conditions and those which are best guess estimates of the true value. Boundary conditions are defined in terms of the model design, are assumed to be exact, and therefore do not contribute to uncertainty in the final result. However, best guess estimates are not defined in terms of the problem definition and therefore will contribute to uncertainty in the result. In this context the best guess estimates become the input variables x_i defined above.

In an experimental determination of efficiency the boundary condition values, e.g. steam temperatures and pressures, would be measured and the measurement process will contribute uncertainty to the result. This is termed random uncertainty in ASME PTC19.1 and would not be zero in an experimental determination of efficiency.

Table 5 categorises the primary variables of the efficiency calculation as either boundary conditions or best guess estimates. For simplicity we assume that numerical and round off errors in the calculation of heat and mass balances and of thermodynamic properties of working fluids are small compared to the uncertainties in model input assumptions and may therefore be neglected.

Defined Boundary Conditions	Best Guess Estimates
Ambient temperature, pressure & humidity	Steam turbine isentropic efficiencies
Coal analysis	ID, PA, FD Fan isentropic efficiencies
Steam cycle parameters,	Feed and CW pump isentropic efficiencies
Steam temperature and pressure	Steam turbine gland leakages
Final feed water temperature	Boiler back end gas temperature
Condenser Backpressure	LP turbine last row blade length

Table 5: Categorisation of variable used in calculation of efficiency.

The function $F\{\dots\}$ relating efficiency to each input variable is complex and it is not possible to obtain the partial differentials $\partial F/\partial x_i$ analytically. However, these values of may be obtained numerically by

$$\frac{\partial F}{\partial x_i} = \frac{F\{x_1, \dots, x_i + \Delta, \dots, x_N\} - F\{x_1, \dots, x_i - \Delta, \dots, x_N\}}{2\Delta} \quad \text{Eqn 4}$$

where

Δ : a small increment in x_i

Values of $u^2(x_i)$ may be estimated as the variance of repeated measurements of x_i , or, in the absence of statistical data, by assuming a probability distribution for the scatter of x_i about the true mean. Taylor and Kuyatt (1994) recommend the use of a constant probability between upper and lower limits (a rectangular distribution) or a constantly decreasing probability from a maximum at the mean value to zero probability above and below selected limits (a triangular distribution) where statistical data is not available. Alternatively, a normal distribution may be assumed.

In the present context where there is a higher likelihood of a particular value of any selected variable occurring, decreasing probability of a particular value occurring at greater distances from the mean value and a physical constraint on certain maxima or minima (e.g. isentropic efficiency can not exceed 100 %) it appears that a triangular probability distribution will be more realistic. In such circumstance $u(x_i) = \frac{1/2(a^+ - a^-)}{\sqrt{6}}$, the most probable value of x_i is $(a^+ + a^-)/2$ and there is a zero probability of x_i falling outside the bounds a^+ and a^- .

Mean, a^+ and a^- , $\frac{\partial F}{\partial x_i}$ values used here for the best guess variables x_i are given in Table 6.

Numerical values of $\frac{\partial F}{\partial x_i}$ were obtained from repeated applications of GateCycle with small changes in the input variable concerned. Mean, upper and lower bounds of the best guess variables were drawn from a variety of sources including experience with current best commercial practice in Australian power plants.

It is noted that the largest contributor to overall uncertainty is uncertainty in the isentropic efficiencies of the steam turbines, and in particular the low pressure steam turbine which contributes around 50 % of overall uncertainty. Isentropic efficiency is affected by numerous small effects which depend on the detail design of the individual machine, Craig and Cox (1971). However, Spencer et al (1963) have shown that performance of large steam turbines is well correlated against volumetric flow, pressure ratio, initial steam conditions and governing stage design. The values of isentropic efficiency applied above are extrapolated from available (largely historical) data on similar units and are therefore considered to be reliable. However, turbine design is advancing rapidly, Leyzerovich (2002), and it is likely that efficiencies assumed here are low side rather than high side estimates. These considerations were not included in the calculation of uncertainty presented below.

