Planning and Cost Assessment Guidelines for Making New Coal-Fired Power Generation Plants in Developing APEC Economies CO_2 Capture-ready

APEC Energy Working Group

March 2010

EWG 01/2008A

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APEC#210-RE-03.2

Document Control

Document ID: O:\41731\ENG\AURECON REPORT\EWG012008A FINAL REP 30 MARCH.DOC

Rev No	Date	Revision Details	Typist	Author	Verifier	Approver
0	8.2.10	Draft	RB/RH	RB	AT	CV
1	10.3.10	Final Revision	RB/RH	RB	AT	CV
2	29.3.10	Client (DOE) comments incorporated	RB/RH	RB	AT	CV

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Executive Summary

This report describes project EWG 01/2008A conducted by Aurecon Australia Pty Ltd on behalf of APEC. It considers new coal-fired power plants in the subject economies and develops guidelines for planning the development of capture-ready coal-fired power plants.

1. Project Objectives

The primary objective of the project is to develop guidelines for planning and cost assessment in relation to making future coal-fired plants in developing APEC economies 'capture-ready' as an aid to capacity building on carbon capture and storage in these economies.

2. Carbon Dioxide Capture and Storage

Carbon dioxide capture and storage is a process consisting of: Capture or separation of CO_2 from industrial and energy related sources; transport of CO_2 to a storage location; and injection into storage site for long term isolation from the atmosphere. Although all three elements are integral to the development of a capture-ready power plant, this report focused on the power plant and allowances necessary to incorporate capture technology.

There are three main technology options for CO_2 capture that have been demonstrated or proposed for coal-fired power plants:

- **Post-combustion**: This system involves the capture of CO_2 from all or part of the flue gas stream. A number of technology options are available, as CO_2 is presently captured from a wide range of manufacturing processes, refining and natural gas processing.
- **Oxy-fuel combustion:** This technology entails burning the fuel in high-purity oxygen. This results in high CO_2 concentrations in the flue gas stream and therefore easier separation. Recycled flue gas is used to control combustion temperatures.
- **Pre-combustion**: This option is only suitable for the IGCC generation technology. It involves the separation of hydrogen and carbon dioxide prior to the combustion of the syngas. The technology is widely applied in the manufacture of fertilisers and in hydrogen production.

As the majority of new coal-fired plants in developing APEC economies use pulverised coal firing, at present the only proven capture technology is chemical absorption post-combustion capture. Amine scrubbing appears to be the most likely technology for near-term chemical scrubbing implementation due to its technological maturity.

The assumption of amine as the solvent was made as it is a near-term technology. It is expected that further development and improvement to the technology will be made to reduce both the energy consumed by the regeneration process and the required degree of cleanliness of the flue gas.

3. Capture-ready Definition

There is not yet a universal definition of carbon dioxide 'capture-ready' for coal-fired power plants. However, there has been a significant amount of work done in this area and a consistent definition is starting to emerge. The U.K. Government recently published a position paper on its response to consultation on carbon capture and storage (DECC, 2009). From the position paper, it is clear that it is the intention of the U.K. government not to consent any future applications for plants greater than 300 MWe unless they can be categorized as carbon capture-ready. The ongoing work of the Global Carbon Capture and Storage Institute includes a discussion paper focused on CCS-ready concepts, policy issue and guidelines. It may be expected that a definition will emerge from this work following stakeholder feedback.

The definition proposed by the International Energy Agency (IEA, 2007) was assumed for this study. It states that a plant may be considered capture-ready when CO_2 capture can be included when the necessary regulatory or economic drivers are in place. The definition requires the project developer to demonstrate that factors in their control that would prevent the retrofit of CO_2 capture have been identified and eliminated. Specific aspects that must be considered include:

- A study of options for CO_2 capture retrofit and potential pre-investments
- Inclusion of sufficient space and access for additional facilities
- Identification of reasonable route(s) to the storage of carbon dioxide

4. Issues that impact the development of Capture-ready

A number of issues have been identified which potentially impact the development and implementation of capture-ready plants both globally and within developing APEC economies. These include:

- Lack of clear definition of what 'capture-ready' is and what it involves: It is expected that the work of organisations such as the GCCSI will assist with the development of universal guidelines for the definition of capture-ready.
- Legal issues: In many economies, the legality of CO_2 storage is not known.
- Absence of Clean Development Mechanism (CDM) funding and other financial incentives: As the construction of capture-ready plants does not lead to an immediate reduction in CO_2 emissions, capture-ready plants are not eligible for funding through schemes such as the CDM.
- Lack of industry awareness of what is involved in making a plant capture-ready: Again due to the lack of a universally recognised definition, most utilities are not aware of what is involved in the design of a capture-ready plant.
- Lack of binding commitments at Government level in developing economies to reduce CO_2 emissions: Without government commitments, utilities are unlikely to implement CCS technologies.
- Technological uncertainty: As CCS technology still under development, there is concern that pre-investment for capture readiness may be misguided, should a technological breakthrough occur.
- Carbon dioxide transport & storage risks: Power plant capture readiness is just part of the overall CCS process. CO_2 transport and storage have associated risks that power utilities will be unwilling to accept.
- Public perception: There is diversity in public perception of CCS. There is concern over the possibility of a catastrophic CO_2 leakage event.
- Lack of technical training: Industry engineers are not trained in CCS technology.

5. Planned Coal-fired Plants in Developing APEC Economies

Coal use in developing APEC economies is rising rapidly. It is expected that by 2030, the use of coal is expected to be four times that of 2007 (USAID, 2007). There is therefore an intense power plant construction program presently underway in many of the economies studied here. It is expected that provided the decision to make a plant 'capture-ready' is taken at the appropriate time, future plants may be designed and built as 'capture-ready'.

A survey was conducted of coal-fired power plants in the region that were under construction. This was carried using internal Aurecon data and publicly available data from power industry journals. Table E.1 summarises the number of units and total capacity for a selection of developing APEC economies.

Table E.1 Planned coal-fired power plants as of April, 2009

Economy	No. of units	Total MW
China	196	111,500
Indonesia	11	5,495
Malaysia	5	2,630
Philippines	5	1,600
Thailand	10	6,000
Viet Nam	52	32,100
TOTAL	**279**	**159,325**

For each plant, data was obtained on unit size, steam conditions, emissions controls and whether the plant is a greenfield or brownfield development.

6. Case Study Potential in Developing APEC Economies

An assessment process was adopted to identify the potential for existing coal-fired plant projects to undergo minor modification at the design stage to be made 'capture-ready'. The process included evaluation of the following criteria for each coal-fired power plant project:

I. *Project Timing*:	Examination of the proposed coal-fired power plant construction program. For a plant to be designed to be 'capture-ready', the decision must be made at plant site selection stage. Therefore of the plants in the planned plant database, only those scheduled for commissioning beyond 2015 are likely to be at an early enough stage of development to permit the incorporation of 'capture-ready' design elements.
II. *Proposed site*:	Unless a brownfield development involves demolition of existing units, it is likely that greenfield sites would have less space constraints and more flexibility. Greenfield developments are therefore more desirable from a capture-ready viewpoint.
III. *Plant specification*:	Review of the proposed plant specifications. A number of facets of the plant design are significant for inclusion of 'capture-ready' in the design. For this analysis, it has been assumed that the following attributes would make it simpler to make the plant 'capture-ready': • Planned installation of FGD and $deNO_x$: As current technology CO_2 capture plant requires high-purity flue gas, FGD and $deNO_x$ are essential. Plants already equipped with FGD and $deNO_x$ are therefore, more 'capture-ready', as space for the retrofit of this equipment is not required and the investment in this necessary technology will have already been made. The requirement for $deNO_x$ is not as essential as the requirement for FGD, as it is relatively low cost and easy to retrofit $deNO_x$ equipment. • Unit size: It is expected that it will be more attractive to retrofit carbon capture and storage to plants with larger unit sizes (Deutch, 2009). Reasons for this include economies of scale and a desire to target larger CO_2 emitters. • Supercritical steam conditions: Higher efficiency plants are better candidates for CO_2 capture as the efficiency impact of the capture equipment is reduced.
IV. *Plant Location:*	Assessment of the proximity of the proposed plants to CO_2 storage locations or to other emitters for either a CO_2 hub or pipeline sharing potential. Other considerations here include the CO_2 capacity of the proposed storage location and the certainty of the storage sink.

The assessment process was applied to the plants currently being built in each of the economies studied. The outcome of this was:

China: Excellent potential for case studies. Seventy two units met all criteria except for location and size. This is reduced to 32 when small units are excluded. Eight power plants were identified that meet all selection criteria: comprising 16 units of between 600 and 1000-MW capacity that are to be located between 25 and 150km of high-prospectivity storage basins.

Indonesia: Indonesia has slight case study potential at present. One of the proposed units meets most of the nominated selection criteria, and Indonesia has moderate storage potential. A few proposed plants are to be located close to storage basins, but the plants are either of small unit size or are not planned to have FGD and $deNO_x$. Future coal-fired plant siting may be able to take storage potential into consideration.

Malaysia: Poor case study potential at present. The Malay Basin in the Gulf of Thailand offers moderate CO_2 storage potential. However, Malaysia has only 2 coal based projects at the planning stage and these are for small (<300-MW) units to be located at least 120km from the storage sink. Future coal-fired plant siting may be able to take storage potential into consideration.

Philippines: Poor case study potential. The Luzon basin has poor storage reservoir quality. Furthermore, the planned coal based projects have small (<300-MW) units

Thailand: Poor case study potential. The Thai Gulf Basin has low CO_2 storage prospectivity.

Viet Nam: Moderate case study potential. There is reportedly potential for some offshore storage. Although many of the plants under construction meet the timing and plant specification criteria, the actual storage potential of the offshore basins is not known.

The potential for future plants to designed and built as 'capture-ready' is only constrained by the plant location criteria. Therefore if storage potential is considered in future coal-fired plant site selection decisions, there is significant potential for 'capture-ready' plants in the region. All other criteria described above can be incorporated into the plant design. As most plants currently being built are supercritical with FGD and deNOx, they already meet the 'plant specification' criterion.

7. Typical Coal-fired Power Project in the Region

To expedite the development of planning and design modifications for 'capture-ready' coal-fired plants, the concept of a *typical* coal-fired plant project for the region was developed. A 2 x 600-MW configuration was selected for the typical plant as:

- The 600-MW size is becoming a standard size for Chinese power plant manufacturers. As the rate of plant construction in China slows, Chinese power plant construction companies are building offshore in other economies in the region
- The surveyed data found that the 600 -MW size class is both the mean and median unit size for new coal-fired plants in the region. This unit size represents almost 50% of the planned capacity additions for the region over the next 5 years. The guidelines presented here would be valid for unit capacities of between 500 and 700 MW.

Therefore, for this study, the capture-ready guidelines have been based on the 600-MW size class, and specifically a plant of 2 x 600-MW capacity. It is expected that conclusions applicable to many future projects will be able to be drawn from the capture-ready guidelines developed for the typical plant.

A generic layout was of the power block was developed for a two-unit station. The drawing was provided in Chapter 7. Features of the layout included:

- In-line arrangement of turbine, boiler and dust collection plant
- Single stack serving both units

- Turbine hall and switchyard at one end, stack at other
- Wet limestone flue gas desulphurisation plant (FGD) located on ‘outside’ of stack
- Total footprint of power block is approximately 310 m x 168 m (5.2 Ha).

Parameter	Specification
Site	Greenfield
Capacity	2 x 600-MW units
Steam conditions	24 MPa / 566C / 566C (supercritical)
Draft plant	2 fans per system (PA, FD, ID)
Dust collection plant	High-efficiency electrostatic precipitator or fabric filter
FGD	Wet limestone scrubbers
$deNO_x$	Selective catalytic reduction (SCR)
Cooling system	Wet cooled (coastal or wet cooling towers)
Design coal	Internationally traded thermal coal

8. Planning Guidelines

In developing economies where capital funding is limited, the concept of the minimum or lowest ‘capture-ready’ pre-investment was explored. A ‘lowest pre-investment’ case was developed, which satisfies the IEA definition of capture-ready, but only requires minimal plant modification

It was assumed that the lowest pre-investment option would provide only modifications necessary not to preclude the possibility of the future retrofit of the plant with carbon capture and storage (in accordance with the IEA capture-ready definition). The generic power plant layout for the 2 x 600-MW plant presented in Chapter 7 was modified to allow for the future capture equipment.

The main items included in the planning guidelines include the following. For comparison, a high pre-investment option is also included:

	Lowest Investment Future scrubbing of 50% of the flue gas, resulting in approximately 45% of CO_2 removal	**High Pre-Investment** Future scrubbing of 100% of the flue gas, resulting in approximately 90% of CO_2 removal
Plant layout	– No change to location of major plant items; – Stack moved 60m further from boiler; – Longer flue gas ducts; – Space allowance for auxiliary boiler and CO_2 capture & compression equipment	– Larger boiler footprint; – Stack moved 85m further from boiler; – Longer flue gas ducts; – Space allowance for CO_2 capture & compression equipment
Additional site area	Total site area 2.9 Ha (9%) larger	Total site area 4.3 Ha (13%) larger
Major equipment:		
Boiler	No change	43% higher steam generation capability
Flue gas emissions control	No change	Sized to allow for greater flue gas flow
Turbine	No change	No change

9. Cost Assessment Guidelines

Based on the plant modification guidelines discussed in Chapter 8, estimates were made of the change in expected construction cost of the different plant areas for the lowest pre-investment case. These values are based on the expected extent of plant modifications and are tabulated in Table E.2.

Table E.2 Lowest Pre-investment plant area incremental cost increases

	Lowest Investment Capture-ready	Cost change (%)
Plant layout	Longer flue gas ducts	4% higher cost of ducts & stack
Site area	Space allowance for auxiliary boiler and CO_2 capture & compression equipment. Total site area 2.9 Ha (9%) larger	8% higher cost of site preparation
Boiler & turbine	No change	0

The corresponding % cost change for the highest pre-investment case is not detailed here as it was taken directly from NETL (2007).

Overall change in plant construction cost

The estimated incremental construction cost associated with making each plant area ‘capture-ready’ was used to estimate an overall cost of capture readiness for the lowest and high pre-investment options. The ‘CR factor’ represents the ratio of the capture ready cost to unmodified cost of the particular plant area. A bolded value means that the factor is greater than unity. These results are presented in Table E.3.

Table E.3 Overall changes in plant construction cost

	Proportion of Plant Cost	Lowest Investment		High Pre-investment*	
		CR factor		CR factor	
Coal handling system	4.2%	1.00	4.2%	1.25	5.2%
Boiler & auxiliaries	35.8%	1.00	35.8%	1.28	45.8%
Turbine & auxiliaries	21.6%	1.00	21.6%	1.22	26.4%
Flue gas cleanup	14.6%	1.00	14.6%	1.31	19.1%
Ducts & stack	4.1%	1.04†	4.3%	1.07	4.4%
CW system	4.3%	1.00	4.3%	1.75	7.5%
Electrical	5.4%	1.00	5.4%	1.55	8.5%
C& I	2.3%	1.00	2.3%	1.19	2.8%
Site improvements	1.6%	1.08†	1.7%	1.12	1.7%
Buildings & structures	6.1%	1.00	6.1%	1.10	6.7%
	100.0%		100.3%		128.2%

*from NETL, (2007)
† Aurecon calculation, estimated from modification described by NETL, (2007)

The above table shows that:

- The only plant areas with a higher cost for the low pre-investment case are the ducts & stack and site improvements or preparation. In contrast, for the high pre-investment case, all plants areas experience an increase in cost.
- The total additional cost of making a plant ‘lowest investment’ capture-ready is approximately 0.3% of the total plant construction cost (excluding land acquisition)

– The additional cost of making a plant 'high pre-investment' capture-ready is approximately 28% of the total plant construction cost (NETL, 2007) (excluding land acquisition)

10. Additional Analyses Required

The following areas were identified as potential shortcomings in the current knowledge base that make advancing the case study projects difficult:

I. Data on actual CO_2 storage potential as distinct from 'storage prospectivity' in developing APEC economies is required. The concept of 'capture-ready' is meaningless unless a CO_2 storage location has been identified.

II. Storage prospectivity and potential in the Viet Nam region. Viet Nam was not included in the 2005 APEC study on regional storage prospectivity. As there is significant coal-fired plant construction program presently underway in Viet Nam, knowledge of potential storage sites is essential for any capture-ready case study.

III. Mechanisms to facilitate the development of capture-ready plants. There are presently few mechanisms that foster the construction of capture-ready plant. Measures that encourage the construction of capture-ready plants are essential to facilitate uptake of the concept.

IV. Demonstration projects are required that prove that post-combustion CCS is viable. Utilities are reluctant to build CO_2 capture-ready plants when there is a lack of demonstrated industry experience with the post-combustion capture technology.

V. At this point is not proven that post-combustion capture will be the preferred technology for PF coal-fired plant CCS retrofit. Other prospective technologies, such as oxy firing have good potential as an option for low pre-investment capture-ready designs. Without a clear definition of the preferred technology for retrofit, it is difficult to progress case studies.

1. Introduction

This report describes project EWG 01/2008A conducted by Aurecon Australia Pty Ltd on behalf of APEC. It considers new coal-fired power plants in the subject economies and develops guidelines for planning the development of capture-ready coal-fired power plants.

1.1 Background

It has been widely acknowledged internationally and within the APEC region that carbon dioxide capture and storage (CCS) is an essential component of any scenario to reduce global CO_2 emissions. At the Hokkaido G8 summit in July 2008, a statement was released recommending the construction of 20 large CCS projects to commence globally by 2010. In addition, the International Energy Agency (IEA) in October 2008 stated *"In the power and industrial sectors alone, CCS could contribute nearly one-fifth of the reductions needed to halve back greenhouse gas emissions by 2050, and this at reasonable cost. - CCS is therefore essential to the achievement of deep emission cuts."*

Developing economies in the APEC region have an average annual growth in GDP of 7% per annum, compared to the overall APEC economy average GDP growth of 5.5%. This is driving increases in power demand and the need for additional coal based power generation. In China, with its 11% p.a. GDP growth, the construction of new power plants is proceeding at an astounding rate. Between 2005 and 2007, there was around 80GW of new coal-fired plant built. Elsewhere in APEC economies, there is also steady growth in electricity demand, and the construction of new coal-fired power plants. Countries, such as Mexico, Thailand, Malaysia and Vietnam, have had strong increases in coal based generating capacity over the past few years

As this construction rate continues, there is an opportunity to incorporate carbon dioxide 'capture-ready' philosophies into the plant designs to ensure that future retrofit of CCS can be carried out in a financially viable manner at some time in the future.

1.2 Objectives

The primary objective of the project is to develop guidelines for planning and cost assessment in relation to making future coal-fired plants in developing APEC economies 'capture-ready' as an aid to capacity building on carbon capture and storage in these economies. These guidelines will be underpinned by case studies of new plants which incorporate 'carbon ready' into the plant design and layout. The results of the case studies will be used for the development of generic planning guidelines for capture-ready plants.

1.3 Definition of capture-ready

There is not yet a universal definition of carbon dioxide 'capture-ready' for coal-fired power plants. However there has been a significant amount of work done in this area and a consistent definition is starting to emerge. The work carried out at MIT (Bohm, 2006) provided a sound basis for subsequent development of a definition by the International Energy Agency (IEA, 2007).

The definition proposed by the International Energy Agency states that a plant may be considered capture-ready when CO_2 capture can be included when the necessary regulatory or economic drivers are in place. The definition requires the project developer to demonstrate that factors in their control that would prevent the retrofit of CO_2 capture have been identified and eliminated. Specific aspects that must be considered include:

- A study of options for CO_2 capture retrofit and potential pre-investments
- Inclusion of sufficient space and access for additional facilities
- Identification of reasonable route(s) to the storage of carbon dioxide

1.4 Scope

As defined by APEC's Request for Proposal EWG 01/2008A, the scope of the study included:

- Review of experience to date in APEC and OECD economies, in the International Energy Agency, and in other relevant international bodies relevant to the technical, cost, and other issues that may impact the development of carbon-capture-ready power plants.
- Identification of relevant data and information needed to define CO_2 Capture-Ready specific to APEC developing economies
- In cooperation with EGCFE members and other experts from government and industry responsible for new coal-fired power generation planning and construction in developing APEC economies, including women experts, either: (1) identify a number of suitable power plant projects in the early siting, planning, and design stages can serve as case studies or (2) develop conceptual plant designs for plants that will be built in developing APEC economies from which conclusions can be drawn.
- Work with appropriate experts to carry out the case studies and synthesize the results.
- The identification and assessment of any potential gender implications of the projects that are the subject of the case studies, with input from women experts.
- Development of a set of general planning and cost assessment guidelines for making new coal-fired power generating plants in developing APEC economies CO_2 capture-ready.
- Identification of any additional detailed engineering and economic analyses necessary to provide a full assessment of CO_2 capture-ready power plants specific to APEC developing economies

1.5 Assumptions

As there is a variety of coal based power generation technologies, various options for CO_2 capture and no universally accepted definition of capture-ready, a number of assumptions have been made in preparing this report:

- Coal-fired plant design: Power generation technology has been assumed to be pulverised coal-fired with super-critical steam conditions.
- Capture technology: A chemical scrubbing post-combustion capture technology has been assumed.
- Capture-ready definition: The definition proposed by IEA (2007) has been adopted.

The above assumptions are explained in the relevant sections of the report.

2. Carbon Dioxide Capture

Carbon dioxide capture and storage is a process consisting of (IPCC, 2005):

i) Capture or separation of CO_2 from industrial and energy related sources
ii) Transport of CO_2 to a storage location
iii) Injection into storage site for long term isolation from the atmosphere

When coal or natural gas is burned for power generation, a flue gas stream comprising predominantly nitrogen, carbon dioxide, water vapour and oxygen is produced. The CO_2 concentration of the flue gas is 12 to 15% by volume for coal-fired plants. For a large coal-fired power plant, the flue gas production rate is very high. For example, a 600-MW coal-fired power plant operating at its rated capacity may produce between 800 and 850 cubic metres of flue gas per second (m^3/s) (Aurecon calculations).

The storage of CO_2 from sources such as power plants requires that the CO_2 is first isolated from other gases. This is because it would be impractical to store flue gas with all its constituents due to costs associated with transportation and compression as well as storage space considerations (GCEP, 2005). The following sections will describe the technology options for separation of CO_2 from the flue gas streams of fossil fuel fired power plants and options for long term isolation from the atmosphere.

2.1 Available Capture Processes

There are three main CO_2 capture processes that have been demonstrated or proposed for coal-fired power plants (EPRI, 2006):

- **Post-combustion**: This system involves the capture of CO_2 from all or part of the flue gas stream. A number of technology options are available, as CO_2 is presently captured from a wide range of manufacturing processes, refining and natural gas processing.
- **Oxy-fuel combustion:** This technology entails burning the fuel in high-purity oxygen. This results in high CO_2 concentrations in the flue gas stream and therefore easier separation. Recycled flue gas is used to control combustion temperatures.
- **Pre-combustion**: This option is only suitable for the IGCC generation technology. It involves the separation of hydrogen and carbon dioxide prior to the combustion of the syngas. The technology is widely applied in the manufacture of fertilisers and in hydrogen production.

These capture systems are discussed in detail in the following sections.

2.1.1 Post-Combustion Carbon Dioxide Capture

Post-combustion capture processes are presently the subject of significant development effort due to their suitability for retrofit to existing power plants. There are several technologies that are either presently used or have been proposed for the removal of CO_2 from flue gas streams. They include:

Chemical absorption processes: These are based on chemical solvents and are currently the preferred option (IPCC, 2005) for post-combustion CO_2 capture. Absorption processes in post-combustion capture make use of the reversible nature of the chemical reaction of an aqueous alkaline solvent, usually an amine, with an acid. Typically, post-combustion capture involves two stages: First, flue gas is passed through an absorber, where a solvent removes most of the CO_2 through a chemical reaction. Then this CO_2-rich solvent goes to a stripper, where it is heated to release the CO_2 and produce a regenerated solvent, which is returned to the absorber. Figure 2.1 illustrates the process schematically.

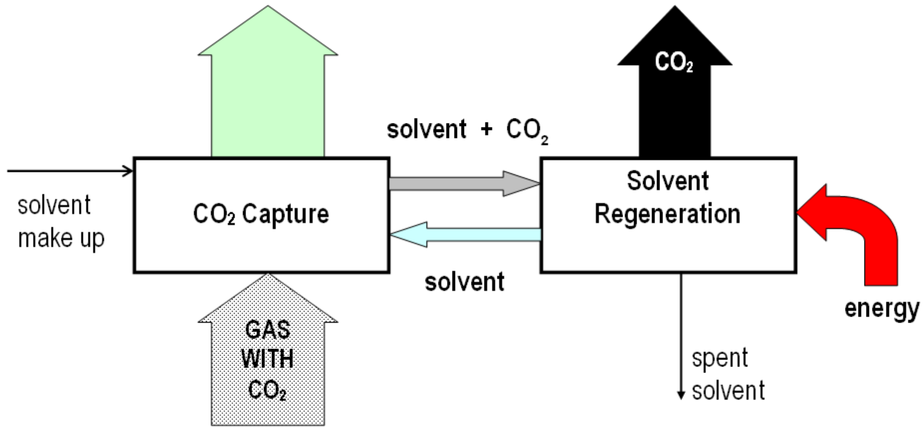


Figure 2.1 Schematic of Chemical Absorption CO_2 Capture Process

Physical absorption: Physical absorption processes involve the use of absorbents that allow CO_2 to permeate a solid or liquid under given conditions, and to desorb under other controlled conditions. Physical solvent scrubbing of CO_2 is established, with Selexol, a liquid glycol based solvent having been used by the natural gas industry for many years. A characteristic of the Selexol process is the low pressure release of CO_2, resulting in additional compression following release.

Membrane separation: Membrane separation systems comprise thin barriers that allow the selective permeation of certain gases, allowing a particular gas to pass through at a higher rate than others. This type of gas separation has been widely used for hydrogen recovery in ammonia synthesis, removal of CO_2 from natural gas and nitrogen separation from air (GGEP, 2005). Figure 2.2 provides a schematic illustration of the membrane separation concept.

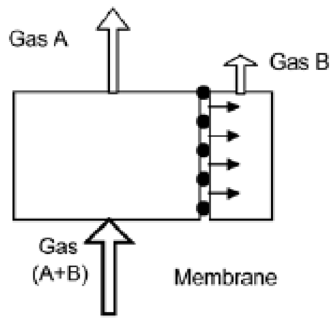


Figure 2.2 Membrane Separation Process

Solid sorbents: Under some conditions, CO_2 can undergo a reversible chemical reaction with a dry absorbent material. The chemical reaction can later be reversed by changing the conditions, resulting in the release of pure CO_2.

Cryogenic separation: Cryogenic separation or low temperature distillation allows separation of CO_2 from O_2/N_2 gas mixtures due to the differing boiling points of these gases. A characteristic of this method of separation is the high refrigeration energy requirement.

2.2 Technology Status

A number of the proposed CO_2 capture technologies are still at the laboratory or pilot stage and therefore are not be suitable for coal-fired power generation at present. Table 2.1 lists the carbon dioxide capture technologies that have been identified and indicates the state of development of the technology.

Table 2.1 Commercial Status of Potential CO_2 Capture Technologies

Capture Type	Technology	Status of Development
Post combustion	Chemical absorption - amine	Economically feasible under specific conditions
	Chemical absorption - chilled ammonia	Demonstration phase
	Membrane separation	Economically feasible under specific conditions
	Solid sorbent	Research phase
	Cryogenic	Economically feasible under specific conditions
Oxy-fuel Combustion		Demonstration phase
Pre-combustion	Physical absorption - Selexol	Economically feasible under specific conditions
	Physical absorption - Rectisol	Economically feasible under specific conditions

Critical factors that impact the suitability of the CO_2 capture technology to be used with coal-fired power generation include:

- maturity and timeframe for availability
- construction cost
- energy consumption and impact of system on power plant output and efficiency
- operating costs
- CO_2 capture efficiency
- requirement for gas pre-treatment

Recent studies suggest that the largest near-term contribution to reducing the cost of post-combustion capture could come from finding better solvents for absorbing and desorbing CO_2, specifically solvents that could process larger amounts of CO_2 for a given mass of solvent and that would require less energy to drive the desorption process (EPRI, 2007). Two carbon dioxide capture technologies that are at or nearing commercialisation are discussed further below with respect to these parameters.

2.2.1 Amine Solvent Process

The most commonly used chemical absorption process for CO_2 capture uses monoethanolamine (MEA) as a solvent. The process is widely used in the beverage industry and for chemicals production.

Carbon dioxide in the gas phase dissolves into a solution of water and amine compounds. The amines react with CO_2 in solution to form protonated amine (AH^+), bicarbonate (HCO_3^-), and carbamate (ACO_2-) (GCEP, 2005). As these reactions occur, more CO_2 is driven from the gas phase into the solution due to the lower chemical potential of the liquid phase compounds at this temperature. When the solution has reached the intended CO_2 loading, it is removed from contact with the gas stream and heated to reverse the chemical reaction and release high-purity CO_2. The CO_2-lean amine solvent is then recycled to contact additional gas. The resulting pure CO_2 stream is recovered at pressures near atmospheric pressure. Compression, and the associated energy costs, would be required for geologic storage. Research on improved solvents with reduced regeneration energy is underway.

Commercial amine absorption systems are available from a number of vendors and are capable of the removal of between 80 and 95% CO_2 in a flue gas stream. They have a relatively low CO_2-loading capability and a relatively high energy requirement for regeneration (EPRI, 2007). A study by EPRI found that the scale up of the MEA technology to coal-fired power plant size would result in a system that would reduce the net power output of the power plant by 29% (EPRI, 2007).

It is essential that acid gases such as NO_x and SO_x be removed from the flue gas prior to passing through the absorber tower. NO_x and SO_x reacts with the amine and will result in a reduction in solvent performance and higher chemical consumption.

2.2.2 Chilled Ammonia Process

This process is also a chemical absorption process but using ammonia rather than an amine as the solvent. Ammonia reacts with CO_2 and water to form ammonium carbonate or bicarbonate. An advantage of chilled ammonia over amine systems is the low temperature solvent regeneration (Ericson, 2006).

Alstom (a French company who provide equipment and services for power generation and rail transport) is one of the companies developing the process. A system is proposed to be installed on American Electric Power's (AEP) 1300-MWe Mountaineer plant in West Virginia, USA. The pilot installation is planned to treat a 100,000 tonnes per annum slip-stream on the existing plant. AEP stated (AEP, 2007) that they have plans for a commercial installation on a 450-MWe unit at their North Eastern Station in Oklahoma.

EPRI, Alstom and We Energies recently completed testing of a 1.7-MW chilled ammonia capture technology pilot plant. The plant used flue gas from an operating coal-fired power plant. The testing which commenced in 2008 successfully demonstrated 90% CO_2 capture. (EPRI, 2009). As this technology is not as developed as amine scrubbing it is also unlikely to be commercially available until at least 2020 (Dalton *et al*, 2007).

A lower energy requirement for sorbent regeneration should result in a lower overall power consumption and reduced impact on overall plant efficiency and output.

2.2.3 Pre Combustion Capture Processes

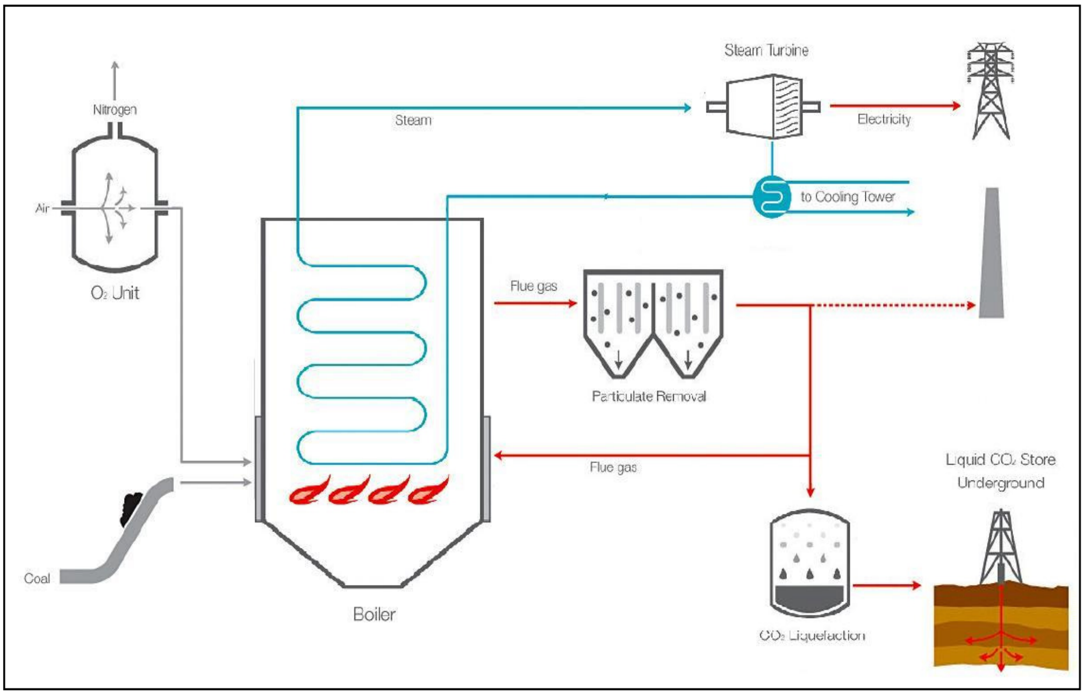
Solvent capture units are presently available at power plant scale. Selexol and Rectisol are trade names for an acid gas removal solvents that can separate acid gases such as hydrogen sulfide and carbon dioxide from feed gas streams, such as synthesis gas produced by gasification of coal, coke, or heavy hydrocarbon oils.

Existing Integrated Gasification Combined Cycle (IGCC) facilities use these processes for the removal of sulphur from syngas prior to combustion. Processes, such as Selexol and Rectisol, are applicable to gas streams that have a high CO_2 partial pressure or total pressure. High-pressure syngas from a coal gasification system is such a gas stream. Solvents, such as Selexol, absorb the CO_2 for later thermal regeneration. The Selexol process is capable of removing more than 85% of CO_2 from a gas stream.

These processes require energy to regenerate the solvents to remove the CO_2. Capture and CO_2 compression on a 250-MW IGCC plant would require 40-MW of additional auxiliary power consumption (Wibberley *et al,* 2006). The Selexol and Rectisol processes are only applicable to IGCC technology. As such they are not suitable for use with pulverised coal power plants.

2.2.4 Oxy-Fuel Combustion Capture Systems

Oxy-firing involves the combustion of a fossil fuel in a mixture of oxygen and recirculated flue gas in order to reduce the net volume of flue gases from the process and to substantially increase the concentration of carbon dioxide in the flue gas. Oxygen combustion combined with flue gas recycle increases the CO_2 concentration of the flue gas from around 15% for conventional pulverised fuel firing up to a theoretical 95% (CCSD, 2007). An oxy-fuel system is illustrated in Figure 2.3.



http://www.callideoxyfuel.com/

Figure 2.3 Oxy-fuel Combustion System for Pulverised Coal-fired Plant

The full-scale application of oxy-fuel technology is still under development. There have been a number of investigations using pilot-scale facilities in the US, Europe, Japan, and Canada. Work is presently underway in Australia at Callide power station. Studies have also assessed the feasibility and economics of retrofits and new power plant.

Technical challenges include investigation of flame stability, heat transfer, level of flue gas clean up necessary and acceptable level of nitrogen and other contaminants for CO_2 compression, and corrosion due to elevated concentrations of SO_2/SO_3 and H_2O in the flue gas.

3. Carbon Dioxide Transport and Storage

3.1 Carbon Dioxide Transport

Once separated from other gases and compressed, CO_2 can be transported to the storage site by pipelines, road, ship or rail. In practice, because of the large volume involved, only pipelines and ships are cost-effective options. The pipeline transport of CO_2 is a well understood and practiced activity which has an excellent safety track record (IEA, 2008). In the USA, for example, there are several thousand kilometres of CO_2 pipelines used to transport CO_2 for use in enhanced oil recovery.

CO_2 transportation costs depend strongly on the quantities and, to a lesser extent, on the distances involved (IEA, 2008). For the foreseeable future, transport of CO_2 by pipeline is the most practical and economic option.

3.2 Carbon Dioxide Storage

There are a number of options that have been proposed for the long term isolation or storage of carbon dioxide from the atmosphere. They include (IPCC, 2005):

- Storage of CO_2 in deep geological formations either onshore or offshore
- Deep ocean storage
- Reaction of CO_2 with metal oxides, so as to convert the CO_2 into minerals, such as a metal carbonate

Deep ocean storage is presently seen as unacceptable due to uncertainties surrounding its environmental impact. Mineral carbonation also has environmental issues and is not expected to be able to provide large-scale CO_2 storage. In the medium term, geological storage is considered to be the best option for long-term CO_2 isolation (IEA, 2008).

Several types of geological formations have been the subject of significant research effort to explore their suitability as long term carbon dioxide repositories. These options use technologies that have been developed by the oil and gas industries. The options include:

- Depleted oil and gas reservoirs
- Enhanced Oil Recovery (EOR)
- Deep saline formations
- Deep unminable coal beds

In each of the above options, geological storage of CO_2 is accomplished by injecting it under pressure into rock formations below the earth's surface. Porous rock formations that have previously held gas or oil are obvious candidates for CO_2 storage.

The carbon dioxide storage effectiveness increases with depth, due to hydrostatic pressure influence on CO_2 density (Cook, 2006). Therefore, CO_2 storage in hydrocarbon reservoirs is expected to take place at depths greater than 800m (IPCC, 2005).

The different geological storage options are at varying stages of technological maturity. Enhanced oil recovery is considered to be a mature technology. It has been carried out in Texas, USA, since the 1970s. Carbon dioxide from natural gas processing and oil production is injected for enhanced oil recovery. It has been estimated that 30 million tonnes of CO_2 are injected annually for EOR (IPCC, 2005).

The use of depleted gas or oil reservoirs for CO_2 storage is considered to be economically feasible under certain conditions (Cook, 2006). Depleted oil and gas reservoirs are excellent possibilities for CO_2 storage for a number of reasons. The oil or gas that originally accumulated did not escape, demonstrating the integrity of the reservoir. Also, the geological structure and physical properties of most oil and gas fields have been extensively studied and characterised. Finally, some of the infrastructure and wells already in place may be utilised for handling CO_2 storage operations.

3.3 Storage Potential in Developing APEC Economies

A critical input to this study is knowledge of the carbon dioxide storage potential of the economies considered in this study. A report commissioned by the Asia Pacific Economic Cooperation (APEC, 2005) *"CO_2 Storage Prospectivity of Selected Sedimentary Basins in the Region of China and South East Asia"* has been used here to make assumptions regarding potential storage locations in the region. The desktop study found that the geological storage potential in the region is varied. Some regions have few choices for geological sinks, whereas other economies have a number of choices.

'Prospectivity' is a term used in the exploration for any geological resource, in this case pore volume for CO_2 storage. Prospectivity is a perception in the mind of a geoscientist/explorer of the likelihood that a resource is present in a given area based on the available information. This perception is developed through examining data (if possible), examining existing knowledge, application of established conceptual models and ideally the generation of new conceptual models or applying an analogue from a neighbouring basin or some other geologically similar setting.

Often prospectivity assessment involves an element of professional judgement (experience) and is influenced considerably by the level of uncertainty associated with absence and/or presence of conflicting or confirming data for a concept. When the level of uncertainty is very high, the prospectivity of an area can and will change with new knowledge and changes in economic and technological factors.

In case of this study, some specific aspects that enter into consideration include; distance to sources of CO_2, rate of CO_2 emission of near-by sources, presence of reservoir-seal pairs, extent of reservoir-seal pair, heterogeneity/homogeneity, porosity and permeability, coal presence, coal rank, availability of depleted hydrocarbon field, basin structure, basin age, basin history, pore water salinity, geothermal gradients and pressures. The list is not exhaustive. Availability of information of these factors in the literature for any given basin will vary markedly. Detailed investigation of these matters is not possible in a 'desktop' study.

The study found that China and Indonesia have good storage potential. Malaysia and Thailand have moderate potential, and the Philippines has quite low storage potential. The results of the study were used in Chapter 5 in the identification of potential capture-ready plants in the focus economies.

4. Capture-ready Concept for Coal-fired Power Plants

4.1 Capture-ready Definitions

There is not yet a universal definition of carbon dioxide ‘capture-ready’ for coal-fired power plants. However there has been a significant amount of work done in this area and a consistent definition is starting to emerge. Gibbins (2004) suggested that ‘capture-ready’ referred to a “*plant designed to have CO_2 capture added at some time in the future with minimal impact of lifetime economic performance*”. The work carried out at MIT (Bohm, 2006) provided a solid basis for subsequent development of a definition by the International Energy Agency (IEA, 2007).

Bohm’s definition stated *“A plant can be considered to be capture-ready if, at some point in the future it can be retrofitted with for carbon capture and sequestration and still be economic to operate”.* A fundamental principle of Bohm’s work is that the *“concept of capture-ready is not a specific plant design; rather it is a spectrum of plant decisions that a power plant owner might undertake in the design and construction of a plant”.*

A further complicating factor is the premise that capture-ready not be restricted to capture alone, but needs to embody capture, transport and storage (Liang *et al,* 2007)

The definition proposed by the International Energy Agency provides more practical guidance in the development of capture-ready designs for coal-fired plant, and recognises the imperative of transport and storage elements as well. The IEA (2007) definition states:

- *“It is one which <u>can include CO_2 capture</u> when necessary regulatory or economic drivers are in place”*
- *”…all known factors in their control that would prevent installation and operation of CO_2 capture have been identified and eliminated. This might include:*
  - *A study of options for CO_2 capture retrofit and potential pre-investments*
  - *Inclusion of sufficient space and access for additional facilities that may be required*
  - *Identification of reasonable route(s) to storage of CO_2.”*

A far broader consideration of capture-ready has been proposed by Markusson (2008). His assertion is that the concept of ‘capture-ready’ is clear but the means to measure if a plant is capture-ready is not a simple yes or no decision. It *“rather can be defined at different points on a scale of readiness (which varies for particular plant-capture configurations)”.* Capture readiness can range from a site area allowance to complex modifications to plant design. Another issue identified by Markusson is that the decision to make a plant ‘capture-ready’ is as much an investment decision as a technical one. A trade off will exist between the cost of making a plant ‘capture-ready’ at the construction stage and the cost of the future retrofit of CCS technology. The degree of capture readiness incorporated into the plant design will determine the ultimate cost of CCS retrofit.