Best guess variable	Mean value	Upper/lower bounds	$\frac{\partial F}{\partial x_i}$
Turbine isentropic efficiency			
HP Turbine	90.2 %	93 % - 88 %	7.36
IP Turbine	89.8 %	93 % - 88 %	9.09
LP Turbine	89.6 %	93 % - 88 %	17.3
Fan isentropic Efficiency			
PA Fan	65 %	70 % - 60 %	0.174
FD Fan	80 %	88 % - 72 %	0.100
ID Fan	75 %	82 % - 68 %	0.505
Pump isentropic efficiency			
Feed pump	85 %	90 % - 80 %	1.19
CW pump	85 %	90 % - 80 %	0.203
Steam gland leakage	4163 kg/h	5200 - 3100 kg/h	0.000
Boiler exit gas temperature	137 °C	145 – 130 °C	0.024
LP last row blade length	762 mm	850 – 650 mm	0.002

Table 6: Variables used in calculating uncertainty of PC plant efficiency calculation.

Input of data from Table 6 into Equation 2 allows the standard uncertainty in the estimate of sent out thermal efficiency to be determined as 0.24 % absolute. The expanded uncertainty of the result is then 0.48 % i.e. assuming a normal distribution of efficiency about the mean, the true value of efficiency will fall within ± 0.48 % absolute of the predicted value to 95 % confidence levels.

An analysis of this nature may be applied to different technologies to allow any performance difference predicted to occur between them to be rigorously assessed. For example, if the estimates of efficiency have uncertainties large relative to the difference between technologies than standard statistical tests should be applied to determine if a true difference between the technology efficiencies exists to the required significance level.

It is noted that a similar approach may be applied to determine if a true difference in cost of power exists between alternative technologies.

6 CONCLUSIONS

This final report of project 3.3 reviews the effect of a number of non-technology related parameters on the performance of selected coal fired power generation technologies. This report is additional to, and should be read as part of, previous publications from this project including Ikeda et al. (2007a), and Ikeda et al. (2007b).

The effect of load reductions to 80 % and 60 % of full load on PC technologies including oxy-fuel technology was investigated. It was found that net efficiency of all technologies decreased as load decreased with the deterioration being more marked for the post combustion capture technology than for the oxy-fuel technology. Both of the technologies with carbon capture exhibited greater deterioration in efficiency with load than did conventional PC plant without carbon capture.

The annual average efficiency of each technology was determined assuming a load profile yielding an 88 % capacity factor and 95 % availability. Under this condition the effect on overall plant efficiency is small. However in the present work the impact of light duty cycles has not been evaluated and it is recommended for further work.

Ambient temperature conditions at five selected sites within eastern Australia were analysed to determine wet and dry bulb temperature duration curves. The reference conditions assumed for Project 3.3 were found to be conservative but there is little performance difference expected between any of the sites and the results published earlier.

However, it was found that significant performance benefit could be obtained by optimising steam turbine design under a given set of ambient conditions. Optimising of condenser conditions and steam turbines for capture ready plants, i.e., those where CO₂ scrubbing is to be implemented in the future, is expected to result in larger low pressure turbines and lower back-pressure conditions for a given set of ambient conditions than are presently used in Australia.

Comparison of the results of the present study with those published by others indicates good overall agreement. Where differences are apparent they can generally be traced to differences in basic assumptions including the omission of FGD plant under Australian conditions and differences in condenser backpressure. However, when compared with one overseas study, the present work estimates a reduced cooling water consumption rate for supercritical PC plant fitted with amine based CO₂ scrubbing equipment. The differences can be largely traced to different assumptions in relation to the process details. However, in view of likely water restrictions on future power generation technologies this difference warrants further study.

Analysis of the uncertainty in the calculation of sent-out thermal efficiency was performed. Based on the 11 key variables examined, the standard uncertainty of the efficiency estimates for the air fired PC flow sheet is calculated to be ± 0.24 %, i.e. the true value of efficiency would fall within the range 40.88 % to 41.84 % for high ash coal CRC296 to a 95 % confidence level.

This estimate of uncertainty does not consider the effect of uncertainty in key cycle parameters such as steam temperatures and pressures (which are assumed to be zero in this study). It also does not consider the effects of the numerous design assumptions implicit in modelling. These factors would include for example steam pipe pressure drop, steam turbine internal arrangements, approach temperatures on feed water heaters, etc. Differences in such assumptions can cause significant differences between models. This is particularly so for technologies such as IGCC, oxy-fuel and Post Combustion Capture equipment where process flow sheets are much less standardised than for conventional steam plant. Developments in these technologies are likely to lead to further gains in performance as flow sheets are optimised. Further work to optimise process flow sheets for the high ambient temperatures and limited water availability conditions typical of Australia is warranted.

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