The definition proposed by NETL (2008) “…*contains the following requirements:*

- *Plant site should have access to CO_2 storage – either locally or through identified route*
- *Space at the plant site should be available for expansion and addition of plant areas, access to existing plant items, storage of equipment during construction and for the provision of expansion without encroachment into established barrier zones.*
- *The CO_2 capture system should not contribute to an increase in emission rate levels relative to the before capture configuration”*

The European Commission has proposed that all new fossil-fired power plants subject to the EU Large Combustion Plant Directive be capture-ready by 2015 and be retrofitted with CCS by 2025. To implement that policy in England and Wales, the UK government has determined that a proposed power station with a capacity equal to or greater than 300 MWe, and of a type covered by the EU Large Combustion Plant Directive, must be built as carbon capture-ready as long as technical and economic feasibility studies demonstrate that the power station can be retrofitted with CCS technology in the future.

The ongoing work of the Global Carbon Capture and Storage Institute includes a discussion paper focused on CCS ready concepts, policy issue and guidelines. The draft report (ICF, 2009) proposes a definition of 'CO_2 Capture-ready':

> '*A plant that is capable of being retrofitted for CO_2 capture with an acceptable economic cost*. *For any reasonable choice of capture technology may include:*
>
> 1. *Adequate space for equipment and construction*
> 2. *Engineering designs and cost estimates*
> 3. *Pre-investment in capture equipment and related additional facilities*
> 4. *Provisions for environmental permits, public acceptance and construction permits, and*
> 5. *Identification or establishment of required business relationships.*

As none of the above definitions are universally accepted, for this study the IEA definition has been assumed.

4.2 Issues that Impact the Development of Capture-ready

A number of issues have been identified which potentially impact the development and implementation of capture-ready plants both globally and within developing APEC economies. These include:

- <u>Lack of clear definition of what 'capture-ready' is and what it involves</u>: It is expected that the work of organisations such as the Global Carbon Capture & Storage Institute (GCCSI) will assist with the development of universal guidelines for the definition of capture-ready. This will allow policymakers to provide guidelines and utilities to be able to make appropriate decisions when planning new plants.

- <u>Legal issues:</u> In many economies the legality of CO_2 storage is not known. This is further complicated by additional issues associated with offshore geological storage and whether this is consistent with existing international laws.

- <u>Absence of Clean Development Mechanism (CDM) funding and other financial incentives</u>: As the construction of capture-ready plants does not lead to an immediate reduction in CO_2 emissions, capture-ready plants are not eligible for funding through schemes such as the CDM. Other incentives need to be developed to encourage utilities to implement capture-ready designs.

- <u>Lack of industry awareness of what is involved in making a plant capture-ready</u>: Again due to the lack of a universally recognised definition and published precedents, most utilities are not aware of what is involved in the design of a capture-ready plant.

- <u>Lack of binding commitments at Government level in developing economies to reduce CO_2 emissions</u>: Without government commitment and policy to either reduce CO_2 emissions or encourage the development of carbon capture and storage projects, utilities are unlikely to implement CCS technologies.

- <u>Technological uncertainty</u>: As CCS technology still under development there is concern that pre-investment for capture readiness may be misguided, should a technological breakthrough occur.

- <u>Carbon dioxide transport & storage risks</u>: Power plant capture readiness is just part of the overall CCS process. CO_2 transport and storage have associated risks that power utilities will be unwilling to accept. Unless utilities are provided with assurance regarding storage safety they are unlikely to implement CCS.

– Public perception: There is diversity in public perception of carbon capture and storage. The greatest public concern centres on the possibility of a catastrophic CO_2 leakage event. (Shackley *et al*, 2005)

– Lack of technical training: Industry engineers are not trained in CCS technology. Carbon capture and storage is not included in most engineering degrees, therefore CCS and capture-ready are not generally understood by the power industry.

4.3 Capture-ready Experience

Plants are beginning to be built in a number of economies around the world which are being described as 'capture-ready'. This is occurring as the term 'capture-ready' being associated with a coal based project is seen to make it acceptable in many jurisdictions. The European Union has recommended that all new coal-fired power plants should be capture-ready by the end of the decade (Irons *et al*, 2009)

Over recent years a number of proposed coal-fired power plant projects have been claimed to be 'capture-ready. Table 4.1 contains a selection of these 'capture-ready' projects.

Table 4.1 Selection of power plant projects categorised as capture ready

Plant	Utility	Size (MW)	Location	Scheduled Start Up	Comment	Reference
Ferrybridge	RWE	2 x 500	UK	2011/12	brownfield	Farley (2007)
Antwerp	E.ON	1100	Belgium	2012	greenfield	EON (2007)
Kingsnorth	E.ON	2 x 800	UK	2012	brownfield; approx 25% CO_2 capture	GCCSI(2009)
Maasvlakte	E.ON	1100	Netherlands	2013	brownfield	EON (2007)
Coolimba	AES	400 - 450	Australia	2013	greenfield	
Sask-Power		350 - 450	Canada	2013	greenfield	
Tilbury	RWE	1600	UK	2014	brownfield	
Blythe	RWE	3 x 800	UK	2014	brownfield	
Wilhelmshaven	E.ON	550	Germany	2015	brownfield	EON (2007)
Hunterston	Peel Energy	2 x 800	UK	2014	greenfield	
Mt Piper extension	Delta Electricity	2 x 1000	Australia	not stated	brownfield;	DOP (2009a)
Munmorah PS rehabilitation	Delta Electricity	2 x 350	Australia	not stated	brownfield; ~ 45% CO_2 capture	DOP (2009b)

5. Capture-ready Plant Designs

As there is no universally accepted definition of ‘capture-ready’, it follows that what constitutes a capture-ready design is also deficient. There has been work conducted by a number of researchers including Bohm *et al* (2007), Gibbins (2006), IEA (2007), Michener (2007), NETL (2008) and others on what specific plant modifications are necessary to make a plant capture-ready.

A common theme with the above work is that the focus is on pre-investment necessary to achieve ‘capture readiness’. As the work predominantly focuses on plant to be built in OECD countries, its relevance to developing APEC economies may be questionable. Many of the above studies have considered a range of capture technologies including post-combustion capture, oxy-fuel firing and pre-combustion capture.

For this study, it has been assumed that pulverised coal-fired plant would be the most widespread technology used in developing economies. For this reason, pre-combustion capture has been excluded from this study. At present amine scrubbing appears to be the most likely technology for near term chemical scrubbing implementation due to its technological maturity.

The assumption of amine as the solvent represents a ‘worst case’ as it is expected that further development and improvement to the technology will be made to reduce both the energy consumed by the regeneration process and the required degree of cleanliness of the flue gas.

Other assumptions regarding the design of the capture plant include:

- The CO_2 compression is steam driven to minimise the auxiliary power requirements
- The plant will already have FGD and $deNO_x$ fitted

5.1 Design Modifications Proposed By IEA

Appendix C contains a summary of the required plant modifications to make a pulverised coal-fired plant post-combustion CO_2 capture-ready in accordance with the IEA (2007) study. This study was a technical investigation that suggested a range of modifications for making a plant capture-ready.

The considerations proposed by IEA for making a plant capture-ready included:

- Plant space and access requirements for:
  - CO_2 scrubbers
  - Compressors
  - Additional cooling water and electricity systems
  - Pipe work and tie-ins
- Routes to CO_2 storage
- Power plant capture-ready pre-investments
  - Over-sizing pipe-racks
  - Provision for expansion of the control system and on-site electrical distribution These are attractive as they are low cost and can result in significant reductions in the costs and downtime for retrofit.
- PF plants with post-combustion capture
  - If the Power Plant is to be built w/o FGD, provision should be made to add a suitable FGD when CO_2 capture is retrofitted.
  - If the plant is to be built with FGD then it should be designed to meet flue gas requirements for CO_2 capture or have provision to be upgraded.

- Economics for capture-ready pre-investment; reasons for not making major pre-investment
  - Discounting: Economic discounting is a well established economic principle, which means that economic resources in the future are worth less than at present.
  - Uncertainty: Uncertainty regarding future regulations, values of carbon credits and when capture will be required. It is uncertain how technologies will develop in future. The costs of capture technologies are expected to decrease in the future. There is also the possibility that substantially different and better technologies may become available.

The significant conclusions from the IEA work include:

(i) Essential requirements for capture-ready:
  - Inclusion of sufficient space and access for the additional facilities
  - Identification of reasonable route(s) to storage of CO_2.

(ii) Desirable pre-investment for capture-ready:
  - Optional further pre-investment could be made to reduce the cost and downtime for CO_2 capture retrofit
  - Opportunities for substantial economically attractive pre-investment are expected to be limited, unless capture is going to be retrofitted relatively soon after start up of the power plant.

5.2 Design Modifications Proposed By NETL

5.2.1 Plant Modifications

The criterion adopted by NETL for capture readiness was to include the necessary pre-investment to ensure that no loss of output occurred post-retrofit. The plant areas that were increased in capacity included (NETL, 2007):

- Coal handling facilities
- Boiler & auxiliaries
- Dust collection plant & FGD
- Ash disposal
- Cooling system
- Turbo-generator

5.2.2 Financial Benefit of Capture-ready

The NETL (2007) study focussed on the financial benefit of building plants as capture-ready, and considered the timing of the eventual retrofit of capture equipment. The study conclusions included:

- The main benefit for pre-investment is achieved by over-sizing the boiler capacity at construction (plant maintains rated capacity when retrofitted with capture). This is in comparison to a 31% de-rate with a retrofit to an unmodified ('business as usual') plant.
- It does not make economic sense to design a plant to be capture-ready unless the retrofit of capture equipment is to occur within a decade of plant construction. The unmodified plant (business as usual) case is more economically viable if the retrofit occurs more than 10 years after plant construction.

6. Potential for Capture-ready Case Studies in Developing APEC Economies

Coal use in developing APEC economies is rising rapidly. It is expected that by 2030, the use of coal is expected to be four times that of 2007 (USAID, 2007). There is therefore an intense power plant construction program presently underway in many of the economies studied here. Unless the decision to require capture readiness is made at an appropriate time in a power plant building program, many new power plants in APEC developing economies will probably be difficult or impossible to retrofit with CCS should this become desirable at a future time.

6.1 Potential for Capture-ready

The following section describes the assessment process which was adopted in this study to identify the potential for existing projects to undergo minor modification to be made 'capture-ready'.

The process included evaluation of the following criteria:

I. *Project Timing*:	Examination of the proposed coal-fired power plant construction program. For a plant to be designed to be 'capture-ready', the decision must be made at plant site selection stage. Therefore, of the plants in the planned plant database, only those scheduled for commissioning beyond 2015 are likely to be at an early enough stage of development to permit the incorporation of 'capture-ready' design elements.
II. *Proposed site*:	It is expected that a greenfield development is more desirable from a capture-ready viewpoint: Unless a brownfield development involves demolition of existing units, it is likely that greenfield sites would have fewer space constraints and more flexibility.
III. *Plant specification*:	Review of the proposed plant specifications. A number of facets of the plant design are significant for inclusion of 'capture-ready' in the design. For this analysis it has been assumed that the following attributes would make it simpler to make the plant 'capture-ready': • Planned installation of FGD and $deNO_x$: As current technology CO_2 capture plant requires high purity flue gas, FGD and $deNO_x$ are essential. Plants already equipped with FGD and $deNO_x$ are therefore more 'capture-ready', as space for the retrofit of this equipment is not required and the investment in this necessary technology will have already been made. The requirement for $deNO_x$ is not as essential as the requirement for FGD, as it is relatively low cost and easy to retrofit $deNO_x$ equipment. • Unit size: It is expected that it will be more attractive to retrofit carbon capture and storage to plants with larger unit sizes (Deutch, 2009). Reasons for this include economies of scale and a desire to target larger CO_2 emitters. • Supercritical steam conditions: Higher efficiency plants are better candidates for CO_2 capture as the efficiency impact of the capture equipment is reduced.
IV. Plant Location:	Assessment of the proximity of the proposed plants to CO_2 storage locations or to other emitters for either a CO_2 hub or pipeline sharing potential. Other considerations here include the CO_2 capacity of the proposed storage location and the certainty of the storage sink.

A survey was conducted of coal-fired power plants in the region that were under construction. This was carried using internal Aurecon data and publicly available data from power industry journals.

6.2 China

China is considered the largest contributor to global greenhouse gas emissions and is projected to continue to grow with around 28% of an estimated 4800GW global capacity by 2030 (IEA, 2009). China is also estimated to contribute three-quarters of the expected 11Gt increase of CO_2 by 2030 (IEA, 2009). As of August 2009, China had more than 800GW of generating capacity (Reuters, 2009) of which approximately 70% was produced by coal based power station. China's coal consumption accounts for about 30% of coal consumed worldwide which makes it the largest global consumer.

China is one of the few developing APEC economies that is actively participating in assessment of the potential for carbon dioxide capture and storage (USAID, 2007). Table 6.1 summarises a number of the CCS projects that are presently active in China.

Table 6.1 Active and Planned Carbon Capture and Storage Projects in China

GreenGen project	Tianjin - 250-MW IGCC demonstration pre-combustion capture & storage
Huaneng co-gen	Beijing: pilot scale post-combustion capture – 3000 tpa CO_2
CPI IGCC project	Langfang, Hebei 2 x 400 MW; 8% of CO2 for enhanced oil recovery (EOR)
Shenhua coal liquefaction project	Ordos Basin, Inner Mongolia – storage assessment pre-feasibility study

Notwithstanding the present activity in China, a similar methodology for the assessment of the potential for 'capture-ready' has been applied to proposed plants in China and is described below.

6.2.1 Proposed Coal-fired Power Plant Projects

China has an ambitious coal-fired power plant construction program underway. This program includes the construction of approximately 196 units across 105 sites with a total generating capacity of 111.5GW. Information on these projects was obtained from Aurecon's project database and via internet search. Details are provided in Appendix A.

A summary of the key features of these plants is included in Table 6.2. The plants considered are scheduled for commissioning between 2010 and 2015

Table 6.2 Chinese coal-fired generating plants scheduled for commissioning between 2010 and 2015

Unit capacity	Total no.	Greenfield	Steam Conditions				Flue Gas	
			USC	SC	Subcrit	N/A	FGD	$deNO_x$
135 to 350 MW	87	37	0	4	61	22	81	36
600 to 700 MW	70	29	6	47	9	8	38	37
>1000 MW	36	17	32	0	0	4	29	12
Totals	**193**	**83**	**38**	**51**	**70**	**34**	**148**	**85**

There are a number of observations that can be made from the Chinese plant data summarised above and presented in Appendix A:

- 45% of the stations have units in the 135 to 350-MW range. The most common unit size is 300 MW.
- At least half of the plants have either supercritical or ultra-supercritical steam conditions.
- A large proportion of plants are fitted with FGD, and 37% of the plants are planned to have both FGD and deNOx.
- Less than half the plants are greenfield developments.

The potential capture-ready criteria described in section 6.1 were considered and applied to the 105 planned plants detailed in Appendix A. As China is now building larger supercritical units with both FGD and deNOx, there are a number of plants with case study potential. A shortlist of plants which are planned for commissioning in 2013 and beyond, are greenfield developments, of supercritical (or USC) design and have at least FGD fitted were identified. These plants are listed in Table 6.3.

Table 6.3 Planned Chinese coal-fired plants: (Greenfield, FGD, Supercritical, >350 MW)

	Project Name	Location	Planned Start Date	(No. Units x MW)	deNO$_x$	FGD
1	Shanghai Caojing Power Plant	Jingshan district, Shanghai	2013	2 x 1000 MW	➼	➼
2	Henan Pingdingshan Second Power Plant	Pingdingshan city, Henan Province	2013	2 x 1000 MW	➼	➼
3	Guangdong Pinghai Power Plant	Huizhou city, Guangdong Province	2013	2 x 1000 MW	➼	➼
4	Datang Nanjing Xiaguan Power Plant Relocation Projects	Qixia district of Nanjing City, Jiangsu Province	2014	2 x 600 MW	➼	➼
5	Fujian Shishi Thermal Power Plant	Shishi City, Fujian Porvince	2013	2 x 600 MW	➼	➼
6	Hainan Huneng Dongfang Power Plant	Dongfang city, Hainan province	2013	2 x 350 MW	➼	➼
7	Inner Mongolia Guohua Hulunbeir Power Plant	Hulunbeir City, Inner Mongolia	2013	2 x 600 MW	➼	➼
8	Henan Taisu Mengjing Power Plant	Mengjing city, Henan Province	2013	2 x 600 MW	➼	➼
9	China Resources Wenzhou Cangnan Power Plant Phase 1	Wenzhou city, Zhejiang Province	2014	2 x 1000 MW		➼
10	Guodian Xingyang Power Plant	Xingyang City, Henan Province	2013	2 x 600 MW		➼
11	Huaneng Haimeng Power Plant Phase 1	Shantou city, Guangdong Province	2013	2 x1000 MW		➼
12	Minquan power plant phase 1	Minquan city, Henan Province	2013	2 x 600 MW		➼
13	Ningxia Shuidonggou Power Plant	Lingwu city, Ningxia	2013	2 x 600 MW		➼
14	Sichuan Huadian Gongxian Power Plant Phase 1	Yibin city, Sichuan Province	2013	2 x 600 MW		➼
15	Jilin Baicheng Power Plant	Baicheng city, Jilin Province	2013	2 x 600 MW		➼
16	Guodian Shangqiu Mingquan Power Plant	Shangqiu city, Henan Province	2013	2 x 600 MW		➼

6.2.2 CO_2 Storage Potential in China

An essential element of capture-ready is the identification of reasonable routes to storage of CO_2. The APEC project "CO_2 Storage Prospectivity of Selected Sedimentary Basins in the Region of China and South East Asia (APEC Energy Working Group Project 06/3003, June 2005), summarised the storage prospectivity of economies in the region.

Table 6.4 below summarises the results of the 2005 APEC project situation regarding CO_2 storage prospectivity in China.

Table 6.4 Summary of CO_2 Storage Prospectivity in China

Basin	Storage Potential	Location
Songliao Basin	High prospectively, ranked 1st in CO_2 storage potential in China.	Northern China
Subei Yellow Sea Basin	High prospectivity	Yellow Sea (on/off shore basins)
Bohai wan Basin	High prospectivity, linked to the Songliao Basin	Northern China (on/off shore basins)
Beibuwan Basin	Intermediate/unresolved prospectivity	South China Sea
East China Sea Basin	Intermediate/unresolved prospectivity	South China Sea
Jianghan Basin	Intermediate/unresolved prospectivity	Eastern China
Nanyyang Basin	Intermediate/unresolved prospectivity	Eastern China
Pearl River Mouth Basin	Intermediate/unresolved prospectivity	South China Sea
Shiwan Dashan Basin	Intermediate/unresolved prospectivity	Southern China/Viet Nam
Taikang Hefei Basin	Intermediate/unresolved prospectivity	Eastern China
Taixian Basis	Intermediate/unresolved prospectivity	South China Sea
Nanpanjiang Depression	Low prospectively	Southern China
Ordos Basin	Low prospectively	Central China
Sichuan Basin	Low prospectively	Central China
Yinggehai Basin	Low prospectively	South China Sea/Viet Nam

6.2.3 Potential for Capture-ready Power Plants in China

Four evaluation criteria for carbon capture-ready power plants were identified in section 6.1. The list of 196 units planned for construction was shortlisted to 16, based on the first three selection criteria: project timing, proposed site and plant specification. These 16 projects are shown in table 6.3 (paragraph 6.1).

The final screening of the shortlisted sixteen plants has been based on the assessment of plant location for the following criteria:

- Proximity to CO_2 storage locations
- CO_2 storage capacity of the proposed storage location
- Certainty of storage location
- Proximity to other emitters/ potential for sharing pipeline and/or other infrastructure

Appendix B details the location of the short listed power plants. In this figure, the relevant sedimentary basins and their CO_2 storage prospectivity are also shown.

Based on the selection criteria as described above, the plants have been divided in four categories from most suitable (“1”) to least suitable (“4”). Eight plants were considered more likely candidates for carbon capture & storage and are depicted in Table 6.3.

Five proposed plants are located ideally at or within 25 km from a high-prospectivity basin therefore these plants are the most suitable to be considered for “carbon capture-ready” design. Two of these plants have been categorised as “1”; however, three of these plants do not have deNOx incorporated in the current design and therefore require some more modifications and additional capital expenditure. Those three plants have been graded as “2” for this reason. A fourth plant has been categorised “2” as it has deNOx incorporated in the design but requires a 150 km pipeline to a high prospectivity basin.

In addition to the six plants above, two more plants are worth consideration. Both plants are a fair distance away from high prospectivity basins. The opportunity for sharing of pipeline and injection infrastructure, which would share its costs between several emitters was the major reason to consider those plants.

Table 6.5 Suitability for Carbon Capture & Storage Ready Power Plants

	Plant Name	Capacity	Estimated CO_2 (Mtpa)	Basin Name	Basin Prospectivity	Distance (km)
1	Henan Taisu Mengjin Power Plant	2 x 600 MW	8.0	Bohai Wan	High	0
	Datang Nanjing Xiaguan plant relocation projects	2 x 600 MW	8.0	Subei Yellow Sea	High	25
2	Jilin Baicheng power plant	2 x 600 MW	8.0	Songliao	High	0
	Guodian Shangqiu Mingquan power plant	2 x 600 MW	8.0	Taikang Hefei	Intermediate	0
				Bohai Wan	High	25
	Minquan power plant Phase 1	2 x 600 MW	8.0	Taikang Hefei	Intermediate	0
				Bohai Wan	High	25
	Henan Pingingshan Second power plant	2 x 1000 MW	12.6	Taikan Hefei	Intermediate	0
				Bohai Wan	High	150
3	Guodian Xingyang power plant	2 x 600 MW	7.6	Taikan Hefei	Intermediate	0
				Bohai Wan	High	350
	Shanghai Caojing power plant	2 x 1000 MW	12.6	Subei Yellow Sea	High	300

6.3 Indonesia

Indonesia has reserves of coal, gas and oil. The generating mix reflects this, with the installed electrical generating capacity estimated at 24.7 GW, with 80 percent coming from thermal (oil, gas, and coal) sources, 18% from hydropower, and 2% from geothermal (EOE, 2009). Demand for electricity is expected to grow by approximately 6-7 % per year.

6.3.1 Proposed Coal-fired Power Plant Projects

The contribution of coal to Indonesia’s energy mix is expected to continue to increase over the next decade. There are currently around six coal-fired power plant projects at the planning stage. Details of the plants are provided in Appendix A. A summary of the types of plant is provided in Table 6.6.

Table 6.6 Coal-fired Generating Units in Indonesia Scheduled for Commissioning between 2010 and 2015

Unit Capacity	Total No.	Greenfield	Steam Conditions				Flue Gas	
			USC	SC	Subcrit	N/A	FGD	deNO$_x$
<300 MW	6	4	0	0	0	6	4	4
600-750 MW	2	0	0	0	0	2	2	0
800-1000MW	3	2	0	2	0	1	3	0
Totals	**11**	**6**	**0**	**2**	**0**	**9**	**9**	**4**

The table shows that the plants with both FGD and deNO$_x$ are in the smaller size range. There are two 1000-MW units with FGD planned for construction on a greenfield site in Central Java. Even though deNO$_x$ equipment is not planned, these units may be case study candidates as deNO$_x$ may be retrofitted at low cost along with the capture equipment.

6.3.2 CO_2 Storage Potential in Indonesia

The earlier APEC project (APEC, 2005) concluded that Indonesia had moderate storage prospectivity. Table 6.7 summarises the prospectivity of a number of storage basins in and around Indonesia.

Table 6.7 Summary of CO_2 Prospectivity in Indonesia

Basin	Storage Potential	Location
NW Java Basin	Good prospectivity	Java
East Java Basin	Very good prospectivity	Java
Kutei Basin	High prospectivity	Kalimantan
North Sumatra		Northern Sumatra (on/off shore basins)
Central Sumatra Basin	Very good prospectivity	Sumatra (on/off shore basins)
Southern Sumatra Basin		Southern Sumatra

6.3.3 Potential for Capture-ready Power Plants in Indonesia

The 2 x 1000-MW plant in Central Java is less than 50km from a CO_2 storage site categorised as having good storage potential. However, as this plant is not planned to have deNO$_x$ equipment fitted, it does not meet our case study selection criteria.

In conclusion, Indonesia has slight case study potential at present. One of the proposed units meets most of the nominated selection criteria, and Indonesia has moderate storage potential. A few proposed plants are to be located close to storage basins, but the plants are either of small unit size or are not planned to have FGD and deNO$_x$.

6.4 Malaysia

Malaysia has approximately 17.6 GW of electric generation capacity, of which 87% is thermal and 13% is hydroelectric. The Malaysian government has adopted a policy of attempting to reduce the Malaysia's heavy reliance on natural gas for electric power generation – resulting in the recent construction of around 4GW of coal based generation. This has resulted in coal's proportion in the generating mix rising from 28% in 2004 to 40% in 2009.

6.4.1 Proposed Coal-fired Power Plant Projects

The intensive coal-fired plant construction program over the past 5 years has slowed. There are presently believed to be just 2 coal-fired plants planned for construction in Malaysia.

These stations include a 1 x 300-MW station in the Dent Peninsular and a 1 x 233-MW station in Sabah. These stations are ~200km and ~320km from storage sites respectively.

6.4.2 CO_2 Storage Potential

The Malay Basin in the Gulf of Thailand offers moderate CO_2 storage potential (APEC,2005).

6.4.3 Potential for capture-ready power plants in Malaysia

Malaysia has poor case study potential at present. The Malay Basin in the Gulf of Thailand offers moderate CO_2 storage potential. However Malaysia has only 2 coal based projects at the planning stage and these are for small (<300-MW) units to be located at least 120km from the storage sink.

6.5 Philippines

6.5.1 Proposed Coal-fired Power Plant Projects

Aurecon identified 3 projects at the planning stage in the Philippines. The projects had unit sizes in the range 200 to 300 MW.

6.5.2 CO_2 Storage Potential

The prospectivity for storage in the Philippines is very low. The Luzon basin has poor reservoir quality (APEC 2005).

6.5.3 Potential for Capture-ready Power Plants in Philippines

The Philippines has poor case study potential. The Luzon basin has poor storage reservoir quality and the planned coal-based projects comprise small (<300-MW) units.

6.6 Thailand

After many years of strong growth, Thailand’s economic growth rate fell to 2.6% in 2008 (CIA, 2009). The Thai electric utility and petroleum industries, which historically have been state-controlled monopolies, have recently been restructured.

6.6.1 Proposed Coal-fired Power Plant Projects

Thailand has more than 25GW of electricity generating capacity –comprised of gas, fuel oil and coal-fired plants. Between 2011 and 2015 around 13 GW of projects are approved to come online. The state-owned utility EGAT will build half of the new capacity, with the other half awarded to Independent Power Producers (IPPs).

Aurecon identified 3 coal-fired power plant projects, comprising 8 units of between 330 MW and 800 MW scheduled for commissioning within the next 5 years. Coal-fired plant projects in Thailand are subjected to significant community opposition due to the public perception of coal as a polluting fuel source. The Map Ta Phut project is to be built in two stages comprising 2 units each. The first two will be sub-critical with FGD and the second two supercritical units with both FGD and $deNO_x$.

6.6.2 CO_2 Storage Potential

The Thai Gulf Basin has low CO_2 storage prospectivity.

6.6.3 Potential for Capture-ready Power Plants

Thailand has poor case study potential as the Thai Gulf Basin is considered to have low CO_2 storage prospectivity. The Map Ta Phut project described above is already past the planning stage and, therefore, unsuitable as a capture-ready case study candidate.

6.7 Viet Nam

Current per capita electricity demand in Viet Nam is among the lowest in the region. However, electricity demand is anticipated to continue to grow at about 16% per year until 2011 (ADB, 2009). The state owned generator EVN expects generating capacity to increase by 3,500 MW to 21,500 MW in 2010.

6.7.1 Proposed Coal-fired Power Plant Projects

A number of new coal-fired plants have been announced by EVN, with almost 10,000 MW of new capacity planned by 2015 (VUSTA, 2007). It is expected that a number of the projects will involve joint ventures with foreign companies.

There are more than 20 coal-fired plants presently under construction and scheduled for commissioning between 2012 and 2016. The plants cover 45 units, ranging in capacity from 300 to 1000 MW. A summary of the plant features is provided in Table 6.8. Details of the individual plants are provided in Appendix A.

Table 6.8 Coal-fired generating plants in Vietnam scheduled for commissioning between 2010 and 2015

Unit Capacity	Total No.	Greenfield	Steam Conditions				Flue Gas	
			USC	SC	Subcrit	N/A	FGD	$deNO_x$
300 MW	5	2	0	0	0	5	2	0
600 to 700 MW	41	16	0	4	0	37	0	0
1000 MW	6	6	0	4	0	2	2	2
Totals	52	24	0	8	0	44	4	2

6.7.2 CO_2 Storage Potential

Viet Nam was not part of the 2005 APEC study. However, based on other reports, limited storage potential exists offshore in depleted oil reservoirs. Potential storage regions include the Jinygehai and Cuu Long basins to the east of Viet Nam. Investigations have been conducted into installing CO_2 capture on new plants and using the CO_2 for enhanced oil recovery (Imai & Reeves, 2004).

6.7.3 Potential for capture-ready power plants

There is poor case study potential in Viet Nam. Although many of the plants under construction meet the timing and plant specification criteria, the actual storage potential of the offshore basins is not known.

6.8 Summary of Candidate Plants for Capture-ready

Across the economies surveyed, the following observations were made regarding new coal-fired plants in developing APEC economies in the region:

- There are more than 250 coal-fired units scheduled for commissioning beyond 2014. These units have a combined capacity of more than 150,000MW. This results in an average unit size of 600 MW.
- The median unit size is also 600 MW. This is illustrated graphically in Figure 6.1
- A large proportion of units have supercritical steam conditions. This data was not available for all of the plants, but 60% of plants where steam conditions were provided, had either supercritical or ultra-supercritical steam conditions specified.
- More than 60% of units are planned to be built with flue gas desulphurisation. $deNO_x$ equipment is to be fitted to more than 25% of units. Around 15% of units are scheduled to be built with both FGD and $deNO_x$.

– Around 25% of units are planned for greenfield construction. A trend appears to be the staged construction of large multi-unit power plants. Therefore the majority of new projects are brownfield plants.

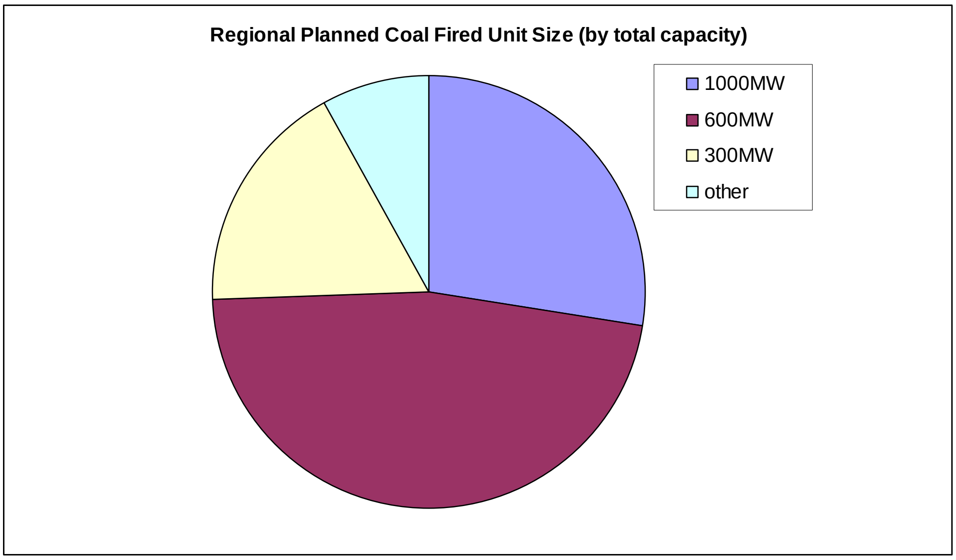


Figure 6.1 Proportion of common unit sizes planned for construction in developing APEC economies

The potential for future plants to designed and built as 'capture-ready' is only constrained by the plant location criteria. Therefore if storage potential is considered in future coal-fired plant site selection decisions, there is significant potential for 'capture-ready' plants in the region. All other criteria described above can be incorporated into the plant design. As most plants currently being built in the region are supercritical with FGD and deNOx, they already meet the 'plant specification' criterion.

7. Typical Coal-fired Plant

7.1 Typical Plant Concept

To expedite the development of planning and design modifications for 'capture-ready' coal-fired plants, the concept of a *typical* coal-fired plant project for the region was explored. Although actual plant specifications and layout are very site specific, generic features of plants in the region have some similarity. It appears that to reduce design and construction costs, most Chinese power plant construction companies have reference plant designs that are applied at many different sites in different economies.

The power plant construction program in China represents the majority of construction in the region. As the rate of plant construction in China slows, Chinese power plant construction companies are building offshore in other economies in the region. It may be, therefore, assumed that the Chinese plants represent designs that are typical of the region. A number of Chinese power plant manufacturers are building 600 MW plants. These companies include Dongfeng Electric Corporation, Shanghai Electric Corporation and Harbin Steam Turbine Co. Ltd.

The data summarised in section 6.9 shows that the 600-MW size class is both the mean and median unit size for new plants in the region. This unit size represents almost 50% of the planned capacity additions for the region over the next 5 years.

Therefore, for this study, the capture-ready guidelines have been based on the 600-MW size class, and specifically a plant of 2 x 600-MW capacity. It is expected that conclusions applicable to many future projects will be able to be drawn from the capture-ready guidelines developed for this typical plant.

7.2 Plant Specification

Table 7.1 defines the plant specification of the typical plant concept. For the purposes of this study, only plant parameters which are impacted by making the plant capture-ready have been included in this report.

Table 7.1 Summary of Typical Coal-fired Plant Specification

Parameter	Specification	Comment
Site	– Greenfield	There are more greenfield projects in region than brownfield. greenfield are more desirable for 'capture-ready'
Capacity	– 2 x 600-MW units	Two unit stations appear to be most common configuration. As the number of units has a large impact on plant layout this is an important assumption.
Turbine	– Tandem compound design – One HP, one single flow IP and a double flow LP	The turbine blading, diaphragms and seals assumed to be designed to the latest high efficiency standards
Boiler	– Supercritical – Pulverised fuel fired – Steam conditions: 24MPa / 566C / 566C – Low NOx burners – Overfire air – Dry furnace bottom ash handling plant	Most new units in region are supercritical. (Chinese manufacturers are now providing supercritical plants.) Best practice includes a low-NOx combustion system. Options of single-tower or two-pass design, and wall- or tangential firing have not been specified as they have no impact on the capture-readiness guidelines.
Draft plant	– 2 fans per system (Primary Air, Forced Draft , Induced Draft)	Although some merchant plants in other economies only have one train of fans per system, new plants in region have two train systems which offer better reliability. The number of ID fans is important for capture-ready designs.

Dust collection	– High efficiency electrostatic precipitator or fabric filter	The flue gas cleaning system design and specification has an important influence over the layout for capture-ready and ultimately design changes necessary to make the plant capture-ready. Present chemical scrubbing carbon capture plants are sensitive to particulate and acid gas concentration.
FGD	– Wet limestone scrubbers	
$deNO_x$	– Selective catalytic reduction (SCR)	
Cooling system	– Wet cooled (coastal or wet cooling towers)	The cooling system does not have a direct influence over modification necessary for capture-ready. However as most plants in the region are wet cooled this has been assumed.
Design coal	– Internationally traded thermal coal	The plant design has assumed internationally traded thermal coal or equivalent. Where coal such as anthracite, low-rank coals or lignite are used, the plant layout may differ.

7.3 Plant Layout

From Aurecon's experience with new coal-fired plant projects in China, Indonesia, Malaysia, Vietnam and Thailand a typical (non capture-ready) plant layout has been synthesised. The layout of the power block is presented in Figure 7.1. As coal and ash handling systems tend to be very site specific and not directly impacted in making a plant capture-ready, they have not been included in these guidelines.

Features of the layout presented include:

- In-line arrangement of turbine, boiler and dust collection plant
- Single stack serving both units
- Turbine hall and switchyard at one end, stack at other
- Wet limestone flue gas desulphurisation plant (FGD) located on 'outside' of stack
- Allowance for selective catalytic reduction (SCR) units in boiler flue system.
- The total footprint of power block as illustrated approximately 4.6 Ha.

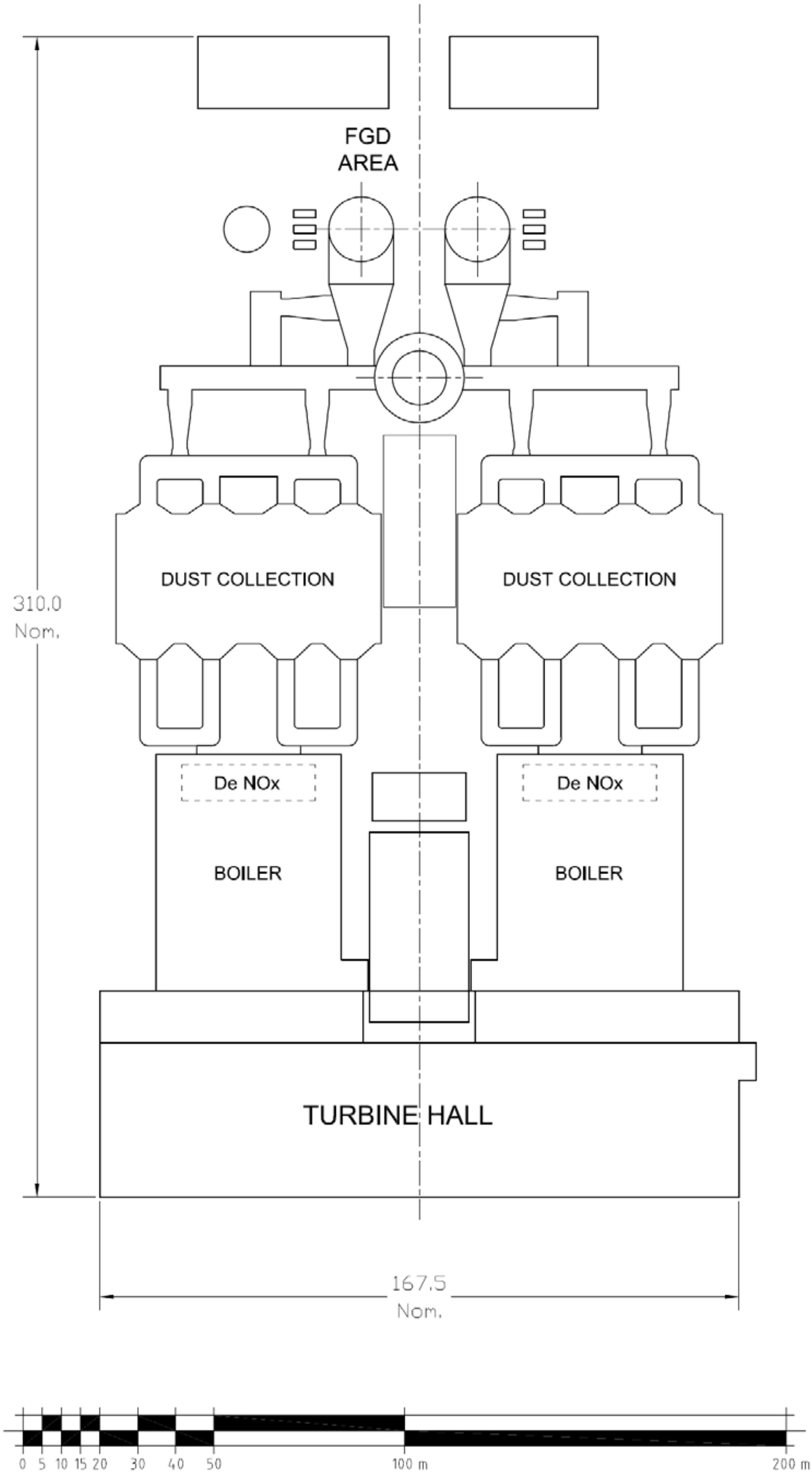


Figure 7.1- Typical Plant Layout for 2 x 600-MW Coal-fired Plant in the Region

8. Planning Guidelines

In Chapter 5 of this report, a description was provided of the features necessary to make a pulverised coal-fired plant ‘capture-ready’, with anticipation of a retrofit with a post-combustion chemical scrubbing process. This chapter discusses the appropriateness of the modifications to new coal-fired plant in developing APEC economies and presents guidelines for the typical plant.

8.1 Level of Capture-Readiness

The modifications described earlier, which were distilled from a number of published works from OECD countries, require high levels of pre-investment. For example, the cost estimate provided by NETL (2007) suggests that making a plant capture-ready represented a construction cost increase of 28% or around US$444/kW ($1575/kW) BAU Case compared to $2019/kW Capture-ready Case). However, the IEA definition of ‘capture-ready’ only requires that the plant be built in such a way as not to make the future retrofit of capture equipment impossible. Therefore, the concept of varying degrees of capture readiness may be explored, with the degree of readiness related to the desired level of pre-investment.

Table 8.1 illustrates 3 possible levels of pre-investment and an overview of the required plant modifications. The energy requirement for amine scrubbing systems means that a reduction in plant output may occur with a retrofit of carbon capture equipment.

Table 8.1 Range of modifications necessary for capture-ready

Level of Pre-investment	Required Plant Modifications
Low	– Identification of CO_2 storage options – Allocation of plant space for additional equipment: CO_2 scrubber, solvent regenerator, CO_2 compressor, auxiliary boiler, ducting and possible booster induced draft fan.
Medium	– Identification of storage options – Turbine steam piping modifications for future take-off – Allocation of plant space for additional equipment: CO_2 scrubber, solvent regenerator, CO_2 compressor, ducting and possible booster induced draft fan.
High	– Identification of storage options – Over-sized boiler for future steam take-off – Allocation of plant space for additional equipment: CO_2 scrubber, solvent regenerator, CO_2 compressor ducting and possible booster induced draft fan.

8.2 Lowest pre-investment option

In addition to the above levels of capture readiness, the concept of the minimum or lowest pre-investment was explored. This option may be appropriate in developing economies where capital is limited and available funding is better spent on minimising the impact of the plant on the local environment.

It has been assumed that the lowest pre-investment option would allow for:

– The minimum modifications necessary so as not to preclude the possibility of the future retrofit of the plant with carbon capture and storage (in accordance with IEA capture-ready definition)

– Allowance for future scrubbing of 50% of the flue gas produced by the plant. This would result in approximately 45% of CO_2 removal. For comparison, the following table illustrates the relative greenhouse intensity of the base plant, plant with 50% capture and a number of gas fired plant options:

	Approximate Generation Intensity (kg CO_2/MWh Sent Out)
Reference plant (specification as per Table 7.1)	800
Reference plant with ~ 50% CO_2 capture	440
Open Cycle Gas Turbine (gas fired)	500
Combined Cycle Gas Turbine (gas fired)	350

– Layout optimised to allow for minimum flue gas duct lengths and steam supply distances

– Site area allowance for future auxiliary boiler, CO_2 scrubber, regenerator and CO_2 compressor and associated ductwork.

Figure 8.1 provides a possible plant layout for the low pre-investment option. The figure shows the unmodified reference as a grey watermark for comparison of layout and space. The features of this layout including the following:

– **Major power block items**: No change to the locations of the major plant items. Note that the boiler, turbine, dust collection plant and dust collection plant outlet ducts are unchanged over the standard layout.

– **Stack**: The most significant change to the layout is the relocation of the stack by 60m further from the dust collection plant. This will allow for future flue gas off-take and scrubbed flue gas return to the stack from the CO_2 capture equipment.

– **Flue gas ducts**: As a result of the stack relocation, the flue gas duct is required to be approximately 60 m longer.

– **Limestone handling**: As a result of the stack relocation, the limestone handling area has been also moved by 40 m away from the boiler.

– **CO_2 capture equipment**: The allocated region for the CO_2 capture and compression equipment is adjacent to dust collection plant and FGD area. This is to minimise duct lengths for the gas from the FGD exit to the CO_2 scrubber and back.

– **Steam supply**: Allowance has been made for an auxiliary boiler for each unit to provide steam for the CO_2 solvent regenerator. The space has been allocated adjacent to the main boilers to facilitate fuel delivery and ash removal (if coal used as fuel). The arrangement will allow for auxiliary boiler fuel flexibility; waste material such as biomass or sewerage sludge if available at the time of retrofit of the carbon capture plant may be a more appropriate fuel choice. Furthermore, as better solvents are developed that require less energy, the auxiliary boiler can be sized accordingly.

– **Total space allocation.** Table 8.2 summarises the different space requirements for the low investment capture-ready layout compared to the base case layout. Site area has been allocated for the auxiliary boiler, additional flue gas duct lengths and the CO_2 capture and compression equipment.

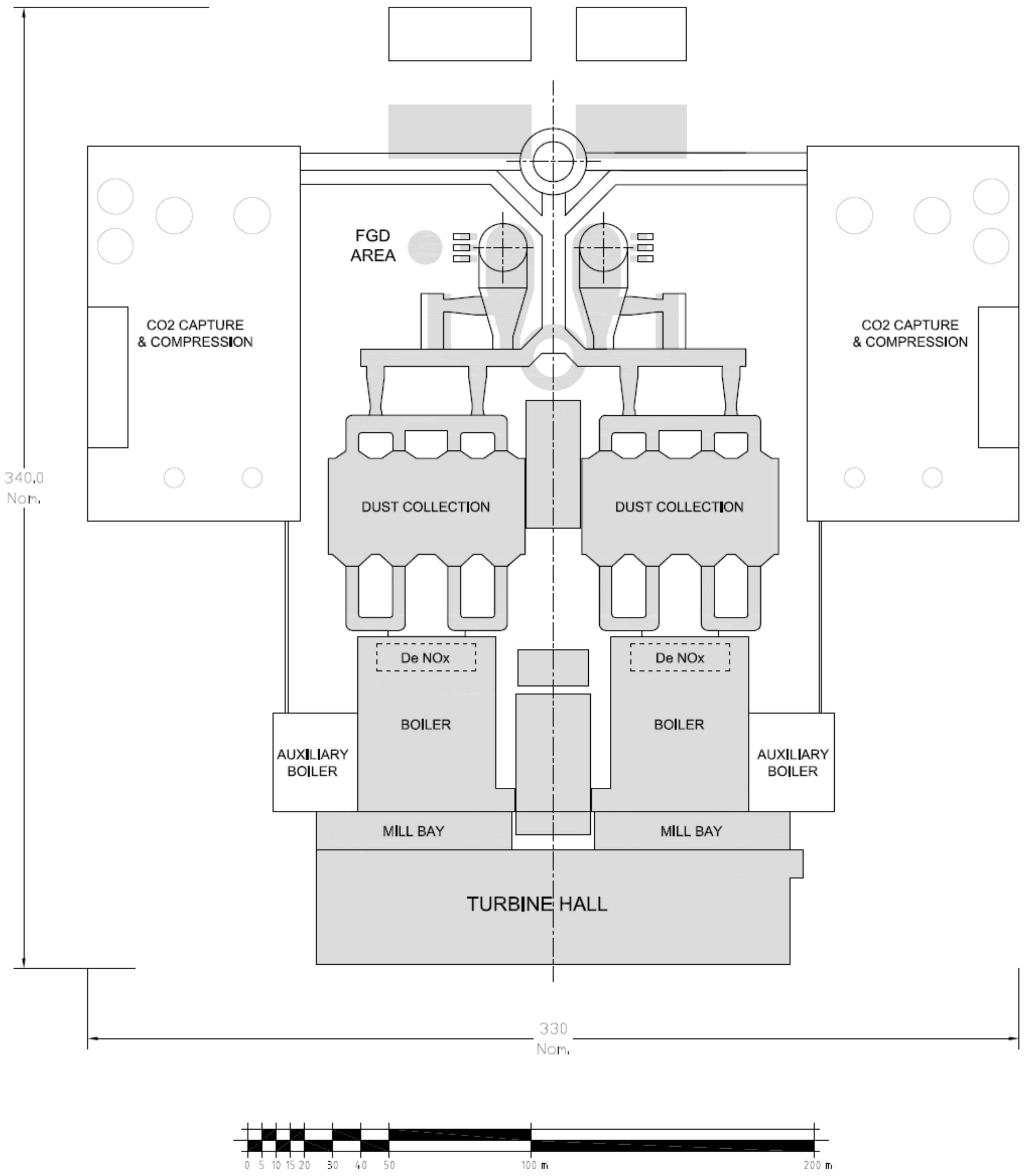


Figure 8.1 Possible Layout for Low-Investment Capture-ready Plant (50% capture)

Table 8.2 Site area requirements: lowest investment capture-ready case compared to base case

	Base Plant	**Lowest Investment Capture-ready**
Boiler & auxiliaries	12,360	12,360
Auxiliary boilers	0	2,100
Turbine & auxiliaries	6,770	6,770
Gaseous emission control & ducts	25,170	32,560
CO_2 capture & compression	0	19,800
Coal stockpile	157,500	157,500
Switchyard	66,150	66,150
Miscellaneous / workshops / BOP	58,350	58,350
TOTAL m^2	**326,300**	**355,590**

The table shows that the additional site area requirement is 29,290 m^2 or 9% greater for the lowest investment capture-ready plant.

8.3 High Pre-Investment option

Figure 8.2 provides a possible plant layout for the high pre-investment option. This option allows for the 100% CO_2 capture and the lowest cost retrofit of carbon capture equipment. The features of this layout including the following:

- **Major power block items**: The turbine hall is unchanged over the base layout. The 43% greater steam generation capability of the boiler (NETL, 2007) has resulted in a larger boiler footprint. The ID fans have been uprated to allow for the additional pressure drop associated with the longer flue gas ductwork.
- **Stack**: The most significant change to the layout is the relocation of the stack by 85m further from the dust collection plant. This will allow for future flue gas off-take and scrubbed flue gas return to the stack from the CO_2 capture equipment.
- **Flue gas ducts**: As a result of the stack relocation, the flue gas duct is required to be approximately 85 m longer.
- **Limestone handling**: As a result of the stack relocation, the limestone handling area has been also moved by 50m away from the boiler.
- **CO_2 capture equipment**: The allocated region for the CO_2 capture and compression equipment is adjacent to dust collection plant and FGD area. This is to minimise duct lengths for the gas from the FGD exit to the CO_2 scrubber and back.
- **Steam supply**: Allowance has been made for a larger boiler to supply the additional steam necessary for solvent regeneration. The steam delivery capability of the boiler is 43% higher than the base case boiler. This has resulted in a boiler footprint approximately 10% larger.
- **Total space allocation.** Table 8.3 summarises the different space requirements for the high investment capture-ready layout compared to the base case layout.

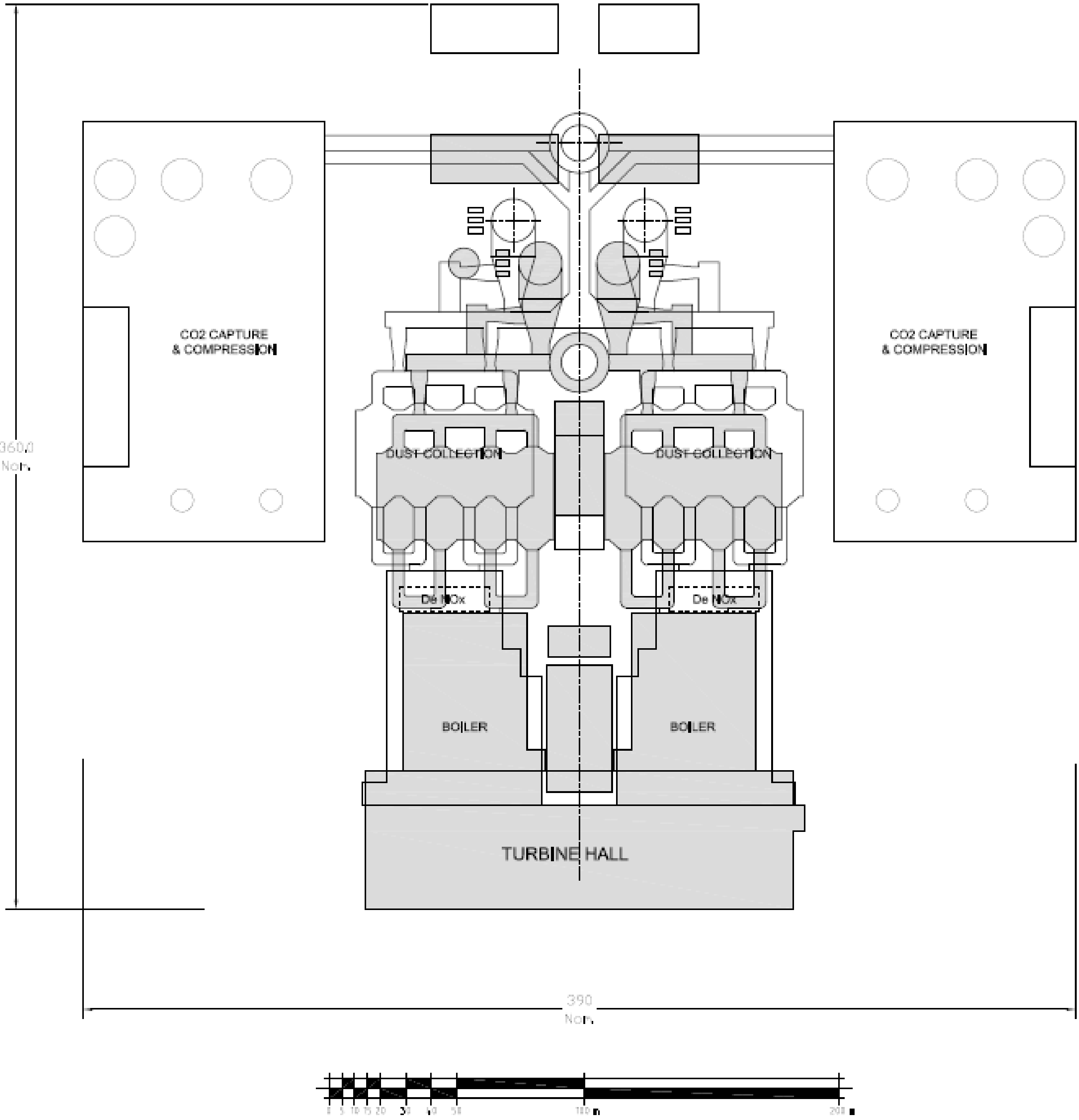


Figure 8.3 Possible Layout for High Pre-Investment Option

Table 8.3 Site area requirements: high investment capture-ready case compared to base case (in m^2)

	Base Plant	High Pre-investment: 100% Capture-ready
Boiler & auxiliaries	12,360	13,500
Turbine & auxiliaries	6,770	6,770
Gaseous emission control & ducts	25,170	35,300
CO_2 capture & compression	0	31,680
Coal stockpile	157,500	157,500
Switchyard	66,150	66,150
Miscellaneous / workshops / BOP	58,350	58,350
TOTAL m^2	**326,300**	**369,250**

The table shows that the additional site area requirement is 42,950 m^2 or 13% greater for the high investment capture-ready plant. The above analysis has not allowed for any increase in stockpile area.

8.4 Summary of Plant Modification Guidelines

Table 8.4 summarises the plant modification requirements for the lowest investment and high pre-investment cases.

Table 8.4 Summary of Plant Modification Guidelines

	Lowest Investment Capture-ready	High Pre-investment: 100% Capture-ready
Plant layout	– No change to location of major plant items – Stack moved 60m further from boiler – Longer flue gas ducts; – Space allowance for auxiliary boiler and CO_2 capture & compression equipment	– Larger boiler footprint; – Stack moved 85m further from boiler – Longer flue gas ducts – Space allowance for CO_2 capture & compression equipment
Additional site area	Total site area 2.9 Ha (9%) larger	Total site area 4.3 Ha (13%) larger
Major equipment		
Boiler	No change	43% higher steam generation capability
Flue gas emissions control	No change	Sized to allow for greater flue gas flow
Turbine	No change	No change

9. Cost Assessment Guidelines

9.1 Background

A number of studies have concluded that there is an overall long term cost benefit associated with making a power plant ‘capture-ready’. These have included Bohm (2006), NETL (2007) and GCCSI (2010). Comparison of the construction cost of a ‘business as usual’ plant followed by a carbon capture retrofit, exceeds the cost of construction of a ‘capture-ready’ plant followed by a carbon capture retrofit. The NETL work reported an overall estimated capital cost saving of more than 20%.

The following cost assessment guidelines have been developed to allow utilities in developing APEC economies estimate the cost impost of making a plant ‘capture-ready’. The estimates provided are presented in the form of a percentage of the overall plant capital cost. This approach has been adopted for the following reasons:

– Plant capital costs may vary significantly between economies and even between geographical regions in a particular economy.

– Plant capital costs are also a function of supply and demand in relation to power plant components as well as raw materials. Therefore total plant costs do not necessarily follow standard cost of living type escalation rates.

– Labour rates can vary significantly between economies and therefore the relativity of labour vs. materials cost may also vary between economies.

– Depending on the construction approach adopted (i.e., engineer, procure & construct (EPC) contract, engineer, procure & construct management (EPCM) contracts, build, own, operate & transfer (BOOT)), the costs may vary significantly depending on which parties are carrying the risk.

For each of the required plant modifications identified in Chapter 8, an estimate of the cost of modification had been made, as a proportion of the total cost of the plant item. This is then rolled up into an overall change in cost based on the proportional cost of each plant area.

9.2 Guideline Development

The base case used for the cost guidelines was the ‘business as usual’ case from the NETL (2007) study. The values provided in the NETL study are consistent with Aurecon’s internal plant construction cost database. The NETL report assumes a 550-MW (net output) unit with FGD and $deNO_x$. The units are, therefore, similar to the 600-MW (gross output) of the reference plant described in Chapter 7. As only the relative weighting of the major plant areas are used, the detailed specification will not influence the outcome.

The base data is presented in Table 9.1. The table shows the proportion of the overall plant cost represented by each of the major plant areas. The column with $US/kW is from NETL (2007). It is not used in the costing guidelines.

Table 9.1 Reference Plant: Assumed Cost Breakdown

	$US/kW (NETL, 2007)	**Proportion of total capital cost**
Coal handling System	66.2	4.2%
Coal preparation & feed	31.0	2.0%
Feedwater & misc BOP	136.0	8.6%
Boiler & auxiliaries	510.4	32.4%
Flue gas cleanup	229.5	14.6%
Ducts & stack	65.1	4.1%
Steam turbine / generator	204.1	13.0%
Cooling water system	67.8	4.3%
Ash & dust	21.9	1.4%
Electrical	85.8	5.4%
Controls & instrumentation	36.9	2.3%
Site improvements	24.4	1.6%
Buildings & structures	96.3	6.1%
	1575.3	**100.00%**

As will be described below, the proportion of total capital cost will be used along with the estimated change to the relevant plant areas to determine the overall cost impact.

9.3 Cost Assessment Guidelines

Based on the plant modification guidelines discussed in Chapter 8, estimates have been made of the change in expected construction cost of the different plant areas for the lowest pre-investment case. These values are based on the expected extent of plant modifications as illustrated in Figure 8.1 relative to Figure 7.1. This is tabulated in Table 9.2.

Table 9.2 Lowest Pre-investment Plant Area Incremental Cost Increases

	Lowest Investment Capture-ready	**Cost change (%)**
Plant layout	Longer flue gas ducts	4% higher cost of ducts & stack
Site area	Space allowance for auxiliary boiler and CO_2 capture & compression equipment. Total site area 2.9 Ha (9%) larger	8% higher cost of site preparation
Boiler & turbine	No change	0

The corresponding % cost change for the highest pre-investment case is not detailed here as it was taken directly from NETL (2007).

9.4 Overall change in plant construction cost

The estimated incremental construction cost associated with making each plant area ‘capture-ready’ was used to estimate an overall cost of capture readiness for the lowest and high pre-investment options. The ‘CR factor’ represents the ratio of the capture ready cost to unmodified cost of the particular plant area. A bolded value means that the factor is greater than unity. These results are presented in Table 9.3.

Table 9.3 Overall changes in plant construction cost

	Proportion of Plant Cost	Lowest Investment		High Pre-investment*	
		CR factor		CR factor	
Coal Handling System	4.2%	1.00	4.2%	1.25	5.2%
Boiler & Auxiliaries	35.8%	1.00	35.8%	1.28	45.8%
Turbine & auxiliaries	21.6%	1.00	21.6%	1.22	26.4%
Flue gas cleanup	14.6%	1.00	14.6%	1.31	19.1%
Ducts & stack	4.1%	1.04†	4.3%	1.07	4.4%
CW system	4.3%	1.00	4.3%	1.75	7.5%
Elect	5.4%	1.00	5.4%	1.55	8.5%
C & I	2.3%	1.00	2.3%	1.19	2.8%
Site improvements	1.6%	1.08†	1.7%	1.12	1.7%
Buildings & structures	6.1%	1.00	6.1%	1.10	6.7%
	100.0%		**100.3%**		**128.2%**

*from NETL (2007)
†Aurecon calculation, estimated from modification described by NETL (2007)

The above table shows that:

– The only plant areas with a higher cost for the low pre-investment case are the ducts & stack and site improvements or preparation. In contrast, for the high pre-investment case, all plants areas experience an increase in cost.

– The total additional cost of making a plant ‘lowest investment’ capture-ready is approximately 0.3% of the total plant construction cost (excluding land acquisition)

– The additional cost of making a plant ‘high pre-investment’ capture-ready is approximately 28% of the total plant construction cost (NETL, 2007) (excluding land acquisition)

10. Additional Analyses Required

The following areas were identified as potential shortcomings in the current knowledge base that make advancing the case study projects difficult:

I. Data on actual CO_2 storage potential as distinct from 'storage prospectivity' in developing APEC economies is required. The concept of 'capture-ready' is meaningless unless a CO_2 storage location has been identified. In many developed economies, CO_2 storage 'atlases' are being developed. The same will be required for developing economies.

II. Storage prospectivity and potential in the Viet Nam region. Viet Nam was not included in the 2005 APEC study on regional storage prospectivity. As there is a significant coal-fired plant construction program presently underway in Viet Nam, knowledge of potential storage sites is essential for any capture-ready case study.

III. Mechanisms to facilitate the development of capture-ready plants. There are presently few mechanisms that foster the construction of capture-ready plant. Measures that encourage the construction of capture-ready plants are essential to facilitate uptake of the concept. This is particularly true in developing economies where there may not be any government imperative or targets for CO_2 reduction.

IV. Demonstration projects are required that prove that post-combustion CCS is viable. Utilities are reluctant to build CO_2 capture-ready plants when there is a lack of demonstrated industry experience with the post-combustion capture technology.

V. At this point, it is not proven that post-combustion capture will be the preferred technology for PF coal-fired plant CCS retrofit. Other prospective technologies, such as oxy firing, have good potential as an option for low pre-investment capture-ready designs. Without a clear definition of the preferred technology for retrofit, it is difficult to progress case studies.

11. Summary and Conclusions

It has been extensively concluded that to control global carbon dioxide emissions the widespread implementation of carbon capture and storage on coal-fired power plants is critical. In developing APEC economies there is significant construction of new coal-fired power stations. There is consequently an opportunity for new coal-fired plants in the region to be built as 'capture-ready' to facilitate the later retrofit of carbon capture technology.

The objectives of this report were to identify case studies of projects in the early siting and planning stage that are made capture-ready and to develop planning and cost assessment guidelines . The project conclusions are summarised in the following sections.

11.1 Carbon Dioxide Capture and Storage

Carbon dioxide capture and storage is a process consisting of: Capture or separation of CO_2 from industrial and energy related sources; transport of CO_2 to a storage location; and injection into storage site for long-term isolation from the atmosphere. Although all three elements are integral to the development of a capture-ready power plant, this report focused on the power plant and allowances necessary to incorporate capture technology.

There are three main technology options for CO_2 capture that have been demonstrated or proposed for coal-fired power plants:

- **Post-combustion**: This system involves the capture of CO_2 from all or part of the flue gas stream. A number of technology options are available, as CO_2 is presently captured from a wide range of manufacturing processes, refining and natural gas processing.
- **Oxy-fuel combustion:** This technology entails burning the fuel in high purity oxygen. This results in high CO_2 concentrations in the flue gas stream and therefore easier separation. Recycled flue gas is used to control combustion temperatures.
- **Pre-combustion**: This option is only suitable for the IGCC generation technology. It involves the separation of hydrogen and carbon dioxide prior to the combustion of the syngas. The technology is widely applied in the manufacture of fertilisers and in hydrogen production.

As the majority of new coal-fired plants in developing APEC economies use pulverised-coal firing, at present the only proven capture technology is chemical absorption post-combustion capture. Amine scrubbing appears to be the most likely technology for near-term chemical scrubbing implementation due to its technological maturity.

The assumption of amine as the solvent represents a 'worst case' as it is expected that further development and improvement to the technology will be made to reduce both the energy consumed by the regeneration process and the required degree of cleanliness of the flue gas.

11.2 Capture-ready Definition

There is not yet a universal definition of carbon dioxide 'capture-ready' for coal-fired power plants. However, there has been a significant amount of work done in this area and a consistent definition is starting to emerge. The U.K Government recently published a position paper on its response to consultation on carbon capture and storage (DECC, 2009). From the position paper, it is clear that it is the intention of the U.K. government not to consent any future applications for plants greater than 300 MWe unless they can be categorized as carbon capture-ready. The ongoing work of the Global Carbon Capture and Storage Institute includes a discussion paper focused on CCS ready concepts, policy issue and guidelines. It may be expected that a definition will emerge from this work following stakeholder feedback.

The definition proposed by the International Energy Agency (IEA, 2007) was assumed for this study. It states that a plant may be considered capture-ready when CO_2 capture can be included when the necessary regulatory or economic drivers are in place. The definition requires the project developer to demonstrate that factors in their control that would prevent the retrofit of CO_2 capture have been identified and eliminated. Specific aspects that must be considered include:

- A study of options for carbon dioxide capture retrofit and potential pre-investments
- Inclusion of sufficient space and access for additional facilities
- Identification of reasonable route(s) to the storage of carbon dioxide

11.3 Issues That Impact the Development of Capture-ready

A number of issues have been identified which potentially impact the development and implementation of capture-ready plants both globally and within developing APEC economies. These include:

- Lack of clear definition of what 'capture-ready' is and what it involves: It is expected that the work of organisations such as the GCCSI will assist with the development of universal guidelines for the definition of capture-ready.
- Legal issues: In many economies the legality of CO_2 storage is not known.
- Absence of Clean Development Mechanism (CDM) funding and other financial incentives: As the construction of capture-ready plants does not lead to an immediate reduction in CO_2 emissions, capture-ready plants are not eligible for funding through schemes such as the CDM.
- Lack of industry awareness of what is involved in making a plant capture-ready: Again due to the lack of a universally recognised definition, most utilities are not aware of what is involved in the design of a capture-ready plant.
- Lack of binding commitments at Government level in developing economies to reduce CO_2 emissions: Without government commitments utilities are unlikely to implement CCS technologies.
- Technological uncertainty: As CCS technology still under development there is concern that pre-investment for capture readiness may be misguided, should a technological breakthrough occur.
- Carbon dioxide transport & storage risks: Power plant capture readiness is just part of the overall CCS process. CO_2 transport and storage have associated risks that power utilities will be unwilling to accept.
- Public perception: There is diversity in public perception of CCS. There is concern over the possibility of a catastrophic CO_2 leakage event.
- Lack of technical training: Industry engineers are not trained in CCS technology.

11.4 Planned Coal-fired Plants in Developing APEC Economies

Coal use in developing APEC economies is rising rapidly. It is expected that by 2030, the use of coal is expected to be four times that of 2007 (USAID, 2007). There is therefore an intense power plant construction program presently underway in many of the economies studied here. It is expected that provided the decision to make a plant 'capture-ready' is taken at the appropriate time, future plants may be designed and built as 'capture-ready'.

A survey was conducted of planned coal-fired power plants in the region. Table 11.1 summarises the number of units and total capacity for a selection of developing APEC economies.

Table 11.1 Planned coal-fired power plants as of April, 2009

Economy	No. of units	Total MW
China	196	111,500
Indonesia	11	5,495
Malaysia	5	2,630
Philippines	5	1,600
Thailand	10	6,000
Viet Nam	52	32,100
TOTAL	**279**	**159,325**

For each plant, data was obtained on unit size, steam conditions, emissions controls and whether the plant is a greenfield or brownfield development

11.5 Case Study Potential in Developing APEC Economies

An assessment process was adopted to identify the potential for 'capture-ready' plant design and implementation in each economy. The process included evaluation of the following criteria for each coal-fired power plant project:

I. *Project Timing*:	Examination of the proposed coal-fired power plant construction program. For a plant to be designed to be 'capture-ready', the decision must be made at plant site selection stage. Therefore, of the plants in the planned plant database, only those scheduled for commissioning beyond 2015 are likely to be at an early enough stage of development to permit the incorporation of 'capture-ready' design elements.
II. *Proposed site*:	Unless a brownfield development involves demolition of existing units, it is likely that greenfield sites would have less space constraints and more flexibility. greenfield developments are, therefore, more desirable from a capture-ready viewpoint.
III. *Plant specification*:	Review of the proposed plant specifications. A number of facets of the plant design are significant for inclusion of 'capture-ready' in the design. For this analysis it has been assumed that the following attributes would make it simpler to make the plant 'capture-ready': • Planned installation of FGD and deNO$_x$: As current technology CO_2 capture plant requires high purity flue gas, FGD and deNO$_x$ are essential. Plants already equipped with FGD and deNO$_x$ are, therefore, more 'capture-ready', as space for the retrofit of this equipment is not required and the investment in this necessary technology will have already been made. The requirement for deNO$_x$ is not as essential as the requirement for FGD, as it is relatively low cost and easy to retrofit deNO$_x$ equipment. • Unit size: It is expected that it will be more attractive to retrofit carbon capture and storage to plants with larger unit sizes (Deutch, 2009). Reasons for this include economies of scale and a desire to target larger CO_2 emitters. • Supercritical steam conditions: Higher efficiency plants are better candidates for CO_2 capture as the efficiency impact of the capture equipment is reduced.
IV. *Plant Location:*	Assessment of the proximity of the proposed plants to CO_2 storage locations or to other emitters for either a CO_2 hub or pipeline sharing potential. Other considerations here include the CO_2 capacity of the proposed storage location and the certainty of the storage sink.

The assessment process was applied to the proposed plants in each of the economies studied. The outcome of this was:

China: Excellent potential for case studies. Seventy two units met all criteria except for location and size. This is reduced to 32 when small units are excluded. Eight power plants were identified that meet all selection criteria: comprising 16 units of between

600 and 1000-MW capacity that are to be located between 25 and 150 km of high-prospectivity storage basins.

Indonesia: Indonesia has slight case study potential at present. One of the proposed units meets most of the nominated selection criteria, and Indonesia has moderate storage potential. A few proposed plants are to be located close to storage basins, but the plants are either of small unit size or are not planned to have FGD and deNO$_x$. Future coal-fired plant siting may be able to take storage potential into consideration.

Malaysia: Poor case study potential at present. The Malay Basin in the Gulf of Thailand offers moderate CO_2 storage potential. However Malaysia has only 2 coal based projects at the planning stage and these are for small (<300-MW) units to be located at least 120km from the storage sink. Future coal-fired plant siting may be able to take storage potential into consideration.

Philippines: Poor case study potential. The Luzon basin has poor storage reservoir quality. Furthermore the planned coal based projects have small (<300-MW) units

Thailand: Poor case study potential. The Thai Gulf Basin has low CO_2 storage prospectivity.

Viet Nam: Moderate case study potential. There is reportedly potential for some offshore storage. Although many of the plants under construction meet the timing and plant specification criteria, the actual storage potential of the offshore basins is not known.

11.6 Typical Coal-fired Power Project in the Region

To expedite the development of planning and design modifications for ‘capture-ready’ coal-fired plants, the concept of a *typical* coal-fired plant project for the region was developed. A 2 x 600-MW configuration was selected for the typical plant as:

- The 600-MW size is becoming a standard size for Chinese power plant manufacturers. As the rate of plant construction in China slows, Chinese power plant construction companies are building offshore in other economies in the region
- The surveyed data found that the 600-MW size class is both the mean and median unit size for new coal-fired plants in the region. This unit size represents almost 50% of the planned capacity additions for the region over the next 5 years. The guidelines presented here would be valid for unit capacities of between 500 and 700 MW.

Therefore, for this study, the capture-ready guidelines have been based on the 600-MW size class, and specifically a plant of 2 x 600-MW capacity. It is expected that conclusions applicable to many future projects will be able to be drawn from the capture-ready guidelines developed for the typical plant.

A generic layout was of the power block was developed for a two-unit station. The drawing was provided in Chapter 7. Features of the layout included:

- In-line arrangement of turbine, boiler and dust collection plant
- Single stack serving both units

Parameter	Specification
Site	Greenfield
Capacity	2 x 600-MW units
Steam conditions	24MPa / 566C / 566C (supercritical)
Draft plant	2 fans per system (PA, FD, ID)
Dust collection plant	High-efficiency electrostatic precipitator or fabric filter

FGD	Wet limestone scrubbers
$deNO_x$	Selective catalytic reduction (SCR)
Cooling system	Wet cooled (coastal or wet cooling towers)
Design coal	Internationally traded thermal coal

– Turbine hall and switchyard at one end, stack at other
– Wet limestone flue gas desulphurisation plant (FGD) located on 'outside' of stack
– Total footprint of power block approximately 310 m x 168 m (5.2 Ha).

11.7 Planning Guidelines

In developing economies where capital funding is limited, the concept of the minimum or lowest 'capture-ready' pre-investment was explored. A 'lowest pre-investment' case was developed, which satisfies the IEA definition of capture-ready, but only requires minimal plant modification

It was assumed that the lowest pre-investment option would provide only modifications necessary not to preclude the possibility of the future retrofit of the plant with carbon capture and storage (in accordance with the IEA capture-ready definition). The generic power plant layout for the 2 x 600-MW plant presented in Chapter 7 was modified to allow for the future capture equipment.

The main items included in the planning guidelines include the following. For comparison, a high pre-investment option is also included:

	Lowest Investment *Future scrubbing of 50% of the flue gas, resulting in approximately 45% of CO_2 removal*	**High Pre-Investment** *Future scrubbing of 100% of the flue gas, resulting in approximately 90% of CO_2 removal*
Plant layout	– No change to location of major plant items; – Stack moved 60 m further from boiler; – Longer flue gas ducts; – Space allowance for auxiliary boiler and CO_2 capture & compression equipment	– Larger boiler footprint; – Stack moved 85 m further from boiler; – Longer flue gas ducts; – Space allowance for CO_2 capture & compression equipment
Additional site area	Total site area 2.9 Ha (9%) larger	Total site area 4.3 Ha (13%) larger
Major equipment		
Boiler	No change	43% higher steam generation capability
Flue gas emissions control	No change	Sized to allow for greater flue gas flow
Turbine	No change	No change

11.8 Cost Assessment Guidelines

The additional costs associated with building a plant to be capture-ready depend on the level of capture readiness required. For the high pre-investment case which provides for minimum cost of retrofit, the capital cost penalty is 28% (NETL, 2007) plus land acquisition costs.

For the lowest pre-investment option, the estimated additional cost is 0.3% of the overall plant capital cost plus land acquisition costs. This was estimated based on a 4% increase in duct & stack cost and an 8% increase in site preparation costs.

11.9 Additional Analyses Required

The following areas were identified as potential shortcomings in the current knowledge base that make progressing the case study projects difficult:

I. Data on actual CO_2 storage potential as distinct from 'storage prospectivity' in developing APEC economies is required. The concept of 'capture-ready' is meaningless unless a CO_2 storage location has been identified.

II. Storage prospectivity and potential in the Viet Nam region. Viet Nam was not included in the 2005 APEC study on regional storage prospectivity. As there is significant coal-fired plant construction program presently underway in Viet Nam, knowledge of potential storage sites is essential for any capture-ready case study.

III. Mechanisms to facilitate the development of capture-ready plants. There are presently few mechanisms that foster the construction of capture-ready plant. Measures that encourage the construction of capture-ready plants are essential to facilitate uptake of the concept.

IV. Demonstration projects are required that prove that post-combustion CCS is viable. Utilities are reluctant to build CO_2 capture-ready plants when there is a lack of demonstrated industry experience with the post-combustion capture technology.

V. At this point is not proven that post-combustion capture will be the preferred technology for PF coal-fired plant CCS retrofit. Other prospective technologies, such as oxy firing, have good potential as an option for low pre-investment capture-ready designs. Without a clear definition of the preferred technology for retrofit, it is difficult to progress case studies.

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13. Abbreviations and Acronyms

BOO	Build Own & Operate
BOP	Balance of plant
CCS	Carbon capture and storage
CDM	Clean Development Mechanism
CR	Capture-ready
CRR	Carbon capture readiness
EOR	Enhanced oil recovery
ESP	Electrostatic Precipitator
FGD	Flue gas desulphurisation
GCCSI	Global Carbon Capture and Storage Institute
HHV	Higher heating value
HP	High pressure
IEA	International Energy Agency
IGCC	Integrated gasification combined cycle
LHV	Lower heating value
LP	Low pressure
NGCC	Natural gas combined cycle
OECD	Organisation for Economic Co-operation and Development
PCC	Post-combustion capture
PF	Pulverised fuel
SC	Supercritical (steam conditions)
SCR	Selective catalytic reduction (deNO$_x$ technology)
USC	Ultra-supercritical (steam conditions)

Appendix A

Planned Power Plant Projects in Economies Considered

Appendix A

Economy	Project Name	Location	Expected Commissioning Date	Greenfield or Brownfield	Capacity (No. units x MW)	Project owner	$deNO_x$	FGD
China	**Shanghai Caojing Power Plant**	Jingshan district, Shanghai	2013	greenfield	2 x 1000 MW	China Power Investment Co.,	➸	
China	**Henan Pingdingshan Second Power Plant**	Pingdingshan City, Henan Province	2013	greenfield	2 x 1000 MW	China Power Investment Co.,	➸	➸
China	**Guangdong Pinghai Power Plant**	Huizhou City, Guangdong Province	2013	greenfield	2x1000 MW	Guangdong Yuedian Group	➸	➸
China	**Jianxi Xingchang Power Plant Phase 1**	Xingchang City, Jiangxi Province	2012	greenfield	2 x 660 MW	China Power Investment Co.,	➸	➸
China	**Datang Nanjing Xiaguan Power Plant Relocation Projects**	Qixia district of Nanjing Coty, Jiangsu Province	2014	greenfield	2 x 600 MW	Datang Group	➸	➸
China	**Fujian Shishi Thermal Power Plant**	Shishi City, Fujian Porvince	2013	greenfield	2 x 600 MW	Fujian Provincial Coal Industry Group	➸	➸
China	**Hainan Huneng Dongfang Power Plant**	Dongfang City, Hainan Province	2013	greenfield	2 x 350 MW	Huaneng Group	➸	➸
China	**Inner Mongolia Guohua Hulunbeir Power Plant**	Hulunbeir City, Inner Mongolia	2013	greenfield	2 x 600 MW	Guohua Group	➸	➸
China	**Henan Taisu Mengjing Power Plant**	Mengjing City, Henan Province	2013	greenfield	2 x 600 MW	Taiwan Taisu Group	➸	➸
China	**Huaneng Yingkou Thermal Power Project**	Yingkou City, Liaoning Province	2014	greenfield	2 x 300 MW	Huaneng Group	➸	➸
China	**Guodian Changzhi Thermal Power Project**	Yangbao Village, Shanxi Province	2014	greenfield	2 x 300 MW	Guodian Group	➸	➸
China	**Jincheng Thermal Power Project**	Zezhou County, Shanxi Province	2014	greenfield	2 x 300 MW	China Investment Co.	➸	➸
China	**Guodian Lanzhou Thermal Power Plant**	Lanzhou City, Gansu Province	2013	greenfield	2 x 300 MW	Guodian Group	➸	➸
China	**Datang Jingzhou Thermal Power Plant**	Jingzhou City, Liaoning Province	2013	greenfield	2 x 300 MW	Datang Power Group	➸	➸
China	**China Resources Nanshan Thermal Power Plant**	Huangge Town in the Nansha District, Guangzhou City	2014	greenfield	2 x 300 MW	China Resources	➸	➸

Economy	Project Name	Location	Expected Commissioning Date	Greenfield or Brownfield	Capacity (No. units x MW)	Project owner	$deNO_x$	FGD
China	**GreenGen**	Tianjin	2013	greenfield	250 MW	Consortium of Power and Coal Companies	➼	➼
China	**China Resources Lianyuan Power plant phase 1**	Lianyuan City, Hunan Province	2013	greenfield	1 x 300 MW	China Huarun Power Co.	➼	➼
China	**Datang Changchun No 3 Thermal Power Plant**	Changchun City, Jilin Province	2013	greenfield	2 x 300 MW	Datang Power Group	➼	
China	**China Resources Wenzhou Cangnan Power Plant Phase 1**	Wenzhou City, Zhejiang Province	2014	greenfield	2 x 1000 MW	China Resources		➼
China	**Guodian Xingyang Power Plant**	Xingyang City, Henan Province	2013	greenfield	2 x 600 MW	Guodian Group		➼
China	**Huaneng Haimeng Power Plant Phase 1**	Shantou City, Guangdong Province	2013	greenfield	2 x 1000 MW	Huaneng Group		➼
China	**Xingxiang Power Plant**	Xingxiang City, Henan Province	2013	greenfield	2 x 1000 MW	China Power Investment Co.,		
China	**Datang Dingxiang Power Plant**	Dingxiang county, Shanxi Province	2013	greenfield	2 x 1000 MW	Datang Power Group		
China	**Minquan power plant phase 1**	Minquan City, Henan Province	2013	greenfield	2 x 600 MW	China Guodian Group		➼
China	**Ningxia Shuidonggou Power Plant**	Lingwu City, Ningxia	2013	greenfield	2 x 600 MW	Beijing International Power Investment Co.		➼
China	**Sichuan Huadian Gongxian Power Plant Phase 1**	Yibin City, Sichuan Province	2013	greenfield	2 x 600 MW	Hudian Group		➼
China	**Jilin Baicheng Power Plant**	Baicheng City, Jilin Province	2013	greenfield	2 x 600 MW	China Power Investment Co.,		➼
China	**Guodian Shangqiu Mingquan Power Plant**	Shangqiu City, Henan Province	2013	greenfield	2 x 600 MW	Guodian Group		➼
China	**Ningxia Yuanyanhu Power Plant**	Yuanyanhu City, Ningxia	2011	greenfield	2 x 600 MW	Shandong Luneng Group		➼

Economy	Project Name	Location	Expected Commissioning Date	Greenfield or Brownfield	Capacity (No. units x MW)	Project owner	deNO$_x$	FGD
China	Guodian Baoqing Coal and Power Plant Phase 1	Shaoyang City, Hunan Province	2010	greenfield	2 x 660 MW	Guodian Group		
China	Ningxia Liupanshan Thermal Power Plant	Liupanshan City, Ningxia autonomous region	2014	greenfield	2 x 330 MW	Ningxia Power Group		➼
China	Datang Baoji Thermal Power Plant	Baoji City, Shaanxi Province	2014	greenfield	2 x 300 MW	Datang Power Group		➼
China	Guangxi Yongfu Power Plant	Guilin City, Guangxi Autonomous region	2013	greenfield	2 x 300 MW	Guodian Group		➼
China	Liaoning Dandong Jingshan Thermal Power Plant	Dandong City, Liaoning Province	2013	greenfield	2 x 300 MW	Dangdong Jingshan Thermal Power Co.		➼
China	Huhehaote Jinqiao Thermal Power Plant	Huhehaote City, Inner Mongolia	2013	greenfield	2 x 300 MW	Beifang United Power Co.		➼
China	Henan Luohe Thermal Power Plant	Luoke City, Henan Province	2013	greenfield	2 x 300 MW	Huadian Group		➼
China	Guodian Yuci Thermal Power Plant	Jingzhong City, Shanxi Province	2013	greenfield	2 x 300 MW	Guodian Group		➼
China	Hebei Xuanhua Thermal Power Plant	Xuanhua City, Hebei Province	2013	greenfield	2 x 300 MW	Hebei Xuanhua Thermal Power Co.		➼
China	Inner Mongolia Jinghai Power Plant	Wuhai City, Inner Mongolia	2013	greenfield	2 x 300 MW	Beijing Jinmei Group		
China	Ningdong Energy-Chemical Base	Ningxia	2020	greenfield	4400 MW	State Grid Corp of China and Huadian Power International Corp		
China	Huaneng Zhengning Power Plant Phase 1	Zhengning county, Ganshu Province	2014	greenfield	2 x 1000 MW	China Huaneng Group		➼
China	Hebei Datang Zhangjiakou Thermal Power Plant	Zhangjiakou City, Hebei Province	2013	greenfield	2 x 300 MW	Datang Power Group		➼
China	Huaneng Fukang Power Plant Phase 1	Fukang City, Xinjiang Autonomous Region	2013	greenfield	2 x 135 MW	China Huaneng Group		

Economy	Project Name	Location	Expected Commissioning Date	Greenfield or Brownfield	Capacity (No. units x MW)	Project owner	$deNO_x$	FGD
China	**Guodian Huangxi Chongzuo Power Plant Phase 1**	Chongzuo City, Guangxi Autonomous region	2010	greenfield	2 x 600 MW	China Guodian Group		➢
China	**Guodian Jianbi Power Plant expension**	Zhengjiang City, Jiangshu Province	2014	brownfield	1 x 1000 MW	Guodian Group	➢	➢
China	**Huaneng Nanjing Jinling Power Plant phase 2**	Nanjing City, Jiangsu Province	2013	brownfield	1 x 1000 MW	Huaneng Group	➢	➢
China	**Huadian Ningxia Lingwu power Plant Phase 2**	Lingwu City, Ningxia	2013	brownfield	2 x 1000 MW	Huadian Group	➢	➢
China	**Huneng Jinggangshan Power Plant Phase 2**	Jinggangshan City, Jianxi Province	2013	brownfield	1 x 600 MW	Huaneng Group	➢	➢
China	**Anhui Tonglin Power Plant Phase 6**	Tonglin City, Anhui Province	2013	brownfield	1 x 1000 MW	Wanneng Power Co.	➢	➢
China	**Huaneng Changchun No. 4 Thermal Power Project**	Changchun City, Jilin Province	2014	brownfield	2 x 300 MW	Huaneng Group	➢	➢
China	**Guodian Huozhou Power Project**	Nanxingzhi Town, Shanxi Province	2014	brownfield	2 x 600 MW	Guodian Group	➢	➢
China	**Dengfeng Power Plant Phase II Expansion Project**	Dengfeng City, Henan Province	2014	brownfield	1 x 600MW	China Resources	➢	➢
China	**Leqing Power Plant Phase II Expansion**	Wenzhou City, Zhejiang Province	2014	brownfield	2 x 660 MW	Zhejiang Energy Group	➢	➢
China	**Hunan Datang Huaying Jingzhushan Power Plant**	Loudi City, Hunan Province	2013	brownfield	1 x 600 MW	Datang Power Group	➢	➢
China	**Shijiazhuang Liangcun Thermal Power Project**	Nanxi Village, Shanxi Province	2014	brownfield	2 x 300 MW	Shijiazhuang Thermal Power Co.	➢	➢
China	**Jilin Jiangnan Thermal Power Plant**	Lilin City, Jilin Province	2014	greenfield	2 x 300 MW	Gudian Group	➢	➢
China	**Datang Matou Thermal Power Plant**	Handan City, Hebei Province	2014	brownfield	2 x 300 MW	Datang Power Group	➢	➢

Economy	Project Name	Location	Expected Commissioning Date	Greenfield or Brownfield	Capacity (No. units x MW)	Project owner	$deNO_x$	FGD
China	**Henan Xingxiang Thermal Power Plant**	Xingxiang City, Henan Province	2013	brownfield	2 x 300 MW	Henan Mongdian Group	➨	➨
China	**Tianjing Junliancheng Thermal Power Plant Phase 5 expansion**	Tianjing City	2013	brownfield	2 x 300 MW	Huadian Group	➨	➨
China	**Shandong Huaneng Baiyanghe Thermal Power Plant**	Baiyanghe City, Shandong Province	2013	brownfield	2 x 300 MW	Huaneng Group	➨	➨
China	**Hubei Hudian Huangshi Thermal Power Plant**	Huangshi City, Hubei Province	2013	brownfield	1 x 300 MW	Huadian Group	➨	➨
China	**Shenyang Jingshan Thermal Power Plant**	Shenyang City, Liaoning Province	2013	brownfield	2 x 200 MW	Shenyang Energy Co.	➨	➨
China	**Sichuan Yibin Thermal Power Plant Expansion**	Yibin City, Sichuan Province	2013	brownfield	1 x 150 MW		➨	➨
China	**Guodian Baoji Second Power plant expansion**	Baoji City, Shaanxi Province	2010	brownfield	2 x 660 MW	China Guodian Group	➨	➨
China	**Guodian Jianbi Power Plant**	Jinabi Town, Zhenjiang City, Jiangsu Province	2014	brownfield	1 x 1000 MW	Guodian Group		
China	**Guohua Suizhong Power Plant phase 2**	Suizhong City, Liaoning Province	2013	brownfield	2 x 1000 MW	China Guohua Power Co.		➨
China	**Anhui Wuhu Power Plant phase 5**	Wuhu City, Anhui Province	2013	brownfield	1 x 600 MW	Hudian Group		➨
China	**Zhejiang Datang Wushashan Power Plant Phase 2**	Ningbo City, Zhejiang Province	2013	brownfield	2 x 1000 MW	Datang Power Group		➨
China	**Guangdong Shajiao A Power Plant Phase 3**	Dongguan City, Guangdong Province	2013	brownfield	2 x 1000 MW	Guangdong Yuedian Group		➨
China	**Guangdong Zhuhai Power Plant Phase 2 units 5 & 6**	Zhuhai City, Guangdong Province	2010	brownfield	2 x 1000 MW	Guangdong Yuedian Group		➨
China	**Wuhan Huaneng Yangluo Power Plant Phase 4 expansion**	Wuhan City, Hubei Province	2010	brownfield	2 x 1000 MW	Huaneng Group		➨
China	**Guodian Huangjingben Power Plant Phase 2**	Shangrao City, Jiangxi Province	2014	brownfield	2 x 600 MW	Guodian Group		➨

Economy	Project Name	Location	Expected Commissioning Date	Greenfield or Brownfield	Capacity (No. units x MW)	Project owner	deNO$_x$	FGD
China	**Fujian Zhangzhou Houshi Power Plant Unit 7 expansion**	Zhangzhou City, Fujian Province	2013	brownfield	1 x 600 MW	Taiwan Taisu Group		➽
China	**Huaneng Yiming Power Plant Phase 3**	Yiming City, Inner Mongolia	2013	brownfield	2 x 600 MW	Huaneng Group		➽
China	**Huadian Xisaishan Power Plant Phase 2**	Huangshi City, Hubei Province	2013	brownfield	2 x 600 MW	Huadian Group		➽
China	**Henan Yuzhou Power Plant phase 2**	Yuzhou City, Henan Province	2012	brownfield	2 x 660 MW	China Datang Group owns 60%		
China	**Anhui Fengtai Power Plant Phase 2**	Huainan City, Anhui Province	2010	brownfield	2 x 660 MW	Huaizhe Coal and Power Co.	➽	
China	**Shanxi Gujiao Power Plant Phase 2**	Gujiao City, Shanxi Province	2010	brownfield	2 x 600 MW	Shanxi Xingneng Power Generation Co.		➽
China	**Inner Mongolia Shangdu Power Plant Phase 3**	Shangdu county, Inner Mongolia	2010	brownfield	2 x 660 MW	Inner Mongolia Shangdu Generation Co.		➽
China	**Guodian Zhijing Power Plant Phase 1**	Zhijing county, Guizhou Province	2010	greenfield	2 x 600 MW	Guodian Group		
China	**Guodian Huozhou Power Plant**	Lingfen City, Shanxi Province	2010	brownfield	2 x 600 MW	Gudian Group		
China	**Shanxi Zhaoguang Power Plant Phase 3**	Huozhou City, Shangxi Province	2010	brownfield	2 x 600 MW	Shangxi Zhaoguang Power Generation Co.		
China	**Xingjiang Fukang Power Plant Phase 2**	Fukang City, Xinjiang Autonomous Region	2014	brownfield	2 x 300 MW	Xingjiang Fukang Energy Development Co.		➽
China	**Huadian Mudanjiang Second Thermal Power Plant**	Mudanjiang City, Helongjiang Province	2013	brownfield	2 x 300 MW	Huadian Group		➽
China	**Xingjiang Guodian Hongyanshi Thermal Power Plant**	Wulumuqi City, Xingjiang Autonomous region	2013	brownfield	2 x 300 MW	Guodian Group		➽

Economy	Project Name	Location	Expected Commissioning Date	Greenfield or Brownfield	Capacity (No. units x MW)	Project owner	deNO$_x$	FGD
China	**Datong Yungan Thermal Power Plant Phase 2**	Datong City, Shanxi Province	2013	brownfield	2 x 300 MW	Datang Power Group		➼
China	**Xingxiang Yuxing Thermal Power Plant**	Xingxiang City, Henan Province	2013	brownfield	2 x 300 MW	Xingxiang Yuxing Power Co.		➼
China	**Shandong Shihen Thermal Power Plant Phase 3**	Shihen City, Shandong Province	2013	brownfield	2 x 300 MW	Guodian Group		➼
China	**Inner Mongolia Baotou No2 Thermal Power Plant expansion**	Baotou City, Inner Mongolia	2013	brownfield	2 x 300 MW	Huadian Group		➼
China	**Jilin Datang Liaoyuan Thermal Power Plant Expansion**	Liaoyuan City, Jilin Province	2013	brownfield	2 x 300 MW	Datang Power Group		➼
China	**Inner Mongolia Tuoketuo Power Plant Phase 4**	Tuoketuo City, Inner Mongolia	2013	brownfield	2 x 600 MW	Datang Power Group		➼
China	**Guodian Dazhou Wanyuan Power Plant Expansion**	Dazhou City, Sichuan Province	2013	brownfield	1 x 300 MW	Guodian Group		➼
China	**Jianshu Huaiyin Thermal Power Plant**	Huaiyin City, Jianshu Province	2013	brownfield	1 x 300 MW	Huaneng Group		➼
China	**Datang Xingyan Huayu Power Plant Phase 2**	Xingyang City, Henan Province	2013	brownfield	2 x 600 MW	Datang Power Group		➼
China	**Xingjiang Huadian Weihuliang Thermal Power Plant Phase 3**	Wulumuqi City, Xingjiang Autonomous region	2013	brownfield	2 x 300 MW	Huadian Group		➼
China	**Datang Xingyang Huayu Power Plant Phase 2**	Xingyang City, Henan Province	2013	brownfield	2 x 600 MW	Datang Power Group		➼
China	**Zhoushan Power Plant Phase 2**	Zhoushan city, Zhejiang Province	2010	brownfield	1 x 300 MW	Zhou Shan Power Company		➼
China	**Guangdong Yunfu Power Plant phase 3**	Yunfu City in Guangdong Province	2010	brownfield	2 x 300 MW			

Economy	Project Name	Location	Expected Commissioning Date	Greenfield or Brownfield	Capacity (No. units x MW)	Project owner	deNO$_x$	FGD
China	**Yongchang Power Plant Expansion projects**	Hexibao Town in Yongchang County, Gansu Province	2014	brownfield	2 x 300 MW			➽
China	**Guizhou Dalong Power Plant Expansion**	Dalong County, Guizhou Province	2013	brownfield	2 x 300 MW	Huadian Group		➽
China	**Heilongjian Hudian Jiamusi combined heat and power plant**	Jiamusi City, Heilongjiang Province	2013	brownfield	2x300 MW	Huadian Group		➽
China	**Guangdong Shaoguan Power Plant Expension**	Shaoguan City, Guangdong Province	2013	brownfield	4 x 600 MW	Guangdong Yuedian Group		
China	**Guohua Xuzhou power plant**	Xuzhou City, Jiangsu Province	2010	brownfield	2 x 1000 MW	Guohua Group		
				46			40	91

Economy	Project Name	Location	Expected Commissioning Date	Greenfield or Brownfield	Capacity (No. units x MW)	Project owner	deNOx	FGD
Indonesia	**Central Java IPP**	Central Java	2014	greenfield	2000 MW	PLN		➼
Indonesia	**Sumbar Power**				2 x 100 MW			
Indonesia	**Cilapap, Central Java**	Cilapap, Central Java	2013	greenfield	660 MW	China National Technical Import and Export Corp		
Indonesia	**The Jambi Project**	Jambi	2014	greenfield	500 MW	EGAT International and Intermining and Energy	➼	➼
Thailand	**Map TA Phut**	Rayong Province of Thailand	2007	greenfield	2 x 717 MW	BLCP, build, own and operate		
Thailand	**Map TA Phut**	Rayong Province of Thailand	2011	unspecified	660 MW	Gheco-One		
Thailand	**Surat Thani Biomass Project**	Surat Thani Province of Thailang	2008	greenfield	8.9 MW	Surat Thani Green Energy Co.		
Thailand	**Hin Krut/ Bo Nok**	Prachuap Khiri Khan	On hold Anti coal activists & locals	unspecified	2100 MW	EGAT		
Thailand	**Bang Pakong Combined Cycle Power Plant**	Bank Pakong Area, Bangkok	2009	brownfield	2 x 700 MW	Marubeni		
Thailand	**Biomass Power Project**	304 Industrial Park in Prachinburi Province	2014	greenfield	1 x 125 MW	Private Sector Operations Development		
Laos/ Thailand	**Hongsa Project**	Northern Laos	2015	unspecified	1800 MW	EGAT/Banpu		

Economy	Project Name	Location	Expected Commissioning Date	Greenfield or Brownfield	Capacity (No. units x MW)	Project owner	deNOx	FGD
Vietnam	**Kien Luong 1**	Hon Lon Island in Nam Du archipelago	2013 - 2014	greenfield	2 x 600 MW	ITA for MIT		
Vietnam	**Kien Luong 2**		2015 - 2016		1200 - 2000 MW	Tan Tao Energy Joint Stock Company		
Vietnam	**Long Phu Power Center**	Mekong Delta	2013	greenfield	2 x 600 MW ph. 1 & 2 and 2 x 1000 MW ph. 3	The National Oil and Gas Group (Petrol Vietnam) and Soc Trang Province's municipal government		
Vietnam	**Can Tho Gas Fired Power Plant**	Can Tho and Ca Mau Provinces in the Cuu Long (Mekong) Delta	2014	greenfield		Chevron		
Vietnam	**Bac Giang Thermo Power Plant**	Bac Giang Province, Yen Dung District	2014	greenfield	2 x 300 MW			
Vietnam	**Long An Thermo Power Plant**	Long An, Southern Provence	2014	greenfield	2 x 600 MW			
Vietnam	**Omon Thermal Power Plant Unit 2**	Mekong Delta	2010	brownfield	1 x 300 MW	TEPSCO and Vietnam Electricity (EVN)		
Vietnam	**Extension Ninh Binh Thermal Power Plant**	Ninh Binh, North Vietnam		brownfield	1 x 300 MW	EVN		
Vietnam	**Nhon Trach Thermal Power Plant**	Nhon Trach Industrial Zone	2013	greenfield		EVN (Lilama is also involved with contracts)		

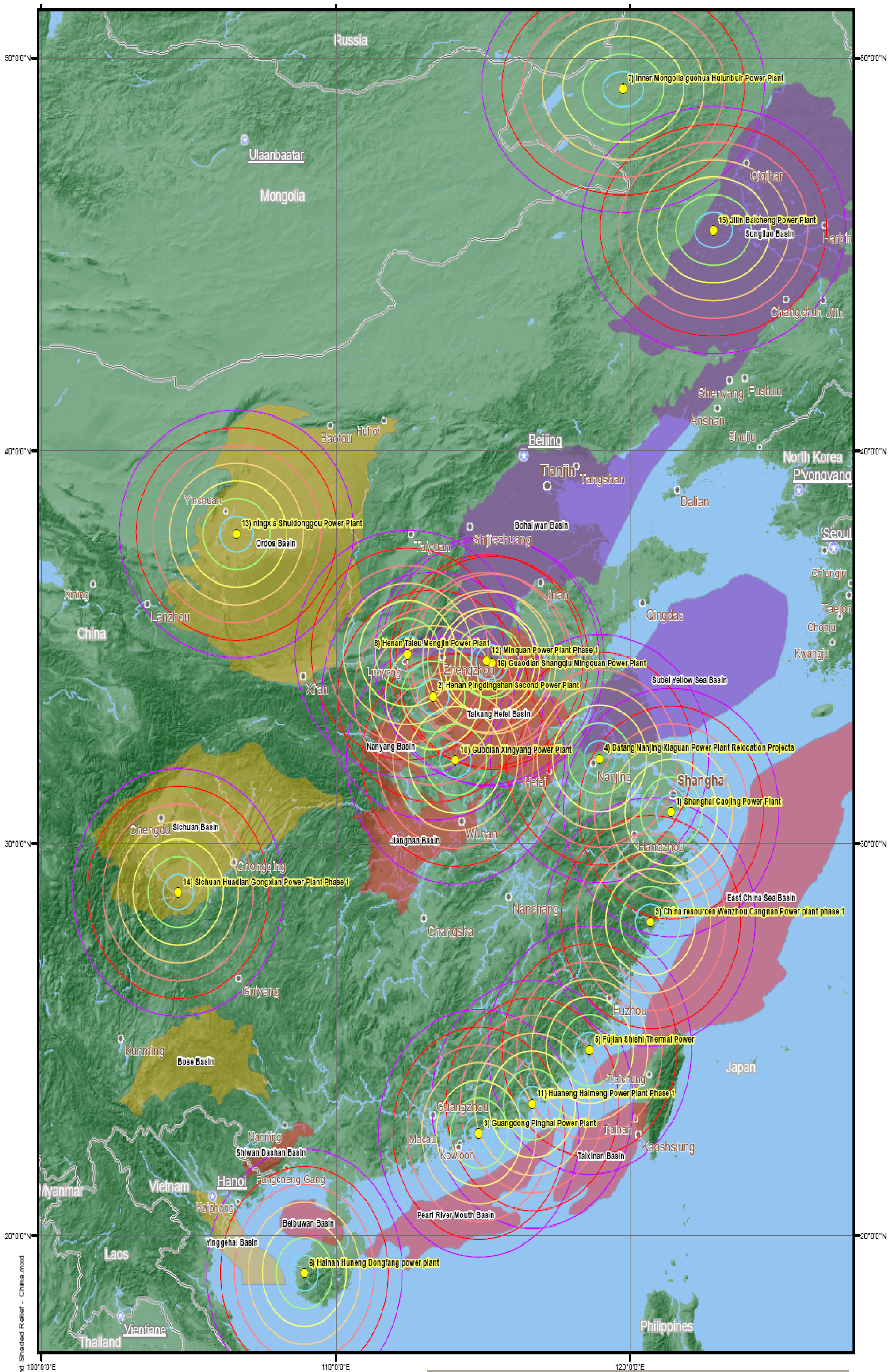
Economy	Project Name	Location	Expected Commissioning Date	Greenfield or Brownfield	Capacity (No. units x MW)	Project owner	deNOx	FGD
Vietnam	**Nghi Son Thermal Power Plant**	Nghe An Province, Northern Vietnam	2014	brownfield	600 MW	EVN		
Vietnam	**Hai Duong Thermo Power Plant**	Hai Duong Province, Kinh Mon District	2014	greenfield	2 x 600 MW	JAKS Resources Berhad		
Vietnam	**Vinh Tan 3**	Vinh Tan Province	2014	greenfield	3 x 660 MW	V Tec (consortium of national and international companies)	➨	➨
Vietnam	**Nghi Son 2**	Nghi Son, Thanh Hoa Province	2013	brownfield	2 x 600 MW	EVN		
Philippines	**Redondo Peninsula Energy Project**	Subic Bay	2014	unspecified	300 MW	JV Aboitiz Power & Taiwan Cogeneration		
Philippines	**Kamanga Project**	Mindanao	2014	unspecified	200 MW ph.1 2 x 350 MW ph.2	Conal Holdings		
Philippines			2014	unspecified		MG Mining and Energy Corp.		
Malaysia	**SEO Biomass Steam and Power Plant**							
Malaysia	**Sabal State Power Project**	East Malaysia's Sabal State	2012	unspecified	1 x 233 MW	China National Electric Equipment Corporation (CNEEC)		
Malaysia	**Sabah Power Plant Project**	Sabah	2014	unspecified	1 x 300 MW	Alstom Asia Pacific		

Economy	Project Name	Location	Expected Commissioning Date	Greenfield or Brownfield	Capacity (No. units x MW)	Project owner	deNO$_x$	FGD
Papua New Guinea	**Ramu Nickel Mine Project**	Madang Region	2009	greenfield	1 x 90 MW	China ENFI Engineering Corporation		
Papua New Guinea	**Nickel Refinery Project**	Madang Region	2009	greenfield	1 x 90 MW	China ENFI Engineering Corporation		
				16			2	3

Appendix B

Candidate Capture-ready Case Study Plants in China

Appendix B



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Created by: R.B 20/07/2009

Legend

- Proposed Power Plants
- Sedimentary Basins
- Prospectivity
  - High
  - Intermediate
  - Low

Distance (Km): 50, 100, 150, 200, 250, 300, 350

Proposed Power Plant	Nearest Basin Name	Prospectivity	Distance (Km)
15) Jilin Baicheng Power Plant	Songliao Basin	High	0
7) Inner Mongolia quohua Hulunbuir Power Plant	Songliao Basin	High	315
8) Henan Taisu Mengjin Power Plant	Bohai wan Basin	High	0
4) Datang Nanjing Xiaquan Power Plant Relocation Projects	Subei Yellow Sea Basin	High	25
1) Shanghai Caojing Power Plant	Subei Yellow Sea Basin	High	210
2) Henan Pingdingshan Second Power Plant	Taikang Hefei Basin	Intermediate	0
10) Guodian Xingyang Power Plant	Taikang Hefei Basin	Intermediate	2
16) Guaodian Shangqiu Mingquan Power Plant	Taikang Hefei Basin	Intermediate	0
12) Minquan Power Plant Phase 1	Taikang Hefei Basin	Intermediate	0
13) ningxia Shuidonggou Power Plant	Ordos Basin	Low	0
9) China resources Wenzhou Cangnan Power plant phase 1	East China Sea Basin	Intermediate	120
5) Fujian Shishi Thermal Power	East China Sea Basin	Intermediate	55
6) Hainan Huneng Dongfang power plant	Yinggehai Basin	Low	74
3) Guangdong Pinghai Power Plant	Pearl River Mouth Basin	Intermediate	120
11) Huaneng Haimeng Power Plant Phase 1	Pearl River Mouth Basin	Intermediate	80
14) Sichuan Huadian Gongxian Power Plant Phase 1	Sichuan Basin	Low	0

A3 scale: 1:12,000,000

Date: 20/07/2009 Version: 0

Projection: WGS 84

China Overview

Distances between Proposed Power Plants and Sedimentary Basin

Appendix C

IEA Capture-ready Plant Modifications

Essential Capture-ready Plant Features (IEA, 2007)

Essential Features	

Plant Location	• Proximity to CO_2 storage location or CO_2 user
	• Proximity to other CO_2 sources (to enable future sharing of pipeline facilities)
	• Consideration given to other location factors:
	  • CO_2 pipeline routes
	  • Health and safety issues associated with CO_2 transportation
	  • Health and safety issues associated with amine handling

Space Requirements	Space is required for: • CO_2 capture equipment • Routing of flue gas via duct from ID fan to CO_2 scrubber • Steam turbine island additions and modifications, such as space for routing LP steam to amine regeneration unit. • Extension and addition of balance of plant systems to cater for additional requirements of the capture equipment. • Additional vehicle movement (amine delivery etc) • Space allocation based on HAZOP study for safe handling of amines and CO_2
Boiler & Auxiliaries	No specific modification is required for the boiler plant. No specific modification is required for the combustion air system. Flue gas system: • Space for the addition of new duct work for interconnection of boiler flue gas system with the amine scrubbing plant. • Depending on specification of FGD equipment (if fitted), allowance may also have to be made for a FGD polisher and booster fan.
$deNO_x$	If $deNO_x$ equipment is not already fitted at the plant, allowance must be made for the later retrofit of either SCR or SNCR equipment. The required concentrations may also be achievable with the use of wet FGDs.
Particulate Removal	Amine scrubber typically have an inlet particulate limit of 5mg/Nm^3. Depending on the type of particulate collection and sulphur removal equipment, there are different essential requirements for capture-ready: • *Plants with ESP or bag filter, wet FGD and future direct contact type flue gas cooler*: The dust concentration in the outlet flue gas of a wet FGD would be expected to be in the region of 5 mg/Nm^3 @6% O2 v/v dry. Furthermore, the downstream direct contact type flue gas coolers (typically used with amine scrubbers) are also effective in removing dust from flue gas. Hence no essential capture-ready requirements are foreseen for PF power plants with such flue gas cleaning schemes. • *Plants with ESP or bag filter, dry FGD and future direct contact type flue gas cooler*: Dry FGDs do not contribute to particulate removal. However, the downstream direct contact type flue gas coolers are very effective in removing the dust from flue gas. Hence, no essential capture-ready requirements are foreseen for plants with such flue gas cleaning schemes. • *Plants with ESP or bag filter, dry FGD plant and other type of flue gas cooler*: With this arrangement, if the dust concentration in flue gas at flue gas cooler outlet is expected to be higher than 5 mg/Nm3 @ 6% O_2 v/v dry, space should be made available at the discharge side of the particulate removal equipment for later additional module installation such as additional ESP zones. • For plants with ESP, SO_3 injection and/or flue gas humidification upstream of the ESP will contribute to additional particulate removal. Hence, provisions in the ESP inlet duct for incorporating SO_3 injection or flue gas humidification in future may be considered.
FGD	SO_2 concentration limits in the flue gas of around 10 to 30 mg/Nm^3 (6% O_2 v/v dry) will be required to be achieved to avoid amine degradation. This requirement is very much lower than the emission levels imposed by current environmental regulations. Therefore sulphur removal measures that would be considered for a conventional plant to meet environmental regulations will not be adequate to meet the amine scrubber requirements. The available options and the essential capture-ready requirements are: • Selection of an appropriate FGD plant to deliver the required SO_2 removal efficiencies suitable for meeting amine scrubber requirements (such FGDs may require additional initial investment and lead to additional operating expenses compared to that of the other options discussed below). It should be noted that well proven FGD plants capable of reducing SO_x levels down to tens of mg/Nm3 are commercially available today. For PF power plants equipped with such FGD units, no essential capture-ready requirements are foreseen.

	• Selection of an FGD that is capable of being upgraded via mechanical or chemical enhancement (e.g. the addition of more spray banks or the use of dibasic acids respectively) to meet the SO_2 limit of an amine scrubber. To enable this, provision should be made in the initial installation to allow the FGD plant to be upgraded to meet the more stringent performance target. • Alternatively an additional polishing unit, in effect a secondary, smaller FGD scrubber, can be installed in future to meet the amine scrubber requirements. To accommodate this polishing unit along with the required duct work, sufficient space should be kept adjacent to the main FGD plant.
Turbo-Generator & Auxiliaries	Solvent regeneration requires significant amounts of heat, typically 110^{o}C to 120^{o}C. In most cases this is best supplies by withdrawing steam from the main steam cycle at the IP/LP crossover. • To enable extraction of steam for use in the amine reboiler, as an essential capture-ready feature, the IP/LP crossover pipe should have provisions to accommodate the required valves and tie-ins for connecting the extraction steam piping. Furthermore, the steam turbine building should have space previsions to route the large LP steam pipe. • After capture retrofit, the steam turbine LP section will see a major flow reduction due to the extraction of up to 50% of the steam flow. The steam turbine can be either operated to achieve the best condenser vacuum to maintain LP stage volumetric flow to its optimum point as far as possible.
Water – Steam – Condensate Cycle	In order to minimise the penalty from CO_2 capture, process opportunities to recover low grade heat from the capture equipment into the water-steam-condensate cycle will be available after the retrofit. To facilitate the heat recovery the follow should be considered: • Provisions in the water steam cycle enabling bypass of the required number of condensate feed water heaters. • Provisions for process integration with the amine scrubber plant.
Cooling Water System	The amine scrubber, flue gas cooler and CO_2 compression plant increase the overall power plant cooling duty. However no essential capture-ready requirement is foreseen, except for the space and provisions for tie-ins. With the reductions in LP steam flow rate the LP turbine can either be operated to achieve the best condenser vacuum to maintain LP stage volumetric flow to its optimum point as far as possible. The main turbine condenser cooling water demand for either case is discussed below: • Operating with the original design condenser pressure after the capture retrofit will allow reduction in cooling water mass flow rate to the condenser. • Operating with best achievable condenser pressure can be accomplished with either the original condenser design cooling water mass flow rate (with lower temperature rise across the condenser) or with reduced cooling water mass flow rate (lower reduction in cooling water flow compares to the previous case). In either case, the main condenser cooling water mass flow rate does not increase. Hence no modification for capture retrofit is required. The essential requirements are only to cater for the additional cooling load of the capture plant auxiliaries and these include: It is expected that using the surplus cooling water made available from the main turbine condenser the total cooling water mass flow rate can be maintain at a similar level. However more heat is being rejected to the system and therefore the cooling load will increase. To accommodate this the following essential requirements are foreseen: • *For PF power plants with closed cycle cooling water system with cooling towers*. Space to add cooling towers or cooling tower modules and provisions to tie-in with the already installed cooling water system network • *For PF power plants with once through fresh water cooling system*. If the plant total cooling water mass flow rate is maintained at the same level prior to and after the capture retrofit, the discharge temperature of the cooling water will increase. If local regulation permits discharge at a slightly high temperature then no essential capture-ready requirement is foreseen. Should an increase in the discharge cooling water temperature not be permitted then additional cooling capacity needs to be installed and space for this shall be considered. • *For power plants with once through sea water cooling system and closed loop fresh water auxiliary cooling water system*. Space shall be kept to add fresh water cooling towers or modules to cater for the increase in cooling water demand. This can be avoided if auxiliaries' cooling is carried out with sea water however the relevant discharge regulations as outlined above must be considered. For steam turbines operating with lower LP exhaust pressure compared to that of the

	original plant, no additional requirements are foreseen.
Balance of Plant	Compressed air system: • Space for addition of compressors and compressed air system components. • Sized of compressed air distribution headers to accommodate additional compressed air from newly added compressors and to handle distribution to additional consumers. Raw water pre-treatment system: • Space shall be considered in the raw water pre-treatment plant area to add additional raw water pre-treatment streams, as required. Demineralisation plant: • No essential capture-ready requirements are foreseen, as the demineralised water requirement is not expected to increase after the CO_2 capture retrofit. Waste Water treatment plant: • Amine scrubbing plant along with flue gas cooler and FGD Polishing unit (if required) will result in generation of additional effluents. This includes provision for the amine waste such as storage and transportation of site or treatment and recycling. Hence the waste water treatment plant should have space for expansion and provisions for integration with additional treatment systems. Electrical: • Space for additional unit auxiliary transformers (UAT). • Provisions in bus ducts to feed the UAT and for power distribution to auxiliaries. • Provisions in underground cable trenches and above ground cable trays to accommodate additional cables. • Space for extension of low-voltage (LV) and high-voltage (HV) switch gear to accommodate additional incomers, feeders and motor control centres (MCC). Chemical: • No essential capture-ready requirements are foreseen, as the water chemistry is not expected to increase after the CO_2 capture retrofit. Pipe racks: • Large LP steam pip between steam turbine and reboiler. • Reboiler condensate return piping between reboiler and LP heater area. • Water-steam-condensate piping between amine scrubbing plant reflux condensers and LP heaters areas. • Drain piping from the large LP steam pipe to reboiler, • Cooling water piping to flue gas cooler and CO_2 compressor inter cooler(s). To accommodate the additional pipe work space should be provided in the appropriate locations especially the steam turbine building. Control & Instrumentation: • Space and provisions for extension of control room. • Space and provisions in cable floor to accommodate control/signalling cables. Safety Systems: • Assessment to meet relevant regulations for handling and storage of amine solvents. • Assessment on health and safety issues related to CO_2 compression and high pressure CO_2 transportation. Fire Protection: • Extension of the fire hydrant network to cater to the capture equipment area is foreseen. This can be met by ensuring provisions are made to expand the fire hydrant network. Plant Infrastructure: • Space at appropriate zones to widen roads and add new roads. • Space to extend office buildings. • Space to extend spares building. • Consideration should also be give to the accessibility of the capture plant areas for vehicles or cranes.
Planning and Approvals	A study should be undertaken to ensure that all technical reason that would prevent installation and operation of CO_2 capture have been identified and eliminated.

Desirable Capture-ready Plant Features (IEA, 2007)

Desirable Features	

Boiler & Auxiliaries	Some possibilities exist for capture-ready pre-investment in the ACR PF boiler draught plant equipment:
	• *For PF power plant with deSO$_x$ plant (FGD) designed to cater for the future requirements, no capture-ready pre investment is foreseen.*
	• *For PF power plants with FGD designed to meet current SO$_x$ emission limits, no capture-ready pre investment is foreseen.* This is explained below:
	  ◦ If the original FGD plant design and construction allows mechanical or chemical enhancement in the future then the pressure drop plant is small. ID fans provided should be able to accommodate this additional load.
	  ◦ If the original FGD plant does not allow for mechanical or chemical enhancement then a polisher will be required. ID fans provided will not be able to accommodate the additional load. Pre-investment can be made by designing the ID fan considering these future requirements, either with spare capacity or with the provision to uprate the motor at the time of retrofit
	• *For new-build power plants without any deSO$_x$ measures:* As above, the ID fans installed with a conventional boiler will probably have insufficient margins to accommodate the FGD and associated duct work. Pre-investment can be made in designing the ID fans considering these future requirements.

deNO$_x$	Consideration of capture-ready pre investment in deNO$_x$ plant depend on the original plant NO$_x$ emissions: • *For plants incorporating post-combustion deNO$_x$ measures to limit NO$_x$ to EU LCPD limit of 200 mg/Nm^3 @ 6% O$_2$ v/v:* These levels of NOx emission are considered adequate to meet the amine scrubber requirements. • *For plants incorporating only in-furnace NO$_x$ control measures:* No capture-ready pre-investment is foreseen for plants having in-furnace deNO$_x$ control measures to limit NO$_x$ concentrations in flue gas to some 800 mg/Nm^3 @6% O$_2$ v/v. If concentrations exceed the 800 mg/Nm^3 @ 6% O$_2$ v/v then additional combustion controls will be required.
Particulate Removal Unit	Consideration of capture-ready pre investment in particulate removal depend on the original plant emissions: • *Plants with ESP or bag filter, wet FGD and future direct contact type flue gas cooler.* No capture-ready pre-investment is foreseen. • *Plants with ESG or bag filter, dry FGD and future direct contact type flue gas cooler.* No capture-ready pre-investment is foreseen. • *Plants with ESG or bag filter, dry FGD and another type of flue gas cooler.* With this arrangement, if the dust concentration at the flue gas cooler outlet is expected to be higher than 5 mg/Nm^3 @6% O$_2$ v/v dry, pre-investment can be made in providing the ESP of bag filter with empty modules for future incorporation of internals to meet the amine scrubber requirements.
FGD Unit	SO$_x$ concentrations limits in the flue gas of the order of 10 to 30 mg/Nm^3 @ 6% O$_2$ v/v dry will be required to prevent amine solvent degradation. This is lower that most current environmental regulations. Pre-investment can include: • Installation of FGD unit designed to meet the 10 to 30 mg/Nm^3 @ 6% O$_2$ v/v dry from initial start-up. This will impact plant efficient before the retrofit is carried out. • Previsions in the FGD unit for planned retrofits to meet the future SO$_x$ level limits.
Water – Steam – Condensate Cycle	During plant operation with post-combustion CO$_z$ capture, almost 50% of the steam is required for the amine scrubbing plant reboiler. This reduces the condensate flow from the condenser to almost 60% of the original flow. Typical condensate system arrangements will lead to pump operation at non-optimum conditions after the capture retrofit. To enable condensate pump to operate at optimum conditions before and after retrofit, pre-investment can be considered in using 3 x 60% condensate pump arrangement.
Cooling Water System	• *For PF power plants with closed cycle cooling water system*. No pre-investment is foreseen to be of value, as addition of a separate auxiliary cooling water network during retrofit is considered to be a more viable option.

	• *For PF power plants with once through fresh water cooling system*. If local regulations or permits do not allow for increase cooling water discharge temperature then pre-investments can be made to accommodate the addition estimated flow in the cooling water system. • *For power plants with once through sea water cooling system*. If local regulations or permits do not allow for increase cooling water discharge temperature then pre-investments can be made to accommodate the addition estimated flow in the cooling water supply and discharge network.
Balance of Plant	Compressed air system: • Sizing and selection of capture-ready plant's compressed air system including the future compressed air requirements. This may require a marginal increase in the capacity of the individual compressors, dryers and receivers. Raw water pre-treatment system: • To cater for the additional cooling water requirements by including estimated future additional cooling water requirements of the capture ready plant's raw water pre-treatment plant. • Increase storage capacity of raw water tank. • Raw water make-up selection and sizing including the future increase in demand. Waste Water treatment plant: As separate waste water treatment plant will be required to treat and safely dispose of the additional effluent from the capture plant no pre-investment is considered worthwhile. Electrical: • Design and construction of cable vaults and cable trenches including pull pits and over head cable trays to handle future cabling work. • Switchgear and Motor Control Centre (MCC) energising cable selection considering estimated additional auxiliary power consumption after capture retrofit (excluding power consumption by amine scrubber unit and CO_2compression plant, as auxiliary loads for these equipment are considered to be met with a dedicated and separate power supply system). Chemical: No pre-investment are foreseen as the water chemistry will not change. Consideration can be given however to the provision in the steam and water analysis system sampling network and panel for easy addition of these sampling points. Pipe racks: • Design of pipe rack structures to handle additional pip loads. • Provisions in pipe racks in the vicinity of the respective systems to accommodate additional piping. • Provisions in the steam turbine building to route larger LP steam piping. Control & Instrumentation: • Sizing the plant network (data highway) to handle future additional signals. • Design of the plant control system to include the estimated additional I/Os required in the future.
Steam Turbine Options: CO_2 Capture using Amine Solvents Regenerated at 110^{o}C to 120^{o}C	Option A: Throttles LP Turbine The IP/LP crossover pressure is set at the desired value for solvent regeneration and space is allowed for a valve downstream of the steam off-take. When capture is retrofitted and steam extracted, the LP inlet is throttled to keep the crossover pressure constant. While this method incurs throttling losses, any steam extraction flow can be accommodates, the losses are reduced if the steam requirements are lowered by improved solvents. Option B: Floating Pressure LP Turbine The initial IP/LP crossover pressure is such that when the predicted amount of steam is extracted for solvent regeneration, it falls to the required value. The IP cylinder must be capable of accommodating the reduced exit pressure and increased stage loadings with capture. This increases the various stress imposed on the turbine and this should be considered in designing the IP turbine. Option C: Clutched Turbine

	The IP/LP crossover pressure is set at the desired value for solvent regeneration and space is provided for a suitably-sized steam off take to be connected. The LP turbine cylinders are sized so that when one is taken out of service the steam flow no longer required exactly matches the requirements for solvent regeneration. The unwanted LOP turbine rotor could be removed and replaced with a lay-shaft or a clutch could be used, possibly with the generator placed between the LP turbine cylinders. These arrangements give the highest possible efficiency with capture, but only if different sized LP cylinders are acceptable and if the regeneration steam flow has been predicted accurately. Option D: Back-pressure Turbine Not a capture-ready option itself, it is possible that plant developers will consider adding a back-pressure unit to a power plant site when capture is retrofitted through provision of a new boiler. Such a unit would help to compensate for the capture energy penalty, by supplying some of the steam required for solvent regeneration and generating additional electricity. Capital cost would be reduced because of the lack of LP cylinders, the smaller alternator and more efficient steam extraction, both from the back pressure unit and, if appropriately designed, from the pre-existing units which would be operating closer to their initial design point. Pre-existing unit in the plant would probably still need to be made capture-ready, but the anticipated maximum extraction steam flow might be reduced